UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2018

OR

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

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 August 3, 2018, there were 33,396,563 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 refer 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.

INTRODUCTORY NOTE REGARDING EGC'S PENDING MERGER

On June 18, 2018, the Company entered into an Agreement and Plan of Merger (the "Merger Agreement") with MLCJR LLC ("Cox"), a Texas limited liability company and an affiliate of Cox Oil LLC, and YHIMONE, Inc., a Delaware corporation and a direct wholly-owned subsidiary of Cox ("Merger Sub"). Upon the terms and conditions set forth in the Merger Agreement, at the consummation of the transactions contemplated by the Merger Agreement, Merger Sub will be merged with and into EGC (the "Merger"), and EGC will survive the Merger as the surviving corporation and an indirect wholly-owned subsidiary of Cox.

Subject to the terms and conditions of the Merger Agreement, at the effective time of the Merger (the "Effective Time"), each issued and outstanding share of EGC common stock, par value $0.01 per share ("Common Stock"), will be converted into the right to receive $9.10 in cash without interest (the "Merger Consideration").

Closing Conditions. The completion of the Merger is subject to satisfaction or waiver of certain closing conditions, including: (i) approval of the Merger Agreement by EGC's stockholders, (ii) there being no law or injunction prohibiting consummation of the Merger; (iii) subject to specified materiality standards, the accuracy of the representations and warranties of the other party; (iv) compliance by the other party in all material respects with its covenants; and (v) the absence of a material adverse effect on the other party. The completion of the Merger is not conditioned on receipt of financing by Cox.

Termination Rights. The Merger Agreement contains certain termination rights for both EGC and Cox and further provides that, upon termination of the Merger Agreement, under certain circumstances, EGC may be required to pay Cox a termination fee equal to $8 million and, in certain other circumstances, EGC may be required to reimburse Cox for its documented out-of-pocket expenses up to $2 million.

Interim Operating Covenants. EGC has agreed to certain covenants in the Merger Agreement restricting the conduct of its business between the date of the Merger Agreement and the Effective Time. The effect of these covenants is that, until the Merger is consummated, EGC will be very limited in its ability to pursue strategic and operational initiatives outside the ordinary course of business. Therefore, if the Merger Agreement is terminated and the Merger does not occur, it will need to renew the financing, cost-cutting, and liability management initiatives that it had been pursuing prior to the execution of the Merger Agreement.

In general, EGC has agreed to conduct its business in the ordinary course, consistent with past practice and use all commercially reasonable efforts to preserve intact its present business organization, retain its officers and key employees, and preserve its relationships with its customers and suppliers and other persons having significant business dealings with it, to the end that its goodwill and ongoing business will not be impaired in any material respect. EGC has also agreed to comply, in all material respects, with all applicable law, except where the failure to comply would not reasonably likely to have, individually or in the aggregate, a material adverse effect, and to not voluntarily resign, transfer or relinquish any right as operator of its oil and gas properties.

In addition, EGC has agreed to specific restrictions relating to the conduct of its business between the date of the Merger Agreement and the Effective Time, including, but not limited to, not to take (or permit any of its subsidiaries to take) the following actions (subject, in each case, to exceptions specified below and in the Merger Agreement or previously disclosed in writing to Cox as provided in the Merger Agreement or as consented to in advance by Cox (which consent shall not be unreasonably withheld, delayed or conditioned) or as required by law or in the event of certain emergencies):

- subject to certain limited exceptions, offer, issue, deliver, grant or sell, or authorize or propose to offer, issue, deliver, grant or sell, any capital stock of, or other equity interests in, EGC or any of its subsidiaries or any securities convertible into, or any rights, warrants or options to acquire, any capital stock or equity interests of EGC or any of its subsidiaries;

- amend or propose to amend its or its subsidiaries' articles of incorporation, bylaws or other comparable organizational documents;

- merge, consolidate or amalgamate with any person other than a wholly owned subsidiary of EGC;

- acquire or agree to acquire any business or any corporation, partnership, association or other business organization or division thereof (other than acquisitions of federal lease blocks);
- authorize or make capital expenditures that are, on an individual basis, in excess of $1,000,000, except for planned capital expenditures disclosed to Cox at signing of the Merger Agreement and reasonable capital expenditures to repair damage resulting from casualty events or required due to an emergency;
- subject to certain limited exceptions, sell, lease, license, transfer, exchange, swap, pledge, subject to any encumbrance or otherwise dispose of, or agree to sell, lease, license, transfer, exchange, swap, pledge, subject to any encumbrance or otherwise dispose of, any of its or their assets or properties;
- incur, create or assume any material indebtedness, or create any material encumbrances on any property or assets of EGC or any of its subsidiaries, other than permitted encumbrances, subject to certain limited exceptions, including capital lease obligations in the ordinary course of business consistent with past practice not to exceed $1,000,000 and trade credit provided to customers in the ordinary course of business consistent with past practice;
- enter into any material contract; and
- terminate, amend, modify or waive any material provision right or benefit of or under any material contract except where that termination, amendment, modification or waiver would not reasonably be likely to have, individually or in the aggregate, a material adverse effect.

Special Stockholder Meeting. As stated in EGC's definitive proxy statement (the "Merger Proxy Statement") filed with the SEC on August 3, 2018, EGC will hold a special meeting of its stockholders on September 6, 2018 at 9 a.m. (Houston Time). At that special meeting, EGC stockholders will be asked to vote on the adoption of the Merger Agreement, which requires the affirmative vote of the holders of two-thirds of the issued and outstanding shares of Common Stock entitled to vote at the EGC special meeting. The record date for the special meeting is August 3, 2018. Therefore, in order to be entitled to notice of, and to vote at, the special meeting or any adjournment or postponement of the special meeting, an individual or entity must be the record holder of shares of Common Stock at the close of business on August 3, 2018.

Anticipated Timing; No Assurance that Closing will Occur. The Merger is expected to close in the third quarter of 2018. However, EGC cannot provide any assurance the combination will be completed on the terms or timeline currently contemplated, or at all.

The above is a summary of certain material terms of the Merger Agreement and is qualified in its entirety by the terms and conditions of the Merger Agreement, which was filed as an exhibit to the Company's current report on Form 8-K filed on June 18, 2018.

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.

These forward-looking statements relate to the transactions contemplated by the Merger Agreement, as well as to EGC's financial and operating performance on a stand-alone basis prior to the consummation of the Merger or if the Merger is not consummated. Important factors that could cause actual results and outcomes to differ materially from those in the forward-looking statements include, but are not limited to those summarized below:

Forward-Looking Statements Relating to the Merger

- the risk that the Merger may not be completed in the third quarter of 2018 or at all, which may adversely affect our business and the price of our common stock;
- the failure to satisfy the conditions to the consummation of the transaction, including the adoption of the Merger Agreement by our stockholders;
- the risk that Cox may not be able to obtain the necessary financing to complete the Merger in accordance with the Merger Agreement;
- the occurrence of any event, change or other circumstance that could give rise to the termination of the Merger Agreement;
- the effect of the announcement or pendency of the transaction on our business relationships, operating results, and business generally;
- risks that the Merger disrupts our current plans and operations;
- the possibility that competing offers or acquisition proposals for the Company will be made;
- lawsuits, if any, relating to the Merger;

Forward-Looking Statements Relating to EGC's Financial and Operating Performance

- 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;
- recent 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”);
- 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; and
- costs associated with perfecting title for mineral rights in some of our properties;

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)

