UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☑ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2018

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number: **001-38019**

ENERGY XXI GULF COAST, INC.

(*Exact name of registrant as specified in its charter*)

Delaware	**20-4278595**
(*State or other jurisdiction of incorporation or organization*)	(*I.R.S. Employer Identification Number*)
1021 Main, Suite 2626 **Houston, Texas**	**77002**
(*Address of principal executive offices*)	(*Zip Code*)

(713) 351-3000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of “large accelerated filer” “accelerated filer” “smaller reporting company” and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☐	Accelerated filer	☑
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

(Do not check if a smaller reporting company)

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

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☑ No ☐

As of May 4, 2018, there were 33,280,813 shares outstanding of the registrant’s common stock, par value $0.01 per share.

ENERGY XXI GULF COAST, INC.

TABLE OF CONTENTS

GLOSSARY OF TERMS

Industry Terms

Below is a list of terms that are common to our industry and where applicable used throughout this Quarterly Report:

Bbl	Standard barrel containing 42 U.S. gallons	**MMBbl**	One million Bbls
Mcf	One thousand cubic feet	**MMcf**	One million cubic feet
Btu	One British thermal unit	**MMBtu**	One million Btu
BOE	Barrel of oil equivalent. Natural gas is converted into one BOE based on six Mcf of gas to one barrel of oil	**MBOE**	One thousand BOEs
DD&A	Depreciation, Depletion and Amortization	**MMBOE**	One million BOEs
Bcf	One billion cubic feet	**NGLs**	Natural gas liquids
BPD	Barrels per day		

Completion refers to the work performed and the installation of permanent equipment for the production of natural gas and/or crude oil from a recently drilled or recompleted well.

Costs and expenses include direct and indirect expenses, including general and administrative expenses, incurred to manage, operate and maintain wells and related equipment and facilities.

Development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry Well is an exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Exploitation is activity undertaken to increase value or realize full value in oil and natural gas field.

Exploratory well is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well or a service well.

Field is 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. For a complete definition of a field, refer to Rule 4-10(a)(8) of Regulation S-X as promulgated by the Securities and Exchange Commission (“SEC”).

Formation is a stratum of rock that is recognizable from adjacent strata consisting mainly of a certain type of rock or combination of rock types with thickness that may range from less than two feet to hundreds of feet.

Gathering and transportation is the cost of moving crude oil or natural gas to the point of sale.

GoM Shelf is an area offshore on the U.S. Gulf of Mexico continental shelf, generally characterized by less than 1,000 feet of water.

Gross acres or gross wells are the total acres or wells in which a working interest is owned.

Horizon is a zone of a particular formation or that part of a formation of sufficient porosity and permeability to form a petroleum reservoir.

Independent oil and gas company is a company that is primarily engaged in the exploration and production sector of the oil and gas business.

Lease operating or well operating expenses are expenses incurred to operate the wells and equipment on a producing lease.

Net acreage and net oil and gas wells are obtained by multiplying gross acreage and gross oil and gas wells by the fractional working interest owned in the properties.

NGL refers to natural gas liquids.

Oil includes crude oil and condensate.

Pipeline facility fee is the straight line lease expense attributable to certain real and personal property constituting a subsea pipeline gathering system located in the shallow GoM Shelf and storage and onshore processing facilities at Grand Isle, Louisiana ("GIGS").

Plugging and abandonment refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from a stratum will not escape into another or to the surface and the removal of associated equipment. Regulations of many states and the federal government require the plugging of abandoned wells.

Production costs are costs incurred to operate and maintain our wells and related equipment and facilities. For a complete definition of production costs, please refer to Rule 4-10(a)(20) of Regulation S-X as promulgated by the SEC.

Productive well is an exploratory, development or extension well that is not a dry well.

Proved area refers to the part of a property to which proved reserves have been specifically attributed.

Proved 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. For a complete definition of proved reserves, refer to Rule 4-10(a)(22) of Regulation S-X as promulgated by the SEC.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. For a complete definition of proved developed oil and gas reserves, refer to Rule 4-10(a)(3) of Regulation S-X as promulgated by the SEC.

Proved undeveloped reserves are reserves 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. For a complete definition of proved undeveloped oil and gas reserves, refer to Rule 4-10(a)(4) of Regulation S-X as promulgated by the SEC.

Reservoir refers to 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.

Seismic is an exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formations. 2-D seismic provides two-dimensional information and 3-D seismic provides three-dimensional pictures.

Unevaluated properties refers to properties for which a determination has not been made as to whether the property contains proved reserves.

Working interest is the operating interest that gives the owner a share of production and the right to drill, produce and conduct operating activities on the property.

Workover refers to the operations on a producing well to restore or increase production and such costs are expensed. If the operations add new proved reserves, such costs are capitalized.

Zone is a stratigraphic interval containing one or more reservoirs.

Other Terms

Tax Code means the Internal Revenue Code of 1986, as amended, including changes made by the Tax Cuts and Jobs Act of 2017 (as defined below).

Tax Cuts and Jobs Act of 2017 refers to tax legislation commonly referred to as the Tax Cuts and Jobs Act of 2017, enacted on December 22, 2017.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain statements and information in this Quarterly Report may constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. The words “believe,” “expect,” “anticipate,” “plan,” “intend,” “foresee,” “should,” “would,” “could” or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments as well as other factors the Company believes are appropriate under the circumstances and their potential effect on us. While management believes that these forward-looking statements are reasonable, such statements are not guarantees of future performance and the actual results or developments anticipated may not be realized or, even if substantially realized, may not have the expected consequences to or effects on the Company’s business or results. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to those summarized below:

- our ability to maintain sufficient liquidity and/or obtain adequate additional financing necessary to (i) maintain our infrastructure, particularly in light of its maturity, high fixed costs, and required level of maintenance and repairs compared to other GoM Shelf producers, (ii) fund our operations and capital expenditures, (iii) execute our business plan, develop our proved undeveloped reserves within five years and (iv) meet our other obligations, including plugging and abandonment and decommissioning obligations;
- disruption of operations and damages due to maintenance or repairs of infrastructure and equipment and our ability to predict or prevent excessive resulting production downtime within our mature field areas;
- our future financial condition, results of operations, revenues, expenses and cash flows;
- our current or future levels of indebtedness, liquidity, compliance with financial covenants and our ability to continue as a going concern;
- the effects of the departure of our former senior leaders and the hiring of a new Chief Executive Officer (“CEO”), Chief Operating Officer (“COO”) and Chief Financial Officer (“CFO”) on our employees, suppliers, regulators and business counterparties;
- recent changes (including announced future changes) in the composition of our board of directors of the Company (the “Board”);
- our inability to retain and attract key personnel;
- our ability to post collateral for current or future bonds or comply with any new regulations or Notices to Lessees and Operators (“NTLs”) imposed by the Bureau of Ocean Energy Management (the “BOEM”);
- our ability to comply with covenants under the three-year secured credit facility (the “Exit Facility”);
- changes in our business strategy;
- sustained declines in the prices we receive for our oil and natural gas production;
- economic slowdowns that can adversely affect consumption of oil and natural gas by businesses and consumers;
- geographic concentration of our assets;
- our ability to make acquisitions and to integrate acquisitions;

- our ability to develop, explore for, acquire and replace oil and natural gas reserves and sustain production;
- our inability to maintain relationships with suppliers, customers, employees and other third parties;
- uncertainties in estimating our oil and natural gas reserves and net present values of those reserves;
- the need to incur ceiling test impairments due to lower commodity prices using SEC methodology, under which commodity prices are computed using the unweighted arithmetic average of the first-day-of-the-month historical price, net of applicable differentials, for each month within the previous 12-month period;
- future derivative activities that expose us to pricing and counterparty risks;
- our ability to hedge future oil and natural gas production may be limited by lack of available counterparties;
- our ability to hedge future oil and natural gas production may be limited by financial/seasonal limits as required under our Exit Facility;
- our degree of success in replacing oil and natural gas reserves through capital investment;
- uncertainties in exploring for and producing oil and natural gas, including exploitation, development, drilling and operating risks;
- our ability to establish production on our acreage prior to the expiration of related leaseholds;
- availability and cost of drilling and production equipment, facilities, field service providers, gathering, processing and transportation;
- disruption of operations and damages due to capsizing, collisions, hurricanes or tropical storms;
- environmental risks;
- availability, cost and adequacy of insurance coverage;
- competition in the oil and natural gas industry;
- the effects of government regulation and permitting and other legal requirements;
- costs associated with perfecting title for mineral rights in some of our properties; and
- uncertainty of our ability to improve our operating structure, financial results and profitability following emergence from chapter 11 of the bankruptcy code and other risks and uncertainties related to our emergence from chapter 11.

For additional information regarding known material factors that could cause our actual results to differ from our projected results, please read (1) Part I, “Item 1A. Risk Factors” in our annual report on Form 10-K for the fiscal year ended December 31, 2017 (the “2017 Annual Report”); (2) Part II, “Item 1A. Risk Factors” in this Quarterly Report; (3) our reports and registration statements filed from time to time with the SEC; and (4) other public announcements we make from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date upon which they are made, whether as a result of new information, future events or otherwise.

PART I – FINANCIAL INFORMATION

ITEM 1. Unaudited Consolidated Financial Statements

ENERGY XXI GULF COAST, INC.
CONSOLIDATED BALANCE SHEETS
(In Thousands, except share information)

	March 31, 2018	December 31, 2017
ASSETS	**(Unaudited)**	
Current Assets		
Cash and cash equivalents	$ 112,062	$ 151,729
Accounts receivable		
Oil and natural gas sales	54,662	55,598
Joint interest billings, net	5,764	6,336
Other	15,290	15,726
Prepaid expenses and other current assets	12,147	21,602
Restricted cash	6,409	6,392
Total Current Assets	206,334	257,383
Property and Equipment		
Oil and natural gas properties, net - full cost method of accounting, including $195.9 million and $200.2 million of unevaluated properties not being amortized at March 31, 2018 and December 31, 2017, respectively	759,483	764,922
Other property and equipment, net	9,157	10,120
Total Property and Equipment, net of accumulated depreciation, depletion, amortization and impairment	768,640	775,042
Other Assets		
Restricted cash	25,758	25,712
Other assets	24,303	18,845
Total Other Assets	50,061	44,557
Total Assets	$ 1,025,035	$ 1,076,982
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 66,769	$ 85,122
Accrued liabilities	41,332	45,494
Asset retirement obligations	53,415	51,398
Derivative financial instruments	32,354	32,567
Current maturities of long-term debt	5,571	21
Total Current Liabilities	199,441	214,602
Long-term debt, less current maturities	58,407	73,952
Asset retirement obligations	620,105	613,453
Other liabilities	12,673	10,783
Total Liabilities	890,626	912,790
Commitments and Contingencies (Note 13)		
Stockholders' Equity		
Preferred stock, $0.01 par value, 10,000,000 shares authorized and no shares outstanding at March 31, 2018 and December 31, 2017	-	-
Common stock, $0.01 par value, 100,000,000 shares authorized and 33,268,478 and 33,254,963 shares issued and outstanding at March 31, 2018 and December 31, 2017 respectively	333	333
Additional paid-in capital	913,828	911,144
Accumulated deficit	(779,752)	(747,285)
Total Stockholders' Equity	134,409	164,192
Total Liabilities and Stockholders' Equity	$ 1,025,035	$ 1,076,982

See accompanying Notes to Consolidated Financial Statements.

