EPL OIL & GAS, INC.
Form 10-K
October 13, 2015

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

Form 10-K

(Mark One)

x	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the fiscal year ended June 30, 2015
	or
o	**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: 001-16179

EPL Oil & Gas, Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	72-1409562 **(I.R.S. Employer Identification No.)**
1021 Main Street, Suite 2626, Houston, Texas (Address of principal executive offices)	77002 **(Zip Code)**

(713) 351-3000

Registrant s telephone number, including area code

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

None

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes x No o

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 o No x

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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 x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer	o	Accelerated filer	o
Non-accelerated filer	x (Do not check if a smaller reporting company)	Smaller reporting company	o

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

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 x No o

There is no market for the common stock of EPL Oil & Gas, Inc.

OMISSION OF CERTAIN INFORMATION:

EPL Oil & Gas, Inc. meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.

DOCUMENTS INCORPORATED BY REFERENCE:

None

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report on Form 10-K (this Form 10-K) 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 identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments as well as other factors the Company believes are appropriate under the circumstances and their potential effect on us. While management believes that these forward-looking statements are reasonable, such statements are not guarantees of future performance and the actual results or developments anticipated may not be realized or, even if substantially realized, may not have the expected consequences to or effects on the Company s business or results. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to those summarized below:

our business strategy;
further or sustained declines in the prices we receive for our oil and gas production;
our future financial condition, results of operations, revenues, cash flows and expenses;
our future levels of indebtedness, liquidity and compliance with debt covenants;
our inability to obtain additional financing necessary to fund our operations, capital expenditures, and to meet our other obligations;
economic slowdowns that can adversely affect consumption of oil and gas by businesses and consumers;
uncertainties in estimating oil and gas reserves and net present values of those reserves.
the need to take ceiling test impairments due to lower commodity prices;
hedging activities exposing us to pricing and counterparty risks;
uncertainties in estimating our oil and gas reserves;
replacing our oil and gas reserves;
geographic concentration of our assets;
uncertainties in exploring for and producing oil and gas, including exploitation, development, drilling and operating risks;
our ability to make acquisitions and to integrate acquisitions;
our ability to establish production on our acreage prior to the expiration of related leaseholds;
availability 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 gas industry;
our inability to retain and attract key personnel;
the effects of government regulation and permitting and other legal requirements;

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costs associated with perfecting title for mineral rights in some of our properties; and

weaknesses in our internal controls.

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 and elsewhere in this Form 10-K, (2) our reports and registration statements filed from time to time with the Securities and Exchange Commission and (3) 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.

EXPLANATORY NOTE RESTATEMENT OF FINANCIAL INFORMATION

In connection with preparing this Form 10-K, we determined that the contemporaneous formal documentation that we had prepared subsequent to our merger with Energy XXI Ltd to support our designations of derivative financial instruments as cash flow hedges in connection with our crude oil and natural gas hedging program did not meet the technical requirements to qualify for cash flow hedge accounting treatment in accordance with ASC Topic 815, *Derivatives and Hedging*. The primary reason for this determination was that the formal hedge documentation lacked specificity of the hedged items and, therefore, the designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment. Consequently, unrealized gains or losses resulting from those derivative financial instruments should have been recorded in our consolidated statements of operations as a component of earnings. Under the cash flow hedge accounting treatment applied subsequent to our merger with Energy XXI Ltd, we had recorded unrealized gains or losses resulting from changes in the fair value of our derivative financial instruments, net of the related tax impact, in accumulated other comprehensive income or loss until the production month when the associated hedge contracts were settled, at which time gains or losses associated with the settled contracts were reclassified to revenues. As a result, we concluded that certain of our previously issued consolidated financial statements should no longer be relied upon and would need to be restated.

This Form 10-K for the year ended June 30, 2015 includes (1) a restated balance sheet as of June 30, 2014, (2) restated consolidated statements of operations, consolidated statements of cash flows, and consolidated statements of stockholders equity (deficit) for the period from June 4, 2014 through June 30, 2014, and (3) restated quarterly consolidated financial statements for the quarters ended September 30, 2014, December 31, 2014, and March 31, 2015. See Item 8, Financial Statements and Supplementary Data, and Item 9A, Controls and Procedures, in Part II of this Form 10-K, including Notes 17 and 18 of the notes to the Consolidated Financial Statements, for more information concerning these restatements. The consolidated financial statements for prior periods presented in this report have been restated primarily to reflect the recognition of gains and losses on derivative financial instruments previously included in accumulated other comprehensive income (loss) as gain (loss) on derivative financial instruments in earnings as a component of revenues and the reclassification of amounts associated with settled contracts previously included in oil and gas sales revenues to gain (loss) on derivative financial instruments as a result of not qualifying for cash flow hedge accounting treatment. The restatement also reflects resulting adjustments to net oil and natural gas properties, impairment of oil and natural gas properties and depreciation, depletion and amortization due to the previous inclusion of the value of the cash flow hedges in our full cost ceiling tests, which is only permitted if the derivative instruments qualify for cash flow hedge accounting. Additionally, resulting adjustments to deferred income taxes and income tax expense (benefit) are also reflected in the restatement.

We do not plan to amend previously filed reports in connection with the restatement. The consolidated financial statements that have been previously filed or otherwise reported for these periods are superseded by the information in this Form 10-K. Other than the historical information reported for the Predecessor Company for periods prior to our merger with Energy XXI Ltd, all financial and accounting information contained in this Form 10-K is presented on a restated basis.

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PART I

Item 1. ***Business***

Overview

EPL Oil & Gas, Inc. (referred to herein as we, our, us, EPL or the Company) was incorporated as a Delawa corporation in January 1998 and is a wholly-owned subsidiary of Energy XXI Gulf Coast, Inc. (EGC), a Delaware corporation and indirect wholly-owned subsidiary of Energy XXI Ltd, an exempted company under the laws of Bermuda and our ultimate parent company (Energy XXI or parent).

On June 3, 2014, Energy XXI, EGC, Clyde Merger Sub, Inc., a wholly owned subsidiary of EGC (Merger Sub), and EPL, completed the transactions contemplated by the Agreement and Plan of Merger, dated as of March 12, 2014 (as amended, the Merger Agreement), by and among Energy XXI, EGC, Merger Sub, and EPL, pursuant to which Merger Sub was merged with and into EPL with EPL continuing as the surviving corporation (the Merger). Pursuant to the Merger Agreement, at the effective time of the Merger (the Effective Time), the issued and outstanding shares of EPL common stock, par value $0.001 per share (EPL Common Stock), were converted, in the aggregate, into the right to receive merger consideration (the Merger Consideration) consisting of approximately 65% in cash and 35% in shares of common stock of Energy XXI, par value $0.005 per share (Energy XXI Common Stock). The Merger and related matters are addressed in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

Our current operations are concentrated in the U.S. Gulf of Mexico shelf (the GoM shelf) focusing on state and federal waters offshore Louisiana, which we consider our core area. We have focused on acquiring and developing assets in this region, because the region is characterized by established exploitation, development and exploration opportunities in both productive horizons and deeper geologic formations. As part of Energy XXI s overall strategy and capital plan, we are focused on developing high quality oil-producing assets with low production decline rates. As of June 30, 2015, we had estimated proved reserves of 57.2 Mmboe, of which 67% were oil and 76% were proved developed. Of these proved developed reserves, 70% were oil reserves.

We produce both oil and natural gas. Throughout this Form 10-K, when we refer to total production, total reserves, percentage of production, percentage of reserves, or any similar term, we have converted our natural gas reserves or production into barrel equivalents. For this purpose, six thousand cubic feet of natural gas is equal to one barrel of oil, which is based on the relative energy content of natural gas and oil. Natural gas liquids are aggregated with oil in this Form 10-K.

For definitions of oil and natural gas terms used frequently in this Form 10-K, please refer to the Glossary of Oil and Natural Gas Terms following the index of Exhibits in Item 15 of Part IV of this Form 10-K.

Available Information

We file or furnish annual, quarterly and current reports and other documents with the Securities and Exchange Commission (the SEC) under the Securities Exchange Act of 1934 (as amended, the Exchange Act). The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any document we file with the SEC at *www.sec.gov*.

Energy XXI maintains a website at *www.energyxxi.com* that contains information about us, which information is available free of charge, including links to our Annual and Transition Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all related amendments as soon as reasonably practicable after electronically filing such reports with, or furnishing them to the SEC. The Energy XXI website and the information contained in it and connected to it shall not be deemed incorporated by reference into this Form 10-K or any other filing that we make with the SEC.

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Properties

As of June 30, 2015, we had working interests in 27 producing fields located in the GoM shelf region. The proved reserves and production from these fields are primarily associated with the following core producing areas: Ship Shoal 208, South Pass 49, West Delta 30 and South Pass 78. These properties represent approximately 74% of our net proved reserves and are ranked based on highest proved reserves as of June 30, 2015.

Ship Shoal 208. We operate and have a 100% working interest in the Ship Shoal 208 field, located 110 miles southwest of New Orleans, Louisiana in approximately 100 feet of water on Outer Continental Shelf (OCS) blocks Ship Shoal 208, 209 and 215. We have 13 platforms and 31 active wells throughout the field. The field s net production for the month of June 2015 of 4.8 MBOED accounted for approximately 17% of our net production. Net proved reserves for the field were 70% oil at June 30, 2015.

South Pass 49. Energy XXI operates and we have a 100% working interest in the South Pass 49 field, which is located near the mouth of the Mississippi River in approximately 400 feet of water. There are 14 active wells located throughout the field. The field is produced from one central production platform and has produced in excess of 121 MMBOE. The field s net production for the month of June 2015 of 4.6 MBOED accounted for approximately 17% of our net production. Net proved reserves for the field were 62% oil at June 30, 2015.

West Delta 30. We operate and have an average 93% working interest in the West Delta 27, 28 and 29 blocks, located 21 miles offshore of Grand Isle, Louisiana in approximately 45 feet of water on the OCS. There are 46 active wells located throughout the field. The field s net production for the month of June 2015 of 5.2 MBOED accounted for approximately 19% of our net production. Net proved reserves for the field were 86% oil at June 30, 2015.

South Pass 78. We operate and own a working interest of 67% in the South Pass 78 complex, which is located 86 miles southeast of New Orleans. It contains 31 producing wells in water depths ranging from approximately 140 to 190 feet in four lease blocks. There are four major production platforms, three of which have producing wells, located throughout the field. The field s net production for the month of June 2015 of 2.7 MBOED accounted for approximately 10% of our net production. Net proved reserves for the field were 52% oil at June 30, 2015.

As of June 30, 2015, we also owned interests in one undeveloped lease in the deepwater Gulf of Mexico and we have a non-operated interest in one developed lease. Our working interests in our leases in this area ranged from 15% to 33%.