	June 30, 2018	December 31, 2017
ASSETS	(Unaudited)	
Current Assets		
Cash and cash equivalents	$ 97,900	$ 151,729
Accounts receivable		
Oil and natural gas sales	55,413	55,598
Joint interest billings, net	4,004	6,336
Other	19,920	15,726
Prepaid expenses and other current assets	11,873	21,602
Restricted cash	6,432	6,392
Total Current Assets	195,542	257,383
Property and Equipment		
Oil and natural gas properties, net - full cost method of accounting, including $192.3 million and $200.2 million of unevaluated properties not being amortized at June 30, 2018 and December 31, 2017, respectively	773,153	764,922
Other property and equipment, net	8,269	10,120
Total Property and Equipment, net of accumulated depreciation, depletion, amortization and impairment	781,422	775,042
Other Assets		
Restricted cash	25,814	25,712
Other assets	29,468	18,845
Total Other Assets	55,282	44,557
Total Assets	$ 1,032,246	$ 1,076,982
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 79,154	$ 85,122
Accrued liabilities	52,111	45,494
Asset retirement obligations	55,952	51,398
Derivative financial instruments	36,793	32,567
Current maturities of long-term debt	17	21
Total Current Liabilities	224,027	214,602
Long-term debt, less current maturities	58,413	73,952
Asset retirement obligations	625,496	613,453
Derivative financial instruments	6,305	-
Other liabilities	14,932	10,783
Total Liabilities	929,173	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 June 30, 2018 and December 31, 2017	-	-
Common stock, $0.01 par value, 100,000,000 shares authorized and 33,396,563 and 33,254,963 shares issued and outstanding at June 30, 2018 and December 31, 2017, respectively	334	333
Additional paid-in capital	916,525	911,144
Accumulated deficit	(813,786)	(747,285)
Total Stockholders' Equity	103,073	164,192
Total Liabilities and Stockholders' Equity	$ 1,032,246	$ 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 June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Revenues				
Oil sales	$ 133,180	$ 118,484	$ 256,968	$ 252,277
Natural gas liquids sales	1,076	2,370	2,419	4,597
Natural gas sales	6,261	13,753	14,643	32,121
Other revenue	2,267	-	3,759	-
Gain (loss) on derivative financial instruments	(26,045)	9,412	(38,879)	13,110
Total Revenues	116,739	144,019	238,910	302,105
Costs and Expenses				
Lease operating	79,296	83,655	161,318	160,922
Production taxes	371	482	1,577	721
Gathering and transportation	3,119	2,678	7,175	13,900
Pipeline facility fee	10,494	10,494	20,988	20,988
Depreciation, depletion and amortization	27,555	38,685	54,966	80,581
Accretion of asset retirement obligations	11,197	9,984	22,315	23,065
Impairment of oil and natural gas properties	-	-	-	40,774
General and administrative expense	15,568	20,716	30,700	42,320
Reorganization items	113	-	349	2,244
Total Costs and Expenses	147,713	166,694	299,388	385,515
Operating Loss	(30,974)	(22,675)	(60,478)	(83,410)
Other Income (Expense)				
Other income, net	191	80	334	102
Interest expense	(3,252)	(3,642)	(6,946)	(7,476)
Total Other Expense, net	(3,061)	(3,562)	(6,612)	(7,374)
Loss Before Income Taxes	(34,035)	(26,237)	(67,090)	(90,784)
Income Tax Expense	-	-	-	-
Net Loss	$ (34,035)	$ (26,237)	$ (67,090)	$ (90,784)
Net Loss per Share				
Basic and Diluted	$ (1.02)	$ (0.79)	$ (2.01)	$ (2.73)
Weighted Average Number of Common Shares Outstanding				
Basic and Diluted	33,427	33,237	33,367	33,234

See accompanying Notes to Consolidated Financial Statements.

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

	Six Months Ended June 30, 2018	2017
Cash Flows From Operating Activities		
Net loss	$ (67,090)	$ (90,784)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	54,966	80,581
Impairment of oil and natural gas properties	-	40,774
Change in fair value of derivative financial instruments	10,531	(10,470)
Accretion of asset retirement obligations	22,315	23,065
Amortization of debt issuance costs	11	6
Deferred rent	4,169	4,031
Provision for loss on accounts receivable	-	300
Stock-based compensation	5,617	3,722
Changes in operating assets and liabilities		
Accounts receivable	(1,677)	27,404
Prepaid expenses and other assets	(1,208)	11,134
Settlement of asset retirement obligations	(34,717)	(27,491)
Accounts payable, accrued liabilities and other	853	(50,738)
Net Cash Provided by (Used in) Operating Activities	(6,230)	11,534
Cash Flows from Investing Activities		
Capital expenditures	(31,954)	(24,496)
Insurance payments received	-	41
Proceeds from the sale of other property and equipment	288	1,279
Net Cash Used in Investing Activities	(31,666)	(23,176)
Cash Flows from Financing Activities		
Payments on long-term debt	(15,556)	(728)
Other	(235)	(61)
Net Cash Used in Financing Activities	(15,791)	(789)
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(53,687)	(12,431)
Cash, Cash Equivalents and Restricted Cash, beginning of period	183,833	223,288
Cash, Cash Equivalents and Restricted Cash, end of period	$ 130,146	$ 210,857

See accompanying Notes to Consolidated Financial Statements.

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

Note 1 — Organization and 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" or the "Predecessor"). The Company is headquartered in Houston, Texas, and engages 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. EGC owns and operates nine of the largest GoM Shelf oil fields ranked by total cumulative oil production to date and utilizes various techniques to increase the recovery factor and thus increase the total oil recovered.

Note 2 — Recent Events

On June 18, 2018, the Company entered into an Agreement and Plan of Merger (the "Merger Agreement") with MLCJR LLC ("Cox"), a Texas limited liability company and an affiliate of Cox Oil LLC, and YHIMONE, Inc., a Delaware corporation and a direct wholly-owned subsidiary of Cox ("Merger Sub"). Upon the terms and conditions set forth in the Merger Agreement, at the consummation of the transactions contemplated by the Merger Agreement, Merger Sub will be merged with and into EGC (the "Merger"), and EGC will survive the Merger as the surviving corporation and an indirect wholly-owned subsidiary of Cox.

Subject to the terms and conditions of the Merger Agreement, at the effective time of the Merger (the "Effective Time"), each issued and outstanding share of EGC common stock, par value $0.01 per share ("Common Stock"), will be converted into the right to receive $9.10 in cash without interest (the "Merger Consideration").

Pursuant to the Merger Agreement, immediately prior to the Effective Time, the vesting of each outstanding EGC restricted stock unit (each, an "RSU") will accelerate (if not already vested), with any performance conditions deemed achieved at target, and be cancelled and converted into the right to receive the Merger Consideration, multiplied by the number of shares of Common Stock subject to that RSU.

The exercise price for each outstanding stock option is greater than the Merger Consideration. As a result, at the Effective Time, each stock option to purchase shares of Common Stock will be cancelled for no consideration.

In accordance with the warrant agreement under which the Company's 2,119,889 outstanding warrants were issued, the warrants will no longer represent the right to acquire shares of Common Stock at the Effective Time. Instead, at that time, each warrant will become exercisable for $9.10 in cash, but the warrant holder would be required to pay the warrant's cash exercise price of $43.66 per share in order to receive $9.10. Therefore, the Merger Agreement provides that, at the Effective Time, each outstanding warrant will be cancelled for no consideration.

The completion of the Merger is subject to satisfaction or waiver of certain closing conditions, including: (i) approval of the Merger Agreement by EGC's stockholders, (ii) there being no law or injunction prohibiting consummation of the Merger; (iii) subject to specified materiality standards, the accuracy of the representations and warranties of the other party; (iv) compliance by the other party in all material respects with its covenants; and (v) the absence of a material adverse effect on the other party. The completion of the Merger is not conditioned on receipt of financing by Cox.

EGC and Cox have made customary representations and warranties in the Merger Agreement. The Merger Agreement also contains customary covenants and agreements whereby EGC has agreed to (i) operate its business in the ordinary course; (ii) use its commercially reasonable efforts to maintain and preserve its present business organization, retain its officers and key employees, and preserve its relationships with its customers and suppliers; and (iii) subject to certain exceptions, not take certain actions relating to its dividends, capital stock or alternative business combinations, among other things, during the period between the execution of the Merger Agreement and the Effective Time. EGC and Cox have each agreed to use commercially reasonable efforts to cause the Merger to be completed.

The Merger Agreement contains certain termination rights for both EGC and Cox and further provides that, upon termination of the Merger Agreement, under certain circumstances, EGC may be required to pay Cox a termination fee equal to $8 million and, in certain other circumstances, EGC may be required to reimburse Cox for its documented out-of-pocket expenses up to $2 million.

As stated in the Merger Proxy Statement, EGC will hold a special meeting of its stockholders on September 6, 2018 at 9 a.m. (Houston time). At that special meeting, EGC stockholders will be asked to vote on the adoption of the Merger Agreement, which requires the affirmative vote of the holders of two-thirds of the issued and outstanding shares of Common Stock entitled to vote at the EGC special meeting. The record date for the special meeting is August 3, 2018. Therefore, in order to be entitled to notice of, and to vote at, the special meeting or any adjournment or postponement of the special meeting, an individual or entity must be the record holder of shares of Common Stock at the close of business on August 3, 2018.

The Merger is expected to close in the third quarter of 2018. However, EGC cannot provide any assurance the combination will be completed on the terms or timeline currently contemplated, or at all. The above is a summary of the material terms of the Merger Agreement and is qualified in its entirety by the terms and conditions of the Merger Agreement, which was filed as an exhibit to the Company's current report on Form 8-K filed on June 18, 2018.

Shortly prior to entering into the Merger Agreement, the Company terminated its previously-disclosed non-binding term sheet with Orinoco Natural Resources, LLC and certain of its affiliates, which provided for the disposition of certain non-core assets, a cash payment, execution of a ten-year second lien note, issuance of common equity, execution of a ten-year master services agreement and a commitment to anchor a potential future financing plan. The termination fee for the term sheet was $1.0 million and was paid subsequent to June 30, 2018.