ENERGY XXI GULF COAST, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In Thousands, except per share information)
(Unaudited)

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Revenues		
Oil sales	$ 123,788	$ 133,793
Natural gas liquids sales	1,343	2,227
Natural gas sales	8,382	18,368
Other revenue	1,492	-
(Loss) gain on derivative financial instruments	(12,834)	3,698
Total Revenues	122,171	158,086
Costs and Expenses		
Lease operating	82,022	77,267
Production taxes	1,206	239
Gathering and transportation	4,056	11,222
Pipeline facility fee	10,494	10,494
Depreciation, depletion and amortization	27,411	41,896
Accretion of asset retirement obligations	11,118	13,081
Impairment of oil and natural gas properties	-	40,774
General and administrative expense	15,132	21,604
Reorganization items	236	2,244
Total Costs and Expenses	151,675	218,821
Operating Loss	(29,504)	(60,735)
Other Income (Expense)		
Other income, net	143	22
Interest expense	(3,694)	(3,834)
Total Other Expense, net	(3,551)	(3,812)
Loss Before Income Taxes	(33,055)	(64,547)
Income Tax Benefit	-	-
Net Loss	$ (33,055)	$ (64,547)
Loss per Share		
Basic and Diluted	$ (0.99)	$ (1.94)
Weighted Average Number of Common Shares Outstanding		
Basic and Diluted	33,296	33,228

See accompanying Notes to Consolidated Financial Statements.

ENERGY XXI GULF COAST, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)
(Unaudited)

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Cash Flows From Operating Activities		
Net loss	$ (33,055)	$ (64,547)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	27,411	41,896
Impairment of oil and natural gas properties	-	40,774
Change in fair value of derivative financial instruments	(213)	(3,409)
Accretion of asset retirement obligations	11,118	13,081
Amortization of debt issuance costs	5	-
Deferred rent	1,930	2,015
Stock-based compensation	2,758	852
Changes in operating assets and liabilities		
Accounts receivable	1,944	15,555
Prepaid expenses and other assets	3,680	6,969
Settlement of asset retirement obligations	(18,804)	(9,316)
Accounts payable, accrued liabilities and other	(13,574)	(57,572)
Net Cash Used in Operating Activities	(16,800)	(13,702)
Cash Flows from Investing Activities		
Capital expenditures	(12,977)	(19,105)
Insurance payments received	-	2,051
Proceeds from the sale of other property and equipment	250	1,269
Net Cash Used in Investing Activities	(12,727)	(15,785)
Cash Flows from Financing Activities		
Payments on long-term debt	(10,002)	(602)
Other	(75)	-
Net Cash Used in Financing Activities	(10,077)	(602)
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(39,604)	(30,089)
Cash, Cash Equivalents and Restricted Cash, beginning of period	183,833	223,288
Cash, Cash Equivalents and Restricted Cash, end of period	$ 144,229	$ 193,199

See accompanying Notes to Consolidated Financial Statements.

ENERGY XXI GULF COAST, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 — Organization

Nature of Operations

Energy XXI Gulf Coast, Inc. ("EGC" or the "Company") was formed in December 2016 after emerging from a voluntary reorganization under chapter 11 proceedings as the restructured successor of Energy XXI Ltd ("EXXI Ltd"). We are headquartered in Houston, Texas, and engage in the development, exploitation, and operation of oil and natural gas properties primarily offshore in the GoM Shelf, which is an area in less than 1,000 feet of water, and also onshore in Louisiana and Texas. We own and operate nine of the largest GoM Shelf oil fields ranked by total cumulative oil production to date and utilize various techniques to increase the recovery factor and thus increase the total oil recovered.

Note 2 – Summary of Significant Accounting Policies and Recent Accounting Pronouncements

Principles of Consolidation and Reporting. The accompanying consolidated financial statements on March 31, 2018 include the accounts of EGC and its wholly-owned subsidiaries and have been prepared in accordance with accounting principles generally accepted in the U.S. ("U.S. GAAP"). All intercompany accounts and transactions are eliminated in consolidation. Our interests in oil and natural gas exploration and production ventures and partnerships are proportionately consolidated. The consolidated financial statements for the prior period include certain reclassifications to conform to the current presentation. Those reclassifications did not have any impact on the previously reported consolidated result of operations or cash flows.

Use of Estimates. The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates of proved reserves are key components of our depletion rate for our proved oil and natural gas properties and the full cost ceiling test limitation. Other items subject to estimates and assumptions include fair value estimates used in fresh start accounting; accounting for acquisitions and dispositions; carrying amounts of property, plant and equipment; asset retirement obligations; deferred income taxes; valuation of derivative financial instruments; among others. Accordingly, our accounting estimates require the exercise of judgment by management in preparing such estimates. While we believe that the estimates and assumptions used in preparation of our consolidated financial statements are appropriate, actual results could differ from those estimates, and any such differences may be material.

Interim Financial Statements. The accompanying consolidated financial statements have been prepared in accordance with U.S. GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by U.S. GAAP for complete financial statements. In the opinion of management, all adjustments of a normal and recurring nature considered necessary for a fair presentation have been included in the accompanying consolidated financial statements. The results of operations for the interim period are not necessarily indicative of the results that will be realized for the entire fiscal year. These consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the 2017 Annual Report.

Recent Accounting Pronouncements. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09"), as a new Accounting Standards Codification (ASC) Topic, ASC 606. ASU 2014-09 is effective for us beginning in the first quarter of 2018. In May 2016, the FASB issued ASU 2016-11, which rescinds certain SEC guidance in the related ASC, including guidance related to the use of the "entitlements" method of revenue recognition used by the Company.

The Company adopted ASC 606 effective January 1, 2018, which replaces previous revenue recognition requirements under FASB ASC Topic 605 – *Revenue Recognition* ("ASC 605"). The standard was adopted using the modified retrospective approach which requires the Company to recognize in retained earnings at the date of adoption the cumulative effect of the application of ASC 606 to all existing revenue contracts which were not substantially complete as of January 1, 2018. The Company has elected the contract modification practical expedient which allows the Company to reflect the aggregate effect of all modifications prior to the date of adoption when applying ASC 606.

Although the adoption of ASC 606 did not have an impact on the Company's net loss or cash flows, it did result in the reclassification of certain fees received under pipeline gathering and transportation and pipeline tariff agreements that were previously included in oil sales to other revenue in the consolidated statements of operations.

The Company has determined that its contracts for the sale of crude oil, unprocessed natural gas and NGLs contain monthly performance obligations to deliver product at locations specified in the contract. Control is transferred at the delivery location, at which point the performance obligation has been satisfied and revenue is recognized. Fees included in the contract that are incurred prior to control transfer are classified as lease operating expense and fees incurred after control transfers are included as a reduction to the transaction price. The transaction price at which revenue is recognized consists entirely of variable consideration based on quoted market prices less various fees and the quantity of volumes delivered.

The Company receives payment for product sales from one to three months after delivery. At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are accrued in accounts receivable, oil and natural gas sales in the consolidated balance sheets. Variances between the Company's estimated revenue and actual payments are recorded in the month the payment is received, however, differences have been and are insignificant.

The Company has elected to utilize the practical expedient in ASC 606 that states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under our contracts, each monthly delivery of product represents a separate performance obligation, therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

The Company previously utilized the entitlements method to account for natural gas imbalances, which is no longer applicable under ASC 606. The impact to the financial statements resulting from this change in accounting for our natural gas imbalances was not significant.

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (*"*ASU 2016-02"), to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. To meet that objective, the FASB amended the FASB Accounting Standards Codification and created *Topic 842, Leases*. The guidance in this ASU supersedes *Topic 840, Leases.* The new standard establishes a right-of-use ("ROU") model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new standard is effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In the normal course of business, we enter into lease agreements to support our operations. We are evaluating the provisions of ASU 2016-02 to determine the quantitative effects it will have on our consolidated financial statements and related disclosures. We believe the adoption and implementation of this ASU will have a material impact on our balance sheet resulting from an increase in both assets and liabilities relating to our leasing activities.

In June 2016, the FASB issued ASU No. 2016-13, *Credit Losses, Measurement of Credit Losses on Financial Instruments* ("ASU 2016-13"). ASU 2016-13 significantly changes how entities will measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The standard will replace today's incurred loss approach with an expected loss model for instruments measured at amortized cost. Entities will apply the standard's provisions as a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. This ASU is effective for public entities for annual and interim periods beginning after December 15, 2019. Early adoption is permitted for all entities for annual periods beginning after December 15, 2018, and interim periods therein. We have not yet determined the effect of this standard on our consolidated financial position, results of operations or cash flows.

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments* ("ASU 2016-15"). ASU 2016-15 provides guidance on eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; including bank-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. Our adoption of ASU 2016-15 on January 1, 2018 using the retrospective transition method had no effect on our consolidated financial position, results of operations or cash flows other than presentation.

In November 2016, the FASB issued ASU No. 2016-18*, Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 requires amounts generally described as restricted cash and restricted cash equivalents be included with cash and cash equivalents when reconciling the total beginning and ending amounts for the periods shown on the statement of cash flows. Our adoption of ASU 2016-18 on January 1, 2018 had no effect on our consolidated financial position, results of operations or cash flows other than presentation.

Note 3 – Property and Equipment

Property and equipment consists of the following (*in thousands*):

	As of March 31, 2018	As of December 31, 2017
Oil and natural gas properties - full cost method of accounting		
Proved properties	$1,328,528	$ 1,307,009
Less: accumulated depreciation, depletion, amortization and impairment	(764,952)	(742,286)
Proved properties, net	563,576	564,723
Unevaluated properties	195,907	200,199
Oil and natural gas properties, net	759,483	764,922
Other property and equipment	13,902	13,780
Less: accumulated depreciation and impairment	(4,745)	(3,660)
Other property and equipment, net	9,157	10,120
Total property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$ 768,640	$ 775,042

Under the full cost method of accounting, at the end of each financial reporting period, we compare the present value of estimated future net cash flows from proved reserves (computed using the unweighted arithmetic average of the first-day-of-the-month historical price, net of applicable differentials, for each month within the previous 12-month period discounted at 10%, plus the lower of cost or fair market value of unevaluated properties and excluding cash flows related to estimated abandonment costs associated with developed properties) to the net capitalized costs of oil and natural gas properties, net of related deferred income taxes. We refer to this comparison as a “ceiling test.” If the net capitalized costs of these oil and natural gas properties exceed the estimated discounted future net cash flows, we are required to write-down the value of our oil and natural gas properties to the amount of the discounted cash flows. For the three months ended March 31, 2018, we did not incur any impairment to our oil and natural gas properties and for the three months ended March 31, 2017, we recorded impairment to oil and natural gas properties of $40.8 million as a result of the decrease in proved reserves and PV-10 value as of March 31, 2017 relative to the estimated reserves prepared by our internal reservoir engineers as of December 31, 2016.

