UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K/A

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): October 1, 2021

Callon Petroleum Company
(Exact name of registrant as specified in its charter)

DE	001-14039	64-0844345
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(I.R.S. Employer Identification Number)**

One Briarlake Plaza
2000 W. Sam Houston Parkway S., Suite 2000
Houston, TX 77042
(Address of principal executive offices, including zip code)

(281) 589-5200
(Registrant's telephone number, including area code)

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

- ☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
- ☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
- ☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
- ☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, $0.01 par value	CPE	NYSE

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (17 CFR §240.12b-2).

☐ Emerging growth company

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

EXPLANATORY NOTE

As previously disclosed in its Current Report on Form 8-K, filed with the U.S. Securities and Exchange Commission on October 5, 2021 (the "Original Form 8-K"), Callon Petroleum Company ("Callon" or the "Company") and Callon Petroleum Operating Company ("CPOC"), Callon's wholly owned subsidiary, entered into purchase and sale agreements with Primexx Resource Development, LLC ("Primexx") and BPP Acquisition, LLC ("BPP"), for the purchase of certain producing oil and gas properties, undeveloped acreage and associated infrastructure assets in the Delaware Basin (collectively, the "Peak Acquisition").

On October 1, 2021, the Company and CPOC completed the Peak Acquisition for a preliminary purchase price of approximately (i) $362.2 million in cash and 6.42 million shares of Company common stock as total consideration for assets acquired from Primexx and (ii) $91.5 million in cash and 2.42 million shares of Company common stock as total consideration for assets acquired from BPP. The purchase and sale agreements with Primexx and BPP provide for customary adjustments to the purchase price based on an effective date of July 1, 2021.

This Current Report on Form 8-K/A amends and supplements the Original Form 8-K to provide the financial statements and information set forth in Item 9.01 hereto.

Item 9.01. Financial Statements and Exhibits

(a) Financial statements of business to be acquired.

The audited annual consolidated financial statements of Primexx Energy Partners, Ltd. and its subsidiaries, which comprise the consolidated balance sheets as of December 31, 2020 and 2019, and the related consolidated statements of operations, changes in partners' equity (deficit), and cash flows for the years then ended, and the related notes to the consolidated financial statements, are filed as Exhibit 99.1 hereto and incorporated by reference herein.

The unaudited quarterly consolidated financial statements of Primexx Energy Partners, Ltd. and its subsidiaries, which comprise the balance sheet as of September 30, 2021, the related consolidated statements of operations, changes in partners' equity (deficit), and cash flows for the nine-month periods ended September 30, 2021 and 2020, and the related notes to the consolidated financial statements, are filed as Exhibit 99.2 hereto and incorporated by reference herein.

The audited annual consolidated financial statements of BPP Energy Partners LLC and its subsidiaries, which comprise the consolidated balance sheets as of December 31, 2020 and 2019, and the related consolidated statements of operations, changes in members' equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements, are filed as Exhibit 99.3 hereto and incorporated by reference herein.

The unaudited quarterly consolidated financial statements of BPP Energy Partners LLC and its subsidiaries, which comprise the balance sheet as of September 30, 2021, the related consolidated statements of operations, changes in partners' equity (deficit), and cash flows for the nine-month periods ended September 30, 2021 and 2020, and the related notes to the consolidated financial statements, are filed as Exhibit 99.4 hereto and incorporated by reference herein.

(b) Pro forma financial information.

The unaudited pro forma condensed combined financial information of the Company, which comprise the balance sheet as of September 30, 2021, the related statements of operations for the year ended December 31, 2020 and nine-month period ended September 30, 2021, and the related notes to the pro forma condensed combined financial information, is filed as Exhibit 99.5 hereto and incorporated by reference herein.

(d) Exhibits.

Exhibit Number	Description
23.1	Consent of Deloitte & Touche LLP with respect to audited consolidated financial statements of Primexx Energy Partners, Ltd. and subsidiaries
23.2	Consent of Deloitte & Touche LLP with respect to audited consolidated financial statements of BPP Energy Partners LLC and subsidiaries
23.3	Consent of Netherland, Sewell & Associates, Inc.
99.1	Audited consolidated financial statements of Primexx Energy Partners, Ltd and subsidiaries as of and for the years ended December 31, 2020 and 2019.
99.2	Unaudited consolidated financial statements of Primexx Energy Partners, Ltd. and subsidiaries as of September 30, 2021 and for the nine-months ended September 30, 2021 and 2020.
99.3	Audited consolidated financial statements of BPP Energy Partners LLC and subsidiaries as of and for the years ended December 31, 2020 and 2019.
99.4	Unaudited consolidated financial statements of BPP Energy Partners LLC and subsidiaries as of September 30, 2021 and for the nine-months ended September 30, 2021 and 2020.
99.5	Unaudited pro forma condensed combined financial information of the Company as of September 30, 2021, and for the year ended December 31, 2020 and the nine months ended September 30, 2021.
99.6	Reserves report summary of Netherland, Sewell & Associates, Inc. with respect to PrimexxResource Development, LLC as of December 31, 2020.
99.7	Reserves report summary of Netherland, Sewell & Associates, Inc. with respect to PrimexxResource Development, LLC as of December 31, 2019.
99.8	Reserves report summary of Netherland, Sewell & Associates, Inc. with respect to BPPAcquisition LLC as of December 31, 2020.
99.9	Reserves report summary of Netherland, Sewell & Associates, Inc. with respect to BPPAcquisition LLC as of December 31, 2019.
104	Cover Page Interactive Data File - the cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Callon Petroleum Company
(Registrant)

November 19, 2021

/s/ Joseph C. Gatto, Jr.
Joseph C. Gatto, Jr.
President and Chief Executive Officer

Exhibit 23.1

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement Nos. 333-251490, 333-235634, and 333-230748 on Form S-3 and Registration Statement Nos. 333-239006 and 333-235635 on Form S-8 of Callon Petroleum Corporation of our report dated March 31, 2021, relating to the financial statements of Primexx Energy Partners, Ltd. included in this Current Report on Form 8-K dated November 19, 2021.

/s/ Deloitte & Touche LLP

Dallas, Texas
November 19, 2021

Exhibit 23.2

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement Nos. 333-251490, 333-235634, and 333-230748 on Form S-3 and Registration Statement Nos. 333-239006 and 333-235635 on Form S-8 of Callon Petroleum Corporation of our report dated March 31, 2021, relating to the financial statements of BPP Energy Partners LLC included in this Current Report on Form 8-K dated November 19, 2021.

/s/ Deloitte & Touche LLP

Dallas, Texas
November 19, 2021

Exhibit 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our reserves reports, dated October 26, 2021, and October 27, 2021, relating to the proved oil and gas reserves of Primexx Resource Development, LLC as of December 31, 2019, and December 31, 2020, respectively (the "Primexx Reports"), and of our reserves reports, dated October 26, 2021, and October 27, 2021, relating to the proved oil and gas reserves of BPP Acquisition LLC as of December 31, 2019, and December 31, 2020, respectively (the "BPP Reports" and, together with the Primexx Reports, our "Reports"), included in or made a part of this Current Report on Form 8-K/A of Callon Petroleum Company (the "Company") dated November 19, 2021, in accordance with the requirements of the Securities Act of 1933, as amended. We further consent to the incorporation by reference of our Reports and references to our firm in the Company's Registration Statements on Form S-3 (No. 333-251490, No. 333-235634, and No. 333-230748) and on Form S-8 (No. 333-239006 and No. 333-235635).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (Scott) Rees III, P.E.

C.H. (Scott) Rees III, P.E.

Chairman and Chief Executive Officer

Dallas, Texas
November 19, 2021

Exhibit 99.1

PRIMEXX ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED FINANCIAL STATEMENTS AND INDEPENDENT AUDITORS' REPORT

December 31, 2020 and 2019

CONTENTS

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of Primexx Energy Partners, Ltd.
Dallas, Texas

We have audited the accompanying consolidated financial statements of Primexx Energy Partners, Ltd. and its subsidiaries (the "Partnership"), which comprise the consolidated balance sheets as of December 31, 2020 and 2019, and the related consolidated statements of operations, changes in partners' equity (deficit), and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Partnership's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Primexx Energy Partners, Ltd. and its subsidiaries as of December 31, 2020 and 2019, and the results of their operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter Regarding Going Concern

The accompanying consolidated financial statements have been prepared assuming that the Partnership will continue as a going concern. As discussed in Note 1 to the consolidated financial statements, the Partnership does not have sufficient liquidity to repay the term loan with BPP Holdco LLC, a related party, maturing on November 10, 2021, and as a result has stated that substantial doubt exists about its ability to continue as a going concern. Management's evaluation of the events and conditions and management's plans regarding these matters are also described in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty. Our opinion is not modified with respect to this matter.

/s/ Deloitte & Touche LLP

March 31, 2021

PRIMEXX ENERGY PARTNERS, LTD. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31
(in thousands)

	2020	2019
Assets		
Current Assets		
Cash and cash equivalents	$7,253	$22,501
Trade accounts receivable	17,028	37,126
Accounts receivable - affiliate	1,350	10,849
Prepaids and other	415	520
Commodity derivatives	14,263	638
Total current assets	40,309	71,634
Property, plant and equipment, net:		
Oil and gas properties, full cost method of accounting	273,167	730,248
Other property and equipment, net ($0 and $1,463 attributable to a consolidated VIE)	90,953	97,259
Commodity derivatives	9,078	544
Loan origination cost, net	2,468	3,142
Prepaids and other	1,059	452
Total Assets	$417,034	$903,279
Liabilities, Preferred Units and Partners' Equity		
Current Liabilities		
Accounts payable	$1,629	$17,780
Oil and gas payable	17,421	27,543
Commodity derivatives	974	11,761
Other current liabilities	54,319	29,511
Current portion of deferred gain on oil gathering system	2,625	2,625
Current portion of long-term debt, net	129,994	129,948
Total current liabilities	206,962	219,168
Line of credit	87,500	138,000
Term loans, net	147,933	147,436
Deferred gain on oil gathering system	24,500	27,125
Commodity derivative	4,775	3,815
Other long-term liabilities	295	—
Asset retirement obligation	5,327	3,664
Deferred tax liability	46	133
Total Liabilities	477,338	539,341
Commitments and contingencies (Note 11)		
Redeemable Series B Preferred Units, net	518,562	451,003
Equity		
Partners' Equity (deficit)	(599,205)	(110,234)
Noncontrolling interest	20,339	23,169
Total (Deficit)	(578,866)	(87,065)
Total Liabilities, Preferred Units and Partners' Equity	$417,034	$903,279

The accompanying notes are an integral part of these consolidated financial statements.

PRIMEXX ENERGY PARTNERS, LTD. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31
(in thousands)

	2020	2019
Revenues		
Oil sales	$139,776	$200,419
Natural gas sales	10,627	8,942
Field service revenue	8,450	20,777
Gain (loss) on derivative instruments, net	93,256	(30,148)
Total revenues	252,109	199,990
Costs and expenses		
Lease operating expenses	41,988	24,800
Repairs	4,820	6,061
Production taxes	6,994	9,516
Transportation and marketing	1,868	1,005
Field service expenses	11,677	26,521
Depreciation, depletion and amortization	106,047	96,783
Impairment of oil and gas properties	457,502	—
General and administrative	7,477	7,027
Total operating expenses	638,373	171,713
(Loss) income from operations	(386,264)	28,277
Other income (expense)		
Gain on sale of saltwater disposal system	—	136,342
Other income	2,882	1,308
Interest expense	(40,138)	(46,500)
Total other income (expense)	(37,256)	91,150
(Loss) income before income taxes	(423,520)	119,427
Income tax (benefit) expense		
Texas margin tax expense	81	—
Deferred tax (benefit) expense	(87)	32
Total income tax (benefit) expense	(6)	32
Net (loss) income	(423,514)	119,395
Net loss (gain) attributable to noncontrolling interest	550	(48,079)
Series B preferred unit distribution	(66,148)	(57,923)
Net (loss) income attributable to other partners	($489,112)	$13,393

The accompanying notes are an integral part of these consolidated financial statements.

PRIMEXX ENERGY PARTNERS, LTD. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' EQUITY (DEFICIT)
(in thousands)

	General Partner	Series A Preferred	Common Units	Noncontrolling Interest	Total Equity
Balance, January 1, 2019	($76)	$37,344	($160,895)	$27,355	($96,272)
Series A Preferred Deemed Distribution	—	12,360	(12,360)	—	—
Sale of interest in SFS	—	—	—	8,759	8,759
Net gain attributable to noncontrolling interest	—	—	—	48,079	48,079
Distribution to noncontrolling interest by SFS	—	—	—	(61,024)	(61,024)
Net income attributable to other partners	—	6,280	7,113	—	13,393
Balance, December 31, 2019	($76)	$55,984	($166,142)	$23,169	($87,065)
Series A Preferred Deemed Distribution	—	12,360	(12,360)	—	—
Purchase of Pecos Property by SFS from noncontrolling interest	—	66	75	(2,280)	(2,139)
Net loss attributable to noncontrolling interest	—	—	—	(550)	(550)
Net loss attributable to other partners	—	(229,342)	(259,770)	—	(489,112)
Balance, December 31, 2020	($76)	($160,932)	($438,197)	$20,339	($578,866)

The accompanying notes are an integral part of these consolidated financial statements.

PRIMEXX ENERGY PARTNERS, LTD. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31
(in thousands)

	2020	2019
Cash flow from operating activities		
Net (loss) income	($423,514)	$119,395
Adjustments to reconcile net income to cash used in operating activities:		
Depreciation, depletion, and amortization	106,047	96,783
Impairment of oil and gas properties	457,502	—
Deferred loan cost amortization	1,826	2,471
Amortization of deferred gain on oil gathering system	(2,625)	(1,750)
Gain on sale of property - net	—	(135,900)
Accretion of discount on preferred unit issuance	1,411	1,409
Unrealized (gain) loss on derivative instruments	(31,985)	28,907
Deferred tax expense	(87)	32
Changes in operating assets and liabilities:		
Trade accounts receivable	20,098	(20,166)
Accounts receivable - affiliate	9,499	(5,240)
Prepaid and other assets	(722)	1,700
Accounts payable	(16,729)	(25,013)
Oil and gas payable	(10,122)	15,059
Accrued liabilities and other	10,913	(13,751)
Net cash provided by operating activities	121,512	63,936
Cash flow from investing activities		
Additions to oil and gas properties	(73,920)	(222,394)
Additions to other property	(9,592)	(49,529)
Proceeds from sale of property	—	380
Proceeds from sale of oil gathering system	—	31,500
Proceeds from sale of saltwater disposal system	—	185,000
Net cash used in investing activities	(83,512)	(55,043)
Cash flow from financing activities		
Proceeds from sale of interest in SFS	—	8,759
Distribution to minority interest owners made by SFS	—	(61,024)
Purchase of Pecos Property by SFS from noncontrolling interest	(2,139)	—
Proceeds from Term Loan	—	50,000
Proceeds from line of credit	44,000	162,000
Repayments of line of credit	(94,500)	(160,000)
Capitalized loan cost	(609)	(1,385)
Net cash used in financing activities	(53,248)	(1,650)
Net change in cash and cash equivalents	(15,248)	7,243
Cash and cash equivalents, beginning of period	22,501	15,258
Cash and cash equivalents, end of period	$7,253	$22,501
Supplemental cash disclosures:		
Property additions included in accrued liabilities	$14,767	$24,466
Cash paid for interest	$37,685	$43,757
Asset retirement obligations incurred, including revisions to estimates	$1,357	$2,850
Non cash settlement - capital lease liability	$—	$13,253
Non cash financing - Redeemable Series B Preferred Units	$66,148	$57,923

The accompanying notes are an integral part of these consolidated financial statements.

PRIMEXX ENERGY PARTNERS AND SUBSIDARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. ORGANIZATION

Primexx Energy Partners, Ltd. ("PEP"), a Texas Limited Partnership, was formed on July 1, 2000, and is engaged in the acquisition, development, production, exploration and sale of crude oil and natural gas properties located primarily in Reeves County Texas.

On July 1, 2016, PEP reorganized and obtained additional investment in the form of Redeemable Series B Preferred units through funds controlled by The Blackstone Group ("Blackstone"). In addition to this investment, Blackstone also obtained a 55% controlling interest in Primexx Energy Corporation ("PEC"), a Texas corporation, and the sole general partner of PEP.

Going Concern, Liquidity, and Management's Plan

The accompanying consolidated financial statements are prepared in accordance with generally accepted accounting principles applicable to a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business.

Management evaluates conditions and events that are relevant to the Partnership's ability to meet its obligations as they become due within one year after the date that the consolidated financial statements are issued. The Partnership has an unsecured term loan payable to BPP Holdco, LLC (a related party, see Notes 6 and 10) with an outstanding principal balance of $130.0 million which matures on November 10, 2021. Management has considered existing cash, availability under the reserves-based line of credit, along with projected future cash flows, and concluded that the Partnership will not have sufficient liquidity to repay the term loan at maturity. These conditions and events raise substantial doubt about the Partnership's ability to continue as a going concern.

In response to these conditions, management has been, and is currently, pursuing a refinancing of this loan through an amendment, extension or refinancing. However, because management's plans have not been finalized and are not within the Partnership's control, these plans cannot be considered probable of occurring as of March 31, 2021, the date the consolidated financial statements were available for issuance. As a result, the Partnership has concluded that management's plans do not alleviate substantial doubt about the Partnership's ability to continue as a going concern.

The consolidated financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts and classification of liabilities that might result from the outcome of this uncertainty.

Principles of Consolidation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. These financial statements include the accounts of Primexx Energy Partners, Ltd. and its subsidiaries: (i) Primexx Energy Finance, LLC (PEF), (ii) Primexx Resource Development, LLC (PRD), (iii) Primexx Operating Corporation (POC), (iv), and Saragosa Field Services, LLC (SFS) (collectively referred to as the Partnership). Intercompany transactions and balances have been eliminated in consolidation.

NOTE 1. ORGANIZATION - CONTINUED

Principles of Consolidation - continued

On July 11, 2018, the Partnership sold approximately 22% of its interest in SFS to a subsidiary of BPP Energy Partners LLC ("BPP"), an affiliated entity (see Note 3 and Note 10). On May 1, 2019 and July 2, 2019, the Partnership sold an additional 6.23% and 1.75%, respectively, of its interest in SFS to BPP. Total sold through the balance sheet date is 30%. Given the Partnership's majority interest and its control of the entity, SFS remains a consolidated entity with the minority shareholder's interest shown as noncontrolling interest in the consolidated financial statements.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets, and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates, and changes in these estimates are recorded when known.

Significant items subject to such estimates include proved reserves and related present value of future net revenues, the carrying value of oil and gas properties, derivative financial instruments, asset retirement obligations, and legal and environmental risks and exposures.

Cash and Cash Equivalents

The Partnership considers all liquid investments with original maturities of three months or less to be cash equivalents. At December 31, 2020 and 2019, the Partnership did not have any cash equivalents.

Trade Accounts Receivable

Substantially all the Partnership's receivables are within the oil and gas industry, primarily from purchasers of oil and gas and joint interest billings. Collectability is dependent upon the general economic conditions of the purchasers and the industry. The receivables are not collateralized.

The Partnership has had minimal bad debts; therefore, the Partnership has not recorded an allowance for doubtful accounts as of December 31, 2020 or 2019. Management considers the following factors when determining the collectability of specific accounts: credit worthiness, past transaction history, current economic industry trends, and changes in payment terms. If the financial condition of the Partnership's purchasers or working interest partners were to deteriorate, adversely affecting their ability to make payments, allowances would be necessary.

Oil and Gas Properties

The Partnership applies the full cost method of accounting for oil and gas properties. Accordingly, all costs incurred in the acquisition, exploration, and development of oil and gas properties are capitalized. Those costs include any internal costs that are directly related to development and exploration activities and capitalized interest associated with certain unproved oil and gas properties with ongoing development activities.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Oil and Gas Properties - continued

Costs associated with proved oil and gas properties are subject to the full cost ceiling limitation which generally limits unamortized capitalized costs to the discounted future net revenues from proved reserves, based on the average of the first day prices and operating cost of the previous twelve months. As a result of the Partnership's proved property impairment assessment as of December 31, 2020, the Partnership recorded a $457.5 million non-cash impairment charge to reduce the carrying value of its proved oil and gas properties, which is included in impairments of oil and gas properties in the statements of operations. There were no impairments of proved oil and gas properties for the year ended December 31, 2019.

Costs associated with unproved properties that have not been impaired and costs associated with uncompleted capital projects are excluded from the depletion base. As proved reserves are established, costs associated with unproved properties become part of our depletion base. We determine the amount of costs to transfer from unproved properties based on our estimate of the potential drilling locations and potential reserves associated with those properties. Costs associated with uncompleted capital projects are included in our depletion base upon completion of the related projects.

Unproved properties are assessed annually to ascertain whether impairment has occurred. The impairment assessment includes consideration of our intent to fully develop our unproved properties, remaining lease terms, geological and geophysical evaluations, our drilling results, potential drilling locations, availability of capital, assignment of proved reserves, expected divestitures, anticipated future capital expenditures and economic considerations, among others. During any period in which impairment is indicated, the accumulated cost associated with the impaired property are transferred to proved properties, become part of our depletion base, and become subject to the full cost ceiling limitation. Unproved properties totaled $0 and $2.8 million were moved to the amortization base due to lease expiration during the years ended December 31, 2020 and 2019, respectively.

Depreciation, depletion and amortization of proved oil and gas properties are computed on the units–of–production method, using estimates of the underlying proved reserves and costs expected to be incurred to develop our proved undeveloped reserves.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas, in which case the gain or loss is recognized in income.

Other Property and Equipment

Other property and equipment includes furniture and fixtures, computer equipment, software, transportation equipment, and field service equipment consisting of gas gathering, gas processing and water management facilities. Property and equipment are recorded at historical cost and depreciated using the straight-line method over their estimated useful lives ranging from 3 to 39 years.

The Partnership assesses the carrying amount of this equipment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the carrying amount exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized. There was no such impairment for the periods presented.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Prepaid and Other Assets

Prepaid and other assets at December 31 consist of the following:

	2020	2019
Inventory	$1,039	$212
Other	435	760
Total prepaid and other assets	$1,474	$972

Derivative Activity

The Partnership uses derivative financial instruments to reduce exposure to fluctuations in commodity prices. These transactions are in the form of crude oil and natural gas options and swaps.

The Partnership reports the fair value of derivatives on the consolidated balance sheets in commodity derivative assets or liabilities as either current or noncurrent. The Partnership determines the current and noncurrent classification based on the timing of expected future cash flows of the individual trades. The Partnership reports these on a gross basis by counterparty.

The Partnership's derivative instruments were not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized along with realized gains and losses in Gain (loss) on derivative instruments, net, in the consolidated statements of operations in the period of change.

Fair Value of Financial Instruments

Certain of our assets and liabilities are measured at fair value as of the reporting period. Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants. Fair value measurements are classified according to the following hierarchy that consists of three broad levels:

Level 1 inputs: Unadjusted quoted prices in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 inputs: Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability or inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 inputs: Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between level 1, level 2, and level 3 of the fair value hierarchy, if applicable, are made at the end of each reporting period.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Loan Origination Costs

Loan origination costs are amortized over the term of the related obligation using the effective interest method. Origination cost associated with our reserves-based line of credit are presented net of amortization within long-term assets. Origination cost associated with our term loans are net of amortization cost and are reported as an offset to the outstanding balance within long-term liabilities.

Other Accrued Liabilities

Other accrued liabilities at December 31 consist of the following:

	2020	2019
Accrued capital expenditures	$14,215	$14,268
Lease operating expenses payable	12,042	10,029
Liability for drilling costs prepaid by joint interest partners	21,927	1,098
Other	6,430	4,116
Total other accrued liabilities	$54,614	$29,511

Asset Retirement Obligations

The Partnership records a liability for asset retirement obligations and increases the carrying value of the related asset in the period in which the liability is incurred. Asset retirement obligations primarily relate to the abandonment of oil and natural gas producing facilities and include costs to dismantle and relocate or dispose of wells and related structures. Accretion expense associated with asset retirement obligations is recorded over time. Our asset retirement obligations are recorded in long- term liabilities within the consolidated balance sheets.

The following table shows the changes in the balances of the asset retirement as of December 31 (in thousands):

	2020	2019
Asset retirement obligation, January 1	$3,664	$575
Liabilities incurred	231	650
Liabilities sold	—	(49)
Liabilities settled	(281)	(1,379)
Changes in estimates	1,407	3,628
Accretion expense	306	239
Asset retirement obligation, December 31	$5,327	$3,664

Comprehensive Income

During the years ended December 31, 2020 and 2019, the Partnership did not have comprehensive income or loss. Accordingly, net income (loss) equals comprehensive income (loss) for the periods presented.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Revenue Recognition

The Partnership enters into contracts with customers to sell its oil and natural gas production. Revenue on these contracts is recognized in accordance with the five-step revenue recognition model. Specifically, revenue is recognized when the Partnership's performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights. Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration the Partnership expects to receive in accordance with the price specified in the contract. Consideration under the oil and natural gas marketing contracts is typically received from the purchaser one to two months after production. At December 31, 2020 and 2019, the Partnership had receivables related to contracts with customers of $12.8 million and $27.9 million, respectively.

Oil Contracts - The majority of the Partnership's oil marketing contracts transfer physical custody and title at or near the wellhead, which is generally when control of the oil has been transferred to the purchaser. Most of the oil produced is sold under contracts using market-based pricing which is then adjusted for differentials based upon delivery location and oil quality. To the extent the differentials are incurred after the transfer of control of the oil, the differentials are included in oil sales on the statements of operations as they represent part of the transaction price of the contract.

If the differentials, or other related costs, are incurred prior to the transfer of control of the oil, those costs are included in transportation and marketing on the Partnership's consolidated statements of operations as they represent payment for services performed outside of the contract with the customer.

Natural Gas Contracts - Most of the Partnership's natural gas is sold at the lease location or at the outlet of the compressor station owned by SFS, which is generally when control of the natural gas has been transferred to the purchaser. To the extent control of the natural gas transfers upstream of transportation and processing activities, revenue is recognized as the net amount received from the purchaser. To the extent that control transfers downstream of those activities, revenue is recognized on a gross basis, and the related costs are classified in transportation and marketing on the Partnership's consolidated statements of operations.

The Partnership does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient allowed for in GAAP. The expedient applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Concentration

The Partnership sold approximately 90% and 91% of its oil and natural gas production to two purchasers during the years ended December 31, 2020 and 2019, respectively.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Income Taxes

The Partnership is organized as limited partnerships except for POC, and federal income tax is assessed against the individual partners rather than against the partnerships. The Partnership evaluates the tax positions taken or expected to be taken in the course of preparing the Partnership's tax returns and disallows the recognition of tax positions not deemed to meet a "more-likely-than- not" threshold of being sustained by the applicable tax authority. The Partnership's management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold.

POC is a C-corporation for federal and state income tax purposes. As POC is wholly owned by the Partnership, the current and deferred income taxes related to POC are shown within the consolidated financial statements. We account for deferred tax assets and liabilities based on the difference between the financial book and tax basis of assets and liabilities using enacted rates expected to be in effect during the year in which the basis differences reverse.