Note 3 – Summary of Significant Accounting Policies and Recent Accounting Pronouncements

Principles of Consolidation and Reporting. The accompanying consolidated financial statements on June 30, 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. EGC's 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 the Company's depletion rate for its 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, the Company's accounting estimates require the exercise of judgment by management in preparing such estimates. While the Company believes 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 the Company 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 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, the Company enters into lease agreements to support operations. The Company is evaluating the provisions of ASU 2016-02 to determine the quantitative effects it will have on its consolidated financial statements and related disclosures. The Company believes the adoption and implementation of this ASU will have a material impact on its balance sheet resulting from an increase in both assets and liabilities relating to its 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. The Company has not yet determined the effect of this standard on its 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. The Company's adoption of ASU 2016-15 on January 1, 2018 using the retrospective transition method had no effect on its 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. The Company's adoption of ASU 2016-18 on January 1, 2018 had no effect on its consolidated financial position, results of operations or cash flows other than presentation.

Note 4 – Property and Equipment

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

	As of June 30, 2018	As of December 31, 2017
Oil and natural gas properties - full cost method of accounting		
Proved properties	$1,372,463	$ 1,307,009
Less: accumulated depreciation, depletion, amortization and impairment	(791,585)	(742,286)
Proved properties, net	580,878	564,723
Unevaluated properties	192,275	200,199
Oil and natural gas properties, net	773,153	764,922
Other property and equipment	13,936	13,780
Less: accumulated depreciation and impairment	(5,667)	(3,660)
Other property and equipment, net	8,269	10,120
Total property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$ 781,422	$ 775,042

Under the full cost method of accounting, at the end of each financial reporting period, the Company compares 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. The Company refers 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, the Company is required to write down the value of oil and natural gas properties to the amount of the discounted cash flows. For the six months ended June 30, 2018, the Company did not incur any impairment to its oil and natural gas properties. For the three months ended June 30, 2018, the Company did not record an impairment to oil and natural gas properties. For the six months ended June 30, 2017, the Company recorded impairment to oil and natural gas properties of $40.8 million. The impairment to oil and natural gas properties for the six months ended June 30, 2017 was primarily due to the difference in SEC reserves and the related PV-10 value relative to the estimated reserves prepared by its 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 and six months ended June 30, 2018, the costs associated with unevaluated properties decreased by $3.6 million and $7.9 million, respectively. For the three months ended June 30, 2018, the decrease of $2.2 million was attributable to ratable amortization and $1.8 million was transferred to evaluated properties due to impairment, partially offset by an addition of $0.4 million related to exploratory drilling costs. For the six months ended June 30, 2018, the decrease of $4.3 million was attributable to ratable amortization and $4.0 million was transferred to evaluated properties due to impairment, partially offset by an addition of $0.4 million related to exploratory drilling costs.

Note 5 – Long-Term Debt

As of June 30, 2018 and December 31, 2017 the Company's outstanding debt consisted of the following (*in thousands*):

	As of June 30, 2018	As of December 31, 2017
Exit Facility	$ 58,447	$ 73,996
Capital lease obligations	17	21
Total debt	58,464	74,017
Less: debt issue costs	34	44
Less: current maturities	17	21
Total long-term debt	$ 58,413	$ 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 it and its subsidiary guarantors' proved developed producing reserves as well as its 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, the Company prepaid $10.0 million outstanding under the Exit Term Loan. No payment was made during the quarter ended June 30, 2018. Due to a potential decline in its estimated trailing twelve-month EBITDA calculation for the twelve-month period ending September 30, 2018, the Company may prepay additional amounts of its outstanding Exit Term Loan in order to prevent a breach of the First Lien Leverage Ratio, and such a prepayment could adversely affect its liquidity. Additionally, due to its decreased cash position, the Company may not meet its required Current Ratio (as defined in the Exit Facility). Under those circumstances, the Company would explore several options to remain in compliance with the terms of the Exit Facility, including modifying the timing of its capital expenditures.

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 on the results of the quarter ended March 31, 2018, the Company made a mandatory prepayment of $5.5 million during the quarter ended June 30, 2018. Based on the results of the quarter ended June 30, 2018, the Company will not be required to make a prepayment during the quarter ended September 30, 2018. 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 possible that it will be required to make a mandatory prepayment with respect to fiscal quarters subsequent to September 30, 2018. In the event of a mandatory prepayment, any such mandatory prepayment would not, in and of itself, constitute a default under the Exit Facility. As of June 30, 2018, the Company is in compliance with all terms of 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.

The Company currently has $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 June 30, 2018, the Company had approximately $58.4 million in borrowings and $201.5 million in letters of credit issued under the Exit Facility.

Note 6 – Asset Retirement Obligations

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

Balance as of December 31, 2017	$ 664,851
Liabilities incurred	8,761
Liabilities settled	(34,717)
Revisions	20,238
Accretion expense	22,315
Total balance as of June 30, 2018	681,448
Less: current portion	55,952
Long-term portion as of June 30, 2018	$ 625,496

Note 7 – Derivative Financial Instruments

The Company enters 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. The Company has historically used various instruments, including financially settled crude oil and natural gas puts, put spreads, swaps, costless collars and three-way collars in its derivative portfolio. With a costless collar, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price of the collar, and the Company was 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 the Company if the settlement price for any settlement period is below the swap fixed price, and the Company is 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 the Company's crude oil production is sold at Heavy Louisiana Sweet. The Company has historically included contracts indexed to NYMEX-WTI, ICE Brent futures and Argus-LLS futures in its derivative portfolio to closely align and manage its 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 June 30, 2018, the Company had the following open crude oil derivative positions:

Remaining Contract Term	Type of Contract	Index	Volumes (MBbls)	Weighted Average Contract Price Swaps
July 2018 - December 2018	Swaps	NYMEX-WTI	1,472.0	$ 50.68
January 2019 - December 2019	Swaps	ICE Brent	1,095.0	$ 61.00

In April 2018, with no cash outlay, 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 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.

The fair values of derivative instruments in the Company's consolidated balance sheets were as follows (*in thousands*):

	Asset Derivative Instruments				Liability Derivative Instruments			
	As of June 30, 2018		As of December 31, 2017		As of June 30, 2018		As of 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	$ 36,793	Current	$ 32,567
	Non-Current	-	Non-Current	-	Non-Current	6,305	Non-Current	-
Total gross derivative financial instruments subject to enforceable master netting agreement		-		-		43,098		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	36,793	Current	32,567
	Non-Current	-	Non-Current	-	Non-Current	6,305	Non-Current	-
		$ -		$ -		$ 43,098		$ 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 June 30, 2018**	**2017**	**Six Months Ended June 30, 2018**	**2017**
Cash settlements	$ (15,301)	$ 2,351	$ (28,348)	$ 2,640
Non-cash gain in fair value	(10,744)	7,061	(10,531)	10,470
Total (loss) gain on derivative financial instruments	$ (26,045)	$ 9,412	$ (38,879)	$ 13,110

The Company monitors the creditworthiness of its counterparties who are also a part of its bank lending group. However, the Company is not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer its position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of its financial counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices and could incur a loss. As of June 30, 2018, the Company had no collateral deposits with our counterparties.

Note 8 – Income Taxes

No cash income taxes were paid during the three months and six months ended June 30, 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.

The Company has estimated its effective income tax rate for the year to be zero, as the Company is forecasting a pre-tax loss at this time. The Company does not believe that its net deferred tax assets are realizable in the future on a more-likely-than-not basis at this time; as such, during the three months and six months ended June 30, 2018, the Company increased its valuation allowance by $5.9 million and $12.3 million, respectively, to reflect the tax effects of this loss. The $12.3 million valuation allowance increase for the six months ended June 30, 2018, when coupled with the $306.2 million valuation allowance at December 31, 2017, results in a valuation allowance of $318.6 million at June 30, 2018. The Company made no changes during the period to its deferred tax assets or valuation allowance related to the Tax Cuts and Jobs Act of 2017.

Note 9 – Stockholders' Equity

Under the Company's certificate of incorporation, the total number of all shares of capital stock that it is 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.

During the three months and six months ended June 30, 2018, we issued 128,085 shares and 141,600 shares, respectively, of our common stock upon vesting of RSUs and as of June 30, 2018, we had 33,396,563 shares of common stock, 285,105 stock options and 2,119,889 warrants outstanding.

Note 10 – Supplemental Cash Flow Information

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

	Six Months Ended June 30, 2018	**2017**
Cash paid for interest	$ 4,626	$ 7,484

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

	Six Months Ended June 30, 2018	**June 30, 2017**
Changes in capital expenditures and accrued liabilities or accounts payable	$ -	$ (164)
Changes in asset retirement obligations	28,999	(133,039)
Changes in other property and equipment	-	(455)

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		
	June 30, 2018	December 31, 2017	June 30, 2017
Cash and cash equivalents	$ 97,900	$ 151,729	$ 178,855
Restricted cash, current	6,432	6,392	6,365
Restricted cash, long term	25,814	25,712	25,637
Total Cash, cash equivalents and restricted cash	$ 130,146	$ 183,833	$ 210,857

Note 11 – Employee Benefit Plans

Long Term Incentive Plans

On December 30, 2016, the Company adopted 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 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). Awards under the 2016 LTIP are awarded to the Service Providers selected at the discretion of the compensation committee (the "Committee") of the board of directors of the Company (the "Board"). However, under the terms of the Energy XXI Ltd's chapter 11 plan of reorganization, 3% of the 5% total new equity on a fully diluted basis reserved under the 2016 LTIP had to be allocated by the Board 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.