Costs associated with unevaluated properties are transferred to evaluated properties either (i) ratably over a period of the related field’s life, or (ii) upon determination as to whether there are any proved reserves related to the unevaluated properties or the costs are impaired or capital costs associated with the development of these properties will not be available. For the three months ended March 31, 2018, the costs associated with unevaluated properties decreased by $4.3 million, of which $2.2 million was the ratable amortization to the evaluated properties and the remaining $2.1 million was transferred to evaluated properties due to impairment.

Note 4 – Long-Term Debt

As of March 31, 2018 and December 31, 2017 our outstanding debt consisted of the following (*in thousands*):

	Successor	
	March 31, 2018	December 31, 2017
Exit Facility	$ 63,996	$ 73,996
Capital lease obligations	21	21
Total debt	64,017	74,017
Less: debt issue costs	39	44
Less: current maturities	5,571	21
Total long-term debt	$ 58,407	$ 73,952

Exit Facility

On December 30, 2016, the Company entered into a secured Exit Facility, which matures on December 30, 2019. The Exit Facility, as amended, is secured by mortgages on at least 90% of the value of our and our subsidiary guarantors' proved developed producing reserves as well as our total proved reserves. The Exit Facility consists of two facilities: (i) a term loan facility (the "Exit Term Loan") and (ii) a revolving credit facility (the "Exit Revolving Facility") for the making of revolving loans and the issuance of letters of credit.

The Exit Facility is guaranteed by substantially all of the wholly-owned subsidiaries of the Company, subject to customary exceptions, and is secured by first priority security interests on substantially all assets of each guarantor. Under the Exit Facility, the borrower will not declare or make a restricted payment, or make any deposit for any restricted payment. Restricted payments include declaration or payment of dividends.

The Company must make a mandatory prepayment of the revolving loans and, if necessary, cash collateralize the outstanding letters of credit if a reduction in the revolving credit capacity would cause the revolving credit exposure to exceed the revolving credit capacity. On or after the determination of the borrowing base, the Company must also make a mandatory prepayment of the revolving loans and, if necessary, cash collateralize the outstanding letters of credit not in favor of ExxonMobil if a borrowing base deficiency arises.

The Exit Facility contains covenants and events of default customary for reserve-based lending facilities. In addition, for each fiscal quarter ending on and after March 31, 2018, the Company must maintain a Current Ratio (as defined in the Exit Facility) of no less than 1.00 to 1.00 and a First Lien Leverage Ratio (as defined in the Exit Facility) of no greater than 4.00 to 1.00 calculated on a trailing four quarter basis. On March 29, 2018, we prepaid $10 million outstanding under the Exit Term Loan. Due to a decline in our estimated trailing twelve-month EBITDA calculation for the twelve-month period ending June 30, 2018, we may be required to prepay additional amounts of our outstanding Exit Term Loan in order to prevent a breach of the First Lien Leverage Ratio, and such a prepayment could adversely affect our liquidity. Under those circumstances, we would also discuss a covenant waiver with our banking group to remain in compliance with that ratio.

Furthermore, for each fiscal quarter ending on and after March 31, 2018, if the Asset Coverage Ratio (as defined in the Exit Facility) is less than 1.50 to 1.00, the Company must make a mandatory prepayment of the Exit Term Loan in an amount equal to the lesser of (i) 7.5% of the aggregate outstanding principal amount of the Exit Term Loan on December 30, 2016 and (ii) the then outstanding principal amount of the Exit Term Loan. Based upon the Company's current expectations with respect to its capital resources, capital expenditures, results from operations and commodity prices, the Company believes that it is reasonably likely that it will be required to make a mandatory prepayment with respect to each fiscal quarter ending on and after March 31, 2018. In that case, the first such payment of approximately $5.55 million will be paid during the fiscal quarter ending June 30, 2018. Any such mandatory prepayment would not, in and of itself, constitute a default under the Exit Facility.

Unused credit capacity under the Exit Revolving Facility will accrue a commitment fee of 0.50% payable quarterly in arrears.

Interest on the outstanding amount of the Exit Term Loan, at the Company's option, will accrue at an interest rate equal to either: (i) the Alternative Base Rate (as defined in the Exit Facility) plus 3.5% per annum or (ii) the one-month LIBO Rate (as defined in the Exit Facility) plus 4.5% per annum. Interest on the Exit Term Loan bearing interest at the

Alternative Base Rate will be payable quarterly; interest on the Exit Term Loan bearing interest at the LIBO Rate will be payable monthly.

Interest on the outstanding amount of revolving loans borrowed under the Exit Revolving Facility, at the Company's option, will accrue at an interest rate equal to either (i) the Alternative Base Rate plus 3.5% per annum or (ii) the one, three or six month LIBO Rate plus 4.5% per annum. Interest on revolving loans that bear interest at the Alternative Base Rate will be payable quarterly; interest on revolving loans that bear interest at the LIBO Rate will be payable at the end of each interest period or, if an interest period exceeds three months, at the end of every three months. The stated amount of each letter of credit issued under the Exit Revolving Facility accrues fees at the rate of 4.5% per annum. There is an issuance fee of 0.25% per annum charged on the stated amount of each letter of credit issued after December 30, 2016.

We currently have $12.5 million available for borrowing, under specific circumstances, as revolving loans subject to a maximum for all such loans of (i) $25 million prior to the date the borrowing base is initially determined and (ii) the borrowing base, on and after the date the borrowing base is initially determined. The borrowing base will be initially determined at a date elected by the Company, and will be redetermined semi-annually thereafter. Currently, the Company has not elected a date for the initial borrowing base determination.

As of March 31, 2018, we had approximately $64 million in borrowings and $201.5 million in letters of credit issued under the Exit Facility.

Note 5 – Asset Retirement Obligations

The following table describes the changes to our asset retirement obligations (*in thousands*):

Balance as of December 31, 2017	$ 664,851
Liabilities incurred	8,722
Liabilities settled	(18,804)
Revisions	7,633
Accretion expense	11,118
Total balance as of March 31, 2018	673,520
Less: current portion	53,415
Long-term portion as of March 31, 2018	$ 620,105

Note 6 – Derivative Financial Instruments

We enter into derivative transactions to reduce exposure to fluctuations in the price of crude oil and natural gas with multiple investment-grade rated counterparties, primarily financial institutions, to reduce the concentration of exposure to any individual counterparty. We have historically used various instruments, including financially settled crude oil and natural gas puts, put spreads, swaps, costless collars and three-way collars in our derivative portfolio. With a costless collar, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price of the collar, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the cap price for the collar. In a fixed price swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the swap fixed price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the swap fixed price.

Derivative financial instruments are recorded at fair value and included as either assets or liabilities in the accompanying consolidated balance sheets. Any gains or losses resulting from changes in fair value of our outstanding derivative financial instruments and from the settlement of derivative financial instruments are recognized in earnings and included in (loss) gain on derivative financial instruments as a component of revenues in the accompanying consolidated statements of operations.

Most of our crude oil production is sold at Heavy Louisiana Sweet. We have historically included contracts indexed to NYMEX-WTI, ICE Brent futures and Argus-LLS futures in our derivative portfolio to closely align and manage our exposure to the associated price risk.

The energy markets have historically been very volatile, and there can be no assurances that crude oil and natural gas prices will not be subject to wide fluctuations in the future. While the use of derivative arrangements helps to limit the downside risk of adverse price movements, they may also limit future gains from favorable price movements.

As of March 31, 2018, we had the following open crude oil derivative positions:

Remaining Contract Term	Type of Contract	Index	Volumes (MBbls)	Weighted Average Contract Price Swaps	
April 2018 - December 2018	Swaps	NYMEX-WTI	2,200.0	$	50.68
April 2018 - June 2018	Swaps	Argus-LLS	182.0	$	55.45
April 2018 - June 2018	Swaps	ICE Brent	227.5	$	56.59

The fair values of derivative instruments in our consolidated balance sheets were as follows (*in thousands*):

	Asset Derivative Instruments				Liability Derivative Instruments			
	March 31, 2018		December 31, 2017		March 31, 2018		December 31, 2017	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivative financial instruments	Current	$ -	Current	$ -	Current	$ 32,354	Current	$ 32,567
	Non-Current	-	Non-Current	-	Non-Current	-	Non-Current	-
Total gross derivative financial instruments subject to enforceable master netting agreement		-		-		32,354		32,567
Derivative financial instruments	Current	-	Current	-	Current	-	Current	-
	Non-Current	-	Non-Current	-	Non-Current	-	Non-Current	-
Gross amounts offset in Balance Sheets		-		-		-		-
Net amounts presented in Balance Sheets	Current	-	Current	-	Current	32,354	Current	32,567
	Non-Current	-	Non-Current	-	Non-Current	-	Non-Current	-
		$ -		$ -		$ 32,354		$ 32,567

The following table presents information about the components of the (loss) gain on derivative financial instruments (*in thousands*).

(Loss) gain on derivative financial instruments	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Cash settlements	$ (13,047)	$ 289
Non-cash gain in fair value	213	3,409
Total (loss) gain on derivative financial instruments	$ (12,834)	$ 3,698

We monitor the creditworthiness of our counterparties who are also a part of our bank lending group. However, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of our financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and could incur a loss. As of March 31, 2018, we had no collateral deposits with our counterparties.

Note 7 – Income Taxes

No cash income taxes were paid during the period ended March 31, 2018, and, based upon current commodity pricing and planned development activity, no cash income taxes are expected to be paid or owed for the year ending December 31, 2018.

We have estimated our effective income tax rate for the year to be zero, as we are forecasting a pre-tax loss at this time. We do not believe that our net deferred tax assets are realizable in the future on a more-likely-than-not basis at this time; as such, we have increased our valuation allowance by $7 million in the quarter ended March 31, 2018 to reflect the tax effect of this loss. This $7 million first quarter valuation allowance increase, when coupled with the $306 million valuation allowance at December 31, 2017, results in a valuation allowance of $313 million at March 31, 2018. We made no changes during the period to our deferred tax assets or valuation allowance related to the Tax Cuts and Jobs Act of 2017.

Note 8 – Stockholders' Equity

Under our certificate of incorporation, the total number of all shares of capital stock that we are authorized to issue is 110 million shares, consisting of 100 million shares of the Company's common stock, par value $0.01 per share, and 10 million shares of preferred stock, par value $0.01 per share.

For the three months ended March 31, 2018, we issued 13,515 shares of our common stock upon vesting of restricted stock units and as of March 31, 2018, we had 33,268,478 shares of common stock and 2,119,889 warrants outstanding.