The realizability of deferred tax assets are evaluated and a valuation allowance is established to reduce the deferred tax assets if it is more likely than not that the related tax benefits will not be realized and we are in a net deferred tax asset position related to each jurisdiction. All deferred items are classified in the long-term portion of assets or liabilities.

The Partnership's policy is to reflect interest and penalties related to uncertain tax positions as part of its income tax expense, when and if they become applicable. Tax positions taken related to the Partnership's pass-through status and those taken in determining their state income tax liability, including deductibility of expenses, have been reviewed and management is of the opinion that material positions taken by the Partnership would more likely than not be sustained by examination. Accordingly, the Partnerships has not recorded an income tax liability for uncertain tax positions. The Partnership's uncertain tax positions are subject to examination under Internal Revenue Service's general statutes for the year ended December 31, 2018 and thereafter.

New Accounting Pronouncements

In February 2016, FASB issued ASU 2016-02 – *Leases* (Topic 842), which requires the recognition of lease assets and lease liabilities by lessees for those leases currently classified as operating leases and makes certain changes to the accounting for lease expenses. This update is effective for fiscal years beginning after December 15, 2021, and for interim periods beginning the following year. ASC 842 should be applied using a modified retrospective approach. The Partnership is in the process of evaluating the impact of this new standard on its financial statements. The new guidance is expected to impact the Partnership's balance sheets due to the recognition of right-of-use assets and lease liabilities that are not currently recognized under current accounting standards. The standard does not apply to leases to explore for or use minerals, oil or gas resources.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

New Accounting Pronouncements - continued

In June 2016, the FASB issued ASU 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments" ("ASU 2016-13"). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires entities to use a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. This update is effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years, with early adoption permitted. Entities will use the modified retrospective approach to apply the standard's provisions and record a cumulative-effect adjustment to retained earnings for additional receivable loss allowances, if any, as of the beginning of the first reporting period in which the guidance is adopted. The Partnership is in the process of evaluating whether it will have a material impact on its consolidated financial statements.

NOTE 3. PROPERTY

Property consisted of the following as of December 31 (in thousands):

	2020	2019
Oil and gas properties:		
Proved oil and gas properties	$1,362,631	$1,272,991
Accumulated depreciation, depletion and amortization and impairment	(1,089,464)	(542,743)
Total net oil and gas properties	273,167	730,248
Other property and equipment:		
Office building attributable to VIE	—	1,472
Land attributable to VIE	—	123
Accumulated depreciation attributable to VIE	—	(132)
Total net property attributable to VIE	—	1,463
Office and equipment	4,013	3,942
Field service assets	131,872	120,032
Accumulated depreciation	(44,932)	(28,178)
Total net other property and equipment	90,953	95,796
Total other property and equipment, net	90,953	97,259
Total net property, plant and equipment	$364,120	$827,507
Supplemental Property Information:		
Depletion expense	$88,900	$76,162
Depreciation expense	$16,621	$20,382

Field Service Assets

SFS is a controlled subsidiary of the Partnership that owns the company’s field services assets in Reeves County which include gas gathering, water management and other oil field service assets.

NOTE 3. PROPERTY - CONTINUED

Acquisitions and Divestitures

On May 18, 2018, PRD and SFS entered into an agreement with Oryx Southern Delaware Holdings, LLC ("Oryx"). This agreement allowed for the construction of a gathering system to collect the Partnership's produced oil and provide firm marketing and shipping arrangements for the product. Further as a part of this agreement, SFS had the first right and option to purchase on or before December 31, 2019 all of the gathering system and all rights and interest in the crude oil gathering agreement between the Partnership and Oryx for the net present value of the construction cost plus six percent. Additionally, if the call was exercised, the Partnership had the ability to put the asset to Oryx or participate through tag-along rights in the event Oryx completed a sale of its assets.

On April 2, 2019, SFS received notice that Oryx had entered into a Purchase and Sale Agreement ("PSA") which constituted an exit event under the agreement. On April 18, 2019, SFS exercised both its call and put rights and settled the transaction with Oryx for a net amount of $31.5 million on May 22, 2019. The Partnership will remain the primary customer of the gathering system and, due to this continued involvement, the gain on this transaction is deferred as a liability and amortized over the life of the gathering agreement as other income. The $31.5 million earned from this transaction was distributed to PRD and BPP in proportion to their equity ownership.

On May 1 and July 2, 2019, the Partnership completed the sale of an additional 6.23% and 1.75% of its equity interest in SFS to BPP for a total sales price of $7.2 million and $1.5 million respectively. These transactions gave BPP their maximum ownership of 30% allowed under the sales agreement reached in 2018.

On December 16, 2019, SFS closed on the sale of its saltwater disposal handling assets to WaterBridge Texas Midstream, LLC ("WaterBridge") for a total price of $185 million in cash at the time of closing with additional incentives of up to $40 million over the subsequent four year period based annual water volumes produced by POC operated wells under a Water Management Services Agreement ("WMSA"). The agreement also gives WaterBridge the first right of refusal to purchase SFS's water recycling facilities at a future time. Simultaneous with closing this sale, the Partnership entered into a WMSA with a term of twenty years for POC's operating area. Upon the closing of this transaction, a distribution of $173.7 million was made to BPP and PRD based on their respective ownership.

Pecos Office Building

On September 9, 2020, SFS exercised its option on behalf of the Partnership to complete the purchase of an office building and land in Pecos, Texas (the "Pecos Property") from the Chairman of the Board of Directors (a common unit holder and previously the Partnership's Chief Executive Officer) for a total payment of $2.1 million. Prior to the purchase, the Partnership had a lease in place with the owner and utilized the office for field operations. The Pecos Property was previously accounted for as a variable interest entity ("VIE") and consolidated within the Partnership's financial statements because the property owner held the option to force a purchase of the property by the Partnership, and the Partnership had the option to force a sale of the property under certain circumstances. Given the related party nature of the transaction and the VIE guidance within GAAP, there is no step-up in basis of the Pecos Property and the excess cash paid over the book value is recorded as a reduction in the equity of SFS. As a result of the transaction, the entire purchase price is a reduction in equity and a financing cash outflow to acquire all of the equity interest in the previously consolidated VIE which is dissolved.

NOTE 4. DERIVATIVE INSTRUMENTS

The Partnership engages in price risk management activities. These activities are intended to manage the Partnership's exposure to fluctuations in commodity prices for crude oil and natural gas. The Partnership utilizes financial commodity derivative instruments, primarily price swaps and options.

Commodity derivatives are classified as Level 2 within the fair value hierarchy. The fair value of these instruments is estimated using forward-looking price curves and discounted cash flows that are observable or that can be corroborated by observable market data.

Natural gas and crude oil derivatives settle against the average of the prompt month NYMEX future prices for natural gas and West Texas Intermediate crude oil.

The fair values of commodity derivatives at December 31 were as follows (in thousands):

	2020	2019
Commodity derivative assets		
Current portion	$14,263	$638
Long-term portion	9,078	544
	23,341	1,182
Commodity derivative liabilities		
Current portion	974	11,761
Long-term portion	4,775	3,815
	5,749	15,576
Net commodity derivatives	$17,592	($14,394)

The following presents the results of the Partnership's oil and gas derivative activity included in revenue in the statements of operations during the periods ended December 31, 2020 and 2019:

	2020	2019
Realized gain (loss)		
Oil derivatives	$61,271	($1,606)
Natural gas derivatives	—	365
Total realized gain (loss)	$61,271	($1,241)
Unrealized gain (loss)		
Oil derivatives	$32,784	($28,541)
Natural gas derivatives	(799)	(366)
Total unrealized gain (loss)	$31,985	($28,907)
Gain (loss) on derivative instruments, net	$93,256	($30,148)

NOTE 4. DERIVATIVE INSTRUMENTS - CONTINUED

The Partnership had the following outstanding open crude oil and natural gas positions as of December 31, 2020:

	Expirations		
	2021	2022	2023
Oil Swaps:			
Notional volume (bbl)	2,585,600	1,167,200	—
Weighted average swap price	$53.44 $53.44	$50.68	$—
Oil Collars:			
Notional volume (bbl)	—	—	627,000
Weighted average put purchased	$—	$—	$40.00
Weighted average call sold	$—	$—	$48.38
Mid-Cush Differential (Basis) Swap:			
Notional volume (bbl)	2,585,600	1,167,200	353,700
Weighted average swap price	$0.93	$1.04	$0.30
Natural Gas Swaps:			
Notional volume (MMBTU)	2,799,000	1,539,100	270,100
Weighted average swap price	$2.54	$2.43	$2.59
Waha Differential (Basis) Swap:			
Notional volume (MMBTU)	3,072,600	1,539,100	270,100
Weighted average swap price	($0.26)	($0.26)	($0.26)

The Partnership had the following outstanding open crude oil and natural gas positions as of December 31, 2019:

	Expirations		
	2020	2021	2022
Oil Swaps:			
Notional volume (bbl)	3,480,373	2,048,000	879,000
Weighted average swap price	$56.35 $53.44	$53.42	$51.12
Mid-Cush Differential (Basis) Swap:			
Notional volume (bbl)	3,480,373	2,048,000	879,000
Weighted average swap price	($0.08)	$0.91	$1.00

NOTE 5. TAXES

POC is a C-corporation for federal and state tax purposes, as such, this entity files its own tax return under those requirements and the effect of its tax positions are reflected in the consolidated financial statements.

NOTE 6. LINE OF CREDIT AND TERM LOAN FACILITIES

Debt as of December 31 (in thousands):

	2020	2019
Reserves-based line of credit	$87,500	$138,000
Term loan - HPS	150,000	150,000
Term loan - Blackstone	130,000	130,000
Deferred loan cost - HPS, net	(2,067)	(2,564)
Deferred loan cost - Blackstone, net	(6)	(52)
	$365,427	$415,384

Reserves-based lines of credit

On July 7, 2015, PRD entered into a senior, first lien credit agreement with Société Générale ("SG"), as administrative agent for a syndicated group of participating banks (the "Bank Group"). The credit agreement provided for a $500 million senior secured revolving credit facility expiring July 7, 2019 (the "Credit Facility").

On November 16, 2018, the Partnership entered into a second amended and restated credit agreement with J.P. Morgan as the administrative agent, replacing Société Générale as the previous administrative agent, for a syndicated group of participating banks. The credit agreement provides for a $750 million senior secured revolving credit facility expiring November 16, 2023. Substantially all the Partnerships oil and gas assets are pledged as collateral and are included in consideration of the borrowing base which is set by J.P. Morgan as administrative agent and is scheduled for redetermination on March 1 and September 1 of each year. In addition, we may request a borrowing base redetermination up to two times per year based on certain factors. The borrowing base at December 31, 2020 is $185 million.

The Credit Facility contains certain financial covenants that must be met by PRD. A current ratio of 1.0 times or greater must be maintained at each quarter end. The calculation of the current ratio under the Credit Agreement dictates that the available, undrawn balance on the Credit Facility be added to current assets of PRD for debt compliance calculation purposes, among other adjustments (which calculation does not include the current assets of, or any accrued interest or current maturities of debt held at PRD's parent entities (PEF or PEP)). Further, the debt to EBITDA ratio for the trailing four-fiscal quarters must be no greater than 3.5 times.

The covenants also include certain customary restrictions on sales or encumbrances of assets, other advances, indebtedness, distributions and mergers or consolidations.

The Credit Facility also requires an annual audit certified by independent certified public accountants whose opinion shall not be materially qualified with a scope of audit or "going concern" explanatory paragraph or like qualification or exception unless such going concern exception is resulting from the occurrence of a pending maturity date of any indebtedness of PRD or its parent entities (PEF or PEP). As discussed in Note 1, the pending maturity of PEP's term loan payable to BPP Holdco, LLC, due November 10, 2021, is indebtedness held by the parent holding company, and as stated in Note 1, resulted in management's conclusion that substantial doubt exists regarding the Partnership's ability to continue as a going concern. Given that the emphasis of matter regarding going concern within the independent auditors' report associated with these financial statements is the result of this pending maturity, management concluded such matter does not result in an event of default.

NOTE 6. LINE OF CREDIT AND TERM LOAN FACILITIES - CONTINUED

Reserves-based lines of credit - continued

The applicable base rate is equal to the London Interbank Offered Rate ("LIBOR") plus a margin ranging from 2.5% to 3.5% based on the percentage of the borrowing base utilized. The Credit Facility carries a commitment fee of 50 basis points on the unused portion of the borrowing base.

Deferred loan costs of $2.5 million and $3.1 million (net of $4.1 million and $3.2 million in amortization) is recorded in long-term assets for the period ended December 31, 2020 and 2019, respectively.

At December 31, 2020, PRD had $0.3 million in outstanding letters of credit which are deducted from borrowing base availability along with the $87.5 million outstanding under the Credit Facility. The availability under the Credit Facility at December 31, 2020 was $97.2 million.

Term loan agreements

HPS Investment Partners Term Loan

On May 4, 2018, PEF entered into a $150 million delayed draw term loan with HPS Investment Partners ("HPS"). An amount of $50 million was funded (less discounts on issuance and related bank fees) upon closing with the remaining balance to be drawn within twelve months of the closing date with a maturity of May 4, 2024.

PEF completed additional draws of $50 million on October 1, 2018 and March 1, 2019 under this term loan for a total amount outstanding of $150 million.

The Notes Purchase Agreement contains various covenants pertaining to the financial condition of PEF. The covenants include as Asset Coverage Ratio of no less than 1.0 times beginning with the quarter ending December 31, 2018. The Asset Coverage Ratio increased to 1.50 times at December 31, 2019. For purposes of the covenant test, total debt is the debt at PEF of $150 million and the outstanding amount drawn on the revolver at PRD. The covenants also include certain restrictions on sales or encumbrances of assets, other advances, indebtedness, distributions and mergers or consolidations.

The Notes Purchase Agreement also requires an annual financial statement audit accompanied by a report and opinion of an independent registered public accounting firm, which report and opinion shall not be subject to a "going concern" explanatory paragraph or like qualification or exception other than a "going concern" qualification resulting from the occurrence of a pending maturity date of indebtedness of PEF or its parent company (PEP). As discussed in Note 1, the pending maturity of PEP's term loan payable to BPP Holdco, LLC, due November 10, 2021, is indebtedness held by the parent holding company, resulted in management's conclusion that substantial doubt exists regarding the Partnership's ability to continue as a going concern. Given that the emphasis of matter regarding going concern within the independent auditors' report associated with these financial statements is the result of this pending maturity, management concluded such matter does not result in an event of default.

Interest on this term loan is payable quarterly and is at a rate equal to the LIBOR plus 7.5%.

Deferred loan cost of $2.0 million and $2.5 million (net of $1.4 million and $0.8 million in amortization) is recorded as an offset to long-term debt for the year ended December 31, 2020 and 2019, respectively.

NOTE 6. LINE OF CREDIT AND TERM LOAN FACILITIES - CONTINUED

Term loan agreements - continued

HPS Investment Partners Term Loan - continued

As part of this credit facility, the Partnership created PEF as a subsidiary of PEP who is the borrower under this agreement.

Blackstone Term Loan

On July 16, 2016, in connection with the Blackstone recapitalization of the Partnership, the Partnership entered into an agreement with BPP Holdco LLC, the Series B Preferred Unit holder, for a term loan in the amount of $130 million, with an original maturity date of January 7, 2020. Proceeds from this second lien facility were used to retire a previous credit facility. Three limited partners of the Partnership have provided guarantees of collection totaling $52.5 million, including a limited partner of the Partnership controlled by the Partnership's Chairman of the Board, which has provided a guarantee of collection totaling $47.9 million.

On March 21, 2019, this agreement was amended to extend the maturity date of April 7, 2020.

On March 25, 2020, this agreement was amended to extend the maturity date to July 7, 2020 and to amend the requirement of an audit opinion that does not contain a going concern emphasis of matter paragraph to allow for any "going concern" qualification resulting from the occurrence of pending maturity date of the Partnership's indebtedness. Given that the emphasis of matter regarding going concern within the independent auditors' report associated with these financial statements is the result of this pending maturity, management concluded such matter does not result in an event of default.

On September 23, 2020, the agreement was amended to extend the maturity date to November 10, 2021.

Interest on this term loan is payable quarterly at an interest rate equal to LIBOR plus 12.0%, subject to a 1% floor.

The term loan agreement contains various covenants pertaining to the financial condition of the Partnership. The covenants include an Asset Coverage Ratio with respect to the relationship between total debt and proved reserves of no less than 1.50 times at December 31, 2019. For purposes of the covenant test, total debt is the debt at PEP of $130 million and PEF of $150 million as well as the outstanding amount drawn on the revolver at PRD.

Capitalized loan cost of $0 and $0.1 million (net of $4.3 million and $3.9 million in amortization) are presented as an offset to long-term debt for the year ended December 31, 2020 and 2019, respectively.

NOTE 7. REDEEMABLE SERIES B PREFERRED UNITS

On July 1, 2016, the Limited Partnership Agreement ("LPA") was amended and restated to allow for the issuance of up to 300,000 Series B Preferred Units with a par value of $1,000 each. The Series B Preferred Unitholders are entitled to receive a distribution of 13.5% compounded interest and payable quarterly on April 1, July 1, October 1, and December 31. The distribution is prior and in preference to any declaration or payment of distributions to Series A Preferred Unit holders and any other classes of equity in the Partnership. The distribution is generally to be paid in additional Series B Preferred Units. At the discretion of the Managing General Partner, however, the distribution may be paid in cash for up to 50% of the amount to be distributed.

NOTE 7. REDEEMABLE SERIES B PREFERRED UNITS - CONTINUED

The activity and balance of the Redeemable Series B Preferred Units are as follows (in thousands):

Balance as of January 1, 2019	**$391,671**
Accretion of discount on issuance	1,409
Interest earned	57,923
Balance as of December 31, 2019	**$451,003**
Accretion of discount on issuance	1,411
Interest earned	66,148
Balance as of December 31, 2020	**$518,562**

NOTE 8. PARTNERS' EQUITY

The limited partners' equity consists of two general classes: (1) Series A Preferred Units, and "Common Units," which are composed of several sub-classes described below.

The Common Units include the initial Class B founding limited partners and Class A limited partners admitted to the Partnership in 2001. In 2013, the Partnership amended and restated its LPA to provide for additional limited partner interests, including the Series A Preferred Units issued to Whittier, and three new sub-classes of Common Units (Class C, Class D, and Class E), made available for issuance as management incentive units. All issued Class C Units were redeemed or converted to Class B Units in February 2016. The Board issued and granted Class D Units to certain outside Board members, which remain issued and outstanding. There are no outstanding Class E Units.

In July 2016, in connection with the Blackstone financing, the Partnership amended and restated its LPA to provide for the Redeemable Series B Preferred Units (discussed in note 7) and their associated warrants (Class F Common Units), as well as a new class of management incentive units (Class G Common Units).

Under the Third Amended and Restated LPA Agreement, the following order of distributions will occur upon a liquidation event:

- First, to the Redeemable Series B Preferred Units until satisfied.
- Second, $100 million to the Legacy Unitholders, which consist of the Series A Preferred, Class A and Class B Common Unit holders in order of preference.
- Lastly, proceeds will be split 55% to the Series F Common Units (and Series G Common Units once certain thresholds are met) and 45% to the Legacy Unitholders.

The Series A Preferred Units are non-voting, perpetual limited partnership units, convertible to Class A-1 Common Units, and are entitled to a priority distribution of 8% per annum, cumulative and non- compounding with no current payment requirement. This payment is reflected as a reclass within the statement of changes in partners' equity as a deemed distribution. Series A Preferred Units were purchased on November 1, 2013, November 15, 2014, and July 1, 2015.

The amount of cumulative deemed distributions to Series A Preferred Units that have not been paid as of December 31, 2020, was $72.7 million; as a result, the Series A Preferred Unit holder's total investment in the Partnership, plus its deemed distribution, equals $227.2 million as of December 31, 2020.

NOTE 8. PARTNERS' EQUITY - CONTINUED

As previously noted, the Class F and Class G Common Units represent equity interests in the Partnership created in connection with the 2016 recapitalization. The Class F Common Units were issued to the holder of the Series B Preferred Unit holders and participate in profits once the Series B Preferred distributions have been satisfied and $100.0 million of distributions have been made to legacy unitholders. Accordingly, the value of these Class F Common Units at issuance was de minimis.

Class G Common Units are issued as management incentive units and are considered "profits interests" for tax purposes. The Class Common G Units receive distributions of partnership profits after certain hurdles are met with respect to the other Preferred and Common Units. Accordingly, the value of these Class G Common Units at issuance was also de minimis. The following table details the activity and number of Class G Common Units outstanding:

Units outstanding as of January 1, 2019	**79,559**
Units granted during 2019	7,621
Forfeitures	—
Units outstanding as of December 31, 2019	**87,180**
Units granted during 2020	—
Forfeitures	—
Units outstanding as of December 31, 2020	**87,180**

The following summarizes the limited partner units issued and outstanding as of December 31, 2020:

Partnership Class	Description	Units Outstanding
Preferred Limited Partners		
Series A Preferred	Non-voting, perpetual, 8% priority distribution, convertible to A-1 Common.	65,999
Series B Preferred	Non-voting, 13.5% cumulative and compounding quarterly. Distribution paid in additional Series B preferred units.	518,562
Common Limited Partners		
Class A	Voting, 9% compounded preferred return, subject to 25% reversion to Class B after an 19% internal rate of return (IRR).	6,667
Class A-1	Issued upon conversion by Series a preferred holder, voting, subject to 30% reversion to Class E after a 20% IRR.	—
Class B	Founders and management units, voting	108,929
Class C	Management profit participation units, voting. 10,000 units are authorized with 0 outstanding.	—
Class D	Director units, profit participation units contingent upon Series A Preferred conversion to Class A-1 Common	2,570
Class E	Management incentive profit participation units, holders of the 30% reversionary interest from Class A-1 Common. 10,000 units are authorized with 0 outstanding.	—
Class F	Participates in profits of the partnership once Series B Preferred Units are retired and certain other hurdles are met.	518,562
Class G	Management incentive profit participation units.	87,180

NOTE 9. MID-TERM INCENTIVE PLAN

In 2020, the Board of Directors established the Mid Term Incentive Plan ("MTIP") as an incentive program for the Partnership's directors, executives, and key employees. The program designates a pool of up to $15.0 million to be granted to employees and provide a cash award when the affiliated Primexx entities (Primexx Energy Partners, Ltd., BPP Energy Partners LLC, and Rock Ridge Royalty Company LLC) have a Liquidity Event. The award is to be split proportionately amongst the affiliated entities based on the cash amount received for each entity. The award vests in two tranches with 65% of the award vesting over a three-year period and 35% of the award is based on personal performance of the grantee as determined by the Board of Directors. The portion that is time vested will fully accelerate and vest upon the change of control of the entities subject to the grantee's continuous service and remaining in good standing with the Partnership through the date of the change in control.

Because the MTIP award is not considered a substantive class of equity, and only pays grantees upon a liquidity event of the entity, there is no expense recorded in the financial statements related to these awards. As of December 31, 2020, the total pool granted to employees under the MTIP was completely distributed.

NOTE 10. RELATED PARTY TRANSACTIONS

As stated in Note 3, the Partnership, through SFS purchased the Pecos Property from the Chairman of the Board for $2.1 million. Prior to the closing of that transaction, the Partnership had a triple net lease agreement for the use of the property as a field office. Lease payments totaling $0.1 million and $0.2 million were paid to the owner in 2020 and 2019, respectively.

The Partnership has an affiliate receivable balance due from PEC in the amount of $0.1 million and $0.1 million as of December 31, 2020 and 2019, respectively.

The Partnership's Blackstone Term Loan is payable to BPP Holdco LLC and the Whittier Trust, both Series B Preferred Unit holders. Additionally, as stated in Note 6, there is a personal guarantee of this note by an entity controlled by the Chairman of the Board. Interest paid related to this debt instrument was $17.6 million ($16.4 million to BPP Holdco and $1.2 million to the Whittier Trust) and $19.1 million ($17.8 million to BPP Holdco and $1.3 million to the Whittier Trust) for the years ended December 31, 2020 and 2019, respectively.

The Partnership entered into an agreement with EagleClaw Midstream ("EagleClaw") on October 1, 2017 to gather and market gas produced pursuant to a gathering and acreage dedication agreement. The Partnership received $15.8 million and $13.9 million in gross sales during the periods ending December 31, 2020 and 2019, respectively. The Partnership and EagleClaw have the same controlling shareholder, however, there is no common management or shared operations between the two entities outside of the gathering agreement described above.

NOTE 10. RELATED PARTY TRANSACTIONS - CONTINUED

BPP Energy Partners LLC

The Partnership has shareholders and management in common with BPP Energy Partners LLC ("BPP"), a company formed to acquire oil-and-gas leases and assets within PEP's operating area. In connection with the formation of BPP, the board approved a shared service agreement between the two companies so that all operations of BPP are conducted by POC and the cost of shared resources (including technology, office space and personnel) are reimbursed to POC by BPP at a rate of cost plus 2%. Additionally, BPP holds non-operated working interest in wells currently being drilled by PEP. Accordingly, PEP is responsible for distributing BPP's share of revenue and invoicing for the related share of capital and lease operating expenses in accordance with the ownership held by BPP.

On July 11, 2018, BPP purchased approximately 22% of SFS from PRD. An incremental 6.23% and 1.75% was purchased on May 1, 2019 and July 2, 2019, respectively. As of the balance sheet date, BPP has purchased 30% equity ownership in SFS (see details of this purchase in Note 3).

Below represents the balances and activity between BPP and POC (in thousands):

	2020	2019
BPP payable to POC	$1,610	$9,906
Revenue paid to BPP by POC	$50,240	$41,723
Capital and lease operating expenses paid to POC for joint interest billings	$43,241	$115,845
General and administrative expenses reimbursement to POC	$4,172	$3,239

BPP had $19.4 million and $0 of unapplied prepaid capital expenditures deposited with PRD and recorded in other current liabilities as of December 31, 2020 and 2019, respectively.

During the year ended December 31, 2019, the Partnership acquired a lease for 203 acres in the amount of $2.0 million (BPP cost basis) from BPP.

Rock Ridge Royalty Company LLC

The Partnership has shareholders and management in common with Rock Ridge Royalty Company LLC ("Rock Ridge"), a Delaware limited liability company formed in late 2016 to acquire and hold mineral and royalty interests in the Delaware Basin. Resources of the Partnership will be utilized in the management and operations of Rock Ridge. These resources include technology, office space and personnel employed by POC. The cost of these resources will be reimbursed by Rock Ridge based on the time allocated by employees to their work on Rock Ridge as well as actual costs incurred by POC and the Partnership. Further, PRD leases certain acreage blocks for future development from Rock Ridge. Lease bonuses are made based on a market analysis and at a price agreed to by the respective boards. As a result, PRD is an operator of certain Rock Ridge properties and pays Rock Ridge its respective royalty for hydrocarbons produced.