On June 30, 2015, we sold our interest in the East Bay field for cash consideration of approximately $21 million, plus the assumption of asset retirement obligations totaling approximately $55.1 million. We retained a 5% overriding royalty interest (applicable only during calendar months if and when the WTI for such month averages over $65) on these assets for a period not to exceed 5 years from the closing date or $7 million whichever occurs first, and we also retained 50% of the deep rights associated with the East Bay field. This area included the South Pass 24 and 27 fields and is located 89 miles southeast of New Orleans, near the mouth of the Mississippi River. See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, for additional information regarding the terms of the sale of our interests in the East Bay field.

See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, for information regarding our oil and gas production, average prices and average costs.

Summary of Oil and Natural Gas Reserves at June 30, 2015

The following table presents our estimated net proved oil and natural gas reserves and the estimated future net revenues and cash flows related to our reserves at June 30, 2015. Our estimates of proved reserves are based on a reserve report prepared as of June 30, 2015 by Netherland, Sewell & Associates, Inc. (NSAI), an independent petroleum engineering firm. Neither PV-10 nor the standardized measure of discounted future net cash flows shown in the table is intended to represent the current market value of the estimated oil and natural gas reserves that we own. Note 19 Supplementary Oil and Natural Gas

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Disclosures (Unaudited) of the consolidated financial statements in Part II, Item 8 of this Form 10-K provides important additional information about our proved oil and natural gas reserves.

We follow the oil and gas reserves estimation and disclosure requirements of the Financial Accounting Standards Board Accounting Standards Codification (ASC) Topic 932, Extractive Activities Oil and Gas (ASC 932), which requires, among other things, that prices used to estimate reserves for SEC disclosure purposes reflect an unweighted, arithmetic average price based upon the closing price on the first day of each of the twelve months during the fiscal year, rather than the year-end price. See Note 19 Supplementary Oil and Natural Gas Disclosures (Unaudited) of the consolidated financial statements in Part II, Item 8 of this Form 10-K for additional information regarding reporting related to oil and natural gas reserves under ASC 932.

	As of June 30, 2015 (dollars in thousands)
Total net proved reserves:	
Oil (Mbbls)	38,623
Natural gas (Mmcf)	111,586
Total (Mboe)	57,219
Net proved developed reserves[1]:	
Oil (Mbbls)	30,804
Natural gas (Mmcf)	77,562
Total (Mboe)	43,731
Net proved undeveloped reserves:	
Oil (Mbbls)	7,819
Natural gas (Mmcf)	34,024
Total (Mboe)	13,490
Present value of estimated future net revenues before income taxes (PV-10)[2][3][5]	$ 825,766
Standardized measure of discounted future net cash flows[4][5]	$ 825,766

(1) Net proved developed non-producing reserves as of June 30, 2015 (6,742 Mbbls and 37,123 Mmcf) were 12,929 Mboe, or 23% of our total proved reserves.

(2) Calculated using oil price of $73.88 per barrel and natural gas price of $3.11 per Mcf held constant for the life of the reserves, computed in accordance with ASC 932, based on the unweighted, arithmetic average of the closing price on the first day of each of the twelve months during the fiscal year, applying historical adjustments, including transportation, quality differentials, and purchaser bonuses, on an individual property basis, to the year-end quantities of estimated proved reserves. The historical adjustments applied to the computed prices are determined by comparing our historical realized price experience with the comparable historical market, or posted, price.

(3) The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, determined in the manner described in footnote (2), discounted at a rate of 10% per year on a pre-tax basis.

(4) The standardized measure of discounted future net cash flows represents the present value of future cash flows after income taxes discounted at 10% per year, as calculated in accordance with SEC guidelines and pricing. However, we do not currently expect any future net income taxes due to our net operating loss carryforwards and our expectations regarding our future taxable income consistent with net losses recorded during the current fiscal year.

(5) PV-10 is considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax

amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. Because the standardized measure is dependent on the unique tax situation of each company, our calculation may not be comparable to those of our competitors. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis.

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Changes in Proved Reserves

Our proved developed reserve estimates decreased by 18.4 MMBOE or 30% to 43.7 MMBOE at June 30, 2015 from 62.1 MMBOE at June 30, 2014. The decrease was primarily due to:

Downward revision of 3.6 MMBOE, primarily due to the effect of reduced oil and gas prices,
Divestiture of 11.0 MMBOE, and
Production of 9.3 MMBOE.
Offset by:

Additions of 2.9 MMBOE, primarily from drilling, recompletions, and wells returned to production that were not previously booked, more than 82% of which are from four fields: South Pass 78, South Pass 49, Ship Shoal 208 and West Delta 30, and
Conversion of 2.6 MMBOE from proved undeveloped to proved developed reserves.

Our proved undeveloped reserve estimates decreased by 13.9 MMBOE or 51% to 13.5 MMBOE at June 30, 2015 from 27.4 MMBOE at June 30, 2014. The decrease was primarily due to:

Downward revisions of 11.2 MMBOE comprised of (i) 1.8 MMBOE due to the effect of reduced oil and gas prices, (ii) 2.8 MMBOE due to certain wells that were no longer scheduled for development within five years, and (iii) 6.6 MMBOE due to new data and field studies. Of the 6.6 MMBOE of downward revisions due to new data and field studies, more than 75% occurred in the following three fields: South Timbalier 26, South Pass 78 and Ship Shoal 208, and
Conversion of 2.6 MMBOE from proved undeveloped to proved developed reserves.

Development of Proved Undeveloped Reserves

Our proved undeveloped (PUD) reserves at June 30, 2015 were 13.5 MMBOE. Future development costs associated with our PUD reserves at June 30, 2015 totaled approximately $203 million. In the fiscal year ended June 30, 2015, we developed approximately 9.4% of our PUD reserves included in our June 30, 2014 reserve report, consisting of 8 gross, 8 net wells at a net cost of approximately $80 million.

As part of Energy XXI s development plan, our reserves development plan is updated on an annual basis, which includes our program to drill PUD locations. Updates to our reserves development plan are based upon Energy XXI s long range criteria, including top value projects, maximization of present value, cash flow and production volumes, drilling obligations, five-year rule requirements, and anticipated availability of certain rig types. The relative portion of total PUD reserves that we develop over the next five years will not be uniform from year to year, but will vary by year depending on several factors; including financial targets such as reducing debt and/or drilling within cash flow, drilling obligatory wells and the inclusion of newly acquired proved undeveloped reserves. As scheduled in Energy XXI s long range plan, all of our PUD locations will be developed within five years from the time they are first recognized as proved undeveloped locations in our reserve report.

Although the schedule for development of our PUDs has historically changed based on external factors such as changes in commodity prices, the availability of capital, acquisitions, regulatory matters and the availability of drilling rigs that are capable of drilling in a given area, and our current PUD schedule is also subject to change due to external factors, we believe our PUDs will be converted in a timely manner given our enhanced focus on development drilling in our long range plan and current availability of capital to execute that plan. Energy XXI senior management continuously monitors our development drilling plan to ensure that there is reasonable certainty of proceeding with our development plans and is required to approve any changes made to the existing long range plan and the related development plan. The following table presents the percentage of PUD reserves scheduled to be developed by fiscal year, in accordance with our long range plan.

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Year Ending June 30,	Percentage of PUD Reserves Scheduled to be Developed	
2017	4	%
2018	28	%
2019	65	%
2020	3	%
Total	100	%

The following table discloses our progress toward the development of PUD reserves during the fiscal year ended June 30, 2015.

	Oil and Natural Gas (MBOE)		Future Development Costs (in thousands)	
Proved undeveloped reserves at June 30, 2014	27,386		$ 402,604	
Extensions and discoveries	250		7,750	
Revisions of previous estimates	(10,146	)	(59,830	)
Changes in prices and costs	(1,018	)	(55,332	)
Sales of reserves	(402	)	(12,400	)
Conversions to proved developed reserves	(2,580	)	(80,062	)
Total reduction in proved undeveloped reserves	(13,896	)	(199,874	)
Proved undeveloped reserves at June 30, 2015	13,490		$ 202,730	

Qualifications of Primary Internal Engineer and Third Party Engineers

Energy XXI s Director of Reserves, Lee I. Williams, is the technical person primarily responsible for overseeing the preparation by NSAI of our reserve estimates and for compliance with Energy XXI s policies. He has 15 years of industry experience with positions of increasing responsibility and has over 10 years experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1998 with a Bachelor of Science Degree in Petroleum Engineering.

At the end of each year, our reserve estimates are prepared by outside petroleum engineering firms. As of June 30, 2015, our estimates of proved reserves are based on a reserve report prepared by the independent petroleum engineering firm NSAI, a nationally recognized engineering firm. At June 30, 2015, 100% of our total estimated net proved reserves were prepared by NSAI. The NSAI report is filed as an exhibit to this Form 10-K.

NSAI provides a complete range of geological, geophysical, petrophysical and engineering services and has the technical experience and ability to perform these services in any of the onshore and offshore oil and gas producing areas of the world. NSAI has a technical staff of over 70 professionals who are knowledgeable with regard to recognized industry reserves and resource definitions, specifically those set forth by the SEC. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Connor B. Riseden and Mr. Shane M. Howell.

Mr. Riseden has been practicing consulting petroleum engineering at NSAI since 2006. Mr. Riseden is a Licensed Professional Engineer in the State of Texas (No. 100566) and has over 13 years of practical experience in petroleum engineering. He graduated from Texas A&M University in 2001 with a Bachelor of Science Degree in Petroleum Engineering and from Tulane University in 2005 with a Master of Business Administration Degree. Mr. Howell has been practicing consulting petroleum geoscience at NSAI since 2005. Mr. Howell is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 11276) and has over 17 years of practical experience in petroleum geosciences. He graduated from San Diego State University in 1997 with a Bachelor of Science Degree in Geological Sciences and in 1998 with a Master of Science Degree in Geological Sciences.

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Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Technologies Used in Reserve Estimation

The SEC allows use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. The term reasonable certainty is defined by the SEC as much more likely to be produced than not and much more likely to increase or remain constant than to decrease. Our internal reservoir engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, pressure data and reservoir simulation.

Oil and Natural Gas Production, Prices and Production Costs Significant Fields

The table below sets forth production information for each field that contains 15% or more of our total proved reserves as of June 30, 2015. On June 3, 2014, we acquired from Energy XXI GOM, LLC additional oil and natural gas interests in our South Pass 49 field. The table below reflects production for this field based on our historical interests in this field prior to the recent acquisition of the additional interests and includes production associated with the additional interests subsequent to June 3, 2014.

	Year Ended June 30, 2015	Six Months Ended June 30, 2014	Year Ended December 31, 2013	2012
Ship Shoal 208:				
Oil (Mbbls)	1,259	540	658	109
Natural gas (Mmcf)	2,397	547	1,130	199
Total (Mboe)	1,659	631	846	142
South Pass 49:				
Oil (Mbbls)	726	138	163	86
Natural gas (Mmcf)	4,383	1,110	2,512	401
Total (Mboe)	1,457	323	582	153
West Delta 30:				
Oil (Mbbls)	1,511	885	2,293	1,142
Natural gas (Mmcf)	2,722	397	2,000	490
Total (Mboe)	1,965	951	2,626	1,224

Costs Incurred in Oil and Natural Gas Activities

The following table sets forth the costs incurred associated with finding, acquiring and developing our proved oil and natural gas reserves.