Note 9 – Supplemental Cash Flow Information

The following table presents our supplemental cash flow information (*in thousands*):

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Cash paid for interest	$ 3,560	$ 2,817
Cash paid for income taxes	-	-

The following table presents our non-cash investing and financing activities (*in thousands*):

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Changes in capital expenditures and accrued liabilities or accounts payable	$ (8,076)	$ (2,660)
Changes in asset retirement obligations	16,355	(133,434)

The following table presents the reconciliation of cash, cash equivalents and restricted cash as presented on the consolidated statement of cash flows *(in thousands)*:

	As of		
	March 31, 2018	December 31, 2017	March 31, 2017
Cash and cash equivalents	$ 112,062	$ 151,729	$ 160,479
Restricted cash, current	6,409	6,392	7,114
Restricted cash, long term	25,758	25,712	25,606
Total Cash, cash equivalents and restricted cash	$ 144,229	$ 183,833	$ 193,199

Note 10 – Employee Benefit Plans

On December 30, 2016, the Company entered into the Energy XXI Gulf Coast, Inc. 2016 Long Term Incentive Plan (the "2016 LTIP"), which is a comprehensive equity-based award plan as part of the compensation for the Company's officers, directors, employees and consultants (the "Service Providers"). The total number of shares of our common stock reserved and available for delivery with respect to awards under the 2016 LTIP was 1,859,552 shares (or 5% of the total new equity). The compensation committee (the "Committee") of the board of directors of the Company (the "Board") generally administers the 2016 LTIP and determines the types of equity based awards (which may include stock option, stock appreciation rights, restricted stock, restricted stock units, bonus stock awards, performance awards, other stock based awards or cash awards) and the terms and conditions (including vesting and forfeiture restrictions) of such awards. Awards under the 2016 LTIP are awarded to the Service Providers selected in the discretion of the Committee; provided, however, that 3% of the 5% total new equity on a fully diluted basis reserved under the 2016 LTIP must be allocated no later than 120 days after December 30, 2016. As of April 29, 2017, the 3% of total new equity had been allocated by the Board.

Under the 2016 LTIP, stock options are issued with an exercise price that is not less than the fair market value of our common stock on the date of grant and expire 10 years from the grant date. Stock options that have been granted to date generally vest ratably over a three-year period. The fair value of each stock option granted is estimated on the date of grant using a Black-Scholes-Merton option valuation model that uses assumptions related to expected term, expected volatility, risk free rate and dividend yield. As of March 31, 2018, we had 285,105 unvested stock options and $1.2 million in unrecognized compensation cost related to unvested stock options.

Under the 2016 LTIP, restricted stock units may be granted as approved by the Committee. To date, the restricted stock units granted by the Committee have a vesting date up to three years from the date of grant and each restricted stock unit represents a right to receive one share of our common stock. During the three months ended March 31, 2018, we granted 796,967 restricted stock units at a weighted average price of $6.12 per restricted stock unit. As of March 31, 2018, we had 1,316,579 unvested restricted stock units and $10.1 million in unrecognized compensation cost related to unvested restricted stock units.

In order to retain key employees and attract new employees with the experience and skill sets that fit our culture and corporate strategy, the Board approved the Energy XXI Gulf Coast, Inc. 2018 Long Term Incentive Plan (the “2018 LTIP”) on April 11, 2018, subject to stockholder approval at the 2018 annual meeting of stockholders to be held on May 17, 2018. If approved by the stockholders, the number of shares of common stock available for awards under the 2018 LTIP would be (i) 1,860,000 plus (ii) the number of shares remaining available for award under the 2016 LTIP on the date of the 2018 annual meeting. As of April 11, 2018, there were 37,835 shares remaining available for award under the 2016 LTIP.

Note 11 — Loss per Share

Basic loss per share of common stock is computed by dividing net loss attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Except when the effect would be anti-dilutive, the diluted earnings per share calculation includes the impact of restricted stock, stock options and other common stock equivalents. The following table sets forth the calculation of basic and diluted loss per share (“EPS”) (*in thousands, except per share data*):

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Net loss	$ (33,055)	$ (64,547)
Weighted average shares outstanding for basic EPS	33,296	33,228
Add dilutive securities	-	-
Weighted average shares outstanding for diluted EPS	33,296	33,228
Loss per share		
Basic and Diluted	$ (0.99)	$ (1.94)

The Company’s restricted stock units granted to the members of the Board which are vested but not yet issued are treated as outstanding for basic loss per share calculations since these shares are entitled to participate in dividends declared on common shares, if any, and undistributed earnings. As participating securities, the shares of restricted stock are included in the calculation of basic EPS using the two-class method. For the three months ended March 31, 2018 and 2017, no net loss was allocated to the participating securities.

For the three months ended March 31, 2018 and 2017, 3,665,257 and 1,206,765 common stock equivalents, respectively, were excluded from the diluted average shares calculation due to an anti-dilutive effect.

Note 12 — Commitments and Contingencies

Litigation. We are involved in various legal proceedings and claims, which arise in the ordinary course of our business. We do not believe the ultimate resolution of any such actions will have a material effect on our consolidated financial position, results of operations or cash flows.

Letters of Credit and Performance Bonds. As of March 31, 2018, we had approximately $325.8 million of performance bonds outstanding and $200 million in letters of credit issued to ExxonMobil relating to assets in the Gulf of Mexico.

In April 2015, the Predecessor received letters from the BOEM stating that certain of its subsidiaries no longer qualified for waiver of certain supplemental bonding requirements for potential offshore decommissioning, plugging and abandonment liabilities. As of March 31, 2018, approximately $174.1 million of our performance bonds are lease and/or area bonds issued to the BOEM, to which the BOEM has access to ensure our commitment to comply with the terms and conditions of those leases. As of March 31, 2018, we also maintained approximately $151.7 million in performance bonds issued to third party assignors including certain state regulatory bodies for eventual decommissioning of certain wells and facilities. As of March 31, 2018, we had $47.9 million in cash collateral provided to surety companies associated with the bonding requirements of the BOEM and third party assignors.

To address the supplemental bonding and other financial assurance concerns expressed to us by the BOEM in April 2015 and thereafter, the Predecessor submitted a long-term financial assurance plan (the “Long-Term Plan”) to the agency. Further, the Predecessor submitted a proposed plan amendment on June 28, 2016 that would revise the executed Long-Term Plan (the “Proposed Plan Amendment”). We continue to work with the BOEM under the Long-Term Plan and the Proposed Plan Amendment.

Drilling Rig Commitments. As of March 31, 2018, we have approximately $10.7 million committed under two rig contracts for drillwells, rig recompletions and plugging and abandonment activities. The contracts’ terms range from February 23, 2018 through September 12, 2018.

Other. We maintain restricted escrow funds as required by certain contractual arrangements. As of March 31, 2018, our restricted cash primarily related to $25.7 million in cash collateral associated with our bonding requirements and approximately $6.1 million in a trust for future plugging, abandonment and other decommissioning costs related to the East Bay field that was sold to Whitney Oil & Gas, LLC and Trimont Energy (NOW), LLC on June 30, 2015. Funds held in trust will be transferred to the buyers of our interests in that field.

We and our oil and natural gas joint interest owners are subject to periodic audits of the joint interest accounts for leases in which we participate and/or operate. As a result of these joint interest audits, amounts payable or receivable by us for costs incurred or revenue distributed by the operator or by us on a lease may be adjusted, resulting in adjustments to our net costs or revenues and related cash flows. When they occur, these adjustments are recorded in the current period, which generally is one or more years after the related cost or revenue was incurred or recognized by the joint account. We do not believe any such adjustments will be material.

Note 13 — Fair Value of Financial Instruments

Certain assets and liabilities are measured at fair value on a recurring basis in our consolidated balance sheets. Valuation techniques are generally classified into three categories: the market approach; the income approach; and the cost approach. The selection and application of one or more of these techniques requires significant judgment and is primarily dependent upon the characteristics of the asset or liability, the principal (or most advantageous) market in which participants would transact for the asset or liability and the quality and availability of inputs. Inputs to valuation techniques are classified as either observable or unobservable within the following hierarchy:

- Level 1 – quoted prices in active markets for identical assets or liabilities.
- Level 2 – inputs other than quoted prices that are observable for an asset or liability. 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; and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market-corroborated inputs).
- Level 3 – unobservable inputs that reflect our own expectations about the assumptions that market participants would use in measuring the fair value of an asset or liability.

For cash and cash equivalents, restricted cash, accounts receivable, prepaid expenses and other current assets, accounts payable, accrued liabilities and certain notes payable, the carrying amounts approximate fair value due to the short-term nature or maturity of the instruments. The carrying value of the Exit Facility approximates its fair value because the interest rate is variable and reflective of market rates, which are Level 2 inputs within the fair value hierarchy.

Our commodity derivative instruments historically consisted of financially settled crude oil and natural gas puts, swaps, put spreads, costless collars and three way collars. We estimated the fair values of these instruments based on published forward commodity price curves, market volatility and contract terms as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published London Interbank offered rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published issuer-weighted corporate default rates. See Note 6 – "Derivative Financial Instruments."

The fair value of our restricted stock units equals the market value of the underlying common stock on the date of grant. For our stock options, we utilize the Black-Scholes-Merton model to determine fair value, which incorporates various assumptions as follows:

- the expected volatility is based on comparable companies' asset volatilities;
- the risk-free interest rate is the related United States Treasury yield curve for periods within the expected term of the option at the time of grant; and
- the dividend yield on our common stock is zero.

During the three months ended March 31, 2018 we did not have any transfers from or to any level within the fair value hierarchy. The following table presents the fair value of our Level 2 financial instruments (*in thousands*):

	Level 2	
	As of March 31, 2018	As of December 31, 2017
Assets:		
Oil and Natural Gas Derivatives	$ -	$ -
Liabilities:		
Oil and Natural Gas Derivatives	$ 32,354	$ 32,567

The following table sets forth the outstanding and estimated fair values of our long-term debt instruments which are classified as Level 2 financial instruments (*in thousands*):

	March 31, 2018		December 31, 2017	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Exit Facility	$ 63,996	$ 63,996	$ 73,996	$ 73,996
	$ 63,996	$ 63,996	$ 73,996	$ 73,996

Note 14 — Prepayments and Accrued Liabilities

Prepayments and other current assets and accrued liabilities consist of the following (*in thousands*):

	March 31, 2018	December 31, 2017
Prepaid expenses and other current assets		
Advances to joint interest partners	$ 830	$ 1,381
Insurance	4,761	5,949
Inventory	315	394
Royalty deposit	1,021	1,021
Other	5,220	12,857
Total prepaid expenses and other current assets	$ 12,147	$ 21,602
Accrued liabilities		
Advances from joint interest partners	-	81
Employee benefits and payroll	3,262	6,791
Interest payable	313	185
Accrued hedge payable	4,381	2,491
Undistributed oil and gas proceeds	17,229	20,079
Severance taxes payable	1,328	558
Other	14,819	15,309
Total accrued liabilities	$ 41,332	$ 45,494

Note 15 — Subsequent Events

In April 2018, we unwound 3,000 BPD of our WTI swaps for the period from April 1, 2018 to June 30, 2018 and replaced the unwound swaps with 3,000 BPD ICE Brent swaps with an average swap price of $61.00 per BBL for the period from January 2019 to December 2019. Additionally, we added 3,000 BPD ICE Brent costless collars with a floor price of $60.00 and a ceiling price of $82.00 for the period April 13, 2018 to June 30, 2018.