Below represents the balances and activity during the respective periods (in thousands):

	2020	2019
Rock Ridge payable to POC	$158	$345
Cash lease bonuses paid by PRD	$47	$—
Revenue paid to Rock Ridge by POC	$5,930	$3,738
General and administrative expenses reimbursement to POC	$2,487	$3,010

NOTE 10. RELATED PARTY TRANSACTIONS - CONTINUED

Jetta Permian L.P.

On May 8, 2020, POC entered into a comprehensive management services agreement ("MSA") with an effective date of June 1, 2020 to manage Jetta Permian, L.P. ("Jetta"), which has shareholders in common with the Partnership. Under this MSA, certain POC officers will serve as officers of Jetta and POC employees will operate and maintain all of Jetta's oil and gas properties, provide back office support and reporting requested by the board and required by Jetta's bank agreements. For these services, POC will receive a monthly fee of $30,000 plus an amount of $900 per operated well and a drilling overhead fee of $9,000 per well per month prorated for drilling days to be paid in the month when wells are drilled. All out-of-pocket expenses paid by POC will be reimbursed by Jetta.

As of December 31, 2020, Jetta has a payable due to POC in the amount of $0.1 million.

NOTE 11. COMMITMENTS AND CONTINGENCIES

The Partnership leases office facilities for its corporate office and field operations under non- cancellable operating leases. Expenses associated with these operating leases were approximately $0.8 million and $1.0 million for the years ended December 31, 2020 and 2019, respectively. Future minimum lease commitments under non-cancellable operating leases are as follows (in thousands):

2021	$1,738
2022	$1,018
2023	$845
2024	$600
Thereafter	$1,550

The Partnership's operations are subject to all the operational and environmental risks normally associated with the crude oil and natural gas industry. Additionally, the Partnership may become involved from time to time in litigation on various matters which are routine to the conduct of its business.

Current economic conditions may adversely affect the results of operations in future periods. The novel coronavirus ("COVID-19") pandemic significantly affected the global economy and created significant volatility in the financial markets. These events, in addition to disruptions in the demand for oil combined with pressures on the global supply-demand balance for oil, resulted in significant volatility in oil prices during 2020. The effects of the COVID-19 pandemic negatively impacted the Partnership's results of operations and led to a reduction in capital activities. The impact of these events on the financial performance of the Partnership's long-term operations is uncertain, including the duration of the COVID-19 pandemic and long-term effects on global oil demand. The financial statements have been prepared using values and information currently available to the Partnership.

NOTE 12. SUBSEQUENT EVENTS

On January 8, 2021, the Partnership and BPP Acquisition LLC, a subsidiary of BPP Energy Partners LLC, entered into an agreement with a third party to contribute oil and gas leases and certain properties to a joint development area comprising 960 gross acres effective February 26, 2021. At closing, the Partnership received total consideration of $2.5 million in exchange for interests in certain properties and future technical consulting services in the joint development area.

NOTE 12. SUBSEQUENT EVENTS - CONTINUED

Subsequent events have been evaluated through March 31, 2021, the date on which the consolidated financial statements were available to be issued.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Geographic Area of Operation

The Partnership's oil and natural gas reserves are located within the continental United States and concentrated in the Delaware Basin of Texas.

Capitalized Oil and Natural Gas Costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion and amortization are as follows (in thousands):

	December 31, 2020	December 31, 2019
Oil and gas properties		
Proved oil and gas properties	$1,362,631	$1,272,991
Accumulated depletion and impairment	(1,089,464)	(542,743)
Net oil and gas properties capitalized	$273,167	$730,248

Costs Incurred in Oil and Natural Gas Activities

Costs incurred in oil and natural gas property acquisition, exploration and development activities are as follows (in thousands):

	December 31, 2020	December 31, 2019
Acquisition costs		
Proved oil and gas properties	$14	$7
Unproved oil and gas properties	3,237	3,135
Development costs	88,801	249,001
Exploration costs	—	789
Total costs incurred	$92,052	$252,932

Results of Operations from Oil and Natural Gas Producing Activities

The following sets forth the revenues and expenses related to the production and sale of oil and natural gas (in thousands). It does not include any realized hedges, interest costs or general and administrative costs and, therefore, is not necessarily indicative of the net operating results of the Partnership's oil and natural gas operations.

	December 31, 2020	December 31, 2019
Oil and natural gas sales	$150,403	$213,106
Production costs	(55,670)	(41,382)
Depletion	(88,900)	(76,162)
Impairment of oil and gas properties	(457,502)	—
Results of operations from oil and natural gas producing activities	($451,669)	$95,562

The reserves as of December 31, 2020 and 2019 presented below were prepared by independent petroleum engineers. The calculation and analysis of interim changes in proved reserves were prepared by the Partnership. Estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. The reserves are located in the Delaware Basin of Texas.

The following tables set forth estimated net quantities of the Partnership's estimated proved reserves, projected future cash inflows, and future production and development costs and are prepared in accordance with guidelines established by the SEC. Accordingly, the reserve estimates are based upon existing economic and operating conditions. For estimates of proved reserves, the average spot prices are determined based upon the 12-month unweighted average of the first day of the month prices adjusted by applying price and cost basis differentials, including transportation and

quality, and are then applied to the period-end estimated quantities of oil, natural gas and natural gas liquids ("NGL") to be produced in the future. Future net cash flows are reduced to present value amounts by applying a ten percent annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by GAAP. These assumptions do not necessarily reflect management's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these reserve quantity estimates are the basis for the valuation process. Reserve estimates are inherently imprecise and estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and natural gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Analysis of Changes in Proved Reserves

The following table sets forth information regarding the Partnership's net ownership interest in estimated quantities of proved developed and undeveloped oil and natural gas quantities and the changes therein for each of the periods presented:

	Oil (MBbls)	**Natural Gas** (MMcf)	**NGLs** (MBbls)	**Total** (MBOE)
Balance, January 1, 2019	53,691	61,649	13,160	77,126
Revisions	(11,462)	(2,374)	(1,972)	(13,830)
Extensions	32,720	41,956	7,622	47,335
Divestitures of reserves	(29)	(33)	(8)	(42)
Production	(3,771)	(4,015)	(738)	(5,178)
Balance, December 31, 2019	71,149	97,183	18,064	105,411
Revisions	(26,722)	(26,490)	(5,010)	(36,147)
Extensions	14,225	23,402	4,324	22,449
Divestitures of reserves	(53)	(97)	(21)	(90)
Production	(3,789)	(5,669)	(1,019)	(5,753)
Balance, December 31, 2020	54,810	88,329	16,338	85,870

Proved developed and undeveloped reserves:	**Oil** (MBbls)	**Natural Gas** (MMcf)	**NGLs** (MBbls)	**Total** (MBOE)
Developed as of December 31, 2018	10,818	14,166	3,177	16,356
Undeveloped as of December 31, 2018	42,873	47,483	9,983	60,770
Balance at December 31, 2018	53,691	61,649	13,160	77,126
Developed as of December 31, 2019	16,616	24,717	4,529	25,265
Undeveloped as of December 31, 2019	54,533	72,466	13,535	80,146
Balance at December 31, 2019	71,149	97,183	18,064	105,411
Developed as of December 31, 2020	12,958	24,419	4,509	21,537
Undeveloped as of December 31, 2020	41,852	63,910	11,829	64,333
Balance at December 31, 2020	54,810	88,329	16,338	85,870

Revisions to previous estimates of proved reserves, either upward or downward, are a result of updated information obtained in the reporting period, including operator drilling activity and production history or changes in economic factors such as commodity prices, operating and development costs.

During the year ended December 31, 2020, the Partnership's extensions and discoveries of 22,449 MBOE resulted primarily from conversions of non-proved and contingent resources to proved due to drilling activity. The Partnership divested 2.3 net producing wells in Reeves County, Texas resulting in negative revisions of 90 MBOE. In addition, the Partnership negatively revised previous estimates by 36,147 MBOE due to the following:

- Downgrade of 25,280 MBOE of proved reserves to non-proved due to the decrease in drilling activity in 2020 resulting in development moving outside of the five-year development window,
- Negative revision of 6,252 MBOE due to downward movement in SEC pricing,
- Increase of 4,098 MBOE due to decreases in gas and NGL processing and basis differentials, and
- Negative revision of 8,713 MBOE attributed to downward revisions of estimated ultimate recovery, changes in operating and development costs, and adjustments to well spacing and development timing.

During the year ended December 31, 2019, the Partnership's extensions and discoveries of 47,335 MBOE resulted primarily from conversions of non-proved and contingent resources to proved due to drilling activity. The Partnership divested 2.0 net producing wells in Reeves County, Texas resulting in negative revisions of 42 MBOE. In addition, the Partnership negatively revised previous estimates by 13,830 MBOE due to the following:

- Removal of 91 MBOE due to plugging and abandonment of 6 wells,
- Negative revision of 1,826 MBOE due to downward movement in SEC pricing,
- Decrease of 4,008 MBOE due to increases in gas and NGL processing and basis differentials, and
- Negative revision of 7,905 MBOE attributed downward revisions of estimated ultimate recovery, changes in operating and development costs, and adjustments to well spacing and development timing.

Standardized Measure of Oil and Gas

The standardized measure and projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value to the Partnership. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary. Our calculations of the standardized measure of discounted future net cash flows and the related changes therein do not include the effect of estimated federal income tax expenses because federal income taxes associated with POC, a C-corporation for federal and state tax purposes and a subsidiary of the Partnership, are not material. All other subsidiaries of the Partnership are pass-through entities. The Partnership is subject to certain state-based taxes; however, these amounts are not material.

As of December 31, 2020, the reserves are comprised of 64% crude oil, 17% natural gas and 19% NGL on an energy equivalent basis.

The values for the December 31, 2020 and 2019 proved reserves were derived based on prices presented in the table below. Crude oil pricing was based on the West Texas Intermediate ("WTI") price; NGL pricing was 21% of WTI for 2020 and 33% of WTI for 2019; natural gas pricing was based on the Henry Hub price. All prices have been adjusted for transportation, quality and basis differentials.

	Oil ($/Bbl)	**Natural Gas** ($/Mcf)	**NGLs** ($/Bbl)
December 31, 2020 (Average)	36.18	-0.005	8.34
December 31, 2019 (Average)	46.51	-0.154	18.14

The following summary sets forth the future net cash flows related to proved oil and natural gas reserves based on the standardized measure prescribed in ASC Topic 932 (in thousands):

	December 31, 2020	December 31, 2019
Future oil and natural gas sales	$2,118,782	$3,621,804
Future production costs	(881,455)	(1,156,192)
Future development costs	(619,403)	(808,903)
Future net cash flows	617,924	1,656,709
10% annual discount	(329,785)	(823,308)
Standardized measure of discounted future net cash flows	$288,139	$833,401

The principal sources of change in the standardized measure of discounted future net cash flows are (in thousands):

	Year Ended December 31,	
	2020	2019
Standardized measure, beginning of year	$833,401	$794,839
Net change in prices and production costs	(179,308)	59,012
Changes in future development costs	382,499	262,594
Oil and gas sales, net of production costs	(94,733)	(171,724)
Extensions and discoveries	61,236	378,088
Divestitures of reserves	(222)	(431)
Revisions of previous quantity estimates	(226,579)	(154,147)
Development costs incurred during the period	35,167	127,944
Accretion of discount	83,340	79,484
Changes in timing and other	(606,662)	(542,258)
Standardized measure, end of year	$288,139	$833,401

Exhibit 99.2

PRIMEXX ENERGY PARTNERS, LTD.
AND SUBSIDIARIES

CONDENSED CONSOLIDATED
FINANCIAL STATEMENTS

As of and for the nine-month periods ended

September 30, 2021 and 2020

CONTENTS

PRIMEXX ENERGY PARTNERS, LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
UNAUDITED
(in thousands)

	September 30, 2021	December 31, 2020
Assets		
Current Assets		
Cash and cash equivalents	$11,724	$7,253
Trade accounts receivable	33,661	17,028
Accounts receivable - affiliate	6,993	1,350
Prepaids and other	1,442	415
Commodity derivatives	1,712	14,263
Total current assets	55,532	40,309
Property, plant and equipment, net:		
Oil and gas properties, full cost method of accounting	361,000	273,167
Other property and equipment, net	83,510	90,953
Commodity derivatives	6,161	9,078
Loan origination cost, net	1,870	2,468
Prepaids and other	1,136	1,059
Total Assets	$509,209	$417,034
Liabilities, Preferred Units and Partners' Equity		
Current Liabilities		
Accounts payable	$19,801	$1,629
Oil and gas payable	34,976	17,421
Commodity derivatives	39,477	974
Other current liabilities	40,632	54,319
Current portion of deferred revenue	2,797	2,625
Current portion of long-term debt, net	129,999	129,994
Total current liabilities	267,682	206,962
Line of credit	148,500	87,500
Term loans, net	148,389	147,933
Deferred revenue	22,531	24,500
Commodity derivatives	29,707	4,775
Other long-term liabilities	308	295
Asset retirement obligation	5,327	5,327
Deferred tax liability	46	46
Total Liabilities	622,490	477,338
Commitments and contingencies (Note 10)		
Redeemable Series B Preferred Units, net	575,325	518,562
Equity		
Partners' Equity (deficit)	(709,606)	(599,205)
Noncontrolling interest	21,000	20,339
Total (Deficit)	(688,606)	(578,866)
Total Liabilities, Preferred Units and Partners' Equity	$509,209	$417,034

The accompanying notes are an integral part of these condensed consolidated financial statements.

PRIMEXX ENERGY PARTNERS, LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
UNAUDITED
(in thousands)

	Nine-Months Ended September 30	
	2021	**2020**
Revenues		
Oil sales	$154,309	$109,594
Natural gas sales	28,858	5,878
Field service revenue	9,985	6,319
(Loss) gain on derivative instruments, net	(101,218)	111,877
Total revenues	91,934	233,668
Costs and expenses		
Lease operating expenses	35,709	33,255
Repairs	7,121	3,347
Production taxes	8,642	5,371
Transportation and marketing	739	897
Field service expenses	9,474	10,878
Depreciation, depletion and amortization	51,073	79,771
Impairment of oil and gas properties	—	325,683
General and administrative	3,964	5,870
Total operating expenses	116,722	465,072
(Loss) from operations	(24,788)	(231,404)
Other income (expense)		
Other income	2,174	2,210
Interest expense	(27,346)	(30,600)
Total other income (expense)	(25,172)	(28,390)
(Loss) before income taxes	(49,960)	(259,794)
Income tax expense		
Texas margin tax expense	40	—
Total income tax expense	40	—
Net (loss)	(50,000)	(259,794)
Net (gain) loss attributable to noncontrolling interest	(4,485)	959
Series B preferred unit distribution	(55,705)	(48,780)
Net (loss) attributable to other partners	($110,190)	($307,615)

The accompanying notes are an integral part of these condensed consolidated financial statements.

PRIMEXX ENERGY PARTNERS, LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' EQUITY (DEFICIT)
UNAUDITED
(in thousands)

	General Partner	Series A Preferred	Common Units	Noncontrolling Interest	Total Equity
Balance, December 31, 2020	($76)	($160,932)	($438,197)	$20,339	($578,866)
Series A Preferred Deemed Distribution	—	9,270	(9,270)	—	—
Net gain attributable to noncontrolling interest	—	—	—	4,485	4,485
Distribution to minority interest owners made by SFS	—	—	—	(4,035)	(4,035)
Transfer of property by SFS	—	(99)	(112)	211	—
Net (loss) attributable to other partners	—	(51,667)	(58,523)	—	(110,190)
Balance, September 30, 2021	($76)	($203,428)	($506,102)	$21,000	($688,606)

	General Partner	Series A Preferred	Common Units	Noncontrolling Interest	Total Equity
Balance, December 31, 2019	($76)	$55,984	($166,142)	$23,169	($87,065)
Series A Preferred Deemed Distribution	—	9,270	(9,270)	—	—
Net (loss) attributable to noncontrolling interest	—	—	—	(959)	(959)
Purchase of noncontrolling interest by SFS	—	67	75	(2,281)	(2,139)
Net (loss) attributable to other partners	—	(144,239)	(163,376)	—	(307,615)
Balance, September 30, 2020	($76)	($78,918)	($338,713)	$19,929	($397,778)

The accompanying notes are an integral part of these condensed consolidated financial statements.

PRIMEXX ENERGY PARTNERS, LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
UNAUDITED
(in thousands)

	Nine-Months Ended September 30	
Cash flows from operating activities	**2021**	**2020**
Net (loss)	($50,000)	($259,794)
Adjustments to reconcile net (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	51,073	79,771
Impairment of oil and gas properties	—	325,683
Deferred loan cost amortization	1,138	1,464
Deferred revenue amortization	(2,078)	(1,969)
Gain on sale of property - net	1	—
Accretion of discount on preferred unit issuance	1,058	1,058
Unrealized loss (gain) on derivative instruments	78,904	(62,933)
Changes in operating assets and liabilities:		
Trade accounts receivable	(16,633)	18,064
Accounts receivable - affiliate	(5,643)	10,629
Prepaid and other assets	(1,085)	(762)
Accounts payable	7,899	(15,697)
Oil and gas payable	17,556	(8,911)
Accrued liabilities and other	(34,832)	(12,280)
Deferred revenue	282	—
Net cash provided by operating activities	47,640	74,323
Cash flows from investing activities		
Additions to oil and gas properties	(97,220)	(67,139)
Proceeds from sale of oil and gas properties	2,188	—
Additions to other property	(5,001)	(8,109)
Net cash (used in) investing activities	(100,033)	(75,248)
Cash flows from financing activities		
Distribution to minority interest owners made by SFS	(4,035)	—
Purchase of Pecos Property by SFS from noncontrolling interest	—	(2,139)
Proceeds from line of credit	109,000	40,500
Repayments of line of credit	(48,000)	(53,500)
Capitalized loan cost	(101)	(507)
Net cash provided by (used in) financing activities	56,864	(15,646)
Net change in cash and cash equivalents	4,471	(16,571)
Cash and cash equivalents, beginning of period	7,253	22,501
Cash and cash equivalents, end of period	$11,724	$5,930
Supplemental cash disclosures:		
Property additions included in accrued liabilities	$31,431	$2,063
Cash paid for interest	$25,546	$28,668
Non cash financing - Redeemable Series B Preferred Units	$55,705	$48,780

The accompanying notes are an integral part of these condensed consolidated financial statements.

PRIMEXX ENERGY PARTNERS AND SUBSIDARIES
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED
FINANCIAL STATEMENTS

NOTE 1. ORGANIZATION

Primexx Energy Partners, Ltd. ("PEP"), a Texas Limited Partnership, was formed on July 1, 2000, and is engaged in the acquisition, development, production, exploration and sale of crude oil and natural gas properties located primarily in Reeves County Texas.

On July 1, 2016, PEP reorganized and obtained additional investment in the form of Redeemable Series B Preferred units through funds controlled by The Blackstone Group ("Blackstone"). In addition to this investment, Blackstone also obtained a 55% controlling interest in Primexx Energy Corporation ("PEC"), a Texas corporation, and the sole general partner of PEP.

Principles of Consolidation

These condensed consolidated financial statements include the accounts of Primexx Energy Partners, Ltd. and its subsidiaries: (i) Primexx Energy Finance ("PEF"), (ii) Primexx Resource Development ("PRD"), (iii) Primexx Operating Corporation ("POC"), (iv), and Saragosa Field Services ("SFS") (collectively referred to as "the Partnership"). Intercompany transactions and balances have been eliminated in consolidation.

On July 11, 2018, the Partnership sold approximately 22% of its interest in SFS to a subsidiary of BPP Energy Partners LLC ("BPP"), an affiliated entity (see Note 3 and Note 9). On May 1, 2019 and July 2, 2019, the Partnership sold an additional 6.23% and 1.75%, respectively, of its interest in SFS to BPP. Total interest sold through the balance sheet date is 30%. Given the Partnership's majority interest and its control of the entity, SFS remains a consolidated entity with the minority shareholder's interest shown as noncontrolling interest in the condensed consolidated financial statements.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The accompanying condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. All dollar amounts in the financial statements and tables in the notes are stated in thousands of U.S. dollars unless otherwise indicated. In preparing the accompanying condensed consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the condensed consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.

In the opinion of management, the accompanying unaudited condensed consolidated balance sheets and related unaudited consolidated statements of operations, cash flows and partners' equity include all adjustments, consisting only of normal recurring items necessary for the fair presentation in conformity with U.S. GAAP. Certain disclosures have been condensed or omitted from these condensed consolidated financial statements. Accordingly, these condensed notes to the condensed consolidated financial statements should be read in conjunction with the audited consolidated financial statements.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Going Concern

The accompanying condensed consolidated financial statements are prepared in accordance with generally accepted accounting principles applicable to a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business.

Management evaluates conditions and events that are relevant to the Partnership's ability to meet its obligations as they become due within one year after the date that the condensed consolidated financial statements are issued. The Partnership has an unsecured term loan payable to BPP Holdco LLC, a related party, with an outstanding principal balance of $130 million which was set to mature on November 10, 2021. As a result of the Callon Divestiture (see Note 11), the maturity date of the term loan was extended to November 30, 2021. If this note is found to be in default, the newly issued note by BPP Holdco LLC for $25 million (see Note 11) will have an accelerated maturity. Management has considered existing cash on hand and available liquidity, and concluded that the Partnership will not have sufficient liquidity to repay the term loan at maturity. This condition raises substantial doubt about the Partnership's ability to continue as a going concern.

In response to these conditions, management's plan includes selling Callon shares to repay the term loan and its remaining obligations as they become due. However, the shares received as consideration are restricted until after the extended maturity date. As management's plans are not within the Partnership's control, these plans cannot be considered probable of occurring as of the date the condensed consolidated financial statements are available for issuance. As a result, the Partnership has concluded that management's plans do not alleviate substantial doubt about the Partnership's ability to continue as a going concern.

The condensed consolidated financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts or the amounts and classification of liabilities that might result from the outcome of this uncertainty.

Use of Estimates

The preparation of the condensed consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets, and liabilities at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates, and changes in these estimates are recorded when known.

Significant items subject to such estimates include proved reserves and related present value of future net revenues, the carrying value of oil and gas properties, derivative financial instruments, asset retirement obligations, and legal and environmental risks and exposures.

Oil and Gas Properties

The Partnership applies the full cost method of accounting for oil and gas properties. Accordingly, all costs incurred in the acquisition, exploration, and development of oil and gas properties are capitalized. Those costs include any internal costs that are directly related to development and exploration activities and capitalized interest associated with certain unproved oil and gas properties with ongoing development activities.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Oil and Gas Properties - continued

The Partnership assesses its oil and gas properties whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Costs associated with proved oil and gas properties are subject to the full cost ceiling limitation which generally limits unamortized capitalized costs to the discounted future net revenues from proved reserves, based on the average of the first day prices and operating cost of the previous twelve months. As a result of the Partnership's proved property impairment assessment as of September 30, 2020, the Partnership recorded a $325.7 million non-cash impairment charge to reduce the carrying value of its proved oil and gas properties, which is included in impairments of oil and gas properties in the statements of operations. There were no impairments of proved oil and gas properties for the nine-month period ended September 30, 2021.

Costs associated with unproved properties that have not been impaired and costs associated with uncompleted capital projects are excluded from the depletion base. As proved reserves are established, costs associated with unproved properties become part of our depletion base. We determine the amount of costs to transfer from unproved properties based on our estimate of the potential drilling locations and potential reserves associated with those properties. Costs associated with uncompleted capital projects are included in our depletion base upon completion of the related projects.

Unproved properties are assessed annually to ascertain whether impairment has occurred. During any period in which impairment is indicated, the accumulated cost associated with the impaired property are transferred to proved properties, become part of our depletion base, and become subject to the full cost ceiling limitation.

Depreciation, depletion and amortization of proved oil and gas properties are computed on the units–of–production method, using estimates of the underlying proved reserves and costs expected to be incurred to develop our proved undeveloped reserves.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas, in which case the gain or loss is recognized in income.

Other Property and Equipment

Other property and equipment includes furniture and fixtures, computer equipment, software, transportation equipment, and field service equipment consisting of gas gathering, gas processing and water management facilities. Property and equipment are recorded at historical cost and depreciated using the straight-line method over their estimated useful lives ranging from 3 to 39 years.

The Partnership assesses the carrying amount of this equipment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the carrying amount exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized. There was no such impairment for the periods presented.

Derivative Activity

The Partnership uses derivative financial instruments to reduce exposure to fluctuations in commodity prices. These transactions are in the form of crude oil and natural gas options and swaps.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Derivative Activity - continued

The Partnership reports the fair value of derivatives on the consolidated balance sheets in commodity derivative assets or liabilities as either current or noncurrent. The Partnership determines the current and noncurrent classification based on the timing of expected future cash flows of the individual trades. The Partnership reports these on a gross basis by counterparty.

The Partnership's derivative instruments were not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized along with realized gains and losses in (Loss) gain on derivative instruments, net, in the condensed consolidated statements of operations in the period of change.

Certain of our assets and liabilities are measured at fair value as of the reporting period. Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants. Fair value measurements are classified according to the following hierarchy that consists of three broad levels:

Level 1 inputs: Unadjusted quoted prices in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 inputs: Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability or inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 inputs: Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between level 1, level 2, and level 3 of the fair value hierarchy, if applicable, are made at the end of each reporting period.

Revenue Recognition

The Partnership enters into contracts with customers to sell its oil and natural gas production. Revenue on these contracts is recognized in accordance with the five-step revenue recognition model. Specifically, revenue is recognized when the Partnership's performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights. Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration the Partnership expects to receive in accordance with the price specified in the contract. Consideration under the oil and natural gas marketing contracts is typically received from the purchaser one to two months after production. At September 30, 2021 and December 31, 2020, the Partnership had receivables related to contracts with customers of $30.1 million and $12.8 million, respectively.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Revenue Recognition - continued

Oil Contracts - The majority of the Partnership's oil marketing contracts transfer physical custody and title at or near the wellhead, which is generally when control of the oil has been transferred to the purchaser. Most of the oil produced is sold under contracts using market-based pricing which is then adjusted for differentials based upon delivery location and oil quality. To the extent the differentials are incurred after the transfer of control of the oil, the differentials are included in oil sales on the statements of operations as they represent part of the transaction price of the contract. If the differentials, or other related costs, are incurred prior to the transfer of control of the oil, those costs are included in transportation and marketing on the Partnership's consolidated statements of operations as they represent payment for services performed outside of the contract with the customer.

Natural Gas Contracts - Most of the Partnership's natural gas is sold at the lease location or at the outlet of the compressor station owned by SFS, which is generally when control of the natural gas has been transferred to the purchaser. To the extent control of the natural gas transfers upstream of transportation and processing activities, revenue is recognized as the net amount received from the purchaser. To the extent that control transfers downstream of those activities, revenue is recognized on a gross basis, and the related costs are classified in transportation and marketing on the Partnership's consolidated statements of operations.