		Year Ended June 30, 2015	Six Months Ended June 30, 2014	Year Ended December 31, 2013	2012
		(In thousands)			
Acquisitions	Proved	$	$ 314,169	$ 46,047	$ 706,322
Acquisitions	Unevaluated	176	9,503	2,200	7,496
Exploration		27,100	56,079	46,100	43,338
Development		244,216	242,217	303,245	180,938
Costs incurred		$ 271,492	$ 621,968	$ 397,592	$ 938,094

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Oil and Natural Gas Production and Prices

Our average daily production represents our net ownership and includes royalty interests and net profit interests owned by us. Our average daily production and average sales prices follow.

	Year Ended June 30, 2015	Six Months Ended June 30, 2014	Year Ended December 31, 2013	2012
Sales Volumes per Day				
Oil (MBbls)	18.3	17.3	16.9	10.4
Natural gas (Mmcf)	43.7	26.5	32.9	17.9
Total (MBOE)	25.6	21.7	22.4	13.4
Percent of BOE from oil	72 %	80 %	76 %	78 %
Average Sales Price				
Oil per Bbl	$ 67.66	$ 99.87	$ 104.01	$ 106.08
Natural gas per Mcf	$ 3.14	$ 4.92	$ 3.81	$ 2.89
Sales price per BOE	$ 58.04	$ 82.74	$ 84.18	$ 86.33

Production Unit Costs

Our production unit costs follow. Production costs include lease operating expense and production taxes.

	Year Ended June 30, 2015	Six Months Ended June 30, 2014	Year Ended December 31, 2013	2012
Average Cost per BOE				
Production costs				
Lease operating expense	$ 22.68	$ 22.93	$ 20.27	$ 19.38
Production taxes	0.87	1.33	1.40	2.66
Total production costs	$ 23.55	$ 24.26	$ 21.67	$ 22.04
Depreciation, depletion and amortization rates	$ 31.99	$ 27.47	$ 24.49	$ 23.21

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of June 30, 2015 and 2014.

	June 30, 2015		2014	
	Gross	Net	Gross	Net
Oil	213	167	359	314
Natural gas	45	33	79	58
Total	258	200	438	372

In this Form 10-K, when referring to wells and acreage, gross refers to the total wells or acres in which we have a working interest and net refers to gross wells or acres multiplied by our working interest.

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Acreage

The following table sets forth information relating to acreage held by us as of June 30, 2015. Developed acreage is assigned to producing wells.

	June 30, 2015					
	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Onshore			125	63	125	63
Offshore	236,197	188,626	181,164	153,306	417,361	341,932
Total	236,197	188,626	181,289	153,369	417,486	341,995

During fiscal years 2016 and 2017, we do not have any leases covering our undeveloped acreage expiring; however, during fiscal year 2018, leases covering 42,903 of our undeveloped gross acreage (32,697 net) will expire.

Drilling Activity

Drilling activity refers to the number of wells completed at any time during the applicable fiscal years, regardless of when drilling was initiated. The following table shows our drilling activity where gross refers to the total wells in which we have a working interest and net refers to gross wells multiplied by our working interest in these wells.

	Year Ended		Six Months Ended		Year Ended December 31,			
	June 30, 2015		June 30, 2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells								
Productive	7.0	7.0	10.0	9.5	13.0	11.5	11.0	9.5
Non-productive					3.0	3.0	1.0	1.0
Total	7.0	7.0	10.0	9.5	16.0	14.5	12.0	10.5
Exploratory Wells								
Productive	2.0	1.5	1.0	0.5			1.0	0.8
Non-productive	1.0	0.6	1.0	1.0	1.0	1.0	2.0	0.7
Total	3.0	2.1	2.0	1.5	1.0	1.0	3.0	1.5

Present Activities

As of June 30, 2015, we were not in the process of drilling any wells.

Delivery Commitments

We had no delivery commitments in the three years ended June 30, 2015.

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, mechanics and materialman s liens, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with the use of our properties or the operation of our business.

We believe that we have satisfactory title to, or rights in, all of our properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. We investigate title prior to the consummation of an acquisition of producing properties and before the commencement of drilling operations on undeveloped properties. We have obtained or conducted a thorough title review on substantially all of our producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and natural gas industry.

Government Regulation

Our oil and gas exploration, production and related operations and activities are subject to extensive rules and regulations promulgated by federal, state and local governmental agencies. Failure to comply with such rules and regulations can result in substantial penalties. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect others in our industry with similar types, quantities and locations of production.

Regulations affecting production. The jurisdictions in which we operate generally require permits for drilling operations, drilling bonds and operating reports and impose other requirements relating to the exploration and production of oil and gas. Such jurisdictions also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells, the spacing, plugging and abandonment of such wells, restrictions on venting or flaring natural gas and requirements regarding the ratability of production.

These laws and regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Moreover, many jurisdictions impose a production or severance tax with respect to the production and sale of oil and natural gas within their jurisdiction. There is generally no regulation of wellhead prices or other, similar direct economic regulation of production, but there can be no assurance that this will remain true in the future.

In the event we conduct operations on federal, state or Indian oil and natural gas leases, our operations may be required to comply with additional regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and on-site security regulations and other appropriate permits issued by the Bureau of Land Management (BLM) or other relevant federal or state agencies.

Regulations affecting sales. The sales prices of oil, natural gas liquids and natural gas are not presently regulated but rather are set by the market. We cannot predict, however, whether new legislation to regulate the price of energy commodities might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties.

The Federal Energy Regulatory Commission (FERC) regulates interstate natural gas pipeline transportation rates and service conditions, which affect the marketing of gas we produce, as well as the revenues we receive for sales of such production. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting interstate transportation. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We do not believe that we will be affected by any such FERC action in a manner materially differently than other natural gas producers in our areas of operation.

The price we receive from the sale of oil and natural gas liquids is affected by the cost of transporting those products to market. Rates charged and terms of service for the interstate pipeline transportation of oil, natural gas liquids and other refined petroleum products also are regulated by FERC. FERC has established an indexing methodology for changing the interstate transportation rates for oil pipelines, which allows such pipelines to take an annual inflation-based rate increase. We are not able to predict with any certainty what effect, if any, these regulations will have on us, but, other factors being equal, the regulations may, over time, tend to increase transportation costs which may have the effect of reducing wellhead prices for oil and natural gas liquids.

Market manipulation and market transparency regulations. Under the Energy Policy Act of 2005 (EPAct 2005), FERC possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation of natural gas by any entity in order to enforce the anti-market manipulation provisions in the EPAct 2005. The Commodity Futures Trading Commission (CFTC) also holds authority to regulate certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act. Likewise, the Federal Trade Commission (FTC) holds authority to regulate wholesale petroleum markets pursuant to the Federal Trade Commission Act and the Energy Independence and Security Act of 2007. With regard to our physical purchases and sales of natural gas, natural gas liquids, and crude oil, our gathering or transportation of these energy commodities, and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by FERC, FTC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation or, for the CFTC, triple the monetary gain to the violator, order disgorgement of profits, and recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

FERC has issued certain market transparency rules pursuant to its EPAct 2005 authority, which may affect some or all of our operations. FERC issued a final rule in 2007, as amended by subsequent orders on rehearing (Order 704), which requires wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including natural gas producers, gatherers, processors, and marketers, to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to, the formation of price indices, as explained in the order. It is the responsibility of the reporting entity to determine which transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC s policy statement on price reporting. FERC s civil penalty authority under EPAct 2005 applies to violations of Order 704.

Oil Pipeline Regulations. We own interests in oil pipelines regulated by FERC under the Interstate Commerce Act (ICA), the Energy Policy Act of 1992 (EPAct of 1992), and the rules and regulations promulgated under those laws and, thus, have interstate tariffs on file with FERC setting forth our interstate transportation rates and charges and the rules and regulations applicable to our jurisdictional transportation service. The ICA and its implementing regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil, natural gas liquids and refined petroleum products pipelines, be just and reasonable and non-discriminatory and that such rates and terms and conditions of service be filed with FERC. Under the ICA, shippers may challenge new or existing rates or services. FERC is authorized to suspend the effectiveness of a challenged rate for up to seven months, though rates are typically not suspended for the maximum allowable period. A successful rate challenge could result in an oil pipeline paying refunds for the period that the rate was in effect and/or reparations for up to two years prior to the filing of a complaint. FERC generally has not investigated oil pipeline rates on its own initiative.

Under the EPAct of 1992, oil pipeline rates in effect for the 365-day period ending on the date of enactment of the EPAct of 1992 are deemed to be just and reasonable under the ICA, if such rates were not subject to complaint, protest or investigation during that 365-day period. These rates are commonly referred to as grandfathered rates. FERC may change grandfathered rates upon complaint only after it is shown that (i) a substantial change has occurred since enactment in either the economic circumstances or the nature of the services that were a basis for the rate; (ii) the complainant was contractually barred from challenging the rate prior to enactment of the EPAct of 1992 and filed the complaint within 30 days of the expiration of the contractual bar; or (iii) a provision of the tariff is unduly discriminatory or preferential. The EPAct of 1992 places no similar limits on challenges to a provision of an oil pipeline tariff as unduly discriminatory or preferential.

The EPAct of 1992 further required FERC to establish a simplified and generally applicable ratemaking methodology for interstate oil pipelines. As a result, FERC adopted an indexing rate methodology which, as currently in effect, allows oil pipelines to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index for Finished Goods, plus 2.65 percent. Rate increases made under the index are subject to protest, but the scope of the protest proceeding is limited to an inquiry into whether the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline s increase in costs. The indexing methodology is applicable to any existing rate, including a grandfathered rate. Indexing includes the requirement that, in any year in which the index is negative, pipelines must file to lower their rates if those rates would otherwise be above the rate ceiling. However, the pipeline is not required to reduce its rates below the level deemed just and reasonable under the EPAct of 1992.

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While an oil pipeline, as a general rule, must use the indexing methodology to change its rates, FERC also retained cost-of-service ratemaking, market-based rates, and settlement rates as alternatives to the indexing approach. A pipeline can follow a cost-of-service approach when seeking to increase its rates above the rate ceiling (or when seeking to avoid lowering rates to the reduced rate ceiling), provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can charge market-based rates if it establishes that it lacks significant market power in the affected markets. In addition, a pipeline can establish rates under settlement.