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Statements we make in this quarterly report on Form 10-Q (the "Quarterly Report") which express a belief, expectation or intention, as well as those that are not historical fact, may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Our forward-looking statements are subject to various risks, uncertainties and assumptions, including those to which we refer under the headings "Cautionary Statement Regarding Forward-Looking Statements" and Part I "Item 1A. Risk Factors" included in our 2017 Annual Report and elsewhere in this Quarterly Report.

Overview

We are headquartered in Houston, Texas, and engage in the development, exploitation, and operation of oil and natural gas properties primarily offshore on the GoM Shelf, which is an area in less than 1,000 feet of water, and also onshore in Louisiana and Texas. We own and operate nine of the largest GoM Shelf oil fields ranked by total cumulative oil production to date and utilize various techniques to increase the recovery factor and thus increase the total oil recovered. At December 31, 2017, our total proved reserves were 88.2 MMBOE of which 84% were oil and 75% were classified as proved developed. We operated or had an interest in 577 gross producing wells on 421,974 net developed acres, including interests in 55 producing fields.

Our geographic concentration on the GoM Shelf exposes us to various challenges, including: a high operating cost environment, operational risks related to hurricanes and storms, relatively steep decline curves, mature infrastructure with corresponding maintenance obligations, which can lead to excessive downtime, permitting and other regulatory requirements and plugging and abandonment liabilities. Over the past year, we have proactively focused our operating plan to address these challenges, including: optimizing our development activity, spending proactively on maintenance of our mature infrastructure and controlling our operating costs through sole sourcing, facility consolidation, and other cost-cutting initiatives.

To better reflect our corporate identity as Energy XXI Gulf Coast, Inc., on March 16, 2018, we announced the change of our NASDAQ ticker symbol for our common stock from "EXXI" to "EGC". Our common stock began trading on the NASDAQ under the symbol "EGC" at the opening of business on March 21, 2018.

Operational Update

The Company is focused on the development of an optimized stand-alone strategy and multi-year plan by approving the 2018 capital and operating budget (the "2018 Capital Budget"). We decided to return to a more active drilling program in 2018, and therefore our focus will be optimizing and enhancing our existing production with an active drilling, recompletion and workover program, evaluating acquisitions, potential dispositions of non-core properties, and continuing to control costs. The 2018 Capital Budget anticipates total 2018 capital expenditures between $145 million and $175 million, including planned investment of $65 million to $75 million in drilling six new wells and for seven to nine recompletions, $10 million to $15 million in facilities improvements and $50 million to $60 million in plugging and abandonment expenditures.

The first well in our 2018 drilling program, the West Delta 73 McCloud well was spud on March 27, 2018. This well was drilled to a total vertical depth of 8,479 feet. This well was completed in April 2018. The Company operates and has a 100% working interest in this well.

In early May 2018, the West Delta 74 C-41ST, Cato development well was spud, and is currently drilling to a total depth of 11,400 feet. We expect to complete this well in the second quarter of fiscal 2018. The Company operates and has a 100% working interest in this well.

Strategic Update

As a complement to the Company's capital plan, the Company has retained Intrepid Partners LLC ("Intrepid") to assist with the consideration of possible alternatives for raising additional capital. No determination has yet been made as to the form or amount of any such additional capital, but it could be in the form of debt, convertible debt, additional common stock or a new series of non-convertible or convertible preferred stock, as well as other financing structures. There can be no assurance that any such capital-raising transaction will be consummated or, if consummated, when that transaction will occur. Furthermore, the Company intends that any such financing would be structured in such a way that it would not preclude a strategic transaction.

The Company is also working to address its plugging and abandonment liability and streamline its asset base. To that end, EGC has entered into a non-binding term sheet with Orinoco Natural Resources, LLC ("ONR") and its affiliates. The term sheet with ONR provides for the disposition of EGC's current non-core asset portfolio (the "Proposed ONR Transaction"). If consummated, the Proposed ONR Transaction is expected to significantly reduce EGC's asset retirement liability, improve profitability and financial stability, lower EGC's cost structure, and facilitate future growth.

Disposition of EGC's Non-Core Assets. Under the Proposed ONR Transaction, EGC would transfer its non-core asset portfolio with significant asset retirement obligations ("ARO") to the Offshore Environmental Fund, LLC, an affiliate of ONR ("OEF"), which would improve EGC's mix of assets and liabilities. The non-core asset portfolio to be transferred to OEF consists of properties that have significant near-term ARO and limited cash flow and development upside, currently producing approximately 3,000 barrels of oil per day and 9.5 million cubic feet of natural gas per day, and includes about 6.7 million BOE of proved reserves, of which 30% is natural gas. By comparison, the oil and gas properties that EGC would retain in the Proposed ONR Transaction are located in EGC's core GoM Shelf fields, with good current production (of which about 80% is oil) and with multiple ongoing and future drilling opportunities.

As a result, EGC's estimated present value of proved reserves discounted at 10% ("PV-10") would increase by $150 million to $464 million, which represents a nearly 50% increase, based on year-end 2017 SEC reserves and forward strip pricing as of April 24, 2018. Furthermore, the Proposed ONR Transaction would remove approximately $320 million of undiscounted ARO liability, which represents 33% of EGC's total undiscounted ARO liability.

Cash and Second Lien Note. In consideration for OEF's acceptance of the non-core assets and assumption of the related ARO liabilities, EGC would also provide OEF a $100 million ten-year second lien note amortized ratably beginning 2019 and bearing interest at 9% per annum. Interest and amortization payments on this note are expected to be more than offset by the expected savings in cash ARO and G&A costs. Furthermore, EGC would pay OEF upfront cash of $12.5 million at closing. EGC believes that the reduction in EGC's ARO liability will enable its existing surety bond providers to release a certain portion of the cash collateral that EGC has posted to those providers. To the extent that cash collateral is released, then EGC will pay OEF an additional cash amount six months after closing equal to $12.5 million or the amount of cash collateral released, whichever is less. OEF has been designed to be a self-sustaining entity with sufficient financial capability to assume all the ARO obligations and associated bonding obligations of the EGC non-core assets and associated liabilities that are to be transferred through the Proposed ONR Transaction.

Issuance of EGC Common Equity. As additional consideration for the acceptance of the non-core assets and assumption of the related ARO liabilities, ONR would receive a 35% equity ownership position in EGC, pro forma for the transaction. In connection with the issuance of those common shares, ONR and EGC would enter into customary lock-up, standstill, voting and registration rights agreements regarding the EGC common stock issued at Closing. Furthermore, ONR would have the right to designate for nomination a number of members to serve on the Board proportionate to ONR's ownership percentage at completion of the Proposed ONR Transaction and, thereafter, as long as ONR retains at least 40% of its shares it receives at closing (i.e., Board representation will not be diluted by future equity issuance). If ONR is entitled to designate more than one individual to serve on the Board, then at least one of those individuals must be unaffiliated with and have no business relationships with ONR or any of its affiliates.

Master Services Agreement. In addition, EGC would sign a 10-year agreement to provide plugging and abandonment and decommissioning services for EGC's core assets with EPIC Companies LLC ("EPIC"), an affiliate of ONR, and a well-respected ARO service provider in the U.S. Gulf of Mexico. EGC and EPIC will agree on a pricing structure for the services to be provided on commercially reasonable terms and at market-supported rates.

Participation in Potential Future Financing. Under the term sheet, ONR and affiliates would commit at closing to anchor a potential future EGC financing with at least a $25 million participation. That financing, which is expected to provide proceeds ranging from $100 million to $150 million, would further bolster EGC's liquidity and provide capital to fund an enhanced drilling and development program beginning in 2019.

The Proposed ONR Transaction would be subject to approval by EGC's stockholders, EGC's lenders, BOEM and the Bureau of Safety and Environmental Enforcement ("BSEE"). The parties are working to complete definitive documentation—as well as the related SEC and other regulatory filings in connection with obtaining necessary approvals from EGC's stockholders, EGC's lenders and regulatory authorities—in order to close the Proposed ONR Transaction in the third quarter of this year. EGC's term sheet with ONR is a non-binding term sheet, and there can be no assurance that the Proposed ONR Transaction will be consummated. Also, if the Proposed ONR Transaction is consummated, it could be completed on terms that are materially different than those described above.

Known Trends and Uncertainties

Commodity Price Volatility. Prices for oil and natural gas historically have been volatile and are expected to continue to be volatile. Although oil prices have recently rebounded to above $60.00 per barrel, there is still significant volatility in commodity prices. Declines in oil and natural gas prices may adversely affect our financial position and results of operations and the quantities and values of our oil and natural gas reserves.

Capital Spending. For 2018, the Company's initial capital budget, excluding acquisitions but including plugging and abandonment is in the range of $145 million to $175 million in total, of which plugging and abandonment costs are expected to be in the range of $50 million to $60 million.

Reserve Quantities. Declining and a prolonged period of depressed commodity prices could have a significant impact on the value and volumetric quantities of our proved reserve portfolio. At December 31, 2017, our total proved reserves were 88.2 MMBOE. The twelve-month unweighted arithmetic average first-day-of-the-month prices adjusted for differentials used to determine our reserves as of December 31, 2017 was $50.99 per barrel of oil, $26.79 per barrel for NGLs and $2.85 per Mcf for natural gas.

Ceiling Test Write-down. For the three months ended March 31, 2018, we did not incur any impairment to our oil and natural gas properties. Ceiling test write-downs will be required if oil and natural gas prices decline, unevaluated property values decrease, estimated proved reserve volumes are revised downward or the net capitalized cost of proved oil and natural gas properties otherwise exceeds the present value of estimated future net cash flows.

Service Costs Fluctuations. The cost to hire an experienced drilling crew and source critical oil-field supplies may increase if the price of oil keeps increasing. We are proactively working toward optimizing operations by minimizing operating expenses through sole sourcing.

BOEM Supplemental Financial Assurance and/or Bonding Requirements. As of March 31, 2018, we had approximately $325.8 million of performance bonds outstanding and $200 million in letters of credit issued to ExxonMobil relating to assets in the Gulf of Mexico. As a lessee and operator of oil and natural gas leases on the federal Outer Continental Shelf in April 2015, the Predecessor received letters from the BOEM stating that certain of its subsidiaries no longer qualified for waiver of certain supplemental bonding requirements for potential offshore decommissioning, plugging and abandonment liabilities. As of March 31, 2018, approximately $174.1 million of our performance bonds are lease and/or area bonds issued to the BOEM, to which the BOEM has access to ensure our commitment to comply with the terms and conditions of those leases. As of March 31, 2018, we also maintained approximately $151.7 million in performance bonds issued to third party assignors including certain state regulatory bodies for eventual decommissioning of certain wells and facilities. In addition, we may be required to provide cash collateral to third party assignors and third party sureties in connection with these performance bonds. As of March 31, 2018, we had $47.9 million in cash collateral provided to surety companies associated with the bonding requirements of the BOEM and third party assignors. We continue to work with the BOEM under the long-term financial assurance plan (the "Long-Term Plan"). If we are unable to provide any additional required bonds as requested, the BSEE or the BOEM may have any of our operations on federal leases suspended or cancelled or otherwise impose monetary penalties. Such actions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Oil Spill Response Plan. We maintain a Regional Oil Spill Response Plan (the "OSRP") that defines our response requirements, procedures and remediation plans in the event we have an oil spill. Oil Spill Response Plans are approved by the BSEE. The OSRP is reviewed annually and updated as necessary, which updates also require BSEE approval. The OSRP specifications are consistent with the requirements set forth by the BSEE. Additionally, the OSRP is tested and drills are conducted twice a year at all levels of the Company.