The Partnership does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient allowed for in GAAP. The expedient applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

NOTE 3. PROPERTY

Property consisted of the following as of (in thousands):

	September 30, 2021	December 31, 2020
Oil and gas properties:		
Proved oil and gas properties	$1,488,968	$1,362,631
Accumulated depreciation, depletion and amortization and impairment	(1,127,968)	(1,089,464)
Total net oil and gas properties	361,000	273,167
Other property and equipment:		
Other property and equipment:		
Office and equipment	5,261	4,013
Field service assets	135,595	131,872
Accumulated depreciation	(57,346)	(44,932)
Total net other property and equipment	83,510	90,953
Total net property, plant and equipment	**$444,510**	**$364,120**

Field Service Assets

SFS is a controlled subsidiary of the Partnership that owns the company's field services assets in Reeves County which include gas gathering, water management and other oil field service assets. Financial information for this entity can be found in the Supplemental Consolidating Schedules.

NOTE 3. PROPERTY - CONTINUED

Acquisitions and Divestitures

On May 18, 2018, PRD and SFS entered into an agreement with Oryx Southern Delaware Holdings, LLC ("Oryx"). This agreement allowed for the construction of a gathering system to collect the Partnership's produced oil and provide firm marketing and shipping arrangements for the product. Further as a part of this agreement, SFS had the first right and option to purchase on or before December 31, 2019 all of the gathering system and all rights and interest in the crude oil gathering agreement between the Partnership and Oryx for the net present value of the construction cost plus six percent. Additionally, if the call was exercised, the Partnership had the ability to put the asset to Oryx or participate through tag-along rights in the event Oryx completed a sale of its assets.

On April 2, 2019, SFS received notice that Oryx had entered into a Purchase and Sale Agreement ("PSA") which constituted an exit event under the agreement. On April 18, 2019, SFS exercised both its call and put rights and settled the transaction with Oryx for a net amount of $31.5 million on May 22, 2019. The Partnership will remain the primary customer of the gathering system and, due to this continued involvement, the gain on this transaction is deferred as a liability and amortized over the life of the gathering agreement as other income. The $31.5 million earned from this transaction was distributed to PRD and BPP in proportion to their equity ownership.

On May 1 and July 2, 2019, the Partnership completed the sale of an additional 6.23% and 1.75% of its equity interest in SFS to BPP for a total sales price of $7.2 million and $1.5 million, respectively. These transactions gave BPP their maximum ownership of 30% allowed under the sales agreement reached in 2018.

On December 16, 2019, SFS closed on the sale of its saltwater disposal handling assets to WaterBridge Texas Midstream, LLC ("WaterBridge") for a total price of $185 million in cash at the time of closing with additional incentives of up to $40 million over the subsequent four-year period based annual water volumes produced by POC operated wells under a Water Management Services Agreement ("WMSA"). The agreement also gives WaterBridge the first right of refusal to purchase SFS's water recycling facilities at a future time. Simultaneous with closing this sale, the Partnership entered into a WMSA with a term of twenty years for POC's operating area. Upon the closing of this transaction, a distribution of $173.7 million was made to BPP and PRD based on their respective ownership.

Pecos Office Building

On September 9, 2020, SFS exercised its option on behalf of the Partnership to complete the purchase of an office building and land in Pecos, Texas (the "Pecos Property") from the Chairman of the Board of Directors (a common unit holder and previously the Partnership's Chief Executive Officer) for a total payment of $2.1 million. Prior to the purchase, the Partnership had a lease in place with the owner and utilized the office for field operations. The Pecos Property was previously accounted for as a variable interest entity ("VIE") and consolidated within the Partnership's financial statements because the property owner held the option to force a purchase of the property by the Partnership, and the Partnership had the option to force a sale of the property under certain circumstances. Given the related party nature of the transaction and the VIE guidance within GAAP, there is no step-up in basis of the Pecos Property and the excess cash paid over the book value is recorded as a reduction in the equity of SFS. As a result of the transaction, the entire purchase price is a reduction in equity and a financing cash outflow to acquire all of the equity interest in the previously consolidated VIE which is dissolved.

NOTE 3. PROPERTY - CONTINUED

Grey Rock Joint Development Agreement

On January 8, 2021, the Partnership and BPP Acquisition LLC, a subsidiary of BPP Energy Partners LLC, entered into an agreement with a third party to contribute oil and gas leases and certain properties to a joint development area comprising 960 gross acres effective February 26, 2021. At closing, the Partnership received total consideration of $2.2 million, which was recorded in oil and gas properties as a reduction in the basis of the full cost pool.

As part of the agreement, the Partnership agreed to provide technical consulting services to the third party over the 18-month development period. Accordingly, proceeds related to the technical consulting services of approximately $0.3 million were deferred as a liability and amortized over the agreement period as other income.

Callon Divestiture

On August 3, 2021, the Partnership and BPP (together "the Primexx Entities") entered into an agreement with Callon Petroleum Company ("Callon") to sell all of the Primexx Entities' oil and gas leasehold interests and infrastructure assets. See Note 11 for additional information.

NOTE 4. DERIVATIVE INSTRUMENTS

The Partnership engages in price risk management activities. These activities are intended to manage the Partnership's exposure to fluctuations in commodity prices for crude oil and natural gas. The Partnership utilizes financial commodity derivative instruments, primarily price swaps and options.

Commodity derivatives are classified as Level 2 within the fair value hierarchy. The fair value of these instruments is estimated using forward-looking price curves and discounted cash flows that are observable or that can be corroborated by observable market data.

Natural gas and crude oil derivatives settle against the average of the prompt month NYMEX future prices for natural gas and West Texas Intermediate crude oil.

The fair values of commodity derivatives were as follows (in thousands):

	September 30, 2021	December 31, 2020
Commodity derivative assets		
Current portion	$1,712	$14,263
Long-term portion	6,161	9,078
	7,873	23,341
Commodity derivative liabilities		
Current portion	39,477	974
Long-term portion	29,707	4,775
	69,184	5,749
Net commodity derivatives	($61,311)	$17,592

NOTE 4. DERIVATIVE INSTRUMENTS - CONTINUED

The following presents the results of the Partnership's oil and gas derivative activity included in revenue in the statements of operations during the periods ended September 30, 2021 and 2020:

	Nine-Months Ended	
	September 30, 2021	September 30, 2020
Realized (loss) gain		
Oil derivatives	($20,693)	$48,944
Natural gas derivatives	(1,621)	—
Total realized (loss) gain	($22,314)	$48,944
Unrealized (loss) gain		
Oil derivatives	($74,088)	$64,723
Natural gas derivatives	(4,816)	(1,790)
Total unrealized (loss) gain	($78,904)	$62,933
(Loss) gain on derivative instruments, net	($101,218)	$111,877

The Partnership had the following outstanding open crude oil and natural gas positions as of September 30, 2021:

	Expirations			
	2021	2022	2023	2024
Oil Swaps:				
Notional volume (bbl)	642,000	1,167,200	—	—
Weighted average swap price	$53.01 $53.44	$50.68	$—	$—
Mid-Cush Differential (Basis) Swap:				
Notional volume (bbl)	642,000	1,606,300	633,400	317,400
Weighted average swap price	$1.01	$0.93	$0.46	$0.55
Oil Collars:				
Notional volume (bbl)	—	439,100	906,700	317,400
Weighted average put purchased	$—	$52.50	$43.08	$48.86
Weighted average call sold	$—	$62.75	$51.63	$56.01
Natural Gas Swaps:				
Notional volume (MMBTU)	444,100	1,539,100	270,100	—
Weighted average swap price	$2.54	$2.43	$2.59	$—
Waha Differential (Basis) Swap:				
Notional volume (MMBTU)	829,500	1,568,500	270,100	—
Weighted average swap price	($0.22)	($0.26)	($0.26)	$—
Natural Gas Collars:				
Notional volume (MMBTU)	99,900	29,400	—	—
Weighted average put purchased	$2.80	$2.80	$—	$—
Weighted average call sold	$3.49	$3.49	$—	$—

NOTE 4. DERIVATIVE INSTRUMENTS - CONTINUED

The Partnership had the following outstanding open crude oil and natural gas positions as of December 31, 2020:

	Expirations		
	2021	2022	2023
Oil Swaps:			
Notional volume (bbl)	2,585,600	1,167,200	—
Weighted average swap price	$53.44 $53.44	$50.68	$—
Mid-Cush Differential (Basis) Swap:			
Notional volume (bbl)	2,585,600	1,167,200	353,700
Weighted average swap price	$0.93	$1.04	$0.30
Oil Collars:			
Notional volume (bbl)	—	—	627,000
Weighted average put purchased	$— $53.44	$—	$40.00
Weighted average call sold	$—	$—	$48.38
Natural Gas Swaps:			
Notional volume (MMBTU)	2,799,000	1,539,100	270,100
Weighted average swap price	$2.54	$2.43	$2.59
Waha Differential (Basis) Swap:			
Notional volume (MMBTU)	3,072,600	1,539,100	270,100
Weighted average swap price	($0.26)	($0.26)	($0.26)

Proceeds from the Callon Divestiture were used to unwind the Partnership's outstanding derivative contracts in conjunction with the closing of the transaction. See Note 11 for additional information.

NOTE 5. LINE OF CREDIT AND TERM LOAN FACILITIES

Debt outstanding is as follows (in thousands):

	September 30, 2021	December 31, 2020
Reserves-based line of credit	$148,500	$87,500
Term loan - HPS	150,000	150,000
Term loan - Blackstone	130,000	130,000
Deferred loan cost - HPS, net	(1,611)	(2,067)
Deferred loan cost - Blackstone, net	(1)	(6)
	$426,888	$365,427

Reserves-based Lines of Credit

On July 7, 2015, PRD entered into a senior, first lien credit agreement with Société Générale ("SG"), as administrative agent for a syndicated group of participating banks (the "Bank Group"). The credit agreement provided for a $500 million senior secured revolving credit facility expiring July 7, 2019 (the "Credit Facility").

NOTE 5. LINE OF CREDIT AND TERM LOAN FACILITIES - CONTINUED

Reserves-based Lines of Credit - continued

On November 16, 2018, the Partnership entered into a second amended and restated credit agreement with J.P. Morgan as the administrative agent, replacing Société Générale as the previous administrative agent, for a syndicated group of participating banks. The credit agreement provides for a $750 million senior secured revolving credit facility expiring November 16, 2023. Substantially all the Partnerships oil and gas assets are pledged as collateral and are included in consideration of the borrowing base which is set by J.P. Morgan as administrative agent and is scheduled for redetermination on March 1 and September 1 of each year. In addition, we may request a borrowing base redetermination up to two times per year based on certain factors. The borrowing base at December 31, 2020 was $185 million.

On April 16, 2021, the borrowing based was reaffirmed at $185 million.

The Credit Facility contains certain financial covenants that must be met by PRD. A current ratio of 1.0 times or greater must be maintained at each quarter end. The calculation of the current ratio under the Credit Agreement dictates that the available, undrawn balance on the Credit Facility be added to current assets of PRD for debt compliance calculation purposes, among other adjustments (which calculation does not include the current assets of, or any accrued interest or current maturities of debt held at PRD's parent entities (PEF or PEP)). Further, the debt to EBITDA ratio for the trailing four-fiscal quarters must be no greater than 3.5 times. The covenants also include certain customary restrictions on sales or encumbrances of assets, other advances, indebtedness, distributions and mergers or consolidations.

The applicable base rate is equal to the London Interbank Offered Rate ("LIBOR") plus a margin ranging from 2.5% to 3.5% based on the percentage of the borrowing base utilized. The Credit Facility carries a commitment fee of 50 basis points on the unused portion of the borrowing base. Interest expense related to the Credit Facility of $3.7 million and $4.4 million was recorded during the nine-month periods ended September 30, 2021 and 2020, respectively.

Amortization of deferred loan costs related to the Credit Facility of $0.7 million and $0.6 million was recorded during the nine-month periods ended September 30, 2021 and 2020, respectively.

Proceeds from the Callon Divestiture were used to pay down the outstanding balance and accrued interest in conjunction with the closing of the transaction. See Note 11 for additional information.

HPS Investment Partners Term Loan

On May 4, 2018, PEF entered into a $150 million delayed draw term loan with HPS Investment Partners ("HPS"). An amount of $50 million was funded (less discounts on issuance and related bank fees) upon closing with the remaining balance to be drawn within twelve months of the closing date with a maturity of May 4, 2024.

PEF completed additional draws of $50 million on October 1, 2018 and March 1, 2019 under this term loan for a total amount outstanding of $150 million.

The Notes Purchase Agreement contains various covenants pertaining to the financial condition of PEF. The covenants include as Asset Coverage Ratio of no less than 1.0 times beginning with the quarter ending December 31, 2018. The Asset Coverage Ratio increased to 1.50 times at December 31, 2019. For purposes of the covenant test, total debt is the debt at PEF of $150 million and the outstanding amount drawn on the revolver at PRD. The covenants also include certain restrictions on sales or encumbrances of assets, other advances, indebtedness, distributions and mergers or consolidations.

NOTE 5. LINE OF CREDIT AND TERM LOAN FACILITIES - CONTINUED

HPS Investment Partners Term Loan - continued

Interest on this term loan is payable quarterly and is at a rate equal to LIBOR plus 7.5%. Interest expense related to the HPS term loan of $8.7 million and $10.3 million was recorded during the nine-month periods ended September 30, 2021 and 2020, respectively.

Amortization of deferred loan costs related to the HPS term loan of $0.5 million and $0.4 million was recorded during the nine-month periods ended September 30, 2021 and 2020, respectively.

As part of this credit facility, the Partnership created PEF as a subsidiary of PEP who is the borrower under this agreement.

Proceeds from the Callon Divestiture were used to pay down the outstanding principal and accrued interest in conjunction with the closing of the transaction. See Note 11 for additional information.

Blackstone Term Loan

On July 16, 2016, in connection with the Blackstone recapitalization of the Partnership, the Partnership entered into an agreement with BPP Holdco LLC, the Series B Preferred Unit holder, for a term loan in the amount of $130 million, with an original maturity date of January 7, 2020. Proceeds from this second lien facility were used to retire a previous credit facility. Three limited partners of the Partnership have provided guarantees of collection totaling $52.5 million, including a limited partner of the Partnership controlled by the Partnership's Chairman of the Board, which has provided a guarantee of collection totaling $47.9 million.

On March 21, 2019, this agreement was amended to extend the maturity date to April 7, 2020.

On March 25, 2020, this agreement was amended to extend the maturity date to July 7, 2020 and to amend the requirement of an audit opinion that does not contain a going concern emphasis of matter paragraph to allow for any "going concern" qualification resulting from the occurrence of pending maturity date of the Partnership's indebtedness.

On September 23, 2020, the agreement was amended to extend the maturity date to November 10, 2021.

On November 9, 2021, the agreement was amended to extend the maturity date to November 30, 2021.

Interest on this term loan is payable quarterly at an interest rate equal to LIBOR plus 12.0%, subject to a 1% floor. Interest expense related to the Blackstone term loan of $12.8 million and $13.3 million was recorded during the nine-month periods ended September 30, 2021 and 2020, respectively, excluding $1.1 million of accretion expense related to the discount on issuance of the Series B Preferred Units (see Note 6) for both respective periods.

Amortization of deferred loan costs related to the Blackstone term loan of $0.1 million and $0.4 million was recorded during the nine-month periods ended September 30, 2021 and 2020, respectively.

The term loan agreement contains various covenants pertaining to the financial condition of the Partnership. The covenants include an Asset Coverage Ratio with respect to the relationship between total debt and proved reserves of no less than 1.50 times at December 31, 2019. For purposes of the covenant test, total debt is the debt at PEP of $130 million and PEF of $150 million as well as the outstanding amount drawn on the revolver at PRD.

The Partnership amended the Blackstone Term Loan in conjunction with the closing of the Callon Divestiture. See Note 11 for additional information.

NOTE 6. REDEEMABLE SERIES B PREFERRED UNITS

On July 1, 2016, the Limited Partnership Agreement ("LPA") was amended and restated to allow for the issuance of up to 300,000 Series B Preferred Units with a par value of $1,000 each. The Series B Preferred Unitholders are entitled to receive a distribution of 13.5% compounded interest and payable quarterly on April 1, July 1, October 1, and December 31. The distribution is prior and in preference to any declaration or payment of distributions to Series A Preferred Unit holders and any other classes of equity in the Partnership. The distribution is generally to be paid in additional Series B Preferred Units. At the discretion of the Managing General Partner, however, the distribution may be paid in cash for up to 50% of the amount to be distributed.

The activity and balance of the Redeemable Series B Preferred Units are as follows (in thousands):

Balance as of December 31, 2020	**$518,562**
Accretion of discount on issuance	1,058
Interest earned	55,705
Balance as of September 30, 2021	**$575,325**

NOTE 7. PARTNERS' EQUITY

The limited partners' equity consists of two general classes: (1) Series A Preferred Units, and "Common Units," which are composed of several sub-classes described below.

The Common Units include the initial Class B founding limited partners and Class A limited partners admitted to the Partnership in 2001. In 2013, the Partnership amended and restated its LPA to provide for additional limited partner interests, including the Series A Preferred Units issued to Whittier, and three new sub-classes of Common Units (Class C, Class D, and Class E), made available for issuance as management incentive units. All issued Class C Units were redeemed or converted to Class B Units in February 2016. The Board issued and granted Class D Units to certain outside Board members, which remain issued and outstanding. There are no outstanding Class E Units.

In July 2016, in connection with the Blackstone financing, the Partnership amended and restated its LPA to provide for the Redeemable Series B Preferred Units (discussed in note 6) and their associated warrants (Class F Common Units), as well as a new class of management incentive units (Class G Common Units).

Under the Third Amended and Restated LPA Agreement, the following order of distributions will occur upon a liquidation event:

- First, to the Redeemable Series B Preferred Units until satisfied.
- Second, $100 million to the Legacy Unitholders, which consist of the Series A Preferred, Class A and Class B Common Unit holders in order of preference.
- Lastly, proceeds will be split 55% to the Series F Common Units (and Series G Common Units once certain thresholds are met) and 45% to the Legacy Unitholders

The Series A Preferred Units are non-voting, perpetual limited partnership units, convertible to Class A-1 Common Units, and are entitled to a priority distribution of 8% per annum, cumulative and non-compounding with no current payment requirement. This payment is reflected as a reclass within the statement of changes in partners' equity as a deemed distribution. Series A Preferred Units were purchased on November 1, 2013, November 15, 2014, and July 1, 2015.

NOTE 7. PARTNERS' EQUITY - CONTINUED

The amount of cumulative deemed distributions to Series A Preferred Units that have not been paid as of September 30, 2021, was $81.9 million; as a result, the Series A Preferred Unit holder's total investment in the Partnership, plus its deemed distribution, equals $236.4 million as of September 30, 2021.

As previously noted, the Class F and Class G Common Units represent equity interests in the Partnership created in connection with the 2016 recapitalization. The Class F Common Units were issued to the holder of the Series B Preferred Unit holders and participate in profits once the Series B Preferred distributions have been satisfied and $100.0 million of distributions have been made to legacy unitholders. Accordingly, the value of these Class F Common Units at issuance was de minimis.

Class G Common Units are issued as management incentive units and are considered "profits interests" for tax purposes. The Class Common G Units receive distributions of partnership profits after certain hurdles are met with respect to the other Preferred and Common Units. Accordingly, the value of these Class G Common Units at issuance was also de minimis.

NOTE 8. MID-TERM INCENTIVE PLAN

In 2020, the Board of Directors established the Mid Term Incentive Plan ("MTIP") as an incentive program for the Partnership's directors, executives, and key employees. The program designates a pool of up to $15.0 million to be granted to employees and provide a cash award when the affiliated Primexx entities (Primexx Energy Partners, Ltd., BPP Energy Partners LLC, and Rock Ridge Royalty Company LLC) have a Liquidity Event. The award is to be split proportionately amongst the affiliated entities based on the cash amount received for each entity. The award vests in two tranches with 65% of the award vesting over a three-year period and 35% of the award is based on personal performance of the grantee as determined by the Board of Directors. The portion that is time vested will fully accelerate and vest upon the change of control of the entities subject to the grantee's continuous service and remaining in good standing with the Partnership through the date of the change in control.

Because the MTIP award is not considered a substantive class of equity, and only pays grantees upon a liquidity event of the entity, there is no expense recorded in the financial statements related to these awards. As of December 31, 2020, the total pool granted to employees under the MTIP was completely distributed.

NOTE 9. RELATED PARTY TRANSACTIONS

As stated in Note 3, the Partnership, through SFS purchased the Pecos Property from the Chairman of the Board for $2.1 million. Prior to the closing of that transaction, the Partnership had a triple net lease agreement for the use of the property as a field office. Lease payments totaling $0.1 million were paid to the owner during the period ending September 30, 2020.

The Partnership has an affiliate receivable balance due from PEC in the amount of $0.1 million as of September 30, 2021 and December 31, 2020, respectively.

The Partnership's Blackstone Term Loan is payable to BPP Holdco LLC and the Whittier Trust, both Series B Preferred Unit holders. Additionally, as stated in Note 5, there is a personal guarantee of this note by an entity controlled by the Chairman of the Board.

NOTE 9. RELATED PARTY TRANSACTIONS - CONTINUED

The Partnership entered into an agreement with EagleClaw Midstream ("EagleClaw") on October 1, 2017 to gather and market gas produced pursuant to a gathering and acreage dedication agreement. The Partnership received $41.3 million and $9.9 million in gross sales during the nine-month periods ending September 30, 2021 and 2020, respectively. The Partnership and EagleClaw have the same controlling shareholder, however, there is no common management or shared operations between the two entities outside of the gathering agreement described above.

BPP Energy Partners LLC

The Partnership has shareholders and management in common with BPP Energy Partners LLC ("BPP"), a company formed to acquire oil-and-gas leases and assets within PEP's operating area. In connection with the formation of BPP, the board approved a shared service agreement between the two companies so that all operations of BPP are conducted by POC and the cost of shared resources (including technology, office space and personnel) are reimbursed to POC by BPP at a rate of cost plus 2%. Additionally, BPP holds non-operated working interest in wells currently being drilled by PEP. Accordingly, PEP is responsible for distributing BPP's share of revenue and invoicing for the related share of capital and lease operating expenses in accordance with the ownership held by BPP.

On July 11, 2018, BPP purchased approximately 22% of SFS from PRD. An incremental 6.23% and 1.75% was purchased on May 1, 2019 and July 2, 2019, respectively. As of the balance sheet date, BPP has purchased 30% equity ownership in SFS (see details of this purchase in Note 3). SFS made distributions totaling $4.0 million to BPP during the nine-month period ended September 30, 2021. There were no distributions made to BPP by SFS during the nine-month period ended September 30, 2020.

Below represents the balances and activity between BPP and POC (in thousands):

	September 30, 2021	September 30, 2020
BPP payable to POC	$6,810	$111
Revenue paid to BPP by POC	$45,723	$34,124
Capital and lease operating expenses paid to POC for joint interest billings	$53,427	$37,548
General and administrative expenses reimbursement to POC	$3,794	$2,238

BPP had $19.4 million of unapplied prepaid capital expenditures deposited with PRD and recorded in other current liabilities as of December 31, 2020, respectively. As of September 30, 2021, PRD refunded the remaining $11.1 million of unapplied prepaid capital expenditures to BPP.

Rock Ridge Royalty Company LLC

The Partnership has shareholders and management in common with Rock Ridge Royalty Company LLC ("Rock Ridge"), a Delaware limited liability company formed in late 2016 to acquire and hold mineral and royalty interests in the Delaware Basin. Resources of the Partnership are utilized in the management and operations of Rock Ridge. These resources include technology, office space and personnel employed by POC. The cost of these resources is reimbursed by Rock Ridge based on the time allocated by employees to their work on Rock Ridge as well as actual costs incurred by POC and the Partnership.

NOTE 9. RELATED PARTY TRANSACTIONS - CONTINUED

Rock Ridge Royalty Company LLC - continued

On June 8, 2021, Rock Ridge entered into an agreement to contribute all its mineral and royalty interests in exchange for a 25% membership interest in DPM HoldCo, LLC ("Desert Peak Minerals"), a subsidiary of KMF Chambers HoldCo, LLC ("KMF"). The closing of the transaction was effective on June 30, 2021. Prior to the transaction, PRD leased certain acreage blocks for future development from Rock Ridge. As a result, PRD was an operator of certain Rock Ridge properties and paid Rock Ridge its respective royalty for hydrocarbons produced. As of September 30, 2021, no payments have been made by the Partnership to Desert Peak Minerals related to the Rock Ridge mineral and royalty interests included in the transaction.

Below represents the balances and activity between Rock Ridge and POC (in thousands):

	September 30, 2021	September 30, 2020
Rock Ridge payable to POC	$52	$345
Revenue paid to Rock Ridge by POC	$3,600	$3,738
Cash lease bonuses paid by POC	$886	$—
General and administrative expenses reimbursement to POC	$584	$3,010

Jetta Permian L.P.

On May 8, 2020, POC entered into a comprehensive management services agreement ("MSA") with an effective date of June 1, 2020 to manage Jetta Permian, L.P. ("Jetta"), which had shareholders in common with the Partnership. Under this MSA, certain POC officers served as officers of Jetta and POC employees operated and maintained all of Jetta's oil and gas properties, provided back office support and reporting requested by the board and required by Jetta's bank agreements. For these services, POC received a monthly fee of $30,000 plus an amount of $900 per operated well and a drilling overhead fee of $9,000 per well per month prorated for drilling days to be paid in the month when wells are drilled. All out-of-pocket expenses paid by POC were reimbursed by Jetta.

On July 15, 2021, Jetta closed a divestiture transaction with a third party to sell all its leasehold interests and related assets effective July 1, 2021.

NOTE 10. COMMITMENTS AND CONTINGENCIES

The Partnership's operations are subject to all the operational and environmental risks normally associated with the crude oil and natural gas industry. Additionally, the Partnership may become involved from time to time in litigation on various matters which are routine to the conduct of its business.

Changes to current economic conditions may adversely affect the results of operations in future periods. The novel coronavirus ("COVID-19") pandemic significantly affected the global economy and created significant volatility in commodity prices during 2020. Commodity prices have recovered in 2021 based on rising demand as global economic activity increased in addition to sustained production cuts by the Organization of the Petroleum Exporting Countries ("OPEC"). However, uncertainty continues to exist regarding the recovery of global oil demand in future periods due to various factors and circumstances beyond the Partnership's control, such as the duration of the pandemic and variant strains of COVID-19, OPEC and other oil producing nations managing the global oil supply, government actions in response to the pandemic, global supply chain constraints, and cost inflation. The financial statements have been prepared using values and information currently available to the Partnership.

NOTE 11. SUBSEQUENT EVENTS

On October 1, 2021, the Primexx Entities closed the divestiture transaction with a subsidiary of Callon. The fair value of consideration received by the Partnership totaled $678.5 million and was comprised of $354.5 million of cash consideration and 6.42 million shares of Callon stock issued to the Partnership in exchange for its oil and gas leasehold interests and infrastructure assets, subject to the finalization of purchase price adjustments within 120 days of closing.

On October 1, 2021, in conjunction with the closing of the transaction, the Partnership entered into a Senior Secured Promissory Note Agreement with Blackstone with an aggregate principal amount of $25 million. The unpaid principal balance bears interest at 2.75% per annum with a maturity date of 365 days after the date the loan was funded.