In order to retain key employees and attract new employees with the experience and skill sets that fit the Company's 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 and the Company's stockholders approved the 2018 LTIP at the 2018 annual meeting of stockholders held on May 17, 2018. Upon approval, the number of shares of common stock available for awards under the 2018 LTIP were (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 June 30, 2018, there were 1,317,083 shares remaining available for award under the 2018 LTIP. As a result of the adoption and stockholder approval of the 2018 LTIP, no additional equity awards or other long term incentive awards may be made under the 2016 LTIP. However, existing awards that were granted under the 2016 LTIP will continue to be subject to the provisions of the 2016 LTIP.

The Compensation Committee generally administers the 2016 LTIP and the 2018 LTIP (together the "Company LTIPs"). The Compensation Committee determines the types of equity based awards (which may include stock option, stock appreciation rights, RSUs, bonus stock awards, performance-based restricted stock units (each a "PBRSU"), other stock based awards or cash awards) and the terms and conditions (including vesting and forfeiture restrictions) of such awards.

Under the Company LTIPs, stock options have been and may be 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 June 30, 2018, there were 285,105 unvested stock options and $0.9 million in unrecognized compensation cost related to unvested stock options. The exercise price for each outstanding stock option is greater than the Merger Consideration. As a result, if the Merger is consummated, at the Effective Time, each stock option to purchase shares of Common Stock will be cancelled for no consideration.

Under the Company LTIPs, RSUs have been and may be granted as approved by the Committee. To date, the RSUs granted by the Committee have a vesting date up to three years from the date of grant and each RSU represents a right to receive one share of our common stock. During the three months and six months ended June 30, 2018, the Committee granted 475,886 and 1,272,853 RSUs at a weighted average price of $6.92 and $6.42 per restricted stock unit, respectively. As of June 30, 2018, there were 1,580,223 unvested RSUs and $10.6 million in unrecognized compensation cost related to unvested RSUs. If the Merger is consummated, immediately prior to the Effective Time, the vesting of each outstanding RSU will accelerate (if not already vested), with any performance conditions deemed achieved at target, and be cancelled and converted into the right to receive the Merger Consideration, multiplied by the number of shares of Common Stock subject to that RSU. The RSUs described in this paragraph do not include performance-based restricted stock units, which are described in the section below titled "Performance-Based Restricted Stock Units."

Performance-Based Restricted Stock Units

On June 7, 2018, the Committee granted 262,500 PBRSUs to certain executive officers. All of the PBRSUs awarded vest equally over a three-year period, but only if the employee is still employed by the Company at the end of each measurement period. In the event of a change in control during a measurement period, the performance for that period shall be deemed to have been achieved at target and the award shall vest based on the employee's service through the end of the period. Based on the performance of the Common Stock compared to a peer group, the employee will vest in (i) a maximum award equal to 150% of the target opportunity for maximum performance level or (ii) 0% of the target opportunity for performance below the threshold level. The PBRSUs were issued under the 2018 LTIP. If the Merger is consummated, immediately prior to the Effective Time, the vesting of each outstanding PBRSU will accelerate, with any performance conditions deemed achieved at target, and be cancelled and converted into the right to receive the Merger Consideration, multiplied by the number of shares of Common Stock subject to that PBRSU. As of June 30, 2018, there were 262,500 unvested PBRSUs and $2.3 million in unrecognized compensation cost related to unvested PBRSUs.

Note 12 — 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 RSUs, 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 June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Net loss	$ (34,035)	$ (26,237)	$ (67,090)	$ (90,784)
Weighted average shares outstanding for basic EPS	33,427	33,237	33,367	33,234
Add dilutive securities	-	-	-	-
Weighted average shares outstanding for diluted EPS	33,427	33,237	33,367	33,234
Loss per share				
Basic and Diluted	$ (1.02)	$ (0.79)	$ (2.01)	$ (2.73)

The Company's RSUs 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 and six months ended June 30, 2018 and 2017, no net loss was allocated to the participating securities.

The following table sets forth the components of common stock equivalents (as calculated under the treasury stock method in accordance with GAAP) that were excluded from the diluted average shares calculation due to their anti-dilutive effect:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Warrants	11,393,213	1,447,992	12,508,419	1,238,023
Options	1,066,237	204,896	1,201,495	269,817
RSUs	33,584	79,509	310,788	23,584
PBRSUs	25,963	-	17,664	-
	12,518,997	1,732,397	14,038,366	1,531,424

The dilutive effect of warrants, options, RSUs and PBRSUs is calculated using the treasury stock method, which assumes that the "proceeds" from the exercise of these instruments are used to purchase common shares at the average market price for the period. Accordingly, these common stock equivalents do not represent the number of shares of Common Stock that would be issued upon exercise or settlement of the applicable warrant, option, RSU or PBRSU. The increase in potentially dilutive shares for the three months ended June 30, 2018 compared to the three months ended June 30, 2017 and the six months ended June 30, 2018 compared to the six months ended June 30, 2017 is due to the decrease in average stock price for the comparative periods. The Company's average stock price for the three months ended June 30, 2018 and 2017 was $6.85 per share and $25.94 per share, respectively. The Company's average stock price for the six months ended June 30, 2018 and 2017 was $6.33 per share and $27.56 per share, respectively. The exercise price for EGC's outstanding warrants is $43.66 per share, and the weighted average exercise price for EGC's outstanding stock options is $28.90 per share for the six month period ended June 30, 2018.

Note 13 — Commitments and Contingencies

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

Letters of Credit and Performance Bonds. As of June 30, 2018, the Company had approximately $328.9 million of performance bonds outstanding and $200.0 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 June 30, 2018, approximately $177.2 million of the Company's performance bonds are lease and/or area bonds issued to the BOEM, to which the BOEM has access to ensure commitment to comply with the terms and conditions of those leases. As of June 30, 2018, the Company 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 June 30, 2018, the Company had $52.3 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 the Company 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"). The Company continues to work with the BOEM under the Long-Term Plan and the Proposed Plan Amendment.

Drilling Rig Commitments. As of June 30, 2018, we have approximately $8.4 million committed under three rig contracts for drillwells, rig recompletions and plugging and abandonment activities. The contracts' terms range from March 17, 2018 through September 12, 2018.

Other. The Company maintains restricted escrow funds as required by certain contractual arrangements. As of June 30, 2018, the Company's restricted cash primarily related to $25.8 million in cash collateral associated with its bonding requirements, $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 and $0.3 million in cash collateral for an office lease. Funds held in trust will be transferred to the buyers of the Company's interests in that field.

The Company and its oil and natural gas joint interest owners are subject to periodic audits of the joint interest accounts for leases in which the Company participates and/or operates. As a result of these joint interest audits, amounts payable or receivable by the Company for costs incurred or revenue distributed by the operator or by the Company on a lease may be adjusted, resulting in adjustments to its 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. The Company does not believe any such adjustments will be material.

Note 14 — Fair Value of Financial Instruments

Certain assets and liabilities are measured at fair value on a recurring basis in the 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.

The Company's commodity derivative instruments historically consisted of financially settled crude oil and natural gas puts, swaps, put spreads, costless collars and three way collars. The Company 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 the Company's nonperformance risk, each based on the current published issuer-weighted corporate default rates. See Note 6 – "Derivative Financial Instruments."

The fair value of the Company's RSUs equals the market value of the underlying common stock on the date of grant. For its stock options, the Company utilizes 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 the Company's common stock is zero.