We have contracted with a spill response management consultant to provide management expertise, personnel and equipment, under our supervision, in the event of an incident requiring a coordinated response. Additionally, we are a member of Clean Gulf Associates ("CGA"), a not-for-profit association of producing and pipeline companies operating in the Gulf of Mexico that has the appropriate equipment and access to appropriate personnel to simultaneously respond to multiple spills. In the event of a spill, CGA mobilizes appropriate equipment and personnel to CGA members.

Hurricanes and Tropical Storms. Since the majority of our production originates in the Gulf of Mexico, we are particularly vulnerable to the effects of hurricanes and other named storms on production. Significant hurricane impacts could include reductions and/or deferrals of future oil and natural gas production and revenues, damage to platforms, pipelines and facilities, increased lease operating expenses for evacuations and repairs and possible acceleration of plugging and abandonment costs.

Operational Information

Operating Highlights	Quarter Ended March 31, 2018	Quarter Ended March 31, 2017
	(In thousands, except per unit amounts)	
Operating revenues		
Oil sales	$ 123,788	$ 133,793
Natural gas liquids sales	1,343	2,227
Natural gas sales	8,382	18,368
Other revenue	1,492	-
(Loss) gain on derivative financial instruments	(12,834)	3,698
Total revenues	122,171	158,086
Percentage of oil revenues prior to (loss) gain on derivative financial instruments	92%	87%
Operating expenses		
Lease operating expense		
Insurance expense	5,195	6,250
Workovers	2,524	2,565
Direct lease operating expense	74,303	68,452
Total lease operating expense	82,022	77,267
Production taxes	1,206	239
Gathering and transportation	4,056	11,222
Pipeline facility fee	10,494	10,494
Depreciation, depletion and amortization	27,411	41,896
Accretion of asset retirement obligations	11,118	13,081
Impairment of oil and natural gas properties	-	40,774
General and administrative	15,132	21,604
Reorganization items	236	2,244
Total operating expenses	151,675	218,821
Operating loss	$ (29,504)	$ (60,735)
Sales volumes per day		
Oil (MBbls)	21.1	29.1
Natural gas liquids (MBbls)	0.4	0.9
Natural gas (MMcf)	30.6	65.9
Total (MBOE)	26.6	41.0
Percent of sales volumes from oil	79%	71%
Average sales price		
Oil per Bbl	$ 65.09	$ 51.11
Natural gas liquid per Bbl	37.01	27.52
Natural gas per Mcf	3.04	3.10
Other revenue per BOE	0.62	-
(Loss) gain on derivative financial instruments per BOE	(5.35)	1.00
Total revenues per BOE	50.97	42.88
Operating expenses per BOE		
Lease operating expense		
Insurance expense	2.17	1.70
Workover and maintenance	1.05	0.70
Direct lease operating expense	31.00	18.56
Total lease operating expense per BOE	34.22	20.96
Production taxes	0.50	0.06
Gathering and transportation	1.69	3.04
Pipeline facility fee	4.38	2.85
Depreciation, depletion and amortization	11.44	11.36
Accretion of asset retirement obligations	4.64	3.55
Impairment of oil and natural gas properties	-	11.06
General and administrative	6.31	5.86
Reorganization items	0.10	0.61
Total operating expenses per BOE	63.28	59.35
Operating loss per BOE	$ (12.31)	$ (16.47)

Results of Operations

Three Months Ended March 31, 2018 Compared With the Three Months Ended March 31, 2017

Our consolidated net loss attributable to common stockholders for the three months ended March 31, 2018 was $33.1 million or $0.99 loss per common share ("per share") as compared to a net loss of $64.5 million or $1.94 per share for the three months ended March 31, 2017. Decrease in net loss was primarily due to no impairment of oil and natural gas properties, lower depreciation, depletion and amortization ("DD&A") expense and a higher realized price for oil offset by lower oil and natural gas sales volumes.

Revenues

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Decrease	Percent Increase (Decrease)
	(In thousands)			
Oil sales	$ 123,788	$ 133,793	$ (10,005)	(7.5)%
Natural gas liquid sales	1,343	2,227	(884)	(39.7)%
Natural gas sales	8,382	18,368	(9,986)	(54.4)%
Other revenue	1,492	-	1,492	-
(Loss) gain on derivative financial instruments	(12,834)	3,698	(16,532)	(447.1)%
Total Revenues	$ 122,171	$ 158,086	$ (35,915)	(22.7)%

As discussed below, our consolidated revenues were $122.2 million and $158.1 million during the three months ended March 31, 2018 and 2017, respectively. The decrease in total revenues of $35.9 million was primarily due to lower oil and natural gas sales volumes and loss on derivative financial instruments, partially offset by a higher realized price for oil.

Revenue price and volume variances by revenue component are presented in the following table and described below.

Price and Volume

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Increase (Decrease)	Percent Increase (Decrease)	Revenue Increase (Decrease)
Price					
Oil sales prices (per Bbl)	$ 65.09	$ 51.11	$ 13.98	27%	$ 36,584
Natural gas liquids sales prices (per Bbl)	37.01	27.52	9.49	34%	768
Natural gas sales prices (per Mcf)	3.04	3.10	(0.06)	(1.9)%	(355)
Other revenue (per BOE)	0.62	-	0.62	-	1,492
Loss on derivative financial instruments (per BOE)	(5.35)	1.00	(6.35)	(635.0)%	(16,532)
Total price variance					21,957
Volume					
Oil sales volumes (MBbls)	1,902	2,618	(716)	(27.4)%	(46,589)
Natural gas liquids volumes (MBbls)	36	81	(45)	(55.1)%	(1,652)
Natural gas sales volumes (MMcf)	2,753	5,927	(3,174)	(53.5)%	(9,631)
BOE sales volumes (MBOE)	2,397	3,687	(1,290)	(35.0)%	
Percent of BOE from oil	79%	71%			
Total volume variance					(57,872)
Total price and volume variance					$ (35,915)

Price Variances

Commodity prices are one of the key drivers of our earnings and net operating cash flow. Higher commodity prices increased revenues by $22.0 million in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year. Average oil prices increased $13.98 per barrel in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year, resulting in higher revenues of $36.6 million. Average natural gas liquids prices increased $9.49 per barrel in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year, resulting in higher revenues of $0.8 million. Average natural gas prices decreased $0.06 per Mcf in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $0.4 million.

Volume Variances

Sales volumes are another key driver of our earnings and net operating cash flow. Oil sales volumes decreased 8.0 MBbls per day in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $46.6 million. Natural gas liquids volumes decreased 0.5 MBbls per day in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $1.7 million. Natural gas sales volumes decreased 35.3 Mcfe per day in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $9.6 million. Sales volumes for the three months ended March 31, 2018 were impacted by excessive production downtime primarily related to severe winter weather, continued production equipment maintenance, pipeline shut-ins, facility-related unscheduled downtime and natural decline. In the first quarter of 2018 and into early May, we experienced increased downtime associated with these temporary shut-ins due to facility improvements as well as pipeline problems. Preventive maintenance continues to be an operating priority to ensure the safety of employees, reduce environmental impact and improve production uptime.

Other Revenue and (Loss) Gain on Derivative Financial Instruments

The Company adopted Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers*, as a new Accounting Standards Codification ("ASC") Topic, ASC 606, effective January 1, 2018. Although the adoption of ASC 606 did not have an impact on the Company's net loss or cash flows, it did result in the reclassification of certain fees received under pipeline gathering and transportation and pipeline tariff agreements totaling to $1.5 million that were previously included in oil sales to other revenue in the consolidated statements of operations.

For the three months ended March 31, 2018, our hedging activities resulted in a loss on derivative activities of $5.35 per BOE compared to a gain of $1.00 per BOE for the same period in the prior fiscal year, resulting in lower revenues of $16.5 million.

Costs and Expenses and Other Income (Expense)

	Three Months Ended March 31, 2018		Three Months Ended March 31, 2017		Increase (Decrease)
	Total	**Per BOE**	**Total**	**Per BOE**	**Total**
Cost and expenses	**(In thousands, except per unit amounts)**				
Lease operating expense					
Insurance expense	$ 5,195	$ 2.17	$ 6,250	$ 1.70	$ (1,055)
Workovers	2,524	1.05	2,565	0.70	(41)
Direct lease operating expense	74,303	31.00	68,452	18.56	5,851
Total lease operating expense	82,022	34.22	77,267	20.96	4,755
Production taxes	1,206	0.50	239	0.06	967
Gathering and transportation	4,056	1.69	11,222	3.04	(7,166)
Pipeline facility fee	10,494	4.38	10,494	2.85	-
Depreciation, depletion and amortization	27,411	11.44	41,896	11.36	(14,485)
Accretion of asset retirement obligations	11,118	4.64	13,081	3.55	(1,963)
Impairment of oil and natural gas properties	-	-	40,774	11.06	(40,774)
General and administrative	15,132	6.31	21,604	5.86	(6,472)
Reorganization items	236	0.10	2,244	0.61	(2,008)
Total costs and expenses	$151,675	$ 63.28	$218,821	$ 59.35	$ (67,146)
Other income (expense)					
Other income, net	143	0.06	22	0.01	121
Interest expense	(3,694)	(1.54)	(3,834)	(1.04)	140
Total other expense, net	$ (3,551)	$ (1.48)	$ (3,812)	$ (1.03)	$ 261

As discussed below, costs and expenses decreased $67.1 million in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year, principally due to no impairment of oil and natural gas properties, lower gathering and transportation expense, lower DD&A and lower general and administrative expense partially offset by an increase in direct lease operating expense due to factors discussed below.

Insurance expense decreased $1.1 million in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year. This decrease was primarily due to lower insurance premiums associated with our 2018 insurance policy renewals.

Direct lease operating expense increased $5.9 million in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year. This increase was primarily due to higher expense maintenance projects, which included expense associated with temporary shut-ins due to facility improvements as well as pipeline problems.

Production taxes increased $1.0 million in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year. This increase was due to additional accruals recorded in the first quarter of 2018 related to state severance tax audits.

Gathering and transportation expense decreased $7.2 million in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year. This decrease was primarily due to deferred pipeline maintenance expenses.