Upon closing, the Partnership used cash proceeds from the Callon Divestiture and the Blackstone Senior Secured Promissory Note to unwind its outstanding derivative contracts for $67.5 million and pay down the outstanding principal balances and accrued interest related to the HPS term loan and the Credit Facility of $151.7 million and $148.9 million, respectively.

The Partnership amended its Term Loan Agreement with Blackstone on October 1, 2021. Accordingly, interest expense related to the Blackstone Term Loan will be paid-in-kind in future interest periods and certain covenants have been eliminated. On November 9, 2021, the Blackstone Term Loan Agreement was amended to extend the maturity date to November 30, 2021.

Subsequent events were evaluated through November 19, 2021, the date the condensed consolidated financial statements were available for issuance.

Exhibit 99.3

BPP ENERGY PARTNERS LLC
AND SUBSIDIARIES

CONSOLIDATED FINANCIAL STATEMENTS
AND INDEPENDENT AUDITORS' REPORT

December 31, 2020 and 2019

CONTENTS

INDEPENDENT AUDITORS' REPORT

To the Board of Managers of BPP Energy Partners LLC

Dallas, Texas

We have audited the accompanying consolidated financial statements of BPP Energy Partners LLC and its subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2020 and 2019, and the related consolidated statements of operations, changes in members' equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of BPP Energy Partners LLC and its subsidiaries as of December 31, 2020 and 2019, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

March 31, 2021

BPP ENERGY PARTNERS LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31
(in thousands)

	2020	2019
Assets		
Current Assets		
Cash and cash equivalents	$3,116	$14,758
Revenue receivable	6,752	14,692
Commodity derivatives	6,060	236
Prepaid and other	19,520	97
Total current assets	35,448	29,783
Property, plant and equipment, net:		
Oil and gas properties, full cost method of accounting	87,383	237,416
Unproved property and uncompleted capital projects excluded from amortization	—	5,681
Total oil and gas properties, net	87,383	243,097
Commodity derivatives	2,809	153
Loan origination cost, net	232	235
Investment in SFS	20,339	21,100
Total Assets	$146,211	$294,368
Liabilities and Members' Equity		
Current Liabilities		
Accounts payable	$—	$49
Accounts payable - affiliate	972	9,906
Other current liabilities	12,329	8,155
Commodity derivatives	76	2,623
Total current liabilities	13,377	20,733
Line of credit	—	—
Term loan, net	73,537	73,167
Commodity derivatives	1,868	1,165
Asset retirement obligation	763	523
Total Liabilities	89,545	95,588
Commitments and contingencies (Note 10)		
Members' Equity	56,666	198,780
Total Liabilities and Members' Equity	$146,211	$294,368

The accompanying notes are an integral part of these consolidated financial statements.

BPP ENERGY PARTNERS LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
THE YEARS ENDED DECEMBER 31
(in thousands)

	2020	2019
Revenues		
Oil sales	$42,544	$54,241
Natural gas sales	1,128	1,372
Gain (loss) on derivative instruments, net	34,279	(4,672)
Total revenues	77,951	50,941
Costs and expenses		
Lease operating expenses	12,539	13,207
Repairs	1,503	727
Production taxes	2,126	2,604
Depreciation, depletion and amortization	28,660	20,615
Impairment of oil and gas properties	163,223	—
General and administrative	3,273	2,536
Total operating expenses	211,324	39,689
(Loss) income from operations	(133,373)	11,252
Other income (expense)		
Interest expense	(7,980)	(7,543)
Equity in (loss) earnings of SFS	(550)	47,942
Net (loss) income	($141,903)	$51,651

The accompanying notes are an integral part of these consolidated financial statements.

BPP ENERGY PARTNERS LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF
CHANGES IN MEMBERS' EQUITY
(in thousands)

	Total Equity
Balance, January 1, 2019	$147,129
Net income	51,651
Balance, December 31, 2019	$198,780
Purchase of interest from related party by SFS	(211)
Net (loss)	(141,903)
Balance, December 31, 2020	$56,666

The accompanying notes are an integral part of these consolidated financial statements.

BPP ENERGY PARTNERS LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
THE YEARS ENDING DECEMBER 31
(in thousands)

Cash flow from operating activities	**2020**	**2019**
Net (loss) income	($141,903)	$51,651
Adjustments to reconcile net (loss) income to cash used in operating activities:		
Depreciation, depletion, and amortization	28,660	20,615
Impairment of oil and gas properties	163,223	—
Deferred loan cost amortization	437	355
Unrealized (gain) loss on derivative instruments	(10,324)	4,644
Equity in loss (earnings) of SFS	550	(47,942)
Distributed equity in earnings of SFS	—	48,977
Changes in operating assets and liabilities:		
Accounts receivable	7,940	(11,287)
Accounts payable	(49)	(548)
Accounts payable - affiliate	(9,183)	2,120
Prepaid and other current assets	(19,423)	(97)
Other liabilities	(3,837)	(8,700)
Net cash provided by operating activities	16,091	59,788
Cash flow from investing activities		
Additions to oil and gas properties	(27,669)	(104,446)
Purchase of equity in SFS, an equity method investment	—	(8,759)
Return of capital from SFS, an equity method investment	—	12,047
Net cash used in investing activities	(27,669)	(101,158)
Cash flow from financing activities		
Proceeds from line of credit	—	45,000
Repayment of line of credit	—	(45,000)
Proceeds from term loan	—	50,000
Capitalized loan cost	(64)	(821)
Net cash (used in) provided by financing activities	(64)	49,179
Net change in cash and cash equivalents	(11,642)	7,809
Cash and cash equivalents, beginning of period	14,758	6,949
Cash and cash equivalents, end of period	$3,116	$14,758
Supplemental cash disclosures:		
Property additions included in accrued liabilities	$8,260	$8,713
Asset retirement obligations incurred, including revisions to estimates	$197	$341
Cash paid for interest	$7,593	$7,208

The accompanying notes are an integral part of these consolidated financial statements.

BPP ENERGY PARTNERS LLC AND SUBSIDARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. ORGANIZATION

BPP Energy Partners LLC ("BPP" or the "Company"), a Delaware limited liability company, was formed on October 16, 2018 to indirectly hold the operations of BPP Acquisition LLC ("BPP Acquisition").

On November 27, 2018, BPP Energy Finance LLC ("BPP EF") was formed as a wholly owned subsidiary of BPP for the purpose of obtaining term loan financing for use in the operations of BPP. BPP EF is the borrower of the term loan and owns all of the interest in BPP Acquisition.

BPP Acquisition was formed on May 4, 2017, and is engaged in the acquisition, development, production, and exploration of crude oil and natural gas properties located in Texas. As the formation of BPP and BPP EF were created as a reorganization of entities under common control, all prior period balances included in these financials are those of BPP Acquisition.

The Company was formed with two classes of Member Interest consisting of Common Interest and Profits Interest. These interests include the Series A Profits Interest, and two series of Common Interest, the Series B Common Interest and Series C Common Interest. The Company's Series B shareholders are owned by funds controlled by The Blackstone Group L.P. ("Blackstone") and have a commitment to fund $300 million. Series C common interest holders have a commitment to fund $34.8 million (see Note 7 for detail on membership interest types). As of December 31, 2020, there is $171.1 million and $19.9 million of the above commitment remaining to be funded for the Series B Common and Series C Common, respectively.

Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). These financial statements include the accounts of BPP Energy Partners, LLC and its subsidiaries: (i) BPP EF, and (ii) BPP Acquisition (collectively referred to as the Company). Intercompany transactions and balances have been eliminated upon consolidation.

On July 11, 2018, the Company purchased approximately 22% of its interest in Saragosa Field Services, LLC ("SFS") from Primexx Energy Partners, Ltd. ("PEP") an affiliated entity. During 2019, the Company purchased an additional 8% of its interest in SFS from PEP. Total purchased through the balance sheet date is 30%. Given that the Company does not have control over SFS, but has significant influence, it is treated as an equity method investment (see Note 4).

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates, and changes in these estimates are recorded when known.

Significant items subject to such estimates include proved reserves and related present value of future net revenues, the carrying value of oil and gas properties, asset retirement obligations, and legal and environmental risks and exposures.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Cash and Cash Equivalents

The Company considers all liquid investments with original maturities of three months or less to be cash equivalents. At December 31, 2020 and 2019, the Company did not have any cash equivalents.

Trade Accounts Receivable

Substantially all the Company's receivables are within the oil and gas industry, primarily from purchasers of oil and gas. Collectability is dependent upon the general economic conditions of the purchasers and the industry. The receivables are not collateralized. The Company has had minimal bad debts; therefore, there is no allowance for doubtful accounts as of December 31, 2020 or 2019. Management considers the following factors when determining the collectability of specific accounts: credit worthiness, past transaction history, current economic industry trends, and changes in payment terms. If the financial condition of the Company's purchasers were to deteriorate, adversely affecting their ability to make payments, allowances would be necessary.

Oil and Gas Properties

The Company applies the full cost method of accounting for oil and gas properties. Accordingly, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized. Those costs include any internal costs that are directly related to development and exploration activities and capitalized interest associated with certain unproved oil and gas properties with ongoing development activities.

Costs associated with proved oil and gas properties are subject to the full cost ceiling limitation which generally limits unamortized capitalized costs to the discounted future net revenues from proved reserves, based on the average of the first day prices and operating cost of the previous twelve months. As a result of the Company's proved property impairment assessment as of December 31, 2020, the Company recorded a $163.2 million noncash impairment charge to reduce the carrying value of its proved oil and gas properties, which is included in impairments of oil and gas properties in the statements of operations. There were no impairments of proved oil and gas properties for the year ended December 31, 2019.

Costs associated with unproved properties that have not been impaired and costs associated with uncompleted capital projects are excluded from the depletion base. As proved reserves are established, costs associated with unproved properties become part of our depletion base. Costs associated with uncompleted capital projects are included in our depletion base upon completion of the related projects.

Unproved properties are assessed annually to ascertain whether impairment has occurred. The impairment assessment includes consideration of our intent to fully develop our unproved properties, remaining lease terms, geological and geophysical evaluations, our drilling results, potential drilling locations, availability of capital, assignment of proved reserves, expected divestitures, anticipated future capital expenditures and economic considerations, among others. During any period in which impairment is indicated, the accumulated costs associated with the impaired property are transferred to proved properties, become part of our depletion base, and become subject to the full cost ceiling limitation. There were no expired leases during the years ended December 31, 2020 and 2019.

Depreciation, depletion and amortization of proved oil and gas properties are computed on the units–of–production method, using estimates of the underlying proved reserves and costs expected to be incurred to develop our proved undeveloped reserves.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Oil and Gas Properties - continued

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas, in which case the gain or loss is recognized in income.

Prepaid and Other Assets

Prepaid and other assets at December 31 consist of the following:

	2020	2019
Prepaid drilling costs	$19,390	$—
Other	130	97
Total prepaid and other assets	$19,520	$97

Derivative Activity

The Company uses derivative financial instruments to reduce exposure to fluctuations in commodity prices. These transactions are in the form of crude oil and natural gas options and swaps.

The Company reports the fair value of derivatives on the consolidated balance sheet in commodity derivative assets or liabilities as either current or noncurrent determined based on the timing of expected future cash flows of the individual trades. The Company reports these on a gross basis by counter party.

The Company's derivative instruments were not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized along with realized gains and losses in Gain (loss) on derivative instruments, net, in the consolidated statements of operations in the period of change.

Fair Value of Financial Instruments

Certain of our assets and liabilities are measured at fair value as of the reporting period. Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants. Fair value measurements are classified according to the following hierarchy that consists of three broad levels:

Level 1 inputs: Unadjusted quoted prices in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 inputs: Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability or inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 inputs: Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Fair Value of Financial Instruments - continued

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between level 1, level 2, and level 3 of the fair value hierarchy, if applicable, are made at the end of each reporting period.

Loan Origination Costs

Loan origination costs are amortized over the term of the related obligation using the effective interest method. Origination cost associated with our reserves-based line of credit are presented net of amortization within long-term assets. Origination cost associated with our term loan is net of amortization cost and are reported as an offset to the outstanding balance within long-term liabilities.

Equity Method Investment

The Company accounts for its interest in SFS under the equity method of accounting because BPP Acquisition does not have a controlling interest in SFS but has significant influence. BPP Acquisition recognizes it share of earnings and losses in SFS in accordance with its ownership percentage.

Other Accrued Liabilities

Other accrued liabilities at December 31 consist of the following:

	2020	2019
Accrued capital expenditures	$8,010	$5,939
Lease operating expenses payable	3,636	1,481
Interest payable	678	728
Other	5	7
Total other accrued liabilities	$12,329	$8,155

Asset Retirement Obligation

The Company records a liability for asset retirement obligations and increases the carrying value of the related asset in the period in which the liability is incurred. Asset retirement obligations primarily relate to the abandonment of oil and natural gas producing facilities and include costs to dismantle and relocate or dispose of wells and related structures. Accretion expense associated with asset retirement obligations is recorded over time.

The following table shows the changes in the balances of the asset retirement as of December 31 (in thousands).

	2020	2019
Asset retirement obligation, January 1	$523	$152
Liabilities incurred	197	148
Liabilities sold	(8)	—
Changes in estimates	8	193
Accretion expense	43	30
Asset retirement obligation, December 31	$763	$523

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Comprehensive income

During the periods ended December 31, 2020 and 2019, the Company did not have any comprehensive income or loss. Accordingly, net income (loss) equals comprehensive income (loss) for the period presented.

Revenue Recognition

The Company's production is sold through its operated partner who enters into contracts with customers to sell its oil and natural gas production on the Company's behalf with all related expenses being passed through to the Company. Revenue on these contracts is recognized in accordance with the five-step revenue recognition model. Specifically, revenue is recognized when the Company's performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights.

Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration the Company expects to receive in accordance with the price specified in the contract. Consideration under the oil and natural gas marketing contracts is typically received from the purchaser one to two months after production by the operator and remitted to the Company as a non-operating interest owner. At December 31, 2020 and 2019, the Company had receivables related to contracts with customers of $6.0 million and $14.6 million, respectively.

For non-operated crude oil and natural gas revenues, the Company's proportionate share of production is generally marketed at the discretion of the operator. For non-operated properties, the Company receives a net payment from the operator representing its proportionate share of sales proceeds which is net of costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds to be received by the Company during the month in which production occurs and it is probable the Company will collect the consideration it is entitled to receive. Proceeds are generally received by the Company within two months after the month in which production occurs.

Oil Contracts - The majority of the Company's oil marketing contracts transfer physical custody and title at or near the wellhead, which is generally when control of the oil has been transferred to the purchaser. Most of the oil produced is sold under contracts using market-based pricing which is then adjusted for differentials based upon delivery location and oil quality. To the extent the differentials are incurred after the transfer of control of the oil, the differentials are included in oil sales on the statements of operations as they represent part of the transaction price of the contract. If the differentials, or other related costs, are incurred prior to the transfer of control of the oil, those costs are included in transportation and marketing on the Company's consolidated statements of operations as they represent payment for services performed outside of the contract with the customer.

Natural Gas Contracts - Most of the Company's natural gas is sold at the lease location or at the outlet of the compressor station owned by SFS, which is generally when control of the natural gas has been transferred to the purchaser. To the extent control of the natural gas transfers upstream of transportation and processing activities, revenue is recognized as the net amount received from the purchaser. To the extent that control transfers downstream of those activities, revenue is recognized on a gross basis, and the related costs are classified in transportation and marketing on the Company's consolidated statements of operations.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Revenue Recognition - continued

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical exemption allowed for in GAAP. The exemption applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

New Accounting Pronouncements

In February 2016, FASB issued ASU 2016-02 – *Leases* (Topic 842), which requires the recognition of lease assets and lease liabilities by lessees for those leases currently classified as operating leases and makes certain changes to the accounting for lease expenses. This update is effective for fiscal years beginning after December 15, 2021, and for interim periods beginning the following year. ASC 842 should be applied using a modified retrospective approach. The Company is in the process of evaluating the impact of this new standard on its financial statements. The new guidance is expected to impact the Company's balance sheets due to the recognition of right-of-use assets and lease liabilities that are not currently recognized under current accounting standards. The standard does not apply to leases to explore for or use minerals, oil or gas resources.

In June 2016, the FASB issued ASU 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments" ("ASU 2016-13"). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires entities to use a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. This update is effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years, with early adoption permitted. Entities will use the modified retrospective approach to apply the standard's provisions and record a cumulative-effect adjustment to retained earnings for additional receivable loss allowances, if any, as of the beginning of the first reporting period in which the guidance is adopted. The Company is in the process of evaluating whether it will have a material impact on its consolidated financial statements.

NOTE 3. PROPERTY

Property consisted of the following at December 31 (in thousands):

	2020	2019
Oil and gas properties:		
Proved oil and gas properties	$305,091	$263,283
Unproved oil and gas properties excluded from amortization	—	5,681
Accumulated depreciation, depletion and amortization and impairment	(217,708)	(25,867)
Total net oil and gas properties	$87,383	$243,097
Supplemental Property Information:		
Depletion expense	$28,618	$20,585
Capitalized interest	$—	$569

NOTE 4. INVESTMENT IN SARAGOSA FIELD SERVICES

On July 11, 2018, the Company completed the purchase of 22% of SFS from Primexx Resource Development, LLC ("PRD"), a wholly owned subsidiary of Primexx Energy Partners Ltd ("PEP") an affiliated entity (see Note 8), with an effective date of January 1, 2018. The purchase was completed for an initial purchase price of $17.8 million. An additional $6.6 million was contributed through year-end to fund additional infrastructure expansion for a total investment of $24.4 million. The Company has the option to purchase additional interest in SFS not to exceed its pro rata portion acreage held when considering the combined acreage of both PRD and BPP up to 30%.

On April 2, 2019, SFS closed on the sale of certain oil gathering assets to Oryx for a net gain of $31.5 million on May 22, 2019. Primexx Operating Corporation ("POC"), a wholly owned subsidiary of PEP and the operator of the oil and gas assets, will remain the primary customer of the gathering system and, due to this continued involvement, the gain on this transaction is deferred as a liability and amortized over the life of the gathering agreement as other income.

On May 1 and July 2, 2019, the Company completed an additional purchase of 6.23% and 1.75%, respectively, of SFS from PRD to bring its total ownership to 30%. The additional purchased amount was completed for a combined purchase price of $8.7 million.

On December 16, 2019, SFS closed on the sale of its saltwater disposal handling assets to WaterBridge Texas Midstream, LLC ("WaterBridge") for a total price of $185 million in cash at the time of closing with additional incentives of up to $40 million over the subsequent four-year period based on annual water volumes produced by POC operated wells under a Water Management Services Agreement ("WMSA"). The agreement also gives WaterBridge the first right of refusal to purchase SFS's water recycling facilities at a future time. Simultaneous with closing this sale, POC entered into a WMSA with a term of twenty years for POC's operating area. Upon the closing of this transaction, a distribution of $173.7 million was made to BPP and PRD based on their respective ownership.

On September 9, 2020, SFS exercised its option to complete the purchase of an office building and land in Pecos, Texas (the "Pecos Property") from the Chairman of the Board of Directors (a common unit holder and previously the Company's Chief Executive Officer) for a total payment of $2.1 million. Prior to the purchase, POC had a lease in place with the owner and utilized the office for field operations. Given the related party nature of the transaction, there is no adjustment to the basis of the Pecos Property and the excess cash paid over the book value is recorded as a reduction in the equity of SFS.

NOTE 4. INVESTMENT IN SARAGOSA FIELD SERVICES - CONTINUED

SFS is accounted for on the equity method basis of accounting. The following details the condensed financial statements as of and for the year December 31, 2020 and 2019 (in thousands):

Condensed Balance Sheet

	2020	2019
Current assets	$7,290	$11,681
Property, plant and equipment, net	89,996	94,667
Total assets	$97,286	$106,348
Current liabilities	4,990	8,855
Total liabilities	29,490	36,016
Members' equity	67,796	70,332
Total Liabilities and Members' Equity	$97,286	$106,348

Condensed Income Statement

	2020	2019
Sales	$25,827	$72,855
Cost of sales	2,371	4,735
Field service expense	10,926	24,841
Production taxes	198	202
Depreciation, depletion and amortization	16,351	19,972
General and administrative	643	1,208
Total operating expenses	30,489	50,958
Gain on sale of saltwater disposal system	—	136,342
Other income	2,829	1,891
Net (loss) income	(1,833)	160,130
Net (loss) income attributable to BPP	(550)	47,942
Net (loss) income attributable to controlling owner	($1,283)	$112,188

NOTE 5. DERIVATIVE INSTRUMENTS

The Company engages in price risk management activities. These activities are intended to manage the Company's exposure to fluctuations in commodity prices for crude oil and natural gas. The Company utilizes financial commodity derivative instruments, primarily price swaps and options.

Commodity derivatives are classified as Level 2 within the fair value hierarchy. The fair value of these instruments is estimated using forward-looking price curves and discounted cash flows that are observable or that can be corroborated by observable market data.

Crude oil derivatives settle against the average of the prompt month NYMEX future prices for West Texas Intermediate.

NOTE 5. DERIVATIVE INSTRUMENTS - CONTINUED

The fair values of commodity derivatives at December 31 were as follows (in thousands):

	2020	2019
Commodity derivative assets		
Current portion	$6,060	$236
Long-term portion	2,809	153
	8,869	389
Commodity derivative liabilities		
Current portion	76	2,623
Long-term portion	1,868	1,165
	1,944	3,788
Net commodity derivatives	$6,925	($3,399)

The following presents the results of the Company's oil and gas derivative activity included in revenue in the statements of operations during the periods ended December 31, 2020 and 2019:

	2020	2019
Realized gain (loss)		
Oil derivatives	$23,955	($28)
Natural gas derivatives	—	—
Total realized gain (loss)	$23,955	($28)
Unrealized gain (loss)		
Oil derivatives	$10,106	($4,644)
Natural gas derivatives	218	—
Total unrealized gain (loss)	$10,324	($4,644)
Gain (loss) on derivative instruments, net	$34,279	($4,672)

NOTE 5. DERIVATIVE INSTRUMENTS - CONTINUED

The Company had the following outstanding open crude oil positions as of December 31, 2020:

	Expirations		
	2021	2022	2023
Oil Swaps:			
Notional volume (bbl)	1,042,700	279,300	—
Weighted average swap price	$53.54 $53.44	$51.06	$—
Oil Collars:			
Notional volume (bbl)	—	30,900	216,200
Weighted average put purchased	$—	$40.00	$40.00
Weighted average call sold	$—	$45.15	$48.36
Mid-Cush Differential (Basis) Swap:			
Notional volume (bbl)	1,042,700	279,300	117,700
Weighted average swap price	$1.00	$1.00	$0.30
Natural Gas Swaps:			
Notional volume (MMBTU)	858,200	702,600	151,800
Weighted average swap price	$3.06	$2.49	$2.59
Waha Differential (Basis) Swap:			
Notional volume (MMBTU)	954,300	702,600	151,800
Weighted average swap price	($0.27)	($0.30)	($0.31)

The Company had the following outstanding open crude oil positions as of December 31, 2019:

	Expirations		
	2020	2021	2022
Oil Swaps:			
Notional volume (bbl)	1,162,000	794,000	264,000
Weighted average swap price	$57.00 $53.44	$53.54	$51.17
Mid-Cush Differential (Basis) Swap:			
Notional volume (bbl)	1,162,000	794,000	264,000
Weighted average swap price	$0.42	$0.99	$1.00

NOTE 6. LINE OF CREDIT AND TERM LOAN FACILITIES

Debt as of December 31, 2020 and 2019 (in thousands):

	2020	2019
Reserves-based line of credit	$—	$—
Term loan - HPS	75,000	75,000
Deferred loan cost - HPS, net	(1,463)	(1,833)
Total debt outstanding	$73,537	$73,167

NOTE 6. LINE OF CREDIT AND TERM LOAN FACILITIES - CONTINUED

Reserves-based Lines of Credit

On November 29, 2018, the Company entered into a senior, first lien credit agreement with J.P. Morgan expiring November 28, 2023. Substantially all of the Company's oil and gas assets are pledged as collateral to be considered as a part of the borrowing base which is set by J.P. Morgan as administrative agent and is redetermined semi-annually. In addition, we may request a borrowing base redetermination up to two times per year based on certain factors. As of December 31, 2020, the borrowing base is $60 million.

The Credit Facility contains certain financial covenants that must be met by BPP. A current ratio of 1.0 times or greater must be maintained at each quarter end. The calculation of the current ratio under the Credit Agreement dictates that the available, undrawn balance on the Credit Facility be added to current assets for debt compliance calculation purposes among other adjustments. Further, the secured debt to EBITDA ratio for the trailing four-fiscal quarters must be no greater than 3.5 times. The covenants also include certain customary restrictions on sales or encumbrances of assets, other advances, indebtedness, distributions and mergers or consolidations.

The applicable base rate is equal to the London Interbank Offered Rate ("LIBOR") plus a margin ranging from 3% t o 4% based on the percentage of the borrowing base utilized. The Credit Facility carries a commitment fee of 50 basis points on the unused portion of the borrowing base.

Deferred loan cost of $0.2 million and $0.2 million (net of $0.1 million and $0.1 million in amortization) is recorded in long-term assets for the period ended December 31, 2020 and 2019, respectively.

Term Loan Agreement

On December 10, 2018, the Company entered into a $75 million delayed draw term loan with HPS Investment Partners ("HPS"). An amount of $25 million was funded (less discounts on issuance and related bank fees) upon closing with the remaining balance to be drawn within twelve months of the closing date with a maturity of December 10, 2024.

The remaining amount of $50 million was drawn during 2019.

Interest on this term loan is payable quarterly and is at a rate equal to the LIBOR plus 8.0%.

The term loan agreement contains various covenants pertaining to the financial condition of the Company. The covenants include an Asset Coverage Ratio with respect to the relationship between total debt and proved reserves of no less than 1.50 times. For purposes of this covenant, total debt is the debt at BPP EF of $75 million plus any outstanding amounts drawn on the revolving credit facility. The covenants also include certain restrictions on sales or encumbrances of assets, other advances, indebtedness, distributions and mergers or consolidations.

As part of this credit facility, the Company created BPP EF as a subsidiary of BPP.

Deferred loan cost of $1.5 million and $1.8 million (net of $0.7 million and $0.3 million in amortization) as of December 31, 2020 and 2019, respectively. These amounts are presented as an offset to long-term debt.

NOTE 7. MEMBERS' INTEREST

The Company has two classes of Member Interest consisting of Common Interest and Profits Interest. These interests include the Series A Profits Interest, and two series of Common Interest, the Series B Common Interest and Series C Common Interest. Series A Profits Interest were issued to legacy unit holders of PEP. Additionally, A Profits Interest have been authorized for issuance to management of the Company as incentive compensation. The following chart details the issuance of these units:

Units outstanding as of January 1, 2019	**500**
Units granted during 2019	60
Forfeitures	—
Units outstanding as of December 31, 2019	**560**
Units granted during 2020	61
Forfeitures	—
Units outstanding as of December 31, 2020	**621**

Series A Profits Interest represent equity interest in the Company and its holders participate in profits of the Company once certain payout thresholds are met for the Series B and C Common Interest holders. Accordingly, the value of the Series A Profits Interest at issuance was de minimis.