During the six months ended June 30, 2018 the Company did not have any transfers from or to any level within the fair value hierarchy. The following table presents the fair value of its Level 2 financial instruments (*in thousands*):

	Level 2	
	As of June 30, 2018	As of December 31, 2017
Assets:		
Oil and Natural Gas Derivatives	$ -	$ -
Liabilities:		
Oil and Natural Gas Derivatives	$ 43,098	$ 32,567

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

	As of June 30, 2018		As of December 31, 2017	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Exit Facility	$ 58,447	$ 58,447	$ 73,996	$ 73,996
	$ 58,447	$ 58,447	$ 73,996	$ 73,996

Note 15 — Prepayments and Accrued Liabilities

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

	As of June 30, 2018	As of December 31, 2017
Prepaid expenses and other current assets		
Advances to joint interest partners	$ 132	$ 1,381
Insurance	6,645	5,949
Inventory	885	394
Royalty deposit	756	1,021
Other	3,455	12,857
Total prepaid expenses and other current assets	$ 11,873	$ 21,602
Accrued liabilities		
Advances from joint interest partners	253	81
Employee benefits and payroll	4,499	6,791
Interest payable	2,493	185
Accrued hedge payable	5,110	2,491
Undistributed oil and gas proceeds	19,421	20,079
Severance taxes payable	1,375	558
Other	18,960	15,309
Total accrued liabilities	$ 52,111	$ 45,494

Note 16 — Subsequent Events

On August 7, 2018, Anthony Franchi, a purported holder of Common Stock, filed a complaint against EGC and the Board in the U.S District Court for the District of Delaware. The case is captioned Anthony Franchi v Energy XXI Gulf Coast, Inc., et al., Case No. 1:18-cv-01203. The complaint alleges that (1) EGC and the Board violated Section 14(a) of the Exchange Act, and Rule 14a-9 promulgated thereunder, by allegedly failing to disclose material information in the Merger Proxy Statement, and (s) the Board, as alleged control persons of EGC, violated Section 20(a) of the Exchange Act in connection with the filing of the allegedly materially deficient Merger Proxy Statement. Mr. Franchi has asked the court to, among other things, (i) enjoin EGC, the Board, Cox and all other persons from proceeding with or consummating the Merger, (ii) alternatively, if the Merger is consummated, rescind the Merger or award rescissory damages, (iii) direct the Board to file a revised Merger Proxy Statement that does not contain any untrue statements of material fact or that states all material facts required in it or necessary to make the statements contained in Merger Proxy Statement not misleading, (iv) declare that EGC and the Board violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder, and/or Section 20(a) of the Exchange Act, and (v) award Mr. Franchi attorneys' and experts' fees. EGC believes that this complaint is without merit. EGC cannot predict the outcome of or estimate the possible loss or range of loss from this matter.

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.

Operational Update

The Board has approved the Company's 2018 capital budget (the "2018 Capital Budget"). We decided to return to a more active drilling program in 2018, and therefore our focus has been optimizing and enhancing our existing production with an active drilling, recompletion and workover program, 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 proposed Merger could disrupt our 2018 Capital Budget as planned. Please refer to the risks discussed in the section titled "Cautionary Statements Regarding Forward Looking Statements—Forward Looking Statements Related to the Merger" above.

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. We operate and have a 100% working interest in this well.

In early May 2018, the West Delta 74 C-41ST, Cato development well was spud, and drilled to a total depth of 11,022 feet with a lateral section of 900 feet. Total depth was reached and the well was completed in June 2018. We operate and have a 100% working interest in this well.

In June 2018, the West Delta 74 D-20 well was recompleted from the F-30 sand and the F-2 sand. We operate and have a 100% working interest in this well.

In June 2018, slot reclamation work began on the South Timbalier 54 G-25ST. The well was spud in July 2018 and will be drilled to a total depth of 14,080 feet. The well is expected to be completed in the third quarter of 2018. We operate and have a 100% working interest in this well.

During the second quarter of 2018, two wells were permanently abandoned, High Island A368 A-6 and A-8; four wells were temporarily abandoned, South Timbalier 187 B-1, West Delta 68 A-2, and High Island 138 D-1 and D-2; and two wells were zonally isolated, Eugene Island 257 D-6 and C-9.

Recent Events

As a complement to our capital plan, we retained Intrepid Partners LLC ("Intrepid") to assist with the consideration of possible alternatives for raising additional capital.

Prior to the execution of the Merger Agreement with Cox, we also worked to address our plugging and abandonment liability and streamline our asset base. In furtherance of those financing, liability management and asset streamlining efforts, on May 2, 2018, we entered into a non-binding term sheet with Orinoco Natural Resources, LLC ("ONR") and its affiliates. On May 10, 2018, in conjunction with the filing of our quarterly report on 10-Q for the first quarter of 2018, we announced that ONR term sheet had been executed.

The term sheet with ONR provided for the disposition of our current non-core asset portfolio (the "Proposed ONR Transaction"). If consummated, the Proposed ONR Transaction was expected to significantly reduce our asset retirement liability, improve profitability and financial stability, lower our cost structure, and facilitate future growth. The non-binding term sheet included the disposition of EGC's non-core assets, a cash payment up front to an affiliate of ONR, the execution of a $100.0 million ten-year second lien note beginning in 2019, the issuance of EGC common equity to ONR, the execution of a ten-year agreement to provide plugging and abandonment and decommissioning services for our core assets with an affiliate of ONR and a commitment from ONR to anchor a potential future financing with us with at least a $25 million participation. The Company worked with ONR to finalize definitive documents for the Proposed ONR Transaction, but the Board determined that the transactions contemplated by the Merger Agreement were in the best interests of the Company and its stockholders. Therefore, shortly prior to entering into the Merger Agreement on June 18, 2018, the Company terminated the non-binding term sheet with ONR and its affiliates. The termination fee for the term sheet was $1.0 million and was paid subsequent to June 30, 2018. For a description of the Merger Agreement and the Merger, please refer to the section above titled "Introductory Note Regarding EGC's Pending Merger." This description is also qualified in its entirety by the terms and conditions of the Merger Agreement, which was filed as an exhibit to the Company's current report on Form 8-K filed on June 18, 2018.

Pursuant to the Merger Agreement, at the Effective Time, EGC will survive the Merger with Merger Sub and continue as an indirect wholly-owned subsidiary of Cox. Subject to the terms and conditions of the Merger Agreement, at the Effective Time each issued and outstanding share of Common Stock will be converted into the right to receive $9.10 in cash without interest.

Closing Conditions. The completion of the Merger is subject to satisfaction or waiver of certain closing conditions, including: (i) approval of the Merger Agreement by EGC's stockholders, (ii) there being no law or injunction prohibiting consummation of the Merger; (iii) subject to specified materiality standards, the accuracy of the representations and warranties of the other party; (iv) compliance by the other party in all material respects with its covenants; and (v) the absence of a material adverse effect on the other party. The completion of the Merger is not conditioned on receipt of financing by Cox.

Termination Rights. The Merger Agreement contains certain termination rights for both EGC and Cox and further provides that, upon termination of the Merger Agreement, under certain circumstances, EGC may be required to pay Cox a termination fee equal to $8 million and, in certain other circumstances, EGC may be required to reimburse Cox for its documented out-of-pocket expenses up to $2 million.

Anticipated Timing; No Assurance that Closing will Occur. The Merger is expected to close in the third quarter of 2018. However, EGC cannot provide any assurance the combination will be completed on the terms or timeline currently contemplated, or at all.

Interim Operating Covenants. EGC has agreed to certain covenants in the Merger Agreement restricting the conduct of its business between the date of the Merger Agreement and the Effective Time. For a description of these covenants, please refer to the section above titled "Introductory Note Regarding EGC's Pending Merger—Interim Operating Covenants."

The effect of these covenants is that, until the Merger is consummated, EGC will be very limited in its ability to pursue strategic and operational initiatives outside the ordinary course of business, including the initiatives that have been described by the Company in its "Management's Discussion and Analysis of Financial Condition and Results of Operations" in its annual report on Form 10-K and quarterly reports Form 10-Q in the last nine months. Therefore, if the Merger Agreement is terminated and the Merger does not occur, it will need to renew certain financing, cost-cutting, and liability management initiatives that it had been pursuing prior to the execution of the Merger Agreement.

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, our 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 June 30, 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 oilfield 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 June 30, 2018, we had approximately $328.9 million of performance bonds outstanding and $201.5 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 June 30, 2018, approximately $177.2 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 June 30, 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 June 30, 2018, we had $52.3 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.