The pipeline facility fee was $10.5 million for both the three months ended March 31, 2018 and 2017 and pertains to the straight line lease expense attributable to the Grand Isle Gathering System (“GIGS”). The straight line lease expense related to GIGS is expected to remain constant throughout the life of the lease. Given the quality of the long-term reserves behind GIGS, CorEnergy Infrastructure Trust, Inc. (“CorEnergy”), the owner and lessor of GIGS, has entered into discussions with us regarding among other things, a potential lease restructuring, that preserve the long-term value of GIGS and seek to support EGC’s further recovery efforts and future success. Any changes to the GIGS lease as a result of the lease restructuring could change the straight line lease expense the Company incurs each period. There can be no assurance that any such discussions will occur and if the discussions do occur, when those discussions will occur or on what terms.

DD&A expense decreased $14.5 million in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year, primarily due to the reductions in our full cost pool in fiscal year 2017.

Accretion of asset retirement obligations decreased by $2.0 million in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year primarily due to downward revisions in the asset retirement obligation liability in fiscal year 2017.

At the end of each quarter, we compare the present value of estimated future net cash flows from proved reserves (computed using the unweighted arithmetic average of the first-day-of-the-month historical price for each month within the previous 12-month period discounted at 10%, plus the lower of cost or fair market value of unevaluated properties and excluding cash flows related to estimated abandonment costs) to our net capitalized costs of oil and natural gas properties, net of related deferred taxes. We refer to this comparison as a "ceiling test." If the net capitalized costs of these oil and gas properties exceed the estimated discounted future net cash flows, we are required to write-down the value of our oil and natural gas properties to the value of the discounted cash flows. For the three months ended March 31, 2018, we did not incur any impairment to our oil and natural gas properties and for the three months ended March 31, 2017, we recorded impairment to oil and natural gas properties of $40.8 million as a result of the decrease in proved reserves and PV-10 value as of March 31, 2017 relative to the estimated reserves prepared by our internal reservoir engineers as of December 31, 2016.

General and administrative expense decreased $6.5 million in the three months ended March 31, 2018 as compared to the same period in the prior fiscal year, primarily due to headcount reductions, partially offset by lower capitalized amounts.

Income Tax Expense

We have not recorded any income tax expense or benefit nor have we made significant federal or state income tax payments in recent years due to our history of operating losses. We do not believe that net deferred tax assets of $313 million as of March 31, 2018 are realizable in the future on a more-likely-than-not basis at this time; accordingly, our valuation allowance as of March 31, 2018 is $313 million. The increase in the valuation allowance of $7 million recorded in the three months ended March 31, 2018 is attributable to additional pre-tax losses incurred for the quarter.

Liquidity and Capital Resources

In fiscal year 2018, we plan to fund our operations primarily through cash on hand and cash flows from operating activities. Future cash flows are subject to a number of variables, and are highly dependent on the prices we receive for oil and natural gas. Our business is capital intensive and our primary use of cash is to fund capital expenditures used to develop our oil and natural gas properties. The 2018 Capital Budget anticipates total 2018 capital expenditures between $145 million and $175 million, including planned investment of $65 million to $75 million in drilling six new wells and for seven to nine recompletions, $10 million to $15 million in facilities improvements and $50 million to $60 million in plugging and abandonment expenditures. The Company believes it has sufficient liquidity as of March 31, 2018, including $112.1 million of cash on hand, $12.5 million available borrowing capacity under the Exit Facility, which is only available under specific circumstances, and funds generated from ongoing operations, to fund anticipated cash requirements for operating and capital expenditures and for principal and interest payments on our outstanding debt.

Given the current level of volatility in the market and the unpredictability of certain costs that could potentially arise in our operations, our liquidity needs could be significantly higher than we currently anticipate. Our ability to maintain adequate liquidity depends on the prevailing market prices for oil and natural gas, our successful operation of our business, and appropriate management of operating expenses and capital spending. Our anticipated liquidity needs are highly sensitive to changes in each of these and other factors.

Due to a decline in our estimated trailing twelve-month EBITDA calculation for the twelve-month period ending June 30, 2018, we may be required to prepay additional amounts of our outstanding Exit Term Loan in order to prevent a breach of the First Lien Leverage Ratio, and such a prepayment could adversely affect our liquidity. Under those circumstances, we would also discuss a covenant waiver with our banking group to remain in compliance with that ratio. In addition, our liquidity may be further adversely affected if the BOEM requires us to provide additional bonding as a means to ensure our decommissioning obligations, such as the plugging of wells, the removal of platforms and other offshore facilities, the abandonment of offshore pipelines and the clearing of the seafloor of obstructions, or if the surety companies providing such bonds on our behalf require us to provide additional cash collateral for new or existing bonds. Any further expense requirement to provide additional bonds or restrictions on our cash to collateralize existing bonds or new bonds would reduce our liquidity.

As discussed above in “Strategic Update,” as a complement to the Company’s capital plan, the Company is working with Intrepid on capital-raising activities. Furthermore, the Company is also working with Intrepid on the Proposed ONR Transaction, which, if consummated, is expected to enhance the Company’s financing efforts.

Given the quality of the long-term reserves behind GIGS, CorEnergy, the owner and lessor of GIGS, has entered into discussions with us regarding among other things, a potential lease restructuring, that preserve the long-term value of GIGS and seek to support EGC’s further recovery efforts and future success.

There can be no assurance that any of the financing or strategic transactions described above will be consummated or, if consummated, when those transactions will occur or on what terms.

Exit Facility

On December 30, 2016, the Company entered into a secured Exit Facility, which matures on December 30, 2019. The Exit Facility, as amended, is secured by mortgages on at least 90% of the value of our and our subsidiary guarantors’ proved developed producing reserves as well as our total proved reserves. The Exit Facility consists of two facilities: (i) a term loan facility (the “Exit Term Loan”) and (ii) a revolving credit facility (the “Exit Revolving Facility”) for the making of revolving loans and the issuance of letters of credit.

The Exit Facility is guaranteed by substantially all of the wholly-owned subsidiaries of the Company, subject to customary exceptions, and is secured by first priority security interests on substantially all assets of each guarantor. Under the Exit Facility, the borrower will not declare or make a restricted payment, or make any deposit for any restricted payment. Restricted payments include declaration or payment of dividends.

The Company must make a mandatory prepayment of the revolving loans and, if necessary, cash collateralize the outstanding letters of credit if a reduction in the revolving credit capacity would cause the revolving credit exposure to exceed the revolving credit capacity. On or after the determination of the borrowing base, the Company must also make a mandatory prepayment of the revolving loans and, if necessary, cash collateralize the outstanding letters of credit not in favor of ExxonMobil if a borrowing base deficiency arises.

The Exit Facility contains covenants and events of default customary for reserve-based lending facilities. In addition, for each fiscal quarter ending on and after March 31, 2018, the Company must maintain a Current Ratio (as defined in the Exit Facility) of no less than 1.00 to 1.00 and a First Lien Leverage Ratio (as defined in the Exit Facility) of no greater than 4.00 to 1.00 calculated on a trailing four quarter basis. On March 29, 2018, we prepaid $10 million outstanding under the Exit Term Loan. Due to a decline in our estimated trailing twelve-month EBITDA calculation for the twelve-month period ending June 30, 2018, we may be required to prepay additional amounts of our outstanding Exit Term Loan in order to prevent a breach of the First Lien Leverage Ratio, and such a prepayment could adversely affect our liquidity. Under those circumstances, we would also discuss a covenant waiver with our banking group to remain in compliance with that ratio.

Furthermore, for each fiscal quarter ending on and after March 31, 2018, if the Asset Coverage Ratio (as defined in the Exit Facility) is less than 1.50 to 1.00, the Company must make a mandatory prepayment of the Exit Term Loan in an amount equal to the lesser of (i) 7.5% of the aggregate outstanding principal amount of the Exit Term Loan on December 30, 2016 and (ii) the then outstanding principal amount of the Exit Term Loan. Based upon the Company’s current expectations with respect to its capital resources, capital expenditures, results from operations and commodity prices, the Company believes that it is reasonably likely that it will be required to make a mandatory prepayment with respect to each fiscal quarter ending on and after March 31, 2018. In that case, the first such payment of approximately $5.55 million will be paid during the fiscal quarter ending June 30, 2018. Any such mandatory prepayment would not, in and of itself, constitute a default under the Exit Facility.

Unused credit capacity under the Exit Revolving Facility will accrue a commitment fee of 0.50% payable quarterly in arrears.

Interest on the outstanding amount of the Exit Term Loan, at the Company’s option, will accrue at an interest rate equal to either: (i) the Alternative Base Rate (as defined in the Exit Facility) plus 3.5% per annum or (ii) the one-month LIBO Rate (as defined in the Exit Facility) plus 4.5% per annum. Interest on the Exit Term Loan bearing interest at the Alternative Base Rate will be payable quarterly; interest on the Exit Term Loan bearing interest at the LIBO Rate will be payable monthly.

Interest on the outstanding amount of revolving loans borrowed under the Exit Revolving Facility, at the Company's option, will accrue at an interest rate equal to either (i) the Alternative Base Rate plus 3.5% per annum or (ii) the one, three or six month LIBO Rate plus 4.5% per annum. Interest on revolving loans that bear interest at the Alternative Base Rate will be payable quarterly; interest on revolving loans that bear interest at the LIBO Rate will be payable at the end of each interest period or, if an interest period exceeds three months, at the end of every three months. The stated amount of each letter of credit issued under the Exit Revolving Facility accrues fees at the rate of 4.5% per annum. There is an issuance fee of 0.25% per annum charged on the stated amount of each letter of credit issued after December 30, 2016.

We currently have $12.5 million available for borrowing, under specific circumstances, as revolving loans subject to a maximum for all such loans of (i) $25 million prior to the date the borrowing base is initially determined and (ii) the borrowing base, on and after the date the borrowing base is initially determined. The borrowing base will be initially determined at a date elected by the Company, and will be redetermined semi-annually thereafter. Currently, the Company has not elected a date for the initial borrowing base determination.

As of March 31, 2018, we had approximately $64 million in borrowings and $201.5 million in letters of credit issued under the Exit Facility.

BOEM Bonding Requirements

The future cost of compliance with our existing supplemental bonding requirements, including such bonding obligations as reflected in the Long-Term Plan, as such plan may be revised by the Proposed Plan Amendment, or any other changes to the BOEM's current NTL supplemental bonding requirements or supplemental bonding rules applicable to us or our subsidiaries' properties could materially and adversely affect our financial condition, cash flows, and results of operations. In addition, we may be required to provide cash collateral to support the issuance of such bonds or other surety. We continue to work with the BOEM under the Long-Term Plan. We can provide no assurance that we can continue in the future to obtain bonds or other surety in all cases or that we will have sufficient operating cash flows to support such supplemental bonding requirements. If we are unable to provide any additional required bonds as requested, the BSEE or the BOEM may have any of our operations on federal leases suspended or cancelled or otherwise impose monetary penalties. Such actions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity For more information about the BOEM's supplement bonding requirements, see "- Known Trends and Uncertainties - BOEM Supplemental Financial Assurance and/or Bonding Requirements" above.