The Company's distribution of profit and loss will be applied as follows:

- First, to the Common Interest Holders based on their pro-rata invested capital until all invested capital is recovered and a cumulative amount of distributions are received to achieve a 13.5% rate of return.
- Second, the vested Series A Profits Interest will receive 12.5% of the distributions with the remainder going to Common Interest Holders until the Common Interest Holders achieve a 20% rate of return and a multiple of 2.05 times their invested capital.
- Third, the vested Series A Profits Interest will receive 22.5% of the distributions with the remainder going to the Common Interest Holders until the Common Interest Holders achieve a 30% rate of return and a multiple of 3.05 times their invested capital.
- Lastly, the vested Series A Profits Interest will receive 32.5% of the distributions with the remainder going to the Common Interest Holders.

NOTE 8. MID-TERM INCENTIVE PLAN

In 2020, the Board of Directors established the Mid Term Incentive Plan ("MTIP") as an incentive program for the Company's directors, executives, and key employees. The program designates a pool of up to $15.0 million to be granted to employees and provide a cash award when the affiliated Primexx entities (Primexx Energy Partners, Ltd., BPP Energy Partners LLC, and Rock Ridge Royalty Company LLC) have a Liquidity Event. The award is to be split proportionately amongst the affiliated entities based on the cash amount received for each entity. The award vests in two tranches with 65% of the award vesting over a three-year period and 35% of the award is based on personal performance of the grantee as determined by the Board of Directors. The portion that is time vested will fully accelerate and vest upon the change of control of the entities subject to the grantee's continuous service and remaining in good standing with the Company through the date of the change in control.

Because the MTIP award is not considered a substantive class of equity, and only pays grantees upon a liquidity event of the entity, there is no expense recorded in the financial statements related to these awards. As of December 31, 2020, the total pool granted to employees under the MTIP was completely distributed.

NOTE 9. RELATED PARTY TRANSACTIONS

Primexx Energy Partners Ltd.

The Company has shareholders and management in common with PEP. In connection with the formation of the Company, the board approved a shared service agreement between the two companies so that all operations of the Company are conducted by a subsidiary of PEP and the cost of shared resources (including technology, office space and personnel) are reimbursed to PEP by the Company at a rate of cost plus 2%. Additionally, the Company holds non-operated working interest in wells currently being drilled by PEP. Accordingly, PEP is responsible for distributing the Company's share of revenue and invoicing for the related share of capital and lease operating expenses in accordance with the ownership held by the Company.

SFS, an equity method investment of BPP, is a controlled subsidiary of PEP that owns the company's field services assets in Reeves County, which include gas gathering, water management, and other oil field service assets. See Note 4 for additional information.

The following amounts were transacted between BPP and PEP (in thousands):

	2020	2019
Affiliate payable to PEP	$1,610	$9,906
Revenue paid from PEP	$50,240	$41,723
Capital and lease operating expenses paid via joint interest billings to PEP	$43,241	$115,845
General and administrative expenses reimbursed	$4,172	$3,239

BPP had $19.4 million and $0 of unapplied prepaid capital expenditures deposited with PRD recorded in current prepaid assets as of December 31, 2020 and 2019, respectively.

During the year ended December 31, 2019, the Company sold a lease for 203 acres in the amount of $2.0 million (the Company's cost basis) to PEP.

Rock Ridge Royalty Company

The Company has shareholders and management in common with Rock Ridge Royalty Company ("RRR") a Delaware limited liability company formed in 2016 to acquire and hold mineral and royalty interests in the Delaware Basin. During 2019, the Company leased approximately 360 acres to BPP receiving a total lease bonus of $3.8 million, respectively.

NOTE 10. COMMITMENTS AND CONTINGENCIES

The Company's operations are subject to all the operational and environmental risks normally associated with the crude oil and natural gas industry. Additionally, the Company may become involved from time to time in litigation on various matters which are routine to the conduct of its business. Management is not currently a party to any material litigation and is not aware of any litigation threatened against the Company that could have a material adverse effect on the Company.

NOTE 10. COMMITMENTS AND CONTINGENCIES - CONTINUED

Current economic conditions may adversely affect the results of operations in future periods. The novel coronavirus ("COVID-19") pandemic significantly affected the global economy and created significant volatility in the financial markets. These events, in addition to disruptions in the demand for oil combined with pressures on the global supply-demand balance for oil, resulted in significant volatility in oil prices during 2020. The effects of the COVID-19 pandemic negatively impacted the Company's results of operations and led to a reduction in capital activities. The impact of these events on the financial performance of the Company's long-term operations is uncertain, including the duration of the COVID-19 pandemic and long-term effects on global oil demand. The financial statements have been prepared using values and information currently available to the Company.

NOTE 11. SUBSEQUENT EVENTS

On January 8, 2021, the Company and PRD entered into an agreement with a third party to contribute oil and gas leases and certain properties to a joint development area comprising 960 gross acres effective February 26, 2021. At closing, the Company received total consideration of $0.9 million in exchange for interests in certain properties and future technical consulting services in the joint development area.

Subsequent events have been evaluated through March 31, 2021, the date on which the financial statements were available to be issued.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Geographic Area of Operation

The Company's oil and natural gas reserves are located within the continental United States and concentrated in the Delaware Basin of Texas.

Capitalized Oil and Natural Gas Costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion and amortization are as follows (in thousands):

	December 31, 2020	December 31, 2019
Oil and gas properties		
Proved oil and gas properties	$305,091	$263,283
Unproved oil and gas properties	—	5,681
Accumulated depletion and impairment	(217,708)	(25,867)
Net oil and gas properties capitalized	$87,383	$243,097

Costs Incurred in Oil and Natural Gas Activities

Costs incurred in oil and natural gas property acquisition, exploration and development activities are as follows (in thousands):

	December 31, 2020	December 31, 2019
Acquisition costs		
Proved oil and gas properties	$14	$1
Unproved oil and gas properties	1,679	13,680
Development costs	34,376	102,178
Exploration costs	—	225
Total costs incurred	$36,069	$116,084

Results of Operations from Oil and Natural Gas Producing Activities

The following sets forth the revenues and expenses related to the production and sale of oil and natural gas (in thousands). It does not include any realized hedges, interest costs or general and administrative costs and, therefore, is not necessarily indicative of the net operating results of the Company's oil and natural gas operations.

	December 31, 2020	December 31, 2019
Oil and natural gas sales	$43,672	$55,613
Production costs	(16,168)	(16,538)
Depletion	(28,618)	(20,585)
Impairment of oil and gas properties	(163,223)	—
Results of operations from oil and natural gas producing activities	($164,337)	$18,490

The reserves as of December 31, 2020 and 2019 presented below were prepared by independent petroleum engineers. The calculation and analysis of interim changes in proved reserves were prepared by the Company. Estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. The reserves are located in the Delaware Basin of Texas.

The following tables set forth estimated net quantities of the Company's estimated proved reserves, projected future cash inflows, and future production and development costs and are prepared in accordance with guidelines established by the SEC. Accordingly, the reserve estimates are based upon existing economic and operating conditions. For estimates of proved reserves, the average spot prices are determined based upon the 12-month unweighted average of the first day of the month prices adjusted by applying price and cost basis differentials,

including transportation and quality, and are then applied to the period-end estimated quantities of oil, natural gas and natural gas liquids ("NGL") to be produced in the future. Future net cash flows are reduced to present value amounts by applying a ten percent annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by GAAP. These assumptions do not necessarily reflect management's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these reserve quantity estimates are the basis for the valuation process. Reserve estimates are inherently imprecise and estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and natural gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Analysis of Changes in Proved Reserves

The following table sets forth information regarding the Company's net ownership interest in estimated quantities of proved developed and undeveloped oil and natural gas quantities and the changes therein for each of the periods presented:

	Oil (MBbls)	**Natural Gas** (MMcf)	**NGLs** (MBbls)	**Total** (MBOE)
Balance, January 1, 2019	13,389	14,106	3,242	18,982
Revisions	(1,684)	2,032	(372)	(1,717)
Extensions	12,098	15,299	2,720	17,368
Acquisitions of reserves	142	404	71	280
Production	(1,014)	(1,080)	(190)	(1,384)
Balance, December 31, 2019	22,931	30,761	5,471	33,529
Revisions	(9,883)	(9,947)	(1,688)	(13,230)
Extensions	5,979	10,416	1,875	9,591
Acquisitions of reserves	60	135	25	108
Production	(1,154)	(1,839)	(330)	(1,791)
Balance, December 31, 2020	17,933	29,526	5,353	28,207

Proved developed and undeveloped reserves:	**Oil** (MBbls)	**Natural Gas** (MMcf)	**NGLs** (MBbls)	**Total** (MBOE)
Developed as of December 31, 2018	2,077	2,315	555	3,018
Undeveloped as of December 31, 2018	11,312	11,791	2,687	15,964
Balance at December 31, 2018	13,389	14,106	3,242	18,982
Developed as of December 31, 2019	5,411	8,060	1,392	8,146
Undeveloped as of December 31, 2019	17,520	22,701	4,079	25,383
Balance at December 31, 2019	22,931	30,761	5,471	33,529
Developed as of December 31, 2020	3,630	6,734	1,225	5,977
Undeveloped as of December 31, 2020	14,303	22,792	4,128	22,230
Balance at December 31, 2020	17,933	29,526	5,353	28,207

Revisions to previous estimates of proved reserves, either upward or downward, are a result of updated information obtained in the reporting period, including operator drilling activity and production history or changes in economic factors such as commodity prices, operating and development costs.

During the year ended December 31, 2020, the Company's extensions and discoveries of 9,591 MBOE resulted primarily from conversions of non-proved and contingent resources to proved due to drilling activity. The Company acquired 108 MBOE in Reeves County, Texas from 0.1 net producing wells and 0.1 net undeveloped locations. In addition, the Company negatively revised previous estimates by 13,230 MBOE due to the following:

- Downgrade of 10,701 MBOE of proved reserves to non-proved due to the decrease in drilling activity in 2020 resulting in development moving outside of the five-year development window,
- Negative revision of 3,326 MBOE due to downward movement in SEC pricing,
- Increase of 792 MBOE due to decreases in gas and NGL processing and basis differentials, and
- Positive revision of 5 MBOE attributed to upward revisions of estimated ultimate recovery, changes in operating and development costs, and adjustments to well spacing and development timing.

During the year ended December 31, 2019, the Company's extensions and discoveries of 17,368 MBOE resulted primarily from conversions of non-proved and contingent resources to proved due to drilling activity. The Company acquired 280 MBOE in Reeves County, Texas from 0.5 net producing wells. In addition, the Company negatively revised previous estimates by 1,717 MBOE due to the following:

- Negative revision of 4,008 MBOE due to downward movement in SEC pricing,
- Decrease of 48 MBOE due to increases in gas and natural gas liquids processing and basis differentials, and
- Positive revision of 2,339 MBOE attributed upward revisions of estimated ultimate recovery, changes in operating and development costs, and adjustments to well spacing and development timing.

Standardized Measure of Oil and Gas

The standardized measure and projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value to the Company. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary. Our calculations of the standardized measure of discounted future net cash flows and the related changes therein do not include the effect of estimated federal income tax expenses because the Company is not subject to federal income taxes. The Company is subject to certain state-based taxes; however, these amounts are not material.

As of December 31, 2020, the reserves are comprised of 64% crude oil, 17% natural gas and 19% NGL on an energy equivalent basis.

The values for the December 31, 2020 and 2019 proved reserves were derived based on prices presented in the table below. The crude oil pricing was based on the West Texas Intermediate ("WTI") price; the NGL pricing was 21% of WTI for 2020 and 33% of WTI for 2019; the natural gas pricing was based on the Henry Hub price. All prices have been adjusted for transportation, quality and basis differentials.

	Oil ($/Bbl)	**Natural Gas** ($/Mcf)	**NGLs** ($/Bbl)
December 31, 2020 (Average)	36.62	0.130	8.32
December 31, 2019 (Average)	46.10	-0.021	18.32

The following summary sets forth the future net cash flows related to proved oil and natural gas reserves based on the standardized measure prescribed in ASC Topic 932 (in thousands):

	December 31, 2020	December 31, 2019
Future oil and natural gas sales	$705,019	$1,156,636
Future production costs	(317,487)	(390,967)
Future development costs	(203,563)	(261,002)
Future net cash flows	183,969	504,667
10% annual discount	(96,586)	(251,002)
Standardized measure of discounted future net cash flows	$87,383	$253,665

The principal sources of change in the standardized measure of discounted future net cash flows are (in thousands):

	Year Ended December 31,	
	2020	2019
Standardized measure, beginning of year	$253,665	$167,641
Net change in prices and production costs	(68,124)	57,424
Changes in future development costs	131,911	54,944
Oil and gas sales, net of production costs	(27,504)	(39,075)
Extensions and discoveries	33,182	150,177
Acquisitions of reserves	340	3,407
Revisions of previous quantity estimates	(127,191)	(28,861)
Development costs incurred during the period	8,564	29,762
Accretion of discount	25,367	16,764
Changes in timing and other	(142,827)	(158,518)
Standardized measure, end of year	$87,383	$253,665

Exhibit 99.4

BPP ENERGY PARTNERS LLC
AND SUBSIDIARIES

CONDENSED CONSOLIDATED
FINANCIAL STATEMENTS

As of and for the nine-month periods ended

September 30, 2021 and 2020

CONTENTS

BPP ENERGY PARTNERS LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
UNAUDITED
(in thousands)

	September 30, 2021	December 31, 2020
Assets		
Current Assets		
Cash and cash equivalents	$18,219	$3,116
Revenue receivable	14,962	6,752
Derivative assets	562	6,060
Prepaid and other current assets	100	19,520
Total current assets	33,843	35,448
Property, plant and equipment, net:		
Oil and gas properties, full cost method of accounting	108,505	87,383
Derivative assets	1,549	2,809
Loan origination cost, net	200	232
Investment in SFS	21,000	20,339
Total Assets	**$165,097**	**$146,211**
Liabilities and Members' Equity		
Current Liabilities		
Accounts payable	$1,464	$—
Accounts payable - affiliate	6,810	972
Accrued liabilities	7,280	12,329
Derivative liabilities	12,799	76
Other current liabilities	61	—
Total current liabilities	**28,414**	**13,377**
Line of credit	7,500	—
Term loan, net	73,800	73,537
Derivative liabilities	8,578	1,868
Asset retirement obligations	763	763
Total Liabilities	**119,055**	**89,545**
Commitments and contingencies (Note 10)		
Members' Equity	46,042	56,666
Total Liabilities and Members' Equity	**$165,097**	**$146,211**

The accompanying notes are an integral part of these condensed consolidated financial statements.

BPP ENERGY PARTNERS LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
UNAUDITED
(in thousands)

	Nine-Months Ended September 30	
	2021	**2020**
Revenues		
Oil sales	$49,870	$33,825
Natural gas sales	7,565	300
(Loss) gain on derivative instruments, net	(34,751)	39,608
Total revenues	22,684	73,733
Costs and expenses		
Lease operating expenses	12,246	8,991
Repairs	2,299	726
Production taxes	2,760	1,659
Depreciation, depletion and amortization	12,040	21,915
Impairment of oil and gas properties	—	114,011
General and administrative	2,116	2,571
Total operating expenses	31,461	149,873
(Loss) from operations	(8,777)	(76,140)
Other income (expense)		
Other income	39	—
Interest expense	(6,582)	(6,048)
Equity in earnings (loss) of SFS	4,485	(959)
Net (loss)	($10,835)	($83,147)

The accompanying notes are an integral part of these condensed consolidated financial statements.

BPP ENERGY PARTNERS LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF
CHANGES IN MEMBERS' EQUITY
UNAUDITED
(in thousands)

	Total Equity
Balance, December 31, 2020	**$56,666**
Transfer of property by SFS	211
Net (loss)	(10,835)
Balance, September 30, 2021	**$46,042**
Balance, December 31, 2019	**$198,780**
Purchase of interest from related party by SFS	(211)
Net (loss)	(83,147)
Balance, September 30, 2020	**$115,422**

The accompanying notes are an integral part of these condensed consolidated financial statements.

BPP ENERGY PARTNERS LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
UNAUDITED
(in thousands)

	Nine-Months Ended September 30	
Cash flows from operating activities	**2021**	**2020**
Net (loss)	($10,835)	($83,147)
Adjustments to reconcile net (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	12,040	21,915
Impairment of oil and gas properties	—	114,011
Deferred loan cost amortization	333	327
Unrealized loss (gain) on derivative instruments	26,190	(21,815)
Equity in (earnings) loss of SFS	(4,485)	959
Distributed equity in earnings of SFS	3,258	—
Deferred revenue amortization	(39)	—
Changes in operating assets and liabilities:		
Accounts receivable	(8,210)	5,473
Accounts payable	1,464	(47)
Accounts payable - affiliate	(2,353)	(10,149)
Prepaid and other current assets	19,420	(1,639)
Other liabilities	(6,094)	(3,892)
Net cash provided by operating activities	30,689	21,996
Cash flows from investing activities		
Additions to oil and gas properties	(24,600)	(23,346)
Proceeds from sale of oil and gas properties	775	—
Return of capital from SFS, an equity method investment	777	—
Net cash (used in) investing activities	(23,048)	(23,346)
Cash flows from financing activities		
Proceeds from line of credit	7,500	—
Capitalized loan cost	(38)	(57)
Net cash provided by (used in) financing activities	7,462	(57)
Net change in cash and cash equivalents	15,103	(1,407)
Cash and cash equivalents, beginning of period	3,116	14,758
Cash and cash equivalents, end of period	$18,219	$13,351
Supplemental cash disclosures:		
Property additions included in accrued liabilities	$9,337	$446
Cash paid for interest	$5,442	$5,748

The accompanying notes are an integral part of these condensed consolidated financial statements.

BPP ENERGY PARTNERS LLC AND SUBSIDARIES
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED
FINANCIAL STATEMENTS

NOTE 1. ORGANIZATION

BPP Energy Partners LLC ("BPP" or the "Company"), a Delaware limited liability company, was formed on October 16, 2018 to indirectly hold the operations of BPP Acquisition LLC ("BPP Acquisition").

On November 27, 2018, BPP Energy Finance LLC ("BPP EF") was formed as a wholly owned subsidiary of BPP for the purpose of obtaining term loan financing for use in the operations of BPP. BPP EF is the borrower of the term loan and owns all of the interest in BPP Acquisition.

BPP Acquisition was formed on May 4, 2017, and is engaged in the acquisition, development, production, and exploration of crude oil and natural gas properties located in Texas. As the formation of BPP and BPP EF were created as a reorganization of entities under common control, all prior period balances included in these financials are those of BPP Acquisition.

Principles of Consolidation

These financial statements include the accounts of BPP Energy Partners, LLC and its subsidiaries: (i) BPP Energy Finance LLC ("BPP EF"), and (ii) BPP Acquisition LLC (collectively referred to as the Company). Intercompany transactions and balances have been eliminated upon consolidation.

On July 11, 2018, the Company purchased approximately 22% of its interest in Saragosa Field Services, LLC ("SFS") from Primexx Energy Partners, Ltd. ("PEP") an affiliated entity. During 2019, the Company purchased an additional 8% of its interest in SFS from PEP. Total purchased through the balance sheet date is 30%. Given that the Company does not have control over SFS, but has significant influence, it is treated as an equity method investment (see Note 4).

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The accompanying condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. In preparing the accompanying condensed consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the condensed consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.

In the opinion of management, the accompanying unaudited condensed consolidated balance sheets and related unaudited consolidated statements of operations, cash flows and members equity include all adjustments, consisting only of normal recurring items necessary for the fair presentation in conformity with U.S. GAAP. Certain disclosures have been condensed or omitted from these condensed consolidated financial statements. Accordingly, these condensed notes to the condensed consolidated financial statements should be read in conjunction with the audited financial statements.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Use of Estimates

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates, and changes in these estimates are recorded when known.

Significant items subject to such estimates include proved reserves and related present value of future net revenues, the carrying value of oil and gas properties, asset retirement obligations, and legal and environmental risks and exposures.

Oil and Gas Properties

The Company applies the full cost method of accounting for oil and gas properties. Accordingly, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized. Those costs include any internal costs that are directly related to development and exploration activities and capitalized interest associated with certain unproved oil and gas properties with ongoing development activities.

The Company assesses its oil and gas properties whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Costs associated with proved oil and gas properties are subject to the full cost ceiling limitation which generally limits unamortized capitalized costs to the discounted future net revenues from proved reserves, based on the average of the first day prices and operating cost of the previous twelve months. As a result of the Company's proved property impairment assessment as of September 30, 2020, the Company recorded a $114.0 million non-cash impairment charge to reduce the carrying value of its proved oil and gas properties, which is included in impairments of oil and gas properties in the statements of operations. There were no impairments of proved oil and gas properties for the nine-month period ended September 30, 2021.

Costs associated with unproved properties that have not been impaired and costs associated with uncompleted capital projects are excluded from the depletion base. As proved reserves are established, costs associated with unproved properties become part of our depletion base. Costs associated with uncompleted capital projects are included in our depletion base upon completion of the related projects.

Unproved properties are assessed annually to ascertain whether impairment has occurred. During any period in which impairment is indicated, the accumulated costs associated with the impaired property are transferred to proved properties, become part of our depletion base, and become subject to the full cost ceiling limitation.

Depreciation, depletion and amortization of proved oil and gas properties are computed on the units–of–production method, using estimates of the underlying proved reserves and costs expected to be incurred to develop our proved undeveloped reserves.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas, in which case the gain or loss is recognized in income.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Derivative Activity

The Company uses derivative financial instruments to reduce exposure to fluctuations in commodity prices. These transactions are in the form of crude oil and natural gas options and swaps.

The Company reports the fair value of derivatives on the consolidated balance sheet in commodity derivative assets or liabilities as either current or noncurrent determined based on the timing of expected future cash flows of the individual trades. The Company reports these on a gross basis by counter party.

The Company's derivative instruments were not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized along with realized gains and losses in (Loss) gain on derivative instruments, net, in the condensed consolidated statements of operations in the period of change.

Fair Value of Financial Instruments

Certain of our assets and liabilities are measured at fair value as of the reporting period. Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants. Fair value measurements are classified according to the following hierarchy that consists of three broad levels:

Level 1 inputs: Unadjusted quoted prices in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 inputs: Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability or inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 inputs: Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between level 1, level 2, and level 3 of the fair value hierarchy, if applicable, are made at the end of each reporting period.

Equity Method Investment

The Company accounts for its interest in SFS under the equity method of accounting because BPP Acquisition does not have a controlling interest in SFS but has significant influence. BPP Acquisition recognizes it share of earnings and losses in SFS in accordance with its ownership percentage.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES - CONTINUED

Revenue Recognition

The Company's production is sold through its operated partner who enters into contracts with customers to sell its oil and natural gas production on the Company's behalf with all related expenses being passed through to the Company. Revenue on these contracts is recognized in accordance with the five-step revenue recognition model. Specifically, revenue is recognized when the Company's performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights.

Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration the Company expects to receive in accordance with the price specified in the contract. Consideration under the oil and natural gas marketing contracts is typically received from the purchaser one to two months after production by the operator and remitted to the Company as a non-operating interest owner. At September 30, 2021 and December 31, 2020, the Company had receivables related to contracts with customers of $15.0 million and $6.0 million, respectively.

For non-operated crude oil and natural gas revenues, the Company's proportionate share of production is generally marketed at the discretion of the operator. For non-operated properties, the Company receives a net payment from the operator representing its proportionate share of sales proceeds which is net of costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds to be received by the Company during the month in which production occurs and it is probable the Company will collect the consideration it is entitled to receive. Proceeds are generally received by the Company within two months after the month in which production occurs.

Oil Contracts - The majority of the Company's oil marketing contracts transfer physical custody and title at or near the wellhead, which is generally when control of the oil has been transferred to the purchaser. Most of the oil produced is sold under contracts using market-based pricing which is then adjusted for differentials based upon delivery location and oil quality. To the extent the differentials are incurred after the transfer of control of the oil, the differentials are included in oil sales on the statements of operations as they represent part of the transaction price of the contract. If the differentials, or other related costs, are incurred prior to the transfer of control of the oil, those costs are included in transportation and marketing on the Company's consolidated statements of operations as they represent payment for services performed outside of the contract with the customer.

Natural Gas Contracts - Most of the Company's natural gas is sold at the lease location or at the outlet of the compressor station owned by SFS, which is generally when control of the natural gas has been transferred to the purchaser. To the extent control of the natural gas transfers upstream of transportation and processing activities, revenue is recognized as the net amount received from the purchaser. To the extent that control transfers downstream of those activities, revenue is recognized on a gross basis, and the related costs are classified in transportation and marketing on the Company's consolidated statements of operations.

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient allowed for in GAAP. The expedient applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

NOTE 3. PROPERTY

Property consisted of the following as of (in thousands):

	September 30, 2021	December 31, 2020
Oil and gas properties:		
Proved oil and gas properties	$338,253	$305,091
Accumulated depreciation, depletion and amortization and impairment	(229,748)	(217,708)
Total net oil and gas properties	$108,505	$87,383

Grey Rock Joint Development Agreement

On January 8, 2021, the Company and Primexx Resource Development, LLC ("PRD"), a wholly owned subsidiary of PEP, an affiliated entity (see Note 9), entered into an agreement with a third party to contribute oil and gas leases and certain properties to a joint development area comprising 960 gross acres effective February 26, 2021. At closing, the Company received total consideration of $0.9 million, which was recorded in oil and gas properties as a reduction in the basis of the full cost pool.

As part of the agreement, management agreed to provide technical consulting services to the third party over the 18-month development period. Accordingly, proceeds related to the technical consulting services of approximately $0.1 million are deferred and recorded in accrued liabilities and amortized over the agreement period as other income.

Callon Divestiture

On August 3, 2021, the Company and PEP (together "the Primexx Entities") entered into an agreement with Callon Petroleum Company ("Callon") to sell all of the Primexx Entities' oil and gas leasehold interests and infrastructure assets. See Note 11 for additional information.

NOTE 4. INVESTMENT IN SARAGOSA FIELD SERVICES

On July 11, 2018, the Company completed the purchase of 22% of SFS from PRD with an effective date of January 1, 2018. The purchase was completed for an initial purchase price of $17.8 million. An additional $6.6 million was contributed through year-end to fund additional infrastructure expansion for a total investment of $24.4 million. The Company has the option to purchase additional interest in SFS not to exceed its pro rata portion acreage held when considering the combined acreage of both PRD and BPP up to 30%.

On April 2, 2019, SFS closed on the sale of certain oil gathering assets to Oryx for a net gain of $31.5 million on May 22, 2019. Primexx Operating Corporation ("POC"), a wholly owned subsidiary of PEP and the operator of the oil and gas assets, will remain the primary customer of the gathering system and, due to this continued involvement, the gain on this transaction is deferred as a liability and amortized over the life of the gathering agreement as other income.