Table of Contents

Operational Information

Operating Highlights	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
	(In thousands, except per unit amounts)			
Operating revenues				
Oil sales	$ 133,180	$ 118,484	$ 256,968	$ 252,277
Natural gas liquids sales	1,076	2,370	2,419	4,597
Natural gas sales	6,261	13,753	14,643	32,121
Other revenue	2,267	-	3,759	-
(Loss) gain on derivative financial instruments	(26,045)	9,412	(38,879)	13,110
Total revenues	116,739	144,019	238,910	302,105
Percentage of oil revenues prior to (loss) gain on derivative financial instruments	93%	88%	93%	87%
Operating expenses				
Lease operating expense				
Insurance expense	5,177	7,101	10,372	13,351
Workovers	2,054	4,535	4,578	7,100
Direct lease operating expense	72,065	72,019	146,368	140,471
Total lease operating expense	79,296	83,655	161,318	160,922
Production taxes	371	482	1,577	721
Gathering and transportation	3,119	2,678	7,175	13,900
Pipeline facility fee	10,494	10,494	20,988	20,988
Depreciation, depletion and amortization	27,555	38,685	54,966	80,581
Accretion of asset retirement obligations	11,197	9,984	22,315	23,065
Impairment of oil and natural gas properties	-	-	-	40,774
General and administrative	15,568	20,716	30,700	42,320
Reorganization items	113	-	349	2,244
Total operating expenses	147,713	166,694	299,388	385,515
Operating loss	$ (30,974)	$ (22,675)	$ (60,478)	$ (83,410)
Sales volumes per day				
Oil (MBbls)	21.1	26.8	21.1	27.9
Natural gas liquids (MBbls)	0.3	1.0	0.4	0.9
Natural gas (MMcf)	23.6	48.9	27.1	57.3
Total (MBOE)	25.3	35.9	26.0	38.4
Percent of sales volumes from oil	83%	75%	81%	73%
Average sales price				
Oil per Bbl	$ 69.54	$ 48.57	$ 67.32	$ 49.88
Natural gas liquid per Bbl	34.98	27.37	36.08	27.44
Natural gas per Mcf	2.92	3.09	2.99	3.10
Other revenue per BOE	0.98	-	0.80	-
(Loss) gain on derivative financial instruments per BOE	(11.30)	2.88	(8.27)	1.89
Total revenues per BOE	50.67	44.08	50.82	43.44
Operating expenses per BOE				
Lease operating expense				
Insurance expense	2.25	2.17	2.21	1.92
Workover and maintenance	0.89	1.39	0.97	1.02
Direct lease operating expense	31.28	22.04	31.14	20.20
Total lease operating expense per BOE	34.42	25.60	34.32	23.14
Production taxes	0.16	0.15	0.34	0.10
Gathering and transportation	1.35	0.82	1.53	2.00
Pipeline facility fee	4.55	3.21	4.46	3.02
Depreciation, depletion and amortization	11.96	11.84	11.69	11.59
Accretion of asset retirement obligations	4.86	3.06	4.75	3.32
Impairment of oil and natural gas properties	-	-	-	5.86
General and administrative	6.76	6.34	6.53	6.09
Reorganization items	0.05	-	0.07	0.32
Total operating expenses per BOE	64.11	51.02	63.69	55.44
Operating loss per BOE	$ (13.44)	$ (6.94)	$ (12.87)	$ (12.00)

Results of Operations

Three Months Ended June 30, 2018 Compared With the Three Months Ended June 30, 2017

Our consolidated net loss attributable to common stockholders for the three months ended June 30, 2018 was $34.0 million or $1.02 loss per common share ("per share") as compared to a net loss of $26.2 million or $0.79 per share for the three months ended June 30, 2017. Increase in net loss was primarily due to an increased loss on derivative financial instruments and lower oil and natural gas volumes, partially offset by an increase in oil prices and lower depreciation, depletion and amortization ("DD&A") expense, general and administrative expenses and lease operating expenses.

Revenues

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Decrease	Percent Increase (Decrease)
	(In thousands)			
Oil sales	$ 133,180	$ 118,484	$ 14,696	12.4%
Natural gas liquid sales	1,076	2,370	(1,294)	(54.6)%
Natural gas sales	6,261	13,753	(7,492)	(54.5)%
Other revenue	2,267	-	2,267	-
Gain (Loss) on derivative financial instruments	(26,045)	9,412	(35,457)	(376.7)%
Total Revenues	$ 116,739	$ 144,019	$ (27,280)	(18.9)%

As discussed below, our consolidated revenues were $116.7 million and $144.0 million during the three months ended June 30, 2018 and 2017, respectively. The decrease in total revenues of $27.3 million was primarily due to lower oil and natural gas volumes and losses 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 June 30, 2018	Three Months Ended June 30, 2017	Increase (Decrease)	Percent Increase (Decrease)	Revenue Increase (Decrease)
Price					
Oil sales prices (per Bbl)	$ 69.54	$ 48.57	$ 20.97	43.2%	$ 51,093
Natural gas liquids sales prices (per Bbl)	34.98	27.37	7.61	27.8%	659
Natural gas sales prices (per Mcf)	2.92	3.09	(0.17)	(5.5)%	(758)
Other revenue (per BOE)	0.98	-	0.98	-	2,267
Gain (Loss) on derivative financial instruments (per BOE)	(11.30)	2.88	(14.18)	(492.4)%	(35,457)
Total price variance					17,804
Volume					
Oil sales volumes (MBbls)	1,915	2,439	(524)	(21.5)%	(36,397)
Natural gas liquids volumes (MBbls)	31	87	(56)	(64.5)%	(1,953)
Natural gas sales volumes (MMcf)	2,147	4,448	(2,301)	(51.7)%	(6,734)
BOE sales volumes (MBOE)	2,304	3,267	(963)	(29.5)%	
Percent of BOE from oil	83%	75%			
Total volume variance					(45,084)
Total price and volume variance					$ (27,280)

Commodity Price Variances

Commodity prices are one of the key drivers of our earnings and net operating cash flow. Higher commodity prices increased revenues by $17.8 million in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year. Average oil prices increased $20.97 per barrel in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in higher revenues of $51.1 million. Average natural gas liquids prices increased $7.61 per barrel in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in higher revenues of $0.7 million. Average natural gas prices decreased $0.17 per Mcf in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $0.8 million.

Commodity Volume Variances

Sales volumes are another key driver of our earnings and net operating cash flow. Oil sales volumes decreased 524 MBbls in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $36.4 million. Natural gas liquids volumes decreased 56 MBbls in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $2.0 million. Natural gas sales volumes decreased 2,301 Mcfe in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $6.7 million. Sales volumes for the three months ended June 30, 2018 were impacted by excessive production downtime primarily related to continued production equipment maintenance, pipeline shut-ins, facility-related unscheduled downtime and natural decline. Preventive maintenance continues to be an operating priority to ensure the safety of employees, reduce environmental impact and improve production uptime.

Other Revenue

We 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 our 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.

Gain (Loss) on Derivative Financial Instruments

For the three months ended June 30, 2018, our hedging activities resulted in a loss on derivative activities of $11.30 per BOE compared to a gain of $2.88 per BOE for the same period in the prior fiscal year, resulting in lower revenues of $35.5 million.

Costs and Expenses and Other Income (Expense)

	Three Months Ended June 30, 2018		Three Months Ended June 30, 2017		Increase (Decrease)
	Total	Per BOE	Total	Per BOE	Total
Cost and expenses	(In thousands, except per unit amounts)				
Lease operating expense					
Insurance expense	$ 5,177	$ 2.25	$ 7,101	$ 2.17	$ (1,924)
Workovers	2,054	0.89	4,535	1.39	(2,481)
Direct lease operating expense	72,065	31.28	72,019	22.04	46
Total lease operating expense	79,296	34.42	83,655	25.60	(4,359)
Production taxes	371	0.16	482	0.15	(111)
Gathering and transportation	3,119	1.35	2,678	0.82	441
Pipeline facility fee	10,494	4.55	10,494	3.21	-
Depreciation, depletion and amortization	27,555	11.96	38,685	11.84	(11,130)
Accretion of asset retirement obligations	11,197	4.86	9,984	3.06	1,213
General and administrative	15,568	6.76	20,716	6.34	(5,148)
Reorganization items	113	0.05	-	-	113
Total costs and expenses	$147,713	$ 64.11	$166,694	$ 51.02	$ (18,981)
Other income (expense)					
Other income, net	191	0.04	80	0.02	111
Interest expense	(3,252)	(0.69)	(3,642)	(1.11)	390
Total other expense, net	$ (3,061)	$ (0.65)	$ (3,562)	$ (1.09)	$ 501

As discussed below, costs and expenses decreased $19.0 million in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year, principally due to lower DD&A, lower general and administrative expenses and lower lease operating expenses, partially offset by an increase in accretion of asset retirement obligations.

Insurance expense decreased $1.9 million in the three months ended June 30, 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 remained the same in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year.

Production taxes decreased $0.1 million in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year.

Gathering and transportation expense increased $0.4 million in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year. This increase was primarily due to increased pipeline maintenance expenses, partially offset by decreases in variable costs associated with production.

The pipeline facility fee was $10.5 million for both the three months ended June 30, 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. Since the announcement of the proposed Merger, we have had no further discussions with CorEnergy regarding a potential lease restructuring. Any changes to the GIGS lease as a result of the lease restructuring could change the straight line lease expense we incur 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 $11.1 million in the three months ended June 30, 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 increased by $1.2 million in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year primarily due to upward revisions in the asset retirement obligation liability in the fourth quarter of 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 June 30, 2018 and 2017, we did not incur any impairment to our oil and natural gas properties.

General and administrative expense decreased $5.1 million in the three months ended June 30, 2018 as compared to the same period in the prior fiscal year, primarily due to headcount reductions and a legal settlement gain of $3.5 million, partially offset by transaction costs related to the proposed Merger and the Proposed ONR Transaction of $4.0 million.