Outer Continental Shelf Regulations. Our operations on federal oil and gas leases in the Gulf of Mexico are subject to regulation by the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM). These leases contain relatively standardized terms and require compliance with detailed BSEE and BOEM regulations and orders issued pursuant to various federal laws, including the Outer Continental Shelf Lands Act (OCSLA). These laws and regulations are subject to change, and many new requirements were imposed by the BSEE and BOEM subsequent to the April 2010 Deepwater Horizon incident. For offshore operations, lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the U.S. Environmental Protection Agency, (the EPA), lessees must obtain a permit from the BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the OCS, calculation of royalty payments and the valuation of production for this purpose, and removal of facilities.

To cover the various obligations of lessees on the OCS, such as the cost to plug and abandon wells and decommission and remove platforms and pipelines at the end of production, the BOEM generally requires that lessees post substantial bonds or other acceptable assurances that such obligations will be met, unless the BOEM exempts the lessee from such financial assurance requirements. As a result of the bankruptcy of another Gulf of Mexico operator, the BOEM has indicated that it may review the estimated cost of future plugging, abandonment, decommissioning and removal obligations of other OCS operators, may evaluate any waivers or exemptions for such financial assurance obligations, and may increase the amount of financial assurance required with respect to these obligations. In April 2015, we received letters from the BOEM stating that certain of our subsidiaries no longer qualify for waiver of certain supplemental bonding requirements for potential offshore decommissioning, plugging and abandonment liabilities. The letters notified us that certain of our subsidiaries must provide approximately $566.5 million in supplemental financial assurance and/or bonding for their offshore oil and gas leases, rights-of-way, and rights-of-use and easements. In June 2015, we reached agreements with the BOEM pursuant to which we provided $54.7 million of supplemental bonds issued to the BOEM, and the BOEM agreed to withdraw its orders with regard to supplemental bonding and postpone until November 15, 2015 the issuance of further requirements of us related to these supplemental bonding obligations. On June 30, 2015, we sold the East Bay field and the $566.5 million of requested supplemental bonding was reduced by approximately $178 million.

On September 22, 2015, the BOEM issued draft guidance (the Draft Guidance) describing revised supplemental bonding procedures the agency plans to use to impose financial assurance obligations for decommissioning activities on the federal OCS. Once the Draft Guidance is finalized, the BOEM will issue these supplemental bonding changes in a revised Notice to Lessees (NTL) in replacement of an existing NTL on supplemental bonding that was made effective on August 28, 2008. Among other things, the Draft Guidance proposes to eliminate the waiver exemption currently allowed by BOEM, whereby certain operators on the OCS projecting a relatively large net worth and meeting certain other criteria have the option of being exempted from posting bonds or other acceptable assurances for such operator s decommissioning obligations by self-insuring for those liabilities, but only so long as the cumulative decommissioning liability amount being self-insured by the operator is no more than 50% of the operator s net worth. Under the Draft Guidance, this waiver option would be eliminated in favor of a broadened self-insurance approach that would allow a larger array of operators on the OCS, not just those with relatively large net worths, who meet certain criteria to seek self-insurance for a portion of their supplemental bond obligations, but eligible operators may only self-insure for an amount that is no more than 10% of their tangible net worth. Under the Draft

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Guidance, the BOEM proposes to establish a phased-in period for establishing compliance with supplemental bonding obligations, whereby operators may seek payment of estimated costs of decommissioning obligations owed under a tailored plan that is approved by the BOEM and requires payment of the supplemental bonding amount in three approximately equal installments of one-third each, by no later than approximately 120, 240 and 360 calendar days, respectively, from the date of BOEM approval of the tailored plan. We currently expect the Draft Guidance to be finalized and a new NTL to be issued by late 2015 or early 2016.

We currently maintain approximately $58.3 million in lease and/or area bonds issued to the BOEM and approximately $122.5 million in bonds issued to predecessor third party assignors including certain state regulatory bodies of certain wells and facilities on leases pursuant to a contractual commitment made by us to those third parties at the time of assignment with respect to the eventual decommissioning of those wells and facilities. Thus, our total supplemental bonding is approximately $180.8 million, with an annual premium expense of $2.7 million. In addition, since June 2015, we have received additional letters from the BOEM in which the BOEM requests additional supplemental bonding for other certain properties previously exempt from supplemental bonding, generally as a result of exempt co-owners either losing their exemptions or no longer owning an interest in the property. Furthermore, we anticipate our supplemental bonding requirements to increase as we further develop or acquire additional properties subject to the BOEM s financial assurance requirements. Although we believe we are currently in compliance with the supplemental bonding requirements, the BOEM may in the future continue to review our plugging, abandonment, decommissioning and removal obligations; re-evaluate the adequacy of our financial assurances; and require us to provide additional supplemental bonding or other surety for most or all of our properties. Furthermore, in addition to the Draft Guidance describing revised supplemental bonding procedures that may be used by the BOEM, the BOEM is actively seeking to adjust its financial assurance requirements mandated by rule for all companies operating in federal waters. In August 2014, the BOEM issued an Advanced Notice of Proposed Rulemaking (ANPR) in which the agency indicated that it was considering bolstering the financial assurance requirements currently mandated by rule. The cost of compliance with our existing supplemental bonding requirements or any other changes to the BOEM s current bonding requirements or regulations applicable to us or our properties could be substantial and could materially and adversely affect our financial condition, cash flows, and results of operations. Please read Risk Factors We and our subsidiaries have been asked by the BOEM to obtain bonds or other surety in order to maintain compliance with BOEM regulations, which may be costly and could potentially reduce borrowings available under our revolving credit facility.

Under certain circumstances, the BSEE may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations. We own certain crude oil pipelines located on the OCS. BSEE regulates terms of service on OCS pipelines to provide open and nondiscriminatory access.

Gathering regulations. Section 1(b) of the federal Natural Gas Act (NGA) exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. Although FERC has not made any formal determinations with respect to any of the natural gas gathering pipeline facilities that we own, we believe that our natural gas gathering pipelines meet the traditional tests that FERC has used to establish a pipeline s status as a gathering pipeline not subject to FERC jurisdiction. The distinction between FERC-regulated transmission facilities and federally unregulated gathering facilities, however, has been the subject of substantial litigation and, over time, FERC s policy for determining which facilities it regulates has changed. In addition, the distinction between FERC-regulated transmission facilities, on the one hand, and gathering facilities, on the other, is a fact-based determination made by FERC on a case-by-case basis. The classification and regulation of our gathering lines may be subject to change based on future determinations by FERC, the courts or the U.S. Congress.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and in some instances complaint-based rate regulation. Our gathering operations may also be subject to state ratable take and common purchaser statutes, designed to prohibit discrimination in favor of one producer over another or one source of supply over another. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. In addition, our natural

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gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services, though we do not believe that we would be affected by any such action in a manner differently than other companies in our areas of operation.

Environmental Regulations

Various federal, state and local laws and regulations relating to the protection of the environment, including the discharge of materials into the environment, may affect our exploration, development and production operations and the costs of those operations. These laws and regulations, among other things, govern the amounts and types of substances that may be released into the environment, the issuance of permits to conduct exploration, drilling and production operations, the handling, discharge and disposition of waste materials, the reclamation and abandonment of wells, sites and facilities, the establishment of financial assurance requirements for oil spill response costs and the decommissioning of offshore facilities and the remediation of contaminated sites. These laws and regulations may impose liabilities for noncompliance and contamination resulting from our operations and may require suspension or cessation of operations in affected areas.

The environmental laws and regulations applicable to us and our operations include, among others, the following United States federal laws and regulations, as amended from time to time:

- Clean Air Act, which governs air emissions;
- Clean Water Act, which governs discharges of pollutants into waters of the United States;
- Comprehensive Environmental Response, Compensation and Liability Act, which imposes strict liability where releases of hazardous substances have occurred or are threatened to occur (commonly known as Superfund);
- Resource Conservation and Recovery Act, which governs the management of solid waste;
- Endangered Species Act, Marine Mammal Protection Act, and Migratory Bird Treaty Act, which govern the protection of animals, flora and fauna;
- Oil Pollution Act of 1990, which imposes liabilities resulting from discharges of oil into navigable waters of the United States;
- Emergency Planning and Community Right-to-Know Act, which requires reporting of toxic chemical inventories;
- Safe Drinking Water Act, which governs underground injection and disposal activities; and
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

We believe our operations are in compliance with applicable environmental laws and regulations. We expect to continue making expenditures on a regular basis relating to environmental compliance. We maintain insurance coverage for spills, pollution and certain other environmental risks, although we are not fully insured against all such risks. Our insurance coverage provides for the reimbursement to us of costs incurred for the containment and clean-up of materials that may be suddenly and accidentally released in the course of our operations, but such insurance does not fully insure pollution and similar environmental risks. We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our consolidated financial position or our results of operations. However, since environmental costs and liabilities are inherent in our operations and in the operations of companies engaged in similar businesses and since regulatory requirements frequently change and may become more stringent, there can be no assurance that material costs and liabilities will not be incurred in the future. Such costs may result in increased costs of operations and acquisitions and decreased production.

Oil Pollution Act. The Oil Pollution Act of 1990 (OPA) and regulations adopted pursuant to OPA impose a variety of requirements on responsible parties related to the prevention of and response to oil spills into waters of the United States, including the OCS. A responsible party includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns joint and several, strict liability, without regard to fault, to each

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responsible party, for all containment and cleanup costs and a variety of public and private damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters, natural resource damages and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by OPA, they are limited. In addition, in December 2014, the BOEM issued a final rule, effective January 12, 2015, which raises OPA s damages liability cap from $75 million to $133.65 million. OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. OPA currently requires a minimum financial responsibility demonstration of $35 million for companies operating on the OCS, although the Secretary of Interior may increase this amount up to $150 million in certain situations. We cannot predict at this time whether OPA will be amended or whether the level of financial responsibility required for companies operating on the OCS will be increased. In any event, if there were to occur an oil discharge or substantial threat of discharge, we may be liable for costs and damages, which costs and liabilities could be material to our results of operations and financial position.

Climate Change. The U.S. Environmental Protection Agency (the EPA) has determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act (CAA). Among the EPA s rules regulating greenhouse gas emissions under the CAA, one requires a reduction in emissions of greenhouse gases from motor vehicles and another requires preconstruction and operating permits for certain large stationary sources of such emissions. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries and certain onshore and offshore oil and natural gas production facilities. In addition, in January 2015, the Obama Administration announced its goal to reduce methane emissions from the oil and gas sector by 40 to 45% from 2012 emission levels by 2025. Subsequent to this announcement, on September 18, 2015, the EPA published a proposed rulemaking that includes new limits for methane emissions and expanded limits for volatile organic compound emissions from new and modified oil and gas production sources and natural gas processing and transmission sources.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances that correspond to their annual emissions of greenhouse gases. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal. As the number of emission allowances declines each year, the cost or value of such allowances is expected to escalate significantly.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Derivative Activities

We are actively engaged in a hedging program designed to manage our commodity price risk and enhance cash flow certainty and predictability. For further information regarding our risk management activities, please read Item 7A, Quantitative and Qualitative Disclosures About Market Risk in this Form 10-K.