On May 1 and July 2, 2019, the Company completed an additional purchase of 6.23% and 1.75%, respectively, of SFS from PRD to bring its total ownership to 30%. The additional purchased amount was completed for a combined purchase price of $8.7 million.

NOTE 4. INVESTMENT IN SARAGOSA FIELD SERVICES - CONTINUED

On December 16, 2019, SFS closed on the sale of its saltwater disposal handling assets to WaterBridge Texas Midstream, LLC ("WaterBridge") for a total price of $185 million in cash at the time of closing with additional incentives of up to $40 million over the subsequent four-year period based on annual water volumes produced by POC operated wells under a Water Management Services Agreement ("WMSA"). The agreement also gives WaterBridge the first right of refusal to purchase SFS's water recycling facilities at a future time. Simultaneous with closing this sale, POC entered into a WMSA with a term of twenty years for POC's operating area. Upon the closing of this transaction, a distribution of $173.7 million was made to BPP and PRD based on their respective ownership.

On September 9, 2020, SFS exercised its option to complete the purchase of an office building and land in Pecos, Texas (the "Pecos Property") from the Chairman of the Board of Directors (a common unit holder and previously the Company's Chief Executive Officer) for a total payment of $2.1 million. Prior to the purchase, POC had a lease in place with the owner and utilized the office for field operations. Given the related party nature of the transaction, there is no adjustment to the basis of the Pecos Property and the excess cash paid over the book value is recorded as a reduction in the equity of SFS.

SFS made distributions totaling $4.0 million to BPP during the nine-month period ended September 30, 2021. There were no distributions made to BPP by SFS during the nine-month period ended September 30, 2020.

SFS is accounted for on the equity method basis of accounting. The following details the condensed financial statements (in thousands):

Condensed Balance Sheet

	September 30, 2021	December 31, 2020
Current assets	$16,029	$7,290
Property, plant and equipment, net	81,517	89,996
Total assets	$97,545	$97,286
Current liabilities	5,006	4,990
Total liabilities	27,545	29,490
Members' equity	70,000	67,796
Total Liabilities and Members' Equity	$97,545	$97,286

NOTE 4. INVESTMENT IN SARAGOSA FIELD SERVICES - CONTINUED

Condensed Income Statement	Nine-Months Ended September 30	
	2021	2020
Sales	$36,380	$18,425
Cost of sales	4,059	2,149
Field service expense	6,487	8,863
Production Taxes	293	146
Depreciation, depletion and amortization	12,380	12,133
General and administrative	276	496
Total operating expenses	23,494	23,787
Other income	2,063	2,164
Net income (loss)	14,950	(3,198)
Net income (loss) attributable to BPP	4,485	(959)
Net income (loss) attributable to controlling owner	$10,465	($2,239)

NOTE 5. DERIVATIVE INSTRUMENTS

The Company engages in price risk management activities. These activities are intended to manage the Company's exposure to fluctuations in commodity prices for crude oil and natural gas. The Company utilizes financial commodity derivative instruments, primarily price swaps and options.

Commodity derivatives are classified as Level 2 within the fair value hierarchy. The fair value of these instruments is estimated using forward-looking price curves and discounted cash flows that are observable or that can be corroborated by observable market data.

Crude oil derivatives settle against the average of the prompt month NYMEX future prices for West Texas Intermediate.

The fair values of commodity derivatives were as follows (in thousands):

	September 30, 2021	December 31, 2020
Commodity derivative assets		
Current portion	$562	$6,060
Long-term portion	1,549	2,809
	2,111	8,869
Commodity derivative liabilities		
Current portion	12,799	76
Long-term portion	8,578	1,868
	21,377	1,944
Net commodity derivatives	($19,266)	$6,925

NOTE 5. DERIVATIVE INSTRUMENTS - CONTINUED

The following presents the results of the Company's oil and gas derivative activity included in revenue in the statements of operations during the periods ended September 30, 2021 and 2020:

	Nine-Months Ended	
	September 30, 2021	**September 30, 2020**
Realized (loss) gain		
Oil derivatives	($8,453)	$17,793
Natural gas derivatives	(108)	—
Total realized (loss) gain	($8,561)	$17,793
Unrealized (loss) gain		
Oil derivatives	($23,859)	$21,942
Natural gas derivatives	(2,331)	(127)
Total unrealized (loss) gain	($26,190)	$21,815
(Loss) gain on derivative instruments, net	($34,751)	$39,608

The Company had the following outstanding open crude oil and natural gas positions as of September 30, 2021:

	Expirations			
	2021	**2022**	**2023**	**2024**
Oil Swaps:				
Notional volume (bbl)	236,500	279,300	—	—
Weighted average swap price	$53.13 $53.44	$51.06	$—	$—
Mid-Cush Differential (Basis) Swap:				
Notional volume (bbl)	236,500	426,800	150,100	75,600
Weighted average swap price	$1.01	$0.93	$0.39	$0.55
Oil Collars:				
Notional volume (bbl)	—	178,400	248,600	75,600
Weighted average put purchased	$—	$50.33	$41.30	$48.44
Weighted average call sold	$—	$59.00	$49.76	$56.07
Natural Gas Swaps:				
Notional volume (MMBTU)	132,900	702,600	151,800	—
Weighted average swap price	$3.06	$2.49	$2.59	$—
Waha Differential (Basis) Swap:				
Notional volume (MMBTU)	270,400	727,800	151,800	—
Weighted average swap price	($0.21)	($0.29)	($0.31)	$—
Natural Gas Collars:				
Notional volume (MMBTU)	45,400	25,200	—	—
Weighted average put purchased	$2.80	$2.80	$—	$—
Weighted average call sold	$3.49	$3.49	$—	$—

NOTE 5. DERIVATIVE INSTRUMENTS - CONTINUED

The Company had the following outstanding open crude oil and natural gas positions as of December 31, 2020:

	Expirations		
	2021	**2022**	**2023**
Oil Swaps:			
Notional volume (bbl)	1,042,700	279,300	—
Weighted average swap price	$53.54 $53.44	$51.06	$—
Mid-Cush Differential (Basis) Swap:			
Notional volume (bbl)	1,042,700	279,300	117,700
Weighted average swap price	$1.00	$1.00	$0.30
Oil Collars:			
Notional volume (bbl)	—	30,900	216,200
Weighted average put purchased	$—	$40.00	$40.00
Weighted average call sold	$—	$45.15	$48.36
Natural Gas Swaps:			
Notional volume (MMBTU)	858,200	702,600	151,800
Weighted average swap price	$3.06	$2.49	$2.59
Waha Differential (Basis) Swap:			
Notional volume (MMBTU)	954,300	702,600	151,800
Weighted average swap price	($0.27)	($0.30)	($0.31)

Proceeds from the Callon Divestiture were used to unwind the Company's outstanding derivative contracts in conjunction with the closing of the transaction. See Note 11 for additional information.

NOTE 6. LINE OF CREDIT AND TERM LOAN FACILITIES

Debt outstanding is as follows (in thousands):

	September 30, 2021	**December 31, 2020**
Reserves-based line of credit	$7,500	$—
Term loan - HPS	75,000	75,000
Deferred loan cost - HPS, net	(1,200)	(1,463)
Total debt outstanding	$81,300	$73,537

Reserves-based Lines of Credit

On November 29, 2018, the Company entered into a senior, first lien credit agreement with J.P. Morgan expiring November 28, 2023. Substantially all of the Company's oil and gas assets are pledged as collateral to be considered as a part of the borrowing base which is set by J.P. Morgan as administrative agent and is redetermined semi-annually. In addition, we may request a borrowing base redetermination up to two times per year based on certain factors. As of December 31, 2020, the borrowing base is $60 million.

On April 16, 2021, the borrowing base was reaffirmed at $60 million.

NOTE 6. LINE OF CREDIT AND TERM LOAN FACILITIES - CONTINUED

Reserves-based Lines of Credit - continued

The Credit Facility contains certain financial covenants that must be met by BPP. A current ratio of 1.0 times or greater must be maintained at each quarter end. The calculation of the current ratio under the Credit Agreement dictates that the available, undrawn balance on the Credit Facility be added to current assets for debt compliance calculation purposes among other adjustments. Further, the secured debt to EBITDA ratio for the trailing four-fiscal quarters must be no greater than 3.5 times. The covenants also include certain customary restrictions on sales or encumbrances of assets, other advances, indebtedness, distributions and mergers or consolidations.

The applicable base rate is equal to the London Interbank Offered Rate ("LIBOR") plus a margin ranging from 3% to 4% based on the percentage of the borrowing base utilized. The Credit Facility carries a commitment fee of 50 basis points on the unused portion of the borrowing base. Interest expense related to the Credit Facility of $0.9 million and $0.3 million was recorded during the nine-month periods ended September 30, 2021 and 2020, respectively.

Amortization of deferred loan costs related to the Credit Facility of $0.1 million was recorded during the nine-month periods ended September 30, 2021 and 2020, respectively.

Proceeds from the Callon Divestiture were used to pay down the outstanding balance and accrued interest in conjunction with the closing of the transaction. See Note 11 for additional information.

Term Loan Agreement

On December 10, 2018, the Company entered into a $75 million delayed draw term loan with HPS Investment Partners ("HPS"). An amount of $25 million was funded (less discounts on issuance and related bank fees) upon closing with the remaining balance to be drawn within twelve months of the closing date with a maturity of December 10, 2024.

The remaining amount of $50 million was drawn during 2019.

Interest on this term loan is payable quarterly and is at a rate equal to the LIBOR plus 8.0%. Interest expense related to the HPS term loan of $5.4 million was recorded during the nine-month periods ended September 30, 2021 and 2020, respectively.

Amortization of deferred loan costs related to the HPS term loan of $0.3 million was recorded during the nine-month periods ended September 30, 2021 and 2020, respectively.

The term loan agreement contains various covenants pertaining to the financial condition of the Company. The covenants include an Asset Coverage Ratio with respect to the relationship between total debt and proved reserves of no less than 1.50 times. For purposes of this covenant, total debt is the debt at BPP EF of $75 million plus any outstanding amounts drawn on the revolving credit facility. The covenants also include certain restrictions on sales or encumbrances of assets, other advances, indebtedness, distributions and mergers or consolidations.

As part of this credit facility, the Company created BPP EF as a subsidiary of BPP.

Proceeds from the Callon Divestiture were used to pay down the outstanding principal and accrued interest in conjunction with the closing of the transaction. See Note 11 for additional information.

NOTE 7. MEMBERS' INTEREST

The Company has two classes of Member Interest consisting of Common Interest and Profits Interest. These interests include the Series A Profits Interest, and two series of Common Interest, the Series B Common Interest and Series C Common Interest. Series A Profits Interest were issued to legacy unit holders of PEP. Additionally, A Profits Interest have been authorized for issuance to management of the Company as incentive compensation.

Series A Profits Interest represent equity interest in the Company and its holders participate in profits of the Company once certain payout thresholds are met for the Series B and C Common Interest holders. Accordingly, the value of the Series A Profits Interest at issuance was de minimis.

The Company's distribution of profit and loss will be applied as follows:

- First, to the Common Interest Holders based on their pro-rata invested capital until all invested capital is recovered and a cumulative amount of distributions are received to achieve a 13.5% rate of return.
- Second, the vested Series A Profits Interest will receive 12.5% of the distributions with the remainder going to Common Interest Holders until the Common Interest Holders achieve a 20% rate of return and a multiple of 2.05 times their invested capital.
- Third, the vested Series A Profits Interest will receive 22.5% of the distributions with the remainder going to the Common Interest Holders until the Common Interest Holders achieve a 30% rate of return and a multiple of 3.05 times their invested capital.
- Lastly, the vested Series A Profits Interest will receive 32.5% of the distributions with the remainder going to the Common Interest Holders.

NOTE 8. MID-TERM INCENTIVE PLAN

In 2020, the Board of Directors established the Mid Term Incentive Plan ("MTIP") as an incentive program for the Company's directors, executives, and key employees. The program designates a pool of up to $15.0 million to be granted to employees and provide a cash award when the affiliated Primexx entities (Primexx Energy Partners, Ltd., BPP Energy Partners LLC, and Rock Ridge Royalty Company LLC) have a Liquidity Event. The award is to be split proportionately amongst the affiliated entities based on the cash amount received for each entity. The award vests in two tranches with 65% of the award vesting over a three-year period and 35% of the award is based on personal performance of the grantee as determined by the Board of Directors. The portion that is time vested will fully accelerate and vest upon the change of control of the entities subject to the grantee's continuous service and remaining in good standing with the Company through the date of the change in control.

Because the MTIP award is not considered a substantive class of equity, and only pays grantees upon a liquidity event of the entity, there is no expense recorded in the financial statements related to these awards. As of December 31, 2020, the total pool granted to employees under the MTIP was completely distributed.

NOTE 9. RELATED PARTY TRANSACTIONS

Primexx Energy Partners Ltd.

The Company has shareholders and management in common with PEP. In connection with the formation of the Company, the board approved a shared service agreement between the two companies so that all operations of the Company are conducted by a subsidiary of PEP and the cost of shared resources (including technology, office space and personnel) are reimbursed to PEP by the Company at a rate of cost plus 2%. Additionally, the Company holds non-operated working interest in wells currently being drilled by PEP. Accordingly, PEP is responsible for distributing the Company's share of revenue and invoicing for the related share of capital and lease operating expenses in accordance with the ownership held by the Company.

SFS, an equity method investment of BPP, is a controlled subsidiary of PEP that owns the company's field services assets in Reeves County, which include gas gathering, water management, and other oil field service assets. See Note 4 for additional information.

The following represents the balances and activity between BPP and PEP (in thousands):

	September 30, 2021	September 30, 2020
Affiliate payable to PEP	$6,810	$111
Revenue paid from PEP	$45,723	$34,124
Capital and lease operating expenses paid via joint interest billings to PEP	$53,427	$37,548
General and administrative expenses reimbursed	$3,794	$2,238

BPP had $19.4 million of unapplied prepaid capital expenditures deposited with PRD and recorded in other current liabilities as of December 31, 2020, respectively. As of September 30, 2021, PRD refunded the remaining $11.1 million of unapplied prepaid capital expenditures to BPP.

NOTE 10. COMMITMENTS AND CONTINGENCIES

The Company's operations are subject to all the operational and environmental risks normally associated with the crude oil and natural gas industry. Additionally, the Company may become involved from time to time in litigation on various matters which are routine to the conduct of its business. Management is not currently a party to any material litigation and is not aware of any litigation threatened against the Company that could have a material adverse effect on the Company.

Changes to current economic conditions may adversely affect the results of operations in future periods. The novel coronavirus ("COVID-19") pandemic significantly affected the global economy and created significant volatility in commodity prices during 2020. Commodity prices have recovered in 2021 based on rising demand as global economic activity increased in addition to sustained production cuts by the Organization of the Petroleum Exporting Countries ("OPEC"). However, uncertainty continues to exist regarding the recovery of global oil demand in future periods due to various factors and circumstances beyond the Company's control, such as the duration of the pandemic and variant strains of COVID-19, OPEC and other oil producing nations managing the global oil supply, government actions in response to the pandemic, global supply chain constraints, and cost inflation. The financial statements have been prepared using values and information currently available to the Company.

NOTE 11. SUBSEQUENT EVENTS

On October 1, 2021, the Primexx Entities closed the divestiture transaction with a subsidiary of Callon. The fair value of consideration received by the Company totaled $212.3 million and was comprised of $90.4 million of cash consideration and 2.42 million shares of Callon stock issued to the Company in exchange for its oil and gas leasehold interests and ownership interest in infrastructure assets, subject to the finalization of purchase price adjustments within 120 days of closing.

Upon closing, the Company used cash proceeds from the Callon Divestiture and cash on hand to unwind its outstanding derivative contracts for $21.5 million and pay down the outstanding principal balances and accrued interest related to the HPS term loan and the Credit Facility of $76.4 million and $7.6 million, respectively.

Subsequent events were evaluated through November 19, 2021, the date the condensed consolidated financial statements were available for issuance.

Exhibit 99.5

Callon Petroleum Company
Unaudited Pro Forma Condensed Combined Financial Information

The following unaudited pro forma condensed combined financial information is derived from the historical consolidated financial statements of Callon Petroleum Company ("Callon" or the "Company"), Primexx Resource Development, LLC ("Primexx") and BPP Acquisition, LLC ("BPP") and has been adjusted to reflect the following:

- Callon's acquisition of Primexx's assets consisting of certain producing oil and gas properties, undeveloped acreage and associated infrastructure assets in the Delaware Basin (the "Primexx Acquisition") for consideration of approximately $342.3 million in cash and 6.42 million shares of the Company's common stock (the "Primexx Stock Consideration"), subject to post-closing adjustments.
- Callon's acquisition of BPP's assets consisting of certain producing oil and gas properties, undeveloped acreage and associated infrastructure assets in the Delaware Basin (the "BPP Acquisition") for consideration of approximately $102.6 million in cash and 2.42 million shares of the Company's common stock (the "BPP Stock Consideration"), subject to post-closing adjustments.
- Callon's acquisition of additional interest in the assets described above from certain interest owners exercising their option to sell their interests (together with the Primexx Acquisition and the BPP Acquisition, the "Acquisitions") for consideration structured similar to the Primexx Acquisition and BPP Acquisition totaling approximately $19.8 million in cash and 0.34 million shares of the Company's common stock, subject to post-closing adjustments.
- Borrowings of approximately $464.7 million under the Company's senior secured revolving credit facility which were used to fund the Acquisitions (the "Borrowing").

Certain of Primexx's and BPP's historical amounts have been reclassified to conform to the financial statement presentation of Callon. Additionally, the adjustments columns in the unaudited pro forma condensed combined financial statements below include adjustments and eliminations made to Primexx's and BPP's historical financial information to reflect certain assets and liabilities retained by Primexx and BPP, respectively, as well as for intercompany eliminations necessary to combine Primexx and BPP as they have shareholders and management in common. The unaudited pro forma condensed combined balance sheet as of September 30, 2021 gives effect to the Acquisitions and Borrowing as if they had occurred on September 30, 2021. The unaudited pro forma condensed combined statements of operations for the year ended December 31, 2020 and the nine months ended September 30, 2021 both give effect to the Acquisitions and Borrowing as if they had occurred on January 1, 2020.

For income tax purposes, the Acquisitions will be treated as an asset purchase such that the tax bases in the assets and liabilities will generally reflect the allocated fair value at closing. Therefore, the Company does not anticipate a material tax consequence for deferred income taxes related to the Acquisitions. Additionally, Callon has not reflected any estimated tax impact related to the Acquisitions or Borrowing in the accompanying unaudited pro forma condensed combined statements of operations for the nine months ended September 30, 2021 or for the year ended December 31, 2020 because it does not anticipate the impact to be material due to the Company's net operating loss carryforwards. The Company's effective tax rate is not meaningful and is expected to remain as such due to the valuation allowance recorded against the Company's net deferred tax assets.

The following unaudited pro forma condensed combined financial information should be read in conjunction with Callon's consolidated financial statements and the related notes thereto, which are included in Callon's Annual Report on Form 10-K for the year ended December 31, 2020 and its Quarterly Report on Form 10-Q for the nine months ended September 30, 2021, and Primexx's and BPP's consolidated financial statements and the related notes thereto, which are included elsewhere in this filing.

Callon Petroleum Company
Unaudited Pro Forma Condensed Combined Balance Sheet
As of September 30, 2021
(In thousands)

	Historical			Transaction Accounting Adjustments		
	Callon - As Reported	Primexx - As Reported	BPP - As Reported	Elimination Adjustments (a)	Acquisitions and Borrowing	Pro Forma Combined
ASSETS						
Current assets:						
Cash and cash equivalents	$3,699	$11,724	$18,219	($29,943)	$7,981 (c)	$11,680
Accounts receivable, net	216,116	40,654	14,962	(55,616)		216,116
Fair value of derivatives	18,605	1,712	562	(2,274)		18,605
Other current assets	30,110	1,442	100	(1,542)	2,232 (c)	32,342
Total current assets	268,530	55,532	33,843	(89,375)	10,213	278,743
Oil and natural gas properties, full cost accounting method:						
Evaluated properties, net	2,565,601	361,000	108,505	(469,505)	623,389 (c)	3,188,990
Unevaluated properties	1,712,428	—	—		312,700 (c)	2,025,128
Total oil and natural gas properties, net	4,278,029	361,000	108,505	(469,505)	936,089	5,214,118
Other property and equipment, net	30,591	83,510	—	(83,510) (b)		30,591
Fair value of derivatives	—	6,161	1,549	(7,710)		—
Deferred financing costs	19,274	—	—			19,274
Loan origination cost, net	—	1,870	200	(2,070)		—
Investment in SFS	—	—	21,000	(21,000)		—
Other assets, net	89,992	1,136	—	(1,136)		89,992
Total assets	$4,686,416	$509,209	$165,097	($674,306)	$946,302	$5,632,718
LIABILITIES AND STOCKHOLDERS' EQUITY						
Current liabilities:						
Accounts payable and accrued liabilities	$442,053	$54,777	$15,554	($70,331)	$13,658 (c)	$455,711
Fair value of derivatives	324,682	39,477	12,799	(52,276)		324,682
Current portion of deferred revenue	—	2,797	—	(2,797)		—
Current portion of long-term debt, net	—	129,999	—	(129,999)		—
Other current liabilities	61,641	40,632	61	(40,693)	28,117 (c)	89,758
Total current liabilities	828,376	267,682	28,414	(296,096)	41,775	870,151
Long-term debt	2,809,610	296,889	81,300	(378,189)	464,678 (d)	3,274,288
Deferred revenue	—	22,531	—	(22,531)		—
Asset retirement obligations	58,703	5,327	763	(6,090)	1,870 (c)	60,573
Fair value of derivatives	15,250	29,707	8,578	(38,285)		15,250
Deferred tax liability	—	46	—	(46)		—
Other long-term liabilities	41,448	308	—	(308)	9,426 (c)	50,874
Total liabilities	3,753,387	622,490	119,055	(741,545)	517,749	4,271,136
Commitments and contingencies						
Redeemable Series B preferred units, net	—	575,325	—	(575,325)		—
Stockholders' equity:						
Common stock	463	—	—		92 (e)	555
Capital in excess of par value	3,365,121	—	—		428,461 (e)	3,793,582
Members' equity	—	—	46,042	(46,042)		—
Partners' equity (deficit)	—	(709,606)	—	709,606		—
Noncontrolling interest	—	21,000	—	(21,000)		—
Accumulated deficit	(2,432,555)	—	—	—		(2,432,555)
Total stockholders' equity	933,029	(688,606)	46,042	642,564	428,553	1,361,582
Total liabilities and stockholders' equity	$4,686,416	$509,209	$165,097	($674,306)	$946,302	$5,632,718

Callon Petroleum Company
Unaudited Pro Forma Condensed Combined Statement of Operations
For the Nine Months Ended September 30, 2021
(In thousands, except per share amounts)

	Historical			Transaction Accounting Adjustments		
	Callon - As Reported	Primexx - As Reported	BPP - As Reported	Reclassification & Elimination Adjustments (a)	Acquisitions and Borrowing	Pro Forma Combined
Operating Revenues:						
Oil	$1,009,780	$154,309	$49,870			$1,213,959
Natural gas	84,819	28,858	7,565	1,380		122,622
Natural gas liquids	124,079	—	—			124,079
Sales of purchased oil and gas	134,164	—	—			134,164
Field service revenue	—	9,985	—	(9,985) **(b)**		—
Total operating revenues	1,352,842	193,152	57,435	(8,605)	—	1,594,824
Operating Expenses:						
Lease operating	129,619	42,830	14,545	1,283 **(b)**		188,277
Production and ad valorem taxes	66,467	8,642	2,760	2,284 **(b)**		80,153
Gathering, transportation and processing	58,887	739	—			59,626
Field service expenses	—	9,474	—	(9,474) **(b)**		—
Cost of purchased oil and gas	139,558	—	—			139,558
Depreciation, depletion and amortization	244,005	51,073	12,040		(8,966) **(c)**	298,152
General and administrative	37,367	3,964	2,116			43,447
Impairment of evaluated oil and gas properties	—	—	—			—
Merger, integration and transaction	3,018	—	—			3,018
Other operating	3,366	—	—			3,366
Total operating expenses	682,287	116,722	31,461	(5,907)	(8,966)	815,597
Income (Loss) From Operations	670,555	76,430	25,974	(2,698)	8,966	779,227
Other (Income) Expenses:						
Interest expense, net of capitalized amounts	76,786	27,346	6,582	(33,928)	(1,016) **(d)**	75,770
Loss on derivative contracts	512,155	101,218	34,751	(135,969)		512,155
Gain on extinguishment of debt	(2,420)	—	—			(2,420)
Equity in earnings of SFS	—	—	(4,485)	4,485		—
Other (income) expense	3,217	(2,174)	(39)	2,213		3,217
Total other (income) expense	589,738	126,390	36,809	(163,199)	(1,016)	588,722
Income (Loss) Before Income Taxes	80,817	(49,960)	(10,835)	160,501	9,982	190,505
Income tax expense	(1,017)	(40)	—			(1,057)
Net Income (Loss)	$79,800	($50,000)	($10,835)	$160,501	$9,982	$189,448
Net loss attributable to noncontrolling interest	—	(4,485)	—	4,485		—
Series B preferred unit distribution	—	(55,705)	—	55,705		—
Income (Loss) Available to Stockholders	$79,800	($110,190)	($10,835)	$220,691	$9,982	$189,448
Net Income (Loss) Per Common Share:						
Basic	$1.77					$3.49
Diluted	$1.69					$3.36
Weighted Average Common Shares Outstanding:						
Basic	45,063				9,181 **(e)**	54,244
Diluted	47,119				9,181 **(e)**	56,300

Callon Petroleum Company
Unaudited Pro Forma Condensed Combined Statement of Operations
For the Year Ended December 31, 2020
(In thousands, except per share amounts)

	Historical			Transaction Accounting Adjustments		
	Callon - As Reported	Primexx - As Reported	BPP - As Reported	Reclassification & Elimination Adjustments (a)	Acquisitions and Borrowing	Pro Forma Combined
Operating Revenues:						
Oil	$850,667	$139,776	$42,544			$1,032,987
Natural gas	51,866	10,627	1,128	1,513		65,134
Natural gas liquids	81,295	—	—			81,295
Sales of purchased oil and gas	49,319	—	—			49,319
Field service revenue	—	8,450	—	(8,450) **(b)**		—
Total operating revenues	1,033,147	158,853	43,672	(6,937)	—	1,228,735
Operating Expenses:						
Lease operating	194,101	46,808	14,042	4,010 **(b)**		258,961
Production and ad valorem taxes	62,638	6,994	2,126	4,207 **(b)**		75,965
Gathering, transportation and processing	77,309	1,868	—			79,177
Field service expenses	—	11,677	—	(11,677) **(b)**		—
Cost of purchased oil and gas	51,766	—	—			51,766
Depreciation, depletion and amortization	480,631	106,047	28,660		(47,376) **(c)**	567,962
General and administrative	37,187	7,477	3,273			47,937
Impairment of evaluated oil and gas properties	2,547,241	457,502	163,223			3,167,966
Merger, integration and transaction	28,482	—	—			28,482
Other operating	10,644	—	—			10,644
Total operating expenses	3,489,999	638,373	211,324	(3,460)	(47,376)	4,288,860
Income (Loss) From Operations	(2,456,852)	(479,520)	(167,652)	(3,477)	47,376	(3,060,125)
Other (Income) Expenses:						
Interest expense, net of capitalized amounts	94,329	40,138	7,980	(48,118)	(50) **(d)**	94,279
(Gain) loss on derivative contracts	27,773	(93,256)	(34,279)	127,535		27,773
(Gain) loss on extinguishment of debt	(170,370)	—	—			(170,370)
Equity in (earnings) loss of SFS	—	—	550	(550)		—
Other (income) expense	2,983	(2,882)	—	2,882		2,983
Total other (income) expense	(45,285)	(56,000)	(25,749)	81,749	(50)	(45,335)
Income (Loss) Before Income Taxes	(2,411,567)	(423,520)	(141,903)	(85,226)	47,426	(3,014,790)
Income tax benefit (expense)	(122,054)	6	—			(122,048)
Net Income (Loss)	($2,533,621)	($423,514)	($141,903)	($85,226)	$47,426	($3,136,838)
Net gain (loss) attributable to noncontrolling interest	—	550	—	(550)		—
Series B preferred unit distribution	—	(66,148)	—	66,148		—
Income (Loss) Available to Stockholders	($2,533,621)	($489,112)	($141,903)	($19,628)	$47,426	($3,136,838)
Net Income (Loss) Per Common Share:						
Basic	($63.79)					($64.15)
Diluted	($63.79)					($64.15)
Weighted Average Common Shares Outstanding:						
Basic	39,718				9,181 **(e)**	48,899
Diluted	39,718				9,181 **(e)**	48,899

Notes to the Unaudited Pro Forma Consolidated Financial Statements

Note 1 - Basis of Presentation

On October 1, 2021, Callon and Callon Petroleum Operating Company, Callon's wholly owned subsidiary, completed its acquisition of certain producing oil and gas properties, undeveloped acreage and associated infrastructure assets in the Delaware Basin for total consideration of $464.7 million in cash and 9.18 million shares of the Company's common stock, subject to post-closing adjustments.