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 $318.6 million as of June 30, 2018 are realizable in the future on a more-likely-than-not basis at this time; accordingly, our valuation allowance as of June 30, 2018 is $318.6 million. The increase in the valuation allowance of $5.9 million recorded in the three months ended June 30, 2018 is attributable to additional pre-tax losses incurred for the quarter.

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

Our consolidated net loss attributable to common stockholders for the six months ended June 30, 2018 was $67.1 million or $2.01 loss per common share (“per share”) as compared to a net loss of $90.8 million or $2.73 per share for the six months ended June 30, 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, lower general and administrative expenses, lower gathering and transportation expenses and a higher realized price for oil, partially offset by a loss on derivative financial instruments and lower oil and natural gas sales volumes.

Revenues

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Increase Decrease	Percent Increase (Decrease)
	(In thousands)			
Oil sales	$ 256,968	$ 252,277	$ 4,691	0.0
Natural gas liquid sales	2,419	4,597	(2,178)	(47.4)%
Natural gas sales	14,643	32,121	(17,478)	(54.4)%
Other revenue	3,759	-	3,759	-
Gain (Loss) on derivative financial instruments	(38,879)	13,110	(51,989)	(396.6)%
Total Revenues	$ 238,910	$ 302,105	$ (63,195)	(20.9)%

As discussed below, our consolidated revenues were $238.9 million and $302.1 million during the six months ended June 30, 2018 and 2017, respectively. The decrease in total revenues of $63.2 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

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Increase (Decrease)	Percent Increase (Decrease)	Revenue Increase (Decrease)
Price Variance					
Crude oil sales prices (per Bbl)	$ 67.32	$ 49.88	$ 17.44	35.0 %	$ 87,712
Natural gas liquids sales prices (per Bbl)	36.08	27.44	8.64	31.5 %	1,448
Natural gas sales prices (per Mcf)	2.99	3.10	(0.11)	(3.5)%	(1,139)
Other revenue (per BOE)	0.80	-	0.80	-	3,759
Gain (Loss) on derivative financial instruments (per BOE)	(8.27)	1.89	(10.16)	(537.6)%	(51,989)
Total price variance					39,791
Volume Variance					
Crude oil sales volumes (MBbls)	3,817	5,057	(1,240)	(24.5)%	(83,021)
Natural gas liquids volumes (MBbls)	67	168	(100)	(60.0)%	(3,626)
Natural gas sales volumes (MMcf)	4,900	10,375	(5,475)	(52.8)%	(16,339)
BOE sales volumes (MBOE)	4,701	6,954	(2,253)	(32.4)%	
Percent of BOE from crude oil	81%	73%			
Total volume variance					(102,986)
Total price and volume variance					$ (63,195)

Commodity Price Variances

Commodity prices are one of the key drivers of our earnings and net operating cash flow. Higher commodity prices increased revenues by $39.8 million in the six months ended June 30, 2018 as compared to the same period in the prior fiscal year. Average oil prices increased $17.44 per barrel in the six months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in higher revenues of $87.7 million. Average natural gas liquids prices increased $8.64 per barrel in the six months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in higher revenues of $1.4 million. Average natural gas prices decreased $0.11 per Mcf in the six months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $1.1 million.

Commodity Volume Variances

Sales volumes are another key driver of our earnings and net operating cash flow. Oil sales volumes decreased 1,240 MBbls in the six months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $83.0 million. Natural gas liquids volumes decreased 100 MBbls in the six months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $3.6 million. Natural gas sales volumes decreased 5,475 Mcfe in the six months ended June 30, 2018 as compared to the same period in the prior fiscal year, resulting in lower revenues of $16.3 million. Sales volumes for the six months ended June 30, 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 half of 2018, 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

We 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 our 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.

Gain (Loss) on Derivative Financial Instruments

For the six months ended June 30, 2018, our hedging activities resulted in a loss on derivative activities of $8.27 per BOE compared to a gain of $1.89 per BOE for the same period in the prior fiscal year, resulting in lower revenues of $52.0 million.

Costs and Expenses and Other Income (Expense)

	Six Months Ended June 30, 2018		Six Months Ended June 30, 2017		Increase (Decrease)
	Total $	**Per BOE**	**Total $**	**Per BOE**	**Total $**
Cost and expenses	**(In thousands, except per unit amounts)**				
Lease operating expense					
Insurance expense	$ 10,372	$ 2.21	$ 13,351	$ 1.92	$ (2,979)
Workover	4,578	0.97	7,100	1.02	(2,522)
Direct lease operating expense	146,368	31.14	140,471	20.20	5,897
Total lease operating expense	161,318	34.32	160,922	23.14	396
Production taxes	1,577	0.34	721	0.10	856
Gathering and transportation	7,175	1.53	13,900	2.00	(6,725)
Pipeline facility fee	20,988	4.46	20,988	3.02	-
Depreciation, depletion and amortization	54,966	11.69	80,581	11.59	(25,615)
Accretion of asset retirement obligations	22,315	4.75	23,065	3.32	(750)
Impairment of oil and natural gas properties	-	-	40,774	5.86	(40,774)
General and administrative	30,700	6.53	42,320	6.09	(11,620)
Reorganization items	349	0.07	2,244	0.32	(1,895)
Total costs and expenses	$ 299,388	$ 63.69	$ 385,515	$ 55.44	$ (86,127)
Other (expense) income					-
Other income, net	334	0.07	102	0.01	232
Interest expense	(6,946)	(1.48)	(7,476)	(1.08)	530
Total other (expense) income, net	$ (6,612)	$ (1.41)	$ (7,374)	$ (1.07)	$ 762

As discussed below, costs and expenses decreased $86.1 million in the six months ended June 30, 2018 as compared to the same period in the prior fiscal year due to no impairment of oil and natural gas properties, lower DD&A, lower general and administrative expenses and lower gathering and transportation expense.

Insurance expense decreased $3.0 million in the six months ended June 30, 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 six months ended June 30, 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 $0.9 million in the six months ended June 30, 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 $6.7 million in the six months ended June 30, 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 $21.0 million for both the six months ended June 30, 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. Since the announcement of the proposed Merger, we have had no further discussions with CorEnergy regarding a potential lease restructuring. Any changes to the GIGS lease as a result of the lease restructuring could change the straight line lease expense we incur 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 $25.6 million in the six months ended June 30, 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 $0.8 million in the six months ended June 30, 2018 as compared to the same period in the prior fiscal year primarily due to downward revisions in the asset retirement obligation liability in the first quarter of 2017.

For the six months ended June 30, 2018, we did not incur any impairment to our oil and natural gas properties and for the six months ended June 30, 2017, our ceiling test computation resulted in impairment of our oil and natural gas properties of $40.8 million. The impairment was due to the difference in SEC proved reserves and the related PV-10 value as of March 31, 2017 prepared by NSAI compared with SEC reserves and PV-10 value as of December 31, 2016 that were prepared by our internal reservoir engineers. The primary non-commodity price factors contributing to the difference between the NSAI March 31, 2017 SEC reserve report and the internally-prepared December 31, 2016 SEC reserve report are: (i) technical reassessments, (ii) higher capital costs and (iii) production during the first quarter of 2017. The impact of those factors was partially offset by higher SEC average commodity prices for both crude oil and natural gas.

General and administrative expense decreased $11.6 million in the six months ended June 30, 2018 as compared to the same period in the prior fiscal year, primarily due to headcount reduction, 2017 severance costs of $5.7 million and a legal settlement gain of $3.5 million, partially offset by transaction costs related to the proposed Merger and the Proposed ONR Transaction of $4.0 million and 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 $318.6 million as of June 30, 2018 are realizable in the future on a more-likely-than-not basis at this time; accordingly, our valuation allowance as of June 30, 2018 is $318.6 million. The increase in the valuation allowance of $12.3 million recorded in the six months ended June 30, 2018 is attributable to additional pre-tax losses incurred for the period.

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. We believe we have sufficient liquidity as of June 30, 2018, including $97.9 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, 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 September 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 requirement to provide additional bonds or restrictions on our cash to collateralize existing bonds or new bonds would reduce our liquidity.

Exit Facility

On December 30, 2016, we 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 our wholly-owned subsidiaries, 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.

We 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, we 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 $10.0 million outstanding under the Exit Term Loan. No payment was made during the quarter ended June 30, 2018. Due to a projected decline in our estimated trailing twelve-month EBITDA calculation for the twelve-month period ending September 30, 2018, we may 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. Additionally, due to our decreased cash position, we may not meet our required Current Ratio. Under those circumstances, we would explore several options to remain in compliance with the terms of the Exit Facility, including modifying the timing of capital expenditures.