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Marketing and Significant Customers

We market substantially all of our oil and natural gas production from the properties we operate. We also market more than half of our oil and natural gas production from the fields we do not operate. The majority of our operated oil and gas production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market-based prices.

Of our total oil and natural gas revenues for the year ended June 30, 2015, Chevron USA, Inc. (Chevron) accounted for approximately 58%, ConocoPhillips accounted for approximately 20%, and Shell Trading (US) Company (Shell) accounted for approximately 20%. We also sell our production to a number of other customers, and we believe that those customers, along with other purchasers of oil and natural gas, would purchase all or substantially all of our production in the event that Chevron, ConocoPhillips or Shell curtailed their purchases.

We transport a portion of our oil and natural gas through third-party gathering systems and pipelines. Transportation space on these gathering systems and pipelines is normally readily available. Our ability to market our oil and gas has at times been limited or delayed due to restricted or unavailable transportation space or weather damage, and cash flow from the affected properties has been and could continue to be adversely impacted.

Employees

Effective January 1, 2015, all remaining EPL employees became employees of Energy XXI Services, LLC, an affiliated party.

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Item 1A. ***Risk Factors***

Oil and natural gas prices are volatile, and a substantial or extended decline in oil and natural gas prices would adversely affect our financial results and impede our growth.

Oil and natural gas prices historically have been volatile and are likely to continue to be volatile in the future. For example, oil prices declined severely during our 2015 fiscal year with continued lower prices in the first quarter of our fiscal year 2016. The WTI crude oil price per barrel for the period from July 1, 2014 to June 30, 2015 ranged from a high of $105.34 to a low of $43.46, a decrease of 58.7%, and the NYMEX natural gas price per MMBtu for the period July 1, 2014 to June 30, 2015 ranged from a high of $4.49 to a low of $2.49, a decrease of 44.5%. As of September 22, 2015, the spot market price for WTI was $45.83. Prices for oil and natural gas fluctuate widely in response to relatively minor changes in the supply and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control, such as:

- domestic and foreign supplies of oil and natural gas;
- price and quantity of foreign imports of oil and natural gas;
- actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil and natural gas price and production controls;
- level of consumer product demand, including as a result of competition from alternative energy sources;
- level of global oil and natural gas exploration and production activity;
- domestic and foreign governmental regulations;
- level of global oil and natural gas inventories;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- weather conditions;
- technological advances affecting oil and natural gas production and consumption;
- overall U.S. and global economic conditions; and
- price and availability of alternative fuels.

Our financial condition, revenues, profitability and the carrying value of our properties depend upon the prevailing prices and demand for oil and natural gas. The speed and severity of the decline in oil prices during our 2015 fiscal year and the continued lower prices in the first quarter of our fiscal year 2016 has materially affected our results of operations and our estimates of our proved oil and natural gas reserves. Any sustained periods of low prices for oil or natural gas are likely to materially and adversely affect our financial position, the quantities of natural gas and oil reserves that we can economically produce, our cash flow available for capital expenditures and our ability to access funds from EGC and EGC s ability to access funds under our revolving credit facility and through the capital markets.

We may not be able to generate sufficient cash flows to service all of our indebtedness and may be forced to take other actions in order to satisfy our obligations under our indebtedness, which may not be successful.

As of June 30, 2015, we had total indebtedness of $1,018 million. Based on our current debt balance, we expect to have substantial interest payments due during fiscal year 2016, totaling $80.1 million. In addition, our $510 million aggregate principal amount 8.25% Senior Notes are due February 15, 2018.

In addition, our revolving credit facility is scheduled to mature on April 9, 2018; however, the maturity of our revolving credit facility will accelerate if EGC s 9.25% Senior Notes are not retired or refinanced by May 15, 2017 or our 8.25% Senior Notes are not retired or refinanced by July 15, 2017.

Our ability to make scheduled payments on, or to refinance, our debt obligations will depend on our financial and operating performance, which is subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We cannot assure you that our business will generate sufficient cash flows from operating activities or that future sources of capital will be available to us in an amount sufficient to permit us to service our indebtedness or repay our indebtedness as it becomes due or to fund our other liquidity needs. In addition, there can be no assurance that we will have the ability to borrow or otherwise raise the amounts necessary to repay or refinance our indebtedness as it matures. If we are unable to generate sufficient cash flow to service our debt or meet our debt obligations as they become due, we may be required to:

- restructure or refinance all or a portion of our debt;
- obtain additional financing;
- sell some of our assets or operations; or
- reduce or delay capital expenditures, including development and exploration efforts.

EGC and EPL may be unable to restructure or refinance our debt, obtain additional financing or capital or sell assets on satisfactory terms, if at all. If we cannot make scheduled payments on our debt, we will be in default under the terms of the agreements governing our debt and, as a result:

- our debt holders could declare all outstanding principal and interest to be due and payable, which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements and the holders of EGC s 11.0% Notes due March 15, 2020 could foreclose against the assets securing their notes;
- the lenders under our revolving credit facility could terminate their commitments to lend us money and foreclose against the assets securing their borrowings; and
- we could be forced into bankruptcy or liquidation.

Our significant level of indebtedness may limit our ability to borrow additional funds or capitalize on acquisition or other business opportunities. In addition, the covenants in the indentures governing our senior notes and our revolving credit facility impose restrictions that may limit our ability to take certain actions. Our failure to comply with these covenants could result in the acceleration of our outstanding indebtedness.

As of June 30, 2015, we had total indebtedness of $1,018 million. Our leverage and the current and future restrictions contained in the agreements governing our indebtedness may reduce our ability to incur additional indebtedness, engage in certain transactions or capitalize on acquisition or other business opportunities. Our indebtedness and other financial obligations and restrictions could have financial consequences. For example, they could:

- impair our ability to obtain additional financing in the future for capital expenditures, potential acquisitions, general business activities or other purposes;
- increase our vulnerability to general adverse economic and industry conditions;
- result in higher interest expense in the event of increases in interest rates since some of our debt is at variable rates of interest;
- require us to dedicate a substantial portion of future cash flow to payments of our indebtedness and other financial obligations, thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general corporate requirements;
- limit our flexibility in planning for, or reacting to, changes in our business and industry; and
- place us at a competitive disadvantage to those who have proportionately less debt.

In addition, our revolving credit facility contains and our indentures governing our unsecured notes contain covenants that restrict our ability to take various actions, such as:

engaging in businesses other than the oil and gas business;

incurring or guaranteeing additional indebtedness or issuing disqualified capital stock;

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Our significant level of indebtedness may limit our ability to borrow additional funds or capitalize on acquisition or ot

- making investments;
- paying dividends, redeeming certain indebtedness or making other restricted payments;
- entering into transactions with affiliates;
- creating or incurring liens;
- transferring or selling assets;
- incurring dividend or other payment restrictions affecting certain subsidiaries;
- consummating a merger, consolidation or sale of all or substantially all our assets; and
- entering into sale/leaseback transactions.

In addition, under our revolving credit facility, there is a restriction on changes in our management. If John D. Schiller, Jr. ceases to be the chief executive officer of our parent company Energy XXI Ltd (except as a result of his death or disability) and a reasonably acceptable successor is not appointed within 180 days, the lenders of our revolving credit facility could declare amounts outstanding thereunder immediately due and payable. In the event that Mr. Schiller ceases to be our parent s chief executive officer, amounts outstanding under our revolving credit facility would not automatically be reclassified as current debt as it is probable that we could identify a successor within the 180 day period. Our revolving credit facility requires, and any future credit facilities may require, us to comply with specified financial ratios, including regarding interest coverage and total leverage coverage.

Our ability to comply with these covenants will likely be affected by events beyond our control and we cannot assure you that we will satisfy those requirements. A prolonged period of oil and gas prices at current levels or a further decline could further increase the risk of our inability to comply with covenants to maintain specified financial ratios. A breach of any of these provisions could result in a default under our debt instruments, which could allow all amounts outstanding thereunder to be declared immediately due and payable, which would in turn trigger cross-acceleration and cross-default rights under our other debt. In addition, our lenders could compel us to apply all of our available cash to repay our borrowings or they could prevent us from making payments on the notes in the event of acceleration of our outstanding indebtedness. In the event of such acceleration, we cannot assure that we would be able to repay our debt or obtain new financing to refinance our debt. Even if new financing was made available to us, it may not be on terms acceptable to us. We may also be prevented from taking advantage of business opportunities that arise if we fail to meet certain ratios or because of the limitations imposed on us by the restrictive covenants under these instruments.

We may be able to incur additional debt in the future. This could exacerbate the risks associated with our indebtedness.

Despite our current level of indebtedness, we may incur more debt in the future, which could further exacerbate the risks described above. The terms of the indentures governing our senior notes and our revolving credit facility do not fully prohibit us or our subsidiaries from incurring more indebtedness, which could intensify the related risks that we now face.

Continued low commodity prices may impact our ability to comply with debt covenants

Based on projected market conditions and commodity prices, we currently expect that we will be in compliance with covenants under our credit agreement for the near term; however, a protracted period of low commodity prices could cause us to not be in compliance with certain financial covenants under our credit agreements in future periods, including prior to June 30, 2016. A breach of the covenants under the Revolving Credit Facility would cause a default under such facility, potentially resulting in acceleration of all amounts outstanding under the Revolving Credit Facility. If the lenders under our credit facility were to accelerate the indebtedness under our revolving credit facility as a result of such defaults, such acceleration of outstanding indebtedness under our Revolving Credit Facility could cause a cross-default or cross-acceleration of all of our other outstanding indebtedness, as well as all of EGC s and our parent s other outstanding indebtedness. As of June 30, 2015, EGC and our parent had outstanding indebtedness of $3,916 million, excluding all of our indebtedness. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding, we may not have sufficient liquidity to repay all of our outstanding indebtedness.

We expect to have substantial capital requirements, and we may be unable to obtain needed financing on satisfactory terms.

We expect to make substantial capital expenditures related to our oil and gas properties. Our capital requirements depend on numerous factors making it difficult to predict the timing and amount of our capital expenditures. We intend to primarily finance our capital expenditures with advances from EGC which intends to primarily finance near term capital expenditures with cash on hand. However, if our capital requirements vary materially from those provided for in EGC s current projections, we or EGC may require additional financing. A decrease in expected revenues or an adverse change in market conditions could make obtaining this financing economically unattractive or impossible.

The cost of raising money in the debt and equity capital markets may increase substantially while the availability of funds from those markets may diminish significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets may increase as lenders and institutional investors could increase interest rates, impose tighter lending standards, refuse to refinance existing debt at maturity at all or on terms similar to our current debt and, in some cases, cease to provide funding to borrowers.

An increase in our indebtedness, as well as the credit market and debt and equity capital market conditions discussed above could further negatively impact our ability to remain in compliance with the financial covenants under our revolving credit facility which could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our growth as expected, we could be required to seek alternative financing, the terms of which may be less favorable to us, or not pursue growth opportunities.