The historical consolidated financial statements have been adjusted in the unaudited pro forma condensed combined financial statements to give effect to pro forma adjustments that are directly attributable to the Acquisitions and Borrowing. The preparation of the unaudited pro forma condensed combined financial statements is in accordance with accounting principles generally accepted in the United States of America. These principles require the use of estimates that affect the reported amounts of revenues and expenses. Actual results could differ from those estimates. The unaudited pro forma condensed combined financial statements are presented for illustrative purposes only to reflect the Acquisitions and Borrowing and do not purport to represent the Company's financial position or what the actual results of operations would have been had the transaction occurred on the respective dates assumed, nor is it necessarily indicative of the Company's future operating results. However, the pro forma adjustments reflected in the unaudited pro forma condensed combined financial statements reflect estimates and assumptions that the Company's management believes to be reasonable. In the opinion of management, all adjustments necessary to present fairly the unaudited pro forma condensed combined financial statements have been made.

Note 2 - Unaudited Pro Forma Condensed Combined Balance Sheet

Adjustments to the Unaudited Pro Forma Condensed Combined Balance Sheet as of September 30, 2021

Reclassification & Elimination Adjustments

The following adjustments have been made to the accompanying unaudited pro forma condensed combined balance sheet as of September 30, 2021 to reclassify certain of Primexx's and BPP's historical amounts to conform to the historical presentation of Callon and to eliminate certain assets and liabilities retained by Primexx and BPP:

a) Represents the elimination of Primexx and BPP balances. See "Acquisitions and Borrowing Adjustments" below for discussion of the assets acquired and liabilities assumed in the Acquisitions.
b) Reflects the elimination of other property and equipment, net associated with Saragosa Field Services ("SFS") as the Company has incorporated those assets into its oil and natural gas properties, net. Upon closing of the Primexx Acquisition and BPP Acquisition, the Company dissolved the SFS entity.

Acquisitions and Borrowing Adjustments

The following adjustments have been made to the accompanying unaudited pro forma condensed combined balance sheet as of September 30, 2021 to reflect the Acquisitions and Borrowing:

c) The Acquisitions will be accounted for as a single transaction because they were entered into at the same time and in contemplation of one another and form a single transaction designed to achieve an overall economic effect. The Acquisitions will be accounted for as a business combination whereby the purchase price is allocated to assets acquired and liabilities assumed based on their estimated acquisition date fair values based on information available at that time. While the Company's valuation procedures are currently in process, it is using a combination of a discounted cash flow model and market data in determining the fair value of the oil and gas properties. Significant inputs into the calculation include future commodity prices, estimated volumes of oil and gas reserves, expectations for timing and amount of future development and operating costs, future plugging and abandonment costs and a risk adjusted discount rate. The current preliminary purchase price allocation is based on a preliminary discounted cash flow analysis. The purchase price allocation for the Acquisitions is subject to change based on the Company's finalization of its valuation procedures as well as purchase price adjustments, which will primarily relate to the revenues, operating expenses and capital expenditures from the effective date to the closing date. The preliminary allocation of the purchase price as of the acquisition date is presented below:

	Purchase Price Allocation
	(In thousands)
Assets	
Current assets	$10,213
Oil and natural gas properties	
Evaluated properties	623,389
Unevaluated properties	312,700
Total oil and natural gas properties	936,089
Total assets acquired	$946,302
Liabilities	
Suspense payable	$13,658
Other current liabilities	28,117
Total current liabilities	41,775
Asset retirement obligations	1,870
Other long-term liabilities	9,426
Total liabilities assumed	$53,071
Net Assets Acquired	$893,231

d) Reflects $464.7 million of borrowings under Callon's senior secured revolving credit facility which were used to fund the Acquisitions.
e) Reflects the increase in Callon's common stock and additional paid-in capital resulting from the issuance of Callon shares for the Acquisitions.

Note 3 - Unaudited Pro Forma Condensed Combined Statement of Operations

Adjustments to the Unaudited Pro Forma Condensed Combined Statement of Operations for the nine months ended September 30, 2021

Reclassification & Elimination Adjustments

The following adjustments have been made to the accompanying unaudited pro forma condensed combined statement of operations for the nine months ended September 30, 2021 to reclassify certain of Primexx's and BPP's historical amounts to conform to the historical presentation of Callon and to eliminate the effects of certain assets and liabilities retained by Primexx and BPP:

a) Represents adjustments to eliminate the effects of assets and liabilities retained by Primexx and BPP and not associated with the oil and natural gas properties acquired.
b) Reflects the elimination of separate revenue and expense line items associated with SFS, a consolidated subsidiary of Primexx, as the Company has incorporated all SFS operations and activities into its ongoing oil and gas operations. Upon closing of the Primexx Acquisition and BPP Acquisition, the Company dissolved the SFS entity.

Acquisitions and Borrowing Adjustments

The following adjustments have been made to the accompanying unaudited pro forma condensed combined statement of operations for the nine months ended September 30, 2021 to reflect the Acquisitions and Borrowing:

c) Reflects adjustment to depreciation, depletion and amortization expense resulting from the change in basis of evaluated properties acquired.
d) Reflects the following adjustments to interest expense, net of capitalized amounts:
    - $8.8 million increase in interest expense as a result of the Borrowing,
    - $1.7 million decrease in interest expense to reflect the reduction in commitment fees as a result of the Borrowing, and
    - $8.1 million increase in capitalized interest as a result of the effects of the Acquisitions and Borrowing.
e) Reflects 9.18 million shares of Callon common stock issued as a portion of the consideration for the Acquisitions.

Adjustments to the Unaudited Pro Forma Condensed Combined Statement of Operations for the year ended December 31, 2020

Reclassification & Elimination Adjustments

The following adjustments have been made to the accompanying unaudited pro forma condensed combined statement of operations for the year ended December 31, 2020 to reclassify certain of Primexx's and BPP's historical amounts to conform to the historical presentation of Callon and to eliminate the effects of certain assets and liabilities retained by Primexx and BPP:

a) Represents adjustments to eliminate the effects of assets and liabilities retained by Primexx and BPP and not associated with the oil and natural gas properties acquired.
b) Reflects the elimination of separate revenue and expense line items associated with SFS, a consolidated subsidiary of Primexx, as the Company has incorporated all SFS operations and activities into its ongoing oil and gas operations. Upon closing of the Primexx Acquisition and BPP Acquisition, the Company dissolved the SFS entity.

Acquisitions and Borrowing Adjustments

The following adjustments have been made to the accompanying unaudited pro forma condensed combined statement of operations for the year ended December 31, 2020 to reflect the Acquisitions and Borrowing:

c) Reflects adjustment to depreciation, depletion and amortization expense resulting from the change in basis of evaluated properties acquired.
d) Reflects the following adjustments to interest expense, net of capitalized amounts:
    - $13.5 million increase in interest expense as a result of the Borrowing,
    - $2.3 million decrease in interest expense to reflect the reduction in commitment fees as a result of the Borrowing, and
    - $11.3 million increase in capitalized interest as a result of the effects of the Acquisitions and Borrowing.
e) Reflects 9.18 million shares of Callon common stock issued as a portion of the consideration for the Acquisitions.

Note 4 - Supplemental Pro Forma Oil and Gas Information

The following tables present the estimated pro forma combined net proved developed and undeveloped oil and natural gas reserves as of December 31, 2020 for Callon, Primexx and BPP, along with a summary of changes in the quantities of net remaining proved reserves during the year ended December 31, 2020. The pro forma reserve information set forth below gives effect to the Acquisitions as if they had been completed on January 1, 2020.

Reserve estimates are inherently imprecise. As such, actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from the estimates.

	Historical			
	Callon - As Reported	Primexx - As Reported	BPP - As Reported	Pro Forma Combined
Total proved reserves				
Oil (MBbls)				
Balance as of January 1, 2020	346,361	71,149	22,931	440,441
Purchase of reserves in place	—	—	60	60
Sale of reserves in place	(9,673)	(53)	—	(9,726)
Extensions and discoveries	25,678	14,225	5,979	45,882
Revisions to previous estimates	(49,336)	(26,722)	(9,883)	(85,941)
Production	(23,543)	(3,789)	(1,154)	(28,486)
Balance as of December 31, 2020	289,487	54,810	17,933	362,230
Natural Gas (MMcf)				
Balance as of January 1, 2020	757,134	97,183	30,761	885,078
Purchase of reserves in place	—	—	135	135
Sale of reserves in place	(20,389)	(97)	—	(20,486)
Extensions and discoveries	44,282	23,402	10,416	78,100
Revisions to previous estimates	(198,628)	(26,490)	(9,947)	(235,065)
Production	(40,801)	(5,669)	(1,839)	(48,309)
Balance as of December 31, 2020	541,598	88,329	29,526	659,453
NGLs (MBbls)				
Balance as of January 1, 2020	67,462	18,064	5,471	90,997
Purchase of reserves in place	—	—	25	25
Sale of reserves in place	(3,049)	(21)	—	(3,070)
Extensions and discoveries	8,349	4,324	1,875	14,548
Revisions to previous estimates	30,214	(5,010)	(1,688)	23,516
Production	(6,850)	(1,019)	(330)	(8,199)
Balance as of December 31, 2020	96,126	16,338	5,353	117,817
Total (MBoe)				
Balance as of January 1, 2020	540,012	105,411	33,529	678,952
Purchase of reserves in place	—	—	108	108
Sale of reserves in place	(16,120)	(90)	—	(16,210)
Extensions and discoveries	41,407	22,449	9,591	73,447
Revisions to previous estimates	(52,227)	(36,147)	(13,230)	(101,604)
Production	(37,193)	(5,753)	(1,791)	(44,737)
Balance as of December 31, 2020	475,879	85,870	28,207	589,956

	Historical			
	Callon - As Reported	Primexx - As Reported	BPP - As Reported	Pro Forma Combined
Proved developed reserves				
Oil (MBbls)				
Balance as of January 1, 2020	152,687	16,616	5,411	174,714
Balance as of December 31, 2020	128,923	12,958	3,630	145,511
Natural gas (MMcf)				
Balance as of January 1, 2020	320,676	24,717	8,060	353,453
Balance as of December 31, 2020	238,119	24,419	6,734	269,272
NGLs (MBbls)				
Balance as of January 1, 2020	24,844	4,529	1,392	30,765
Balance as of December 31, 2020	43,315	4,509	1,225	49,049
Total proved developed reserves (MBoe)				
Balance as of January 1, 2020	230,977	25,265	8,146	264,388
Balance as of December 31, 2020	211,925	21,537	5,977	239,439
Proved undeveloped reserves				
Oil (MBbls)				
Balance as of January 1, 2020	193,674	54,533	17,520	265,727
Balance as of December 31, 2020	160,564	41,852	14,303	216,719
Natural gas (MMcf)				
Balance as of January 1, 2020	436,458	72,466	22,701	531,625
Balance as of December 31, 2020	303,479	63,910	22,792	390,181
NGLs (MBbls)				
Balance as of January 1, 2020	42,618	13,535	4,079	60,232
Balance as of December 31, 2020	52,811	11,829	4,128	68,768
Total proved undeveloped reserves (MBoe)				
Balance as of January 1, 2020	309,035	80,146	25,383	414,564
Balance as of December 31, 2020	263,954	64,333	22,230	350,517
Total proved reserves				
Oil (MBbls)				
Balance as of January 1, 2020	346,361	71,149	22,931	440,441
Balance as of December 31, 2020	289,487	54,810	17,933	362,230
Natural gas (MMcf)				
Balance as of January 1, 2020	757,134	97,183	30,761	885,078
Balance as of December 31, 2020	541,598	88,329	29,526	659,453
NGLs (MBbls)				
Balance as of January 1, 2020	67,462	18,064	5,471	90,997
Balance as of December 31, 2020	96,126	16,338	5,353	117,817
Total proved reserves (MBoe)				
Balance as of January 1, 2020	540,012	105,411	33,529	678,952
Balance as of December 31, 2020	475,879	85,870	28,207	589,956

The pro forma standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves as of December 31, 2020 is as follows:

	Historical			
	Callon - As Reported	Primexx - As Reported	BPP - As Reported	Pro Forma Combined
	(In thousands)			
Future cash inflows	$12,458,033	$2,118,782	$705,019	$15,281,834
Future costs				
Production	(5,433,496)	(881,455)	(317,487)	(6,632,438)
Development and net abandonment	(2,204,301)	(619,403)	(203,563)	(3,027,267)
Future net inflows before income taxes	4,820,236	617,924	183,969	5,622,129
Future income taxes	(65,405)	—	—	(65,405)
Future net cash flows	4,754,831	617,924	183,969	5,556,724
10% discount factor	(2,444,441)	(329,785)	(96,586)	(2,870,812)
Standardized measure of discounted future net cash flows	$2,310,390	$288,139	$87,383	$2,685,912

The changes in the pro forma standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves for the year ended December 31, 2020 are as follows:

	Historical			
	Callon - As Reported	Primexx - As Reported	BPP - As Reported	Pro Forma Combined
	(In thousands)			
Standardized measure at the beginning of the period	$4,951,026	$833,401	$253,665	$6,038,092
Sales and transfers, net of production costs	(649,781)	(94,733)	(27,504)	(772,018)
Net change in sales and transfer prices, net of production costs	(2,719,579)	(179,308)	(68,124)	(2,967,011)
Net change due to purchases of in place reserves	—	—	340	340
Net change due to sales of in place reserves	(202,928)	(222)	—	(203,150)
Extensions, discoveries, and improved recovery, net of future production and development costs incurred	250,759	61,236	33,182	345,177
Changes in future development cost	361,008	382,499	131,911	875,418
Previously estimated development costs incurred	318,470	35,167	8,564	362,201
Revisions of quantity estimates	(671,800)	(226,579)	(127,191)	(1,025,570)
Accretion of discount	536,958	83,340	25,367	645,665
Net change in income taxes	383,999	—	—	383,999
Changes in production rates, timing and other	(247,742)	(606,662)	(142,827)	(997,231)
Aggregate change	(2,640,636)	(545,262)	(166,282)	(3,352,180)
Standardized measure at the end of the period	$2,310,390	$288,139	$87,383	$2,685,912

Exhibit 99.6

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

October 27, 2021

Primexx Operating Corporation
Two Energy Square
4849 Greenville Avenue, Suite 1600
Dallas, Texas 75206

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2020, to the Primexx Resource Development, LLC (PRD) interest in certain oil and gas properties located in Reeves County, Texas. Also included is PRD's share of the volumes, fees, and revenue for its interest in Saragosa Field Services, LLC (SFS), which provides gas gathering services. It is our understanding that Primexx Operating Corporation (Primexx) is a wholly owned subsidiary of PRD. It is also our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by PRD at the as-of date of this report. We completed our evaluation on or about February 4, 2021. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Callon Petroleum Company's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the PRD interest in these properties, as of December 31, 2020, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	12,957.5	4,508.8	24,418.6	235,934.9	167,655.0
Proved Undeveloped	41,852.0	11,829.0	63,909.5	381,988.9	120,484.4
Total Proved	54,809.5	16,337.8	88,328.1	617,923.8	288,139.4

Totals may not add because of rounding.

Note: The oil reserves and future net revenue include PRD's share of the volumes, fees, and revenue for its interest in SFS. For the purposes of this report, PRD's share of the SFS revenue excludes fees paid by third parties.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2020, there are no proved developed non-producing reserves for these properties. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

Gross revenue is PRD's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for PRD's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2020. For oil and NGL volumes, the average West Texas Intermediate spot price of $39.54 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $1.985 per MMBTU is adjusted for energy content, transportation fees, and market differentials; for certain properties, gas prices are negative after adjustments. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $36.18 per barrel of oil, $8.34 per barrel of NGL, and -$0.005 per MCF of gas.

Operating costs used in this report are based on operating expense records of Primexx and SFS. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Primexx are included to the extent that they are covered under joint operating agreements for the Primexx-operated properties. PRD's working interest share of fees paid to SFS for gas gathering is offset by PRD's share of the SFS revenue; these fees have been included at the field level and, therefore, do not affect the future net revenue or economic limits at the well level. For the purposes of this report, PRD's share of the SFS revenue excludes fees paid by third parties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Primexx and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are our estimates of the costs to abandon the wells, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the PRD interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on PRD receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the Primexx-operated properties will be developed consistent with current development plans as provided to us by Primexx, that the nonoperated properties will be developed consistent with recent history, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with

actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, geologic maps, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Primexx, other interest owners, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Michael J. Kingrey, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2015 and has over 6 years of prior industry experience. William J. Knights, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Michael J. Kingrey
Michael J. Kingrey, P.E. 128848
Vice President

Date Signed: October 27, 2021

By: /s/ William J. Knights
William J. Knights, P.G. 1532
Vice President

Date Signed: October 27, 2021

MJK:KAT

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs*. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:
  (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty

through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*

b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*

c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*

d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*

f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.7

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

October 26, 2021

Primexx Operating Corporation
Two Energy Square
4849 Greenville Ave, Suite 1600
Dallas, Texas 75206

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2019, to the Primexx Resource Development, LLC (PRD) interest in certain oil and gas properties located in Reeves County, Texas. Also included is PRD's share of the volumes, fees, and revenue for its interest in Saragosa Field Services, LLC (SFS), which provides gas gathering and gas lift services. It is our understanding that Primexx Operating Corporation (Primexx) is a wholly owned subsidiary of PRD. It is also our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by PRD at the as-of date of this report. We completed our evaluation on or about January 31, 2020. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Callon Petroleum Company's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the PRD interest in these properties, as of December 31, 2019, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	16,615.6	4,529.0	24,717.3	531,912.8	353,975.9
Proved Undeveloped	54,532.7	13,534.9	72,466.1	1,124,795.4	479,424.8
Total Proved	71,148.4	18,063.9	97,183.4	1,656,708.0	833,400.6

Totals may not add because of rounding.

Note: The oil reserves and future net revenue include PRD's share of the volumes, fees, and revenue for its interest in SFS. For the purposes of this report, PRD's share of the SFS revenue excludes fees paid by third parties.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2019, there are no proved developed non-producing reserves for these properties. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

Gross revenue is PRD's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for PRD's share of production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2019. For oil and NGL volumes, the average West Texas Intermediate spot price of $55.85 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.578 per MMBTU is adjusted for energy content, transportation fees, and market differentials; for certain properties, gas prices are negative after adjustments. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $46.51 per barrel of oil, $18.14 per barrel of NGL, and -$0.154 per MCF of gas.

Operating costs used in this report are based on operating expense records of Primexx and SFS. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels; included in these costs are estimated costs for artificial lift installations. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Primexx are included to the extent that they are covered under joint operating agreements for the Primexx-operated properties. PRD's working interest share of fees paid to SFS for gas gathering and gas lift services are offset by PRD's share of the SFS revenue; these fees have been included at the field level and, therefore, do not affect the future net revenue or economic limits at the well level. For the purposes of this report, PRD's share of the SFS revenue excludes fees paid by third parties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Primexx and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the PRD interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on PRD receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the Primexx-operated properties will be developed consistent with current development plans as provided to us by Primexx, that the nonoperated properties will be developed consistent with recent history, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the

interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, geologic maps, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Primexx, other interest owners, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Michael J. Kingrey, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2015 and has over 6 years of prior industry experience. William J. Knights, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Michael J. Kingrey
Michael J. Kingrey, P.E. 128848
Vice President

Date Signed: October 26, 2021

By: /s/ William J. Knights
William J. Knights, P.G. 1532
Vice President

Date Signed: October 26, 2021

MJK:KAT

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs*. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:
  (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty

through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*

b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*

c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*

d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*

f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.8

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

October 27, 2021

Primexx Operating Corporation
Two Energy Square
4849 Greenville Avenue, Suite 1600
Dallas, Texas 75206

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2020, to the BPP Acquisition LLC (BPP) interest in certain oil and gas properties located in Reeves County, Texas. Also included is BPP's share of the volumes, fees, and revenue for its interest in Saragosa Field Services, LLC (SFS), which provides gas gathering services. It is our understanding that Primexx Operating Corporation (Primexx) conducts all oil and gas operations for BPP. It is also our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by BPP at the as-of date of this report. We completed our evaluation on or about February 4, 2021. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Callon Petroleum Company's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the BPP interest in these properties, as of December 31, 2020, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	3,630.3	1,225.0	6,733.6	60,891.4	45,008.6
Proved Undeveloped	14,303.3	4,128.1	22,791.7	123,077.4	42,374.3
Total Proved	17,933.5	5,353.2	29,525.3	183,968.9	87,382.9

Totals may not add because of rounding.

Note: The oil reserves and future net revenue include BPP's share of the volumes, fees, and revenue for its interest in SFS. For the purposes of this report, BPP's share of the SFS revenue excludes fees paid by third parties.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2020, there are no proved developed non-producing reserves for these properties. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

Gross revenue is BPP's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for BPP's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2020. For oil and NGL volumes, the average West Texas Intermediate spot price of $39.54 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $1.985 per MMBTU is adjusted for energy content, transportation fees, and market differentials; for certain properties, gas prices are negative after adjustments. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $36.62 per barrel of oil, $8.32 per barrel of NGL, and $0.130 per MCF of gas.

Operating costs used in this report are based on operating expense records of Primexx and SFS. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Primexx are included to the extent that they are covered under joint operating agreements for the Primexx-operated properties. BPP's working interest share of fees paid to SFS for gas gathering is offset by BPP's share of the SFS revenue; these fees have been included at the field level and, therefore, do not affect the future net revenue or economic limits at the well level. For the purposes of this report, BPP's share of the SFS revenue excludes fees paid by third parties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Primexx and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are our estimates of the costs to abandon the wells, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the BPP interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on BPP receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the Primexx-operated properties will be developed consistent with current development plans as provided to us by Primexx, that the nonoperated properties will be developed consistent with recent history, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with

actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, geologic maps, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Primexx, other interest owners, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Michael J. Kingrey, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2015 and has over 6 years of prior industry experience. William J. Knights, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Michael J. Kingrey
Michael J. Kingrey, P.E. 128848
Vice President

Date Signed: October 27, 2021

By: /s/ William J. Knights
William J. Knights, P.G. 1532
Vice President

Date Signed: October 27, 2021

MJK:KAT

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs*. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:
  (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty

through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*

b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*

c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*

d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*

f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.9

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

October 26, 2021

Primexx Operating Corporation
Two Energy Square
4849 Greenville Ave, Suite 1600
Dallas, Texas 75206

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2019, to the BPP Acquisition LLC (BPP) interest in certain oil and gas properties located in Reeves County, Texas. Also included is BPP's share of the volumes, fees, and revenue for its interest in Saragosa Field Services, LLC (SFS), which provides gas gathering and gas lift services. It is our understanding that Primexx Operating Corporation (Primexx) conducts all oil and gas operations for BPP. It is also our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by BPP at the as-of date of this report. We completed our evaluation on or about January 31, 2020. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Callon Petroleum Company's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the BPP interest in these properties, as of December 31, 2019, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	5,410.6	1,391.5	8,060.2	171,441.8	116,167.3
Proved Undeveloped	17,520.0	4,079.3	22,701.4	333,224.6	137,497.8
Total Proved	22,930.6	5,470.8	30,761.6	504,666.5	253,665.1

Totals may not add because of rounding.

Note: The oil reserves and future net revenue include BPP's share of the volumes, fees, and revenue for its interest in SFS. For the purposes of this report, BPP's share of the SFS revenue excludes fees paid by third parties.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2019, there are no proved developed non-producing reserves for these properties. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

Gross revenue is BPP's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for BPP's share of production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2019. For oil and NGL volumes, the average West Texas Intermediate spot price of $55.85 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.578 per MMBTU is adjusted for energy content, transportation fees, and market differentials; for certain properties, gas prices are negative after adjustments. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $46.10 per barrel of oil, $18.32 per barrel of NGL, and -$0.021 per MCF of gas.

Operating costs used in this report are based on operating expense records of Primexx and SFS. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels; included in these costs are estimated costs for artificial lift installations. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Primexx are included to the extent that they are covered under joint operating agreements for the Primexx-operated properties. BPP's working interest share of fees paid to SFS for gas gathering and gas lift services are offset by BPP's share of the SFS revenue; these fees have been included at the field level and, therefore, do not affect the future net revenue or economic limits at the well level. For the purposes of this report, BPP's share of the SFS revenue excludes fees paid by third parties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Primexx and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the BPP interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on BPP receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the Primexx-operated properties will be developed consistent with current development plans as provided to us by Primexx, that the nonoperated properties will be developed consistent with recent history, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the

interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, geologic maps, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Primexx, other interest owners, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Michael J. Kingrey, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2015 and has over 6 years of prior industry experience. William J. Knights, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Michael J. Kingrey
Michael J. Kingrey, P.E. 128848
Vice President

Date Signed: October 26, 2021

By: /s/ William J. Knights
William J. Knights, P.G. 1532
Vice President

Date Signed: October 26, 2021

MJK:KAT

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs*. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:
  (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty

through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*

b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*

c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*

d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*

f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.