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, we 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 on the results of the quarter ended March 31, 2018, the Company made a mandatory prepayment of $5.5 million during the quarter ended June 30, 2018. Based on the results of the quarter ended June 30, 2018, we will not be required to make a prepayment during the quarter ended September 30, 2018. Based upon our current expectations with respect to our capital resources, capital expenditures, results from operations and commodity prices, we believe that it is possible that we will be required to make a mandatory prepayment with respect to fiscal quarters subsequent to September 30, 2018. In the event of a mandatory prepayment, any such mandatory prepayment would not, in and of itself, constitute a default under the Exit Facility. As of June 30, 2018, we are in compliance with all terms of 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 our 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 our 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 us, and will be redetermined semi-annually thereafter. Currently, we have not elected a date for the initial borrowing base determination.

As of June 30, 2018, we had approximately $58.4 million in borrowings and $201.5 million in letters of credit issued under the Exit Facility.

Impact of Merger on Exit Facility

Under the terms of the Exit Facility, all amounts outstanding under the Exit Facility must be repaid in full at the Effective Time, and all outstanding letters of credit under the Exit Facility must be replaced at that time.

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 six months ended June 30, 2018, our capital expenditures including plugging and abandonment obligations totaled $67.2 million, of which $39.8 million was related to development and recompletion activities in our core properties and $27.4 million was spent on plugging and abandonment obligations. For 2018, our 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.

As described in the section above titled “Introductory Note Regarding EGC’s Pending Merger—Interim Operating Covenants,” under the terms of the Merger Agreement, our ability to make capital expenditures prior to the Effective is very limited.

Cash Flows

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

	Six Months Ended June 30, 2018	2017
	(In thousands)	
Net cash provided by (used in) operating activities	$ (6,230)	$ 11,534
Net cash used in investing activities	(31,666)	(23,176)
Net cash used in financing activities	(15,791)	(789)
Net decrease in cash, cash equivalents and restricted cash	$ (53,687)	$ (12,431)

Operating Activities

Net cash provided by (used in) operating activities for the six months ended June 30, 2018 and 2017 was $(6.2) million and $11.5 million, respectively. The cash used in operating activities increased primarily due to higher derivative settlements of $31.0 million and lower cash inflows from oil, natural gas liquids and natural gas price and volume variances of $11.2 million, partially offset by lower cash outflows for general and administrative expenses of $13.3 million, lower gathering and transportation expenses of $6.7 million and $2.9 million associated with operating assets and liabilities.

Investing Activities

Net cash used in investing activities for the six months ended June 30, 2018 and 2017 was $31.7 million and $23.2 million, respectively. The increase in cash used in investing activities was primarily due to $7.5 million increase in capital expenditures resulting from increased development drilling in 2018, partially offset by $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 six months ended June 30, 2018 and 2017 was $15.8 million and $0.8 million, respectively. During the six months ended June 30, 2018, cash used in financing activities consists primarily of a $15.6 million prepayment of the Exit Term Loan. During the six months ended June 30, 2017, cash used in financing activities consists primarily of $0.7 million used to repay debt.

Contractual Obligations

Our contractual obligations at June 30, 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 3 – "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 3 – "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 June 30, 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, with no cash outlay, 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 June 30, 2018, we had the following open crude oil derivative positions:

Remaining Contract Term	Type of Contract	Index	Volumes (MBbls)	Weighted Average Contract Price Swaps
July 2018 - December 2018	Swaps	NYMEX-WTI	1,472.0	$ 50.68
January 2019 - December 2019	Swaps	ICE Brent	1,095.0	$ 61.00

As of June 30, 2018, our crude oil contracts outstanding were in a net liability position of approximately $43.1 million. A 10% increase in crude oil prices would increase the net liability position by approximately $19.2 million, while a 10% decrease in crude oil prices would decrease the liability positon by approximately $17.8 million. These fair value changes assume volatility based on prevailing market parameters as of June 30, 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 June 30, 2018, we had approximately $58.4 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 $0.1 million. 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 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 is being 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 June 30, 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 June 30, 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

On August 7, 2018, Anthony Franchi, a purported holder of Common Stock, filed a complaint against EGC and the Board in the U.S District Court for the District of Delaware. The case is captioned Anthony Franchi v Energy XXI Gulf Coast, Inc., et al., Case No. 1:18-cv-01203. The complaint alleges that (1) EGC and the Board violated Section 14(a) of the Exchange Act, and Rule 14a-9 promulgated thereunder, by allegedly failing to disclose material information in the Merger Proxy Statement, and (s) the Board, as alleged control persons of EGC, violated Section 20(a) of the Exchange Act in connection with the filing of the allegedly materially deficient Merger Proxy Statement. Mr. Franchi has asked the court to, among other things, (i) enjoin EGC, the Board, Cox and all other persons from proceeding with or consummating the Merger, (ii) alternatively, if the Merger is consummated, rescind the Merger or award rescissory damages, (iii) direct the Board to file a revised Merger Proxy Statement that does not contain any untrue statements of material fact or that states all material facts required in it or necessary to make the statements contained in Merger Proxy Statement not misleading, (iv) declare that EGC and the Board violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder, and/or Section 20(a) of the Exchange Act, and (v) award Mr. Franchi attorneys' and experts' fees. EGC believes that this complaint is without merit. EGC cannot predict the outcome of or estimate the possible loss or range of loss from this matter. It is possible that additional, similar complaints may be filed or that this complaint is amended. If this occurs, EGC does not intend to announce the filing of each additional, similar complaint or any amended complaint unless it contains materially new or different allegations.

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. Except for the risk factors discussed below, there have been no material changes in the risk factors set forth in our 2017 Annual Report.

While the Merger Agreement is in effect, we may be limited in our ability to pursue other attractive business opportunities.

While the Merger Agreement is in effect, we have agreed to refrain from taking certain actions with respect to our business and financial affairs pending the consummation of the Merger or termination of the Merger Agreement. These restrictions could be in effect for an extended period of time if the consummation of the Merger is delayed. These limitations do not preclude us from conducting our business in the ordinary or usual course [or from acquiring assets or businesses] so long as such activity does not have a "material adverse effect," as such term is defined in the Merger Agreement, or exceed certain thresholds specifically provided in the Merger Agreement.

In addition to the economic costs associated with pursuing the Merger, our management will continue to devote substantial time and other human resources to the proposed Merger, which could limit our ability to pursue other attractive business opportunities, including potential joint ventures, stand-alone projects and other transactions. If we are unable to pursue such other attractive business opportunities, our growth prospects and the long-term strategic position of our business following the Merger could be adversely affected.

The Merger is subject to conditions and may not be consummated even if the required EGC stockholder approvals are obtained.

The Merger is subject to the satisfaction or waiver of certain conditions, some of which are out of the control of EGC, including approval of the Merger Agreement by EGC stockholders. The Merger Agreement also contains other conditions that, if not satisfied or waived, would result in the Merger not occurring, regardless of whether the EGC stockholders have voted in favor of the Merger-related proposals presented to them. Satisfaction of some of these other conditions to the Merger is not entirely in the control of EGC. In addition, EGC can agree not to consummate the Merger even if EGC stockholder approval have been received. The closing conditions to the Merger may not be satisfied, and EGC may choose not to, or may be unable to, waive an unsatisfied condition, which may cause the Merger not to occur.

The Merger Agreement contains provisions granting both EGC the right to terminate the Merger Agreement for certain reasons, including, among others (1) by mutual consent of EGC and Cox; (2) by either party if the Merger has not been consummated on or before November 15, 2018; (3) if certain changes in rules or regulations prohibit the consummation of the Merger; (4) if EGC fails to obtain EGC stockholder approval; or (5) if a breach of, or an inaccuracy in, the representations or warranties is not cured within thirty days. Furthermore, Cox may terminate the Merger Agreement in the event that, prior to EGC stockholder approval, EGC issues a change of recommendation pursuant to the terms of the Merger Agreement, and EGC may terminate the Merger Agreement in order to accept a Superior Proposal (as defined in the Merger Agreement) so long as EGC (1) has complied in all material respects with its obligations under the Merger Agreement relating to the Superior Proposal and (2) has paid Cox a termination fee.

Failure to complete the Merger or delays in completing the Merger could negatively impact our stock price.

If the Merger is not completed for any reason, we may be subject to a number of material risks, including the following:

- we will not realize the benefits expected from the Merger, including a potentially enhanced financial and competitive position;

- the price of our shares of Common Stock may decline to the extent that the current market price of these securities reflects a market assumption that the Merger will be completed; and

- some costs relating to the Merger, such as certain investment banking fees and legal and accounting fees, must be paid even if the Merger is not completed.

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
2.1	Agreement and Plan of Merger among MLCJR LLC, YHIMONE, Inc. and Energy XXI Gulf Coast, Inc., dated as of June 18, 2018	2.1 to the Company's Report on Form 8-K filed on June 18, 2018
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: August 9, 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 June 30, 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: August 9, 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 June 30, 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: August 9, 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 June 30, 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: August 9, 2018	Douglas E. Brooks Chief Executive Officer
	/S/ TIFFANY THOM CEPAK
Date: August 9, 2018	Tiffany Thom Cepak Chief Financial Officer