Without additional capital resources, we may be forced to limit or defer our planned natural gas and oil exploration and development program and this will adversely affect the recoverability and ultimate value of our natural gas and oil properties, in turn negatively affecting our business, financial condition and results of operations. We may also be unable to obtain sufficient credit capacity with counterparties to finance the hedging of our future crude oil and natural gas production which may limit our ability to manage price risk. As a result, we may lack the capital necessary to obtain credit necessary to enter into derivative contracts to hedge our future crude oil and natural gas production or to capitalize on other business opportunities.

We have been asked by the BOEM to obtain bonds or other surety in order to maintain compliance with BOEM regulations, which may be costly and could potentially reduce borrowings available under our revolving credit facility.

To cover the various obligations of lessees on the OCS, such as the cost to plug and abandon wells and decommission and remove platforms and pipelines at the end of production, the BOEM generally requires that lessees post substantial bonds or other acceptable assurances that such obligations will be met unless the BOEM exempts the lessee from such financial assurance requirements. As a result of the bankruptcy of another Gulf of Mexico operator, the BOEM indicated that it may review the estimated cost of future plugging, abandonment, decommissioning and removal obligations of other OCS operators, may evaluate any waivers or exemptions for such financial assurance obligations, and may increase the amount of financial assurance required with respect to these obligations. In April 2015, we received letters from the BOEM stating that certain of our subsidiaries no longer qualify for waiver of certain supplemental bonding requirements for potential offshore decommissioning, plugging and abandonment liabilities. The letters notified us that certain of our subsidiaries must provide approximately $566.5 million in supplemental financial assurance and/or bonding for their offshore oil and gas leases, rights-of-way, and rights-of-use and easements. In June 2015, we reached agreements with the BOEM pursuant to which we provided $54.7 million of supplemental bonds issued to the BOEM, and the BOEM agreed to withdraw its orders with regard to supplemental bonding and postpone until November 15, 2015 the issuance of further requirements of us related to these supplemental bonding obligations. On June 30, 2015, we sold the East Bay field and the $566.5 million of requested supplemental bonding was reduced by approximately $178 million.

On September 22, 2015, the BOEM issued Draft Guidance relating to supplemental bonding procedures that will, among other things, eliminate the waiver exemption currently allowed by BOEM with respect to supplemental bonding and, instead, broaden the self-insurance approach that would allow more operators on the OCS to seek self-insurance for a portion of their supplemental bond obligations, but only for an amount that is no more than 10% of such operators tangible net worth. Further, the Draft Guidance would implement a phased-in period for establishing compliance with supplemental bonding obligations, whereby operators may seek payment of estimated costs of decommissioning obligations owed under a tailored plan that is approved by the BOEM and requires payment of the supplemental bonding amount in three equal installment of one-third each, by no later than 120, 240 and 360 calendar days, respectively, from the date of BOEM approval of the tailored plan.

We currently maintain approximately $58.3 million in lease and/or area bonds issued to the BOEM and approximately $122.5 million in bonds issued to predecessor third party assignors of certain wells and facilities on leases pursuant to a contractual commitment made by us to those third parties at the time of assignment with respect to the eventual decommissioning of those wells and facilities. Thus, our total supplemental bonding is approximately $180.8 million, with an annual premium expense of $2.7 million. In addition, since June 2015, we have received additional letters from the BOEM in which the BOEM requests additional supplemental bonding for certain other properties previously exempt from supplemental bonding, generally as a result of exempt co-owners either losing their exemptions or no longer owning an interest in the property. Furthermore, we anticipate our supplemental bonding requirements to increase as we further develop or acquire additional properties subject to the BOEM s financial assurance requirements.

Although we believe we are currently in compliance with the supplemental bonding requirements, the BOEM may in the future continue to review our plugging, abandonment, decommissioning and removal obligations; re-evaluate the adequacy of our financial assurances; and require us to provide additional supplemental bonding or other surety for most or all of our properties. Furthermore, in addition to the Draft Guidance describing revised supplemental bonding procedures that may be used by the BOEM, the BOEM is actively seeking to adjust its financial assurance requirements mandated by rule for all companies operating in federal waters. In August 2014, the BOEM issued an ANPR in which the agency indicated that it was considering bolstering the financial assurance requirements currently mandated by rule. The cost of compliance with our existing supplemental bonding requirements or any other changes to the BOEM s current bonding requirements or regulations applicable to us or our properties could be substantial and could materially and adversely affect our financial condition, cash flows, and results of operations. In addition, we may be required to provide letters of credit to support the issuance of these bonds or other surety. Such letters of credit would likely be issued under our credit facility and would reduce the amount of borrowings available under such facility in the amount of any such letter of credit obligations. We can provide no assurance that we can continue to obtain bonds or other surety in all cases, and if we are unable to obtain the additional required bonds or assurances as requested, the BOEM may require any of our operations on federal leases to be suspended or terminated, and such action could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Our estimates of future asset retirement obligations may vary significantly from period to period and are especially significant because our operations include the U.S. Gulf of Mexico.

We are required to record a liability for the discounted present value of our asset retirement obligations to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas production operations. These costs are typically considerably more expensive for offshore operations as compared to most land-based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths. Estimating future restoration and removal costs in the U.S. Gulf of Mexico is especially difficult because most of the removal obligations are many years in the future, regulatory requirements are subject to change or more restrictive interpretation, and asset removal technologies are constantly evolving, which may result in additional or increased costs. As a result, we may make significant increases or decreases

Our estimates of future asset retirement obligations may vary significantly from period to period and are especially s to our estimated asset retirement obligations in future periods. For example, because we operate in the U.S. Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes. The estimated cost to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Accordingly, our estimate of future asset retirement obligations could differ dramatically from what we may ultimately incur as a result of damage from a hurricane.

Moreover, the timing for pursuing restoration and removal activities has accelerated for operators in the U.S. Gulf of Mexico following the DOI s issuance of a NTL, effective October 2010, that established a more stringent regimen for the timely decommissioning of what is known as idle iron wells, platforms and pipelines that are no longer producing or serving exploration or support functions with respect to an operator s lease in the U.S. Gulf of Mexico. Historically, many oil and natural gas producers in the Gulf of Mexico have delayed the plugging, abandoning or removal of idle iron until they met the final decommissioning regulatory requirement, which has been established as being within one year after the lease expires or terminates, a time period that sometimes is years after use of the idle iron has been discontinued. The idle iron NTL establishes new triggers for commencing decommissioning activities any well that has not been used during the past five years for exploration or production on active leases and is no longer capable of producing in paying quantities must be permanently plugged or temporarily abandoned within three years time. Plugging or abandonment of wells may be delayed by two years if all of such wells hydrocarbon and sulfur zones are appropriately isolated. Similarly, platforms or other facilities no longer useful for operations must be removed within five years of the cessation of operations. The triggering of these plugging, abandonment and removal activities under what may be viewed as an accelerated schedule in comparison to historical decommissioning efforts may serve to increase, perhaps materially, our future plugging, abandonment and removal costs, which may translate into a need to increase our estimate of future asset retirement obligations required to meet such increased costs. Moreover, as a result of the implementation of this NTL, there is expected to be increased demand for salvage contractors and equipment operating in the U.S. Gulf of Mexico, resulting in increased estimates of plugging, abandonment and removal costs and associated increases in operators asset retirement obligations.

In addition to the Draft Guidance describing revised supplemental bonding procedures that may be used by the BOEM, in August 2014, the BOEM issued an ANPR in which the agency indicated that it was considering increasing the financial assurance requirements mandated by rule. The cost of compliance with our existing supplemental bonding requirements or any other changes to the BOEM s current bonding requirements or regulations applicable to us or our properties could be substantial and could materially and adversely affect our financial condition, cash flows, and results of operations. We can provide no assurance that we can continue to obtain bonds or other surety in all cases, and if we are unable to obtain the additional required bonds or assurances as requested, the BOEM may require any of our operations on federal leases to be suspended or terminated, and such action could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity. Please read Risk Factors *We have been asked by the BOEM to obtain bonds or other surety in order to maintain compliance with BOEM regulations, which may be costly and could potentially reduce borrowings available under our revolving credit facility*.

Lower oil and gas prices and other factors may result in ceiling test write-downs of our asset carrying values.

Under the full cost method of accounting, we are required to perform each quarter, a ceiling test that determines a limit on the book value of our oil and gas properties. If the net capitalized cost of proved oil and gas properties, net of related deferred income taxes, plus the cost of unevaluated oil and gas properties, exceeds the present value of estimated future net cash flows discounted at 10%, net of related tax effects, plus the cost of unevaluated oil and gas properties, the excess is charged to expense and reflected as additional accumulated depreciation, depletion and amortization. As of the reported balance sheet date, capitalized costs of an oil and gas producing company may not exceed the full cost limitation calculated under the above described rule based on the average prices for oil and natural gas. However, if prior to the balance sheet date, we enter into certain hedging arrangements for a portion of our future natural gas and oil production, thereby enabling us to receive future cash flows that are higher than the estimated future cash flows indicated, these higher hedged prices are used if they qualify as cash flow hedges.

The recent declines in oil prices have adversely affected our financial position and results of operations and the quantities of oil and natural gas reserves that we can economically produce. For the second, third and fourth quarters of fiscal year 2015, we recognized ceiling test write-downs of our oil and natural gas properties totaling $1,678.8 million.

Based on the average oil and natural gas price calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month for the 12 months ending September 30, 2015, we presently expect to incur an impairment of $300 million to $500 million in the first fiscal quarter of 2016. If the current low commodity price environment or downward trend in oil prices continues beyond first fiscal quarter of 2016, we could incur further impairment to our full cost pool in fiscal 2016 based on the average oil and natural gas price calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the previous 12-month period under the SEC pricing methodology.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves.

This Form 10-K contains estimates of our future net cash flows from our proved reserves. We base the estimated discounted future net cash flows from our proved reserves on average prices for the preceding twelve-month period and costs in effect at the time of the estimate. As a result of significant recent declines in commodity prices, such average sales prices are significantly in excess of more recent prices. Unless commodity prices or reserves increase, the estimated discounted future net cash flows from our proved reserves would generally be expected to decrease as additional months with lower commodity sales prices will be included in this calculation in the future. Actual future net cash flows from our natural gas and oil properties will be affected by factors such as:

- the volume, pricing and duration of our natural gas and oil hedging contracts;
- supply of and demand for natural gas and oil;
- actual prices we receive for natural gas and oil;
- our actual operating costs in producing natural gas and oil;
- the amount and timing of our capital expenditures and decommissioning costs;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our actual recovery of reserves may differ from our proved reserve estimates.