Capital Expenditures

For the three months ended March 31, 2018, our capital expenditures including plugging and abandonment obligations totaled $21.8 million, of which $8.9 million was related to development and recompletion activities in our core properties and $12.8 million was spent on plugging and abandonment obligations. For 2018, the Company's initial capital budget, excluding acquisitions but including plugging and abandonment is expected to be in the range of $145 million to $175 million, of which plugging and abandonment costs are expected to be in the range of $50 million to $60 million. We believe that our capital resources from existing cash balances and anticipated cash flow from operating activities will be adequate to fund anticipated cash requirements for capital expenditures in 2018. However, given the current level of volatility in the market and the unpredictability of certain costs that could potentially arise in our operations, our liquidity needs could be significantly higher than we currently anticipate. Our long-term liquidity requirements and the adequacy of our capital resources are difficult to predict. If we limit, defer or eliminate our capital expenditure plan or are unsuccessful in developing reserves and adding production through our capital program or our cost-cutting efforts are too overreaching, the value of our oil and natural gas properties and our financial condition and results of operations could be adversely affected.

Cash Flows

The following table sets forth selected historical information from our statement of cash flows:

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(In thousands)	
Net cash provided by (used in) operating activities	$ (16,800)	$ (13,702)
Net cash used in investing activities	(12,727)	(15,785)
Net cash used in financing activities	(10,077)	(602)
Net decrease in cash, cash equivalents and restricted cash	$ (39,604)	$ (30,089)

Operating Activities

Net cash used in operating activities for the three months ended March 31, 2018 and 2017 was $16.8 million and $13.7 million, respectively. The cash used in operating activities increased primarily due to lower cash inflows of $21.7 million attributable to oil, natural gas liquids and natural gas price and volume variances partially offset by lower cash outflows of $17.6 million associated with operating assets and liabilities.

Investing Activities

Net cash used in investing activities for the three months ended March 31, 2018 and 2017 was $12.7 million and $15.8 million, respectively. The decrease in cash used in investing activities was primarily due to $6.1 million reduction in capital expenditures partially offset by $2.1 million in insurance proceeds and $1.0 million received on sale of other property and equipment in the prior period.

Financing Activities

Net cash used in financing activities for the three months ended March 31, 2018 and 2017 was $10.1 million and $0.6 million, respectively. During the three months ended March 31, 2018, cash used in financing activities consists primarily of a $10.0 million prepayment of the Exit Term Loan. During the three months ended March 31, 2017, cash used in financing activities consists primarily of $0.6 million used to repay debt.

Contractual Obligations

Our contractual obligations at March 31, 2018 did not change materially from those disclosed in Item 7 of our 2017 Annual Report.

Critical Accounting Policies

Our significant accounting policies are summarized in Note 2 – “Revision of Prior Period Financial Statements, Summary of Significant Accounting Policies and Recent Accounting Pronouncements” of Notes to our Consolidated Financial Statements included in our 2017 Annual Report and Note 2 – “Summary of Significant Accounting Policies and Recent Accounting Pronouncements” of Notes to our Consolidated Financial Statements in this Quarterly Report.

Recent Accounting Pronouncements

For a description of recent accounting pronouncements, see Note 2 – “Summary of Significant Accounting Policies and Recent Accounting Pronouncements” of Notes to Consolidated Financial Statements in this Quarterly Report.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

General

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our 2017 Annual Report.

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

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

Commodity Price Risk

Our major market risk exposure continues to be the pricing applicable to our oil and natural gas production. Our revenues, profitability and future rate of growth depend substantially upon the market prices of oil and natural gas, which are volatile and may fluctuate widely. Oil and natural gas price declines adversely affect our revenues, cash flows and profitability. If we were to experience an extended depressed pricing environment, declines could impact the extent to which we develop portions of our oil and natural gas properties, and could possibly include temporarily shutting in certain wells that are uneconomic to produce. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The energy markets have historically been very volatile, and there can be no assurance that crude oil and natural gas prices will improve.

We utilize commodity-based derivative instruments with major financial institutions to reduce exposure to fluctuations in the price of crude oil and natural gas. We have historically used various instruments, including financially settled crude oil and natural gas puts, put spreads, swaps, costless collars and three-way collars in our derivative portfolio. Any gains or losses resulting from the change in fair value from hedging transactions and from the settlement of hedging contracts are recorded in earnings as a component of revenues. With a costless collar, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price of the collar, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the cap price for the collar. In a fixed price swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the swap fixed price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the swap fixed price.

In April 2018, we unwound 3,000 BPD of our WTI swaps for the period from April 1, 2018 to June 30, 2018 and replaced the unwound swaps with 3,000 BPD ICE Brent swaps with an average swap price of $61.00 per BBL for the period from January 2019 to December 2019. Additionally, we added 3,000 BPD ICE Brent costless collars with a floor price of $60.00 and a ceiling price of $82.00 for the period April 13, 2018 to June 30, 2018.

As of March 31, 2018, we had the following open crude oil derivative positions:

Remaining Contract Term	Type of Contract	Index	Volumes (MBbls)	Weighted Average Contract Price Swaps
April 2018 - December 2018	Swaps	NYMEX-WTI	2,200.0	$ 50.68
April 2018 - June 2018	Swaps	Argus-LLS	182.0	$ 55.45
April 2018 - June 2018	Swaps	ICE Brent	227.5	$ 56.59

As of March 31, 2018, our crude oil contracts outstanding were in a net liability position of approximately $32.4 million. A 10% increase in crude oil prices would increase the net liability position by approximately $16.6 million, while a 10% decrease in crude oil prices would decrease the liability positon by approximately $16.6 million. These fair value changes assume volatility based on prevailing market parameters as of March 31, 2018.

Our ultimate realized gain or loss with respect to commodity price fluctuations will depend on the future exposures that arise during the period as well as our derivative strategies and commodity prices at the time.

Interest Rate Risk

Our exposure to changes in interest rates relates primarily to our variable rate debt obligations. Specifically, we are exposed to changes in interest rates as a result of borrowings under our Exit Facility, and the terms of such facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. Historically, we have managed our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. Following emergence from bankruptcy, we are no longer liable for interest on our fixed rate indebtedness. Therefore, we are exposed to interest rate risk for the indebtedness on which we are paying variable interest, specifically our Exit Facility. As of March 31, 2018, we had approximately $64 million of outstanding floating-rate debt. A 10% change in floating interest rates on period-end floating rate debt balances would change the year to date interest expense by approximately $30,000. We currently have no interest rate hedge positions in place to reduce our exposure to changes in interest rates.

We generally invest cash equivalents in high-quality credit instruments consisting primarily of money market funds with maturities of 90 days or less. We do not expect any material loss from cash equivalents and therefore we believe our interest rate exposure on invested funds is not material.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and our principal financial officer, we evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”)) as of the end of the period covered by this Quarterly Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based on this evaluation and as a result of a material weakness identified during preparation of the Company’s consolidated financial statements for the fiscal year ended December 31, 2017 which has not been fully remediated, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were not effective at the reasonable assurance level as of the end of the period covered by this Quarterly Report. The remediation plan as outlined in the annual report on Form 10-K for the fiscal year ended December 31, 2017 will be implemented and the effectiveness of controls of such remediation will be tested during fiscal year 2018.

Changes in Internal Control over Financial Reporting

During the quarter ended March 31, 2018, management was in the process of designing and implementing additional procedures in response to a material weakness in its control environment identified during the preparation of its consolidated financial statements for the fiscal year ended December 31, 2017, including, but not limited to enhancing communication and sharing of data among the accounting, land, operations and legal departments to timely identify changes in asset retirement obligations.

Other than changes related to the item noted above, there was no change in our system of internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during our quarterly period ended March 31, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. Legal Proceedings

We are involved in various legal proceedings and claims, which arise in the ordinary course of our business. We do not believe the ultimate resolution of any such actions will have a material effect on our consolidated financial position, results of operations or cash flows.

ITEM 1A. Risk Factors

Our business faces many risks. Any of the risks discussed in this Quarterly Report or in our other SEC filings, could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations. For a detailed discussion of the risk factors that should be understood by any investor contemplating investment in our common stock, please refer to the section entitled Part I “Item 1A. Risk Factors” in our 2017 Annual Report. There have been no material changes in the risk factors set forth in our 2017 Annual Report.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds.

During the first quarter of 2018, the Company did not make any unregistered sales of equity securities, and neither it nor any “affiliated purchaser” (as defined in Rule 10b-18(a)(3) under the Exchange Act) made any purchases of shares or other units of any class of the Company’s equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

Under the Exit Facility, the Company may not declare or make a restricted payment, or make any deposit for any restricted payment. Restricted payments include declaration or payment of dividends

ITEM 3. Defaults upon Senior Securities

None

ITEM 4. Mine Safety Disclosures.

Not applicable

ITEM 5. Other Information

None

ITEM 6. Exhibits

The exhibits listed on the accompanying Exhibit Index are filed or incorporated by reference as part of this Quarterly Report, and such Exhibit Index is incorporated herein by reference.

EXHIBIT INDEX

Exhibit Number	Exhibit Description	Incorporated by Reference to the Following
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a–14 of the Securities and Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a–14 of the Securities and Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Furnished herewith
101.INS	XBRL Instance Document	Filed herewith
101.SCH	XBRL Taxonomy Extension Schema Document	Filed herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	Filed herewith
101.DEF	XBRL Taxonomy Extension Label Linkbase Document	Filed herewith
101.LAB	XBRL Taxonomy Extension Definition Linkbase Document	Filed herewith
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, Energy XXI Gulf Coast, Inc. has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ENERGY XXI GULF COAST, INC.

By: /S/ DOUGLAS E. BROOKS
Douglas E. Brooks
Duly Authorized Officer and Chief Executive Officer

By: /S/ TIFFANY THOM CEPAK
Tiffany Thom Cepak
Duly Authorized Officer and Chief Financial Officer

Date: May 10, 2018

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A – 14(A) AND RULE 15D – 14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Douglas E. Brooks, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended March 31, 2018 of Energy XXI Gulf Coast, Inc. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: May 10, 2018

/S/ DOUGLAS E. BROOKS
Douglas E. Brooks
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A – 14(A) AND RULE 15D – 14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Tiffany Thom Cepak, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended March 31, 2018 of Energy XXI Gulf Coast, Inc. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: May 10, 2018

/S/ TIFFANY THOM CEPAK
Tiffany Thom Cepak
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with this quarterly report on Form 10-Q for the quarter ended March 31, 2018 of Energy XXI Gulf Coast, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned Douglas E. Brooks, Chief Executive Officer of the Company, and Tiffany Thom Cepak, Chief Financial Officer of the Company, each certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

	/S/ DOUGLAS E. BROOKS
Date: May 10, 2018	Douglas E. Brooks Chief Executive Officer
	/S/ TIFFANY THOM CEPAK
Date: May 10, 2018	Tiffany Thom Cepak Chief Financial Officer