This Form 10-K contains estimates of our proved oil and gas reserves. Estimating crude oil and natural gas reserves is complex and inherently imprecise. It requires interpretation of the available technical data and making many assumptions about future conditions, including price and other economic conditions. In preparing such estimates, projection of production rates, timing of development expenditures and available geological, geophysical, production and engineering data are analyzed. The extent, quality and reliability of this data can vary. This process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. If our interpretations or assumptions used in arriving at our reserve estimates prove to be inaccurate, the amount of oil and gas that will ultimately be recovered may differ materially from the estimated quantities and net present value of reserves owned by us. Any inaccuracies in these interpretations or assumptions could also

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materially affect the estimated quantities of reserves shown in the reserve reports summarized in this Form 10-K. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses, decommissioning liabilities and quantities of recoverable oil and gas reserves most likely will vary from estimates. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

We may be limited in our ability to maintain or book additional proved undeveloped reserves under the SEC s rules.

We have included in this Form 10-K certain estimates of our proved reserves as of June 30, 2015 prepared in a manner consistent with our interpretation of the SEC rules relating to modernizing reserve estimation and disclosure requirements for oil and natural gas companies, as well as the interpretation of our independent petroleum consultant who prepares our reserve estimates. Included within these SEC reserve rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Further, if we postpone drilling of proved undeveloped reserves beyond this five-year development horizon, we may have to write off reserves previously recognized as proved undeveloped. We cannot assure you that our long-term plans will not change based on commodity prices, costs or our liquidity in a manner that would require us to reduce our proved reserve estimate in the future due to the five-year development rule or otherwise. During the year ended June 30, 2015, we were required to reduce proved reserve estimates by 2.8 Mmboe due to the five year development rule.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 24% of our proved reserves as of June 30, 2015 were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserves data included in the reserves engineer reports assumes that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. In addition, there are external factors such as such as changes in commodity prices, the availability of capital, the availability of drilling rigs (capable of drilling in the given area), that could result in certain development plans being delayed and/or accelerated relative to the current schedule.

Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the present value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. For example, our proved reserves of 57.2 Mmboe and $826 million of PV-10 as of June 30, 2015 were lower than our proved reserves of 89.5 Mboe and $2,482 million of PV-10 as of June 30, 2014 in part due to the rescheduling or write off of certain of our reserves as a result of lower oil and gas prices and reductions in our capital expenditure budget as compared to our June 30, 2014 reserve report. Delays in the development of these reserves could cause us to have to reclassify our proved reserves as unproved reserves. Please read Business Development of Proved Undeveloped Reserves.

As of June 30, 2015, approximately 24% of our total proved reserves were undeveloped and approximately 23% of our total proved reserves were developed non-producing. There can be no assurance that all of those

reserves will ultimately be developed or produced.

While we have plans or are in the process of developing plans for exploiting and producing a majority of our proved reserves, there can be no assurance that all of those reserves will ultimately be developed or produced. Furthermore, there can be no assurance that all of our undeveloped and developed non-producing reserves will ultimately be produced during the time periods we have planned, at the costs we have budgeted, or at all, which could result in the write-off of previously recognized reserves.

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As of June 30, 2015, approximately 24% of our total proved reserves wereundeveloped and approximately 23% of

Unless we replace crude oil and natural gas reserves, our future reserves and production will decline.

A large portion of our drilling activity is located in mature oil-producing areas of the GoM shelf. Accordingly, increases in our future crude oil and natural gas production depend on our success in finding or acquiring additional reserves that are economically recoverable. If we are unable to replace reserves through drilling or acquisitions on economic terms, our level of production and cash flows will be adversely affected. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of crude oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. We also may not be successful in obtaining funds to acquire additional reserves.

Production periods or reserve lives for Gulf of Mexico properties subject us to higher reserve replacement needs and may impair our ability to reduce production during periods of low oil and natural gas prices.

High production rates generally result in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial few years when compared to other regions in the U.S. Typically, 50% of the reserves of properties in the Gulf of Mexico are depleted within three to four years with natural gas wells having a higher rate of depletion than oil wells. Due to high initial production rates, production of reserves from reservoirs in the Gulf of Mexico generally decline more rapidly than from other producing reservoirs. The vast majority of our existing operations are in the Gulf of Mexico. As a result, our reserve replacement needs from new prospects may be greater than those of other oil and gas companies with longer-life reserves in other producing areas. Also, our expected revenues and return on capital will depend on prices prevailing during these relatively short production periods. Our need to generate revenues to fund ongoing capital commitments or repay debt may limit our ability to slow or shut in production from producing wells during periods of low prices for oil and natural gas.

The borrowing base under our revolving credit facility may be reduced in the future if commodity prices decline, which will limit our available funding for exploration and development. We may have difficulty obtaining additional credit, which could adversely affect our operations and financial position.

We and EGC depend on the revolving credit facility for a portion of its future capital needs. As of June 30, 2015, our borrowing base under our revolving credit sub-facility was $150 million of the total $500 million borrowing base of EGC s revolving credit facility. As of June 30, 2015, we had borrowed the full $150 million.

In the future, we and EGC may not be able to access adequate funding under the revolving credit facility as a result of (1) a decrease in the borrowing base due to the outcome of a subsequent borrowing base redetermination, or (2) an unwillingness or inability on the part of the lending counterparties to meet their funding obligations.

Our borrowing base will be redetermined semi-annually by our lenders in their sole discretion. We expect the next determination of the borrowing base under the revolving credit facility will occur in the fall of 2015, although an early redetermination is possible. In addition, the lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our revolving credit facility. The lenders will redetermine the borrowing base based on an engineering report with respect to our natural gas and oil reserves, which will take into account the prevailing natural gas and oil prices at such time. If oil and natural gas commodity prices continue to deteriorate, the revised borrowing base under our revolving credit facility may be reduced. If the borrowing base is reduced or maintained, the new borrowing base is subject to approval by banks holding not less than 67% of the lending commitments under our revolving credit facility, and the final borrowing base may be lower than the level recommended by the agent for the bank group. As we have borrowed all available capacity under our current borrowing base, if our borrowing base were adjusted downward, we would be required to pay down amounts outstanding under our revolving credit sub-facility to reduce our level of borrowing, or we must pledge other natural gas and oil properties as

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collateral. We do not currently have any substantial properties which could serve as additional collateral, and we may not have the financial resources in the future to make any mandatory principal prepayments required under our revolving credit facility. If funding is not available from internally generated cash flow, additional borrowings from or investments by EGC in the Company when needed, or is available only on unfavorable terms, it could adversely affect our development plans as currently anticipated, which could have a material adverse effect on our production, revenues and results of operations.

Our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, making us vulnerable to risks associated with operating in one geographic area.

Unlike other entities that are geographically diversified, we do not have the resources to effectively diversify our operations or benefit from the possible spreading of risks or offsetting of losses. By consummating acquisitions only in the Gulf of Mexico and the U.S. Gulf Coast, our lack of diversification may:

- subject us to numerous economic, competitive and regulatory developments, any or all of which may have an adverse impact upon the particular industry in which we operate; and
- result in our dependency upon a single or limited number of hydrocarbon basins.

In addition, the geographic concentration of our properties in the Gulf of Mexico and the U.S. Gulf Coast means that some or all of the properties could be affected should the region experience:

- severe weather, such as hurricanes and other adverse weather conditions;
- delays or decreases in production, the availability of equipment, facilities or services;
- delays or decreases in the availability of capacity to transport, gather or process production; and/or
- changes in the regulatory environment.

During the 2008 hurricane season, production from certain of our properties was reduced as a result of damage to third party pipelines caused by two hurricanes. The hurricane damage limited our ability to sell our production from certain properties for extended periods of time during the third and fourth quarters of 2008. If mechanical problems, storms or other events were to curtail a substantial portion of the production, such a curtailment could have a material adverse effect on our business, financial condition, results of operations and cash flows. In accordance with industry practice, we maintain insurance against some, but not all, of these risks and losses. For additional information, please read Our insurance may not protect us against all of the operating risks to which our business is exposed.

Because all or a number of the properties could experience many of the same conditions at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other producers who have properties over a wider geographic area.

The nature of our business involves numerous uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

We engage in exploration and development drilling activities, which are inherently risky. These activities may be unsuccessful for many reasons. In addition to a failure to find oil or natural gas, drilling efforts can be affected by adverse weather conditions such as hurricanes and tropical storms in the Gulf of Mexico, cost overruns, equipment shortages and mechanical difficulties. Therefore, the successful drilling of an oil or gas well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, could cause a well to become uneconomic or only marginally economic. In addition to their costs, unsuccessful wells could impede our efforts to replace reserves.

Our business involves a variety of operating risks, which include, but are not limited to:

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of gas, oil and formation water;
- natural disasters, such as hurricanes and other adverse weather conditions;
- pipe, cement, subsea well or pipeline failures;
- casing collapses;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations; and
- environmental hazards, such as gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. We could also incur substantial losses due to costs and/or liability incurred as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

Our offshore operations involve special risks that could affect our operations adversely.

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties. In particular, we are not intending to put in place business interruption insurance due to its high cost. We therefore may not be able to rely on insurance coverage in the event of such natural phenomena.

Unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.

We may become responsible for unanticipated costs associated with abandoning and reclaiming wells, facilities and pipelines. Abandonment and reclamation of facilities and the costs associated therewith is often referred to as decommissioning. Should decommissioning be required that is not presently anticipated or the decommissioning be accelerated, such as can happen after a hurricane, such costs may exceed the value of reserves remaining at any particular time. We may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could have a material adverse effect on our financial position and results of operations.

Our insurance may not protect us against all of the operating risks to which our business is exposed.

We maintain insurance for some, but not all, of the potential risks and liabilities associated with our business. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Due to market conditions, including with respect to commodity prices

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such as for oil and natural gas, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance policies are economically unavailable or available only for reduced amounts of coverage. Consistent with industry practice, we are not fully insured against all risks, including high-cost business interruption insurance and drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our financial condition and results of operations. Due to a number of catastrophic events like the terrorist attacks on September 11, 2001, Hurricanes Ivan, Katrina, Rita, Gustav and Ike, and the April 20, 2010 Deepwater Horizon incident, insurance underwriters increased insurance premiums for many of the coverages historically maintained and issued general notices of cancellation and significant changes for a wide variety of insurance coverages. The oil and natural gas industry suffered damage from Hurricanes Ivan, Katrina, Rita, Gustav and Ike. As a result, insurance costs have increased significantly from the costs that similarly situated participants in this industry have historically incurred. Insurers are requiring higher retention levels and limit the amount of insurance proceeds that are available after a major wind storm in the event that damages are incurred. If storm activity in the future is severe, insurance underwriters may no longer insure Gulf of Mexico assets against weather-related damage. In addition, we do not intend to put in place business interruption insurance due to its high cost. If an accident or other event resulting in damage to our operations, including severe weather, terrorist acts, war, civil disturbances, pollution or environmental damage, occurs and is not fully covered by insurance or a recoverable indemnity from a vendor, it could adversely affect our financial condition and results of operations. Moreover, we may not be able to maintain adequate insurance in the future at rates we consider reasonable or be able to obtain insurance against certain risks.

Weather Based Insurance Linked Securities may not payout in case of a hurricane or may not fully cover damage.

We utilize Weather Based Insurance Linked Securities (Securities) to supplement our windstorm insurance coverage to mitigate potential loss to our most valuable oil and gas properties from hurricanes in the Gulf of Mexico. These Securities are generally structured to provide for payments of negotiated amounts should a hurricane having a pre-established category pass within specific pre-defined areas encompassing our oil and gas producing fields. While these Securities are meant to provide some excess windstorm coverage, there can be no certainty that these Securities will meet the payout criteria even if there is substantial damage by a hurricane of a lower category than that specified in the Securities. In addition, the payment made may not be sufficient to cover any actual damage incurred from a storm.

Competition for oil and gas properties and prospects is intense and some of our competitors have larger financial, technical and personnel resources that could give them an advantage in evaluating and obtaining properties and prospects.

We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil and gas and securing trained personnel. Many of our competitors are major or independent oil and gas companies that possess and employ financial resources that allow them to obtain substantially greater technical and personnel resources than ours. We actively compete with other companies when acquiring new leases or oil and gas properties. For example, new leases acquired from the BOEM are acquired through a sealed bid process and are generally awarded to the highest bidder. These additional resources can be particularly important in reviewing prospects and purchasing properties. The competitors may also have a greater ability to continue drilling activities during periods of low oil and gas prices, such as the current decline in oil prices, and to absorb the burden of current and future governmental regulations and taxation. Competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Competitors may also be able to pay more for productive oil and gas properties and exploratory prospects than we are able or willing to pay. Further, our competitors may be able to expend greater resources on the existing and changing technologies that we believe will impact attaining success in the industry. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted.

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Market conditions or transportation impediments may hinder access to oil and gas markets, delay production or increase our costs.

Market conditions (including with respect to commodity prices such as for oil and natural gas), the unavailability of satisfactory oil and natural gas transportation or the remote location of our drilling operations may hinder our access to oil and natural gas markets or delay production. The availability of a ready market for oil and gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines or trucking and terminal facilities. In deepwater operations, market access depends on the proximity of and our ability to tie into existing production platforms owned or operated by others and the ability to negotiate commercially satisfactory arrangements with the owners or operators. We may be required to shut in wells or delay initial production for lack of a market or because of inadequacy or unavailability of pipeline or gathering system capacity. Restrictions on our ability to sell our oil and natural gas may have several other adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possible loss of a lease due to lack of production. In the event that we encounter restrictions in our ability to tie our production to a gathering system, we may face considerable delays from the initial discovery of a reservoir to the actual production of the oil and gas and realization of revenues. In some cases, our wells may be tied back to platforms owned by parties with no economic interests in these wells. There can be no assurance that owners of such platforms will continue to operate the platforms. If the owners cease to operate the platforms or their processing equipment, we may be required to shut in the associated wells, which could adversely affect our results of operations.

Most of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

We own leasehold interests in areas not currently held by production. Unless production in paying quantities is established on units containing certain of these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. We currently do not have leases expiring in fiscal years 2016 or 2017, but leases covering approximately 21% of our net acreage could potentially expire in fiscal year 2018.

Our drilling plans for areas not currently held by production are subject to change based upon various factors, including factors that are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. On our acreage that we do not operate, we have less control over the timing of drilling, therefore there is additional risk of expirations occurring in those sections.

We are not the operator on all of our properties and therefore are not in a position to control the timing of development efforts, the associated costs, or the rate of production of the reserves on such properties.

As we carry out our planned drilling program, we will not serve as operator of all planned wells. We operated approximately 88% of our proved reserves (including approximately 24% attributable to the South Pass 49 field operated by Energy XXI) at June 30, 2015. As a result, we may have limited ability to exercise influence over the operations of some non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator s expertise and financial resources;
- approval of other participants in drilling wells;

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selection of technology; and

the rate of production of the reserves.

Each of these factors, including others, could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our vendors, customers and by counterparties to our price risk management arrangements. Some of our vendors, customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Many of our vendors, customers and counterparties finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. From time to time, the availability of credit is more restrictive. Additionally, many of our vendors , customers and counterparties equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices and the lack of availability of debt or equity financing may result in a significant reduction in our vendors, customers and counterparties liquidity and ability to make payments or perform on their obligations to us. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our vendors, customers and/or counterparties could reduce our cash flows.

We sell the majority of our production to three customers.

Chevron, ConocoPhillips and Shell each accounted for approximately 58%, 20%, and 20% respectively, of our total oil and natural gas revenues during the year ended June 30, 2015. Our inability to continue to sell our production to Chevron, ConocoPhillips or Shell, if not offset by sales with new or other existing customers, could have a material adverse effect on our business and operations.

Our success depends on dedicated and skillful management and staff, whose departure could disrupt our business operations.

Our success depends on our ability to retain and attract experienced engineers, geoscientists and other professional staff. We depend to a large extent on the efforts, technical expertise and continued employment of these personnel and members of our management team. If a significant number of them resign or become unable to continue in their present role and if they are not adequately replaced, our business operations could be adversely affected.

Additionally, if John D. Schiller, Jr. ceases to be the chief executive officer of Energy XXI (except as a result of his death or disability) and a reasonably acceptable successor is not appointed within 180 days, the lenders of our revolving credit facility could declare amounts outstanding thereunder immediately due and payable. Such an event could have a material adverse effect on our business and operations.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute exploration and exploitation plans on a timely basis and within budget, and consequently could adversely affect our anticipated cash flow.

We utilize third-party services to maximize the efficiency of our organization. The cost of oil field services may increase or decrease depending on the demand for services by other oil and gas companies. There is no assurance that we will be able to contract for such services on a timely basis or that the cost of such services will remain at a satisfactory or affordable level. Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploitation and exploration operations, which could have a material adverse effect on our business, financial condition or results of operations.

If we place hedges on future production and encounter difficulties meeting that production, we may not realize the originally anticipated cash flows.

Our assets consist of a mix of reserves, with some being developed while others are undeveloped. To the extent that we sell the production of these reserves on a forward-looking basis but do not realize that anticipated level of production, our cash flow may be adversely affected if energy prices rise above the prices for the forward-looking sales. In this case, we would be required to make payments to the purchaser of the forward-looking sale equal to the difference between the current commodity price and that in the sales contract multiplied by the physical volume of the shortfall. There is the risk that production estimates could be inaccurate or that storms or other unanticipated problems could cause the production to be less than the amount anticipated, causing us to make payments to the purchasers pursuant to the terms of the hedging contracts.

Our price risk management activities could result in financial losses or could reduce our income, which may adversely affect our cash flows.

We enter into derivative contracts to reduce the impact of oil and natural gas price volatility on our cash flow from operations. Currently, we use a combination of crude oil and natural gas put, swap and collar arrangements to mitigate the volatility of future oil and natural gas prices received on our production.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial decrease in our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our price risk management activities are subject to the following risks:

- a counterparty may not perform its obligation under the applicable derivative instrument;
- production is less than expected;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures.

During periods of declining commodity prices, our commodity price derivative positions increase, which increases our counterparty exposure.

Deepwater operations present special risks that may adversely affect the cost and timing of reserve development.

Currently, we own interests in one undeveloped lease in the deepwater Gulf of Mexico and we have a non-operated interest in one developed lease. We may evaluate additional activity in the deepwater Gulf of Mexico in the future. Exploration for oil or natural gas in the deepwater of the Gulf of Mexico generally involves greater operational and financial risks than exploration on the shelf. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. Deepwater wells often use subsea completion techniques with subsea trees tied back to host production facilities with flow lines. The installation of these subsea trees and flow lines requires substantial time and the use of advanced remote installation mechanics. These operations may encounter mechanical difficulties and equipment failures that could result in cost overruns. Furthermore, the deepwater operations generally lack the physical and oilfield service infrastructure present on the shelf. As a result, a considerable amount of time may elapse between a deepwater discovery and the marketing of the associated oil or natural gas, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of infrastructure, some reserve discoveries in the deepwater may never be produced economically.

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Additional deepwater drilling laws and regulations, delays in the processing and approval of drilling permits and exploration and oil spill response plans, and other related restrictions arising after the Deepwater Horizon incident in the Gulf of Mexico may have a material adverse effect on our business, financial condition, or results of operations.

In response to the Deepwater Horizon incident in the Gulf of Mexico in April 2010, BSEE and BOEM, each agencies of the U.S. Department of the Interior, have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. These governmental agencies have also implemented and enforced new rules, Notices to Lessees and Operators and temporary drilling moratoria that imposed safety and operational performance measures on exploration, development and production operators in the Gulf of Mexico or otherwise resulted in a temporary cessation of drilling activities. Compliance with these added and more stringent regulatory restrictions in addition to any uncertainties or inconsistencies in current decisions and rulings by governmental agencies and delays in the processing and approval of drilling permits and exploration, development and oil spill response plans could adversely affect or delay new drilling and ongoing development efforts. Moreover, these governmental agencies are continuing to evaluate aspects of safety and operational performance in the Gulf of Mexico and, as a result, are developing and implementing new, more restrictive requirements such as, for example, the 2013 amendments to the federal Workplace Safety Rule regarding the utilization of a more comprehensive safety and environmental management system, (SEMS), which amended rule is sometimes referred to as SEMS II, and, more recently, the April 17, 2015 proposed rulemaking by the BSEE that would impose more stringent requirements with respect to use of blow out preventers and related well control equipment.

Among other adverse impacts, these additional measures could delay or disrupt our operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding requirements and incurrence of associated added costs, limit operational activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities. If similar material spill incidents were to occur in the future, the United States or other countries could elect again to issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development. We cannot predict the full impact of any new laws or regulations on our drilling operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations.

Further, the deepwater areas of the Gulf of Mexico (as well as international deepwater locations) lack the degree of physical and oilfield service infrastructure present in shallower waters. Therefore, despite our oil spill response capabilities, it may be difficult for us to quickly or effectively execute any contingency plans related to future events similar to the Deepwater Horizon incident. The matters described above, individually or in the aggregate, could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

If we are unable to acquire or renew permits and approvals required for operations, we may be forced to suspend or cease operations altogether.

The construction and operation of energy projects require numerous permits and approvals from governmental agencies. In addition, many governmental agencies have increased regulatory oversight and permitting requirements in recent years. We may not be able to obtain all necessary permits and approvals or obtain them in a timely manner, and as a result our operations may be adversely affected. In addition, obtaining all necessary permits and approvals may necessitate substantial expenditures to comply with the requirements of these permits and approvals, future changes to these permits or approvals, or any adverse changes in the interpretation of existing permits and approvals, and these may create a risk of expensive delays or loss of value if a project is unable to proceed as planned due to changing requirements or local opposition.

Our operations are subject to environmental and other government laws and regulations that are costly and could potentially subject us to substantial liabilities.

As described in more detail below, our business activities are subject to regulation by multiple federal, state and local governmental agencies. Our historical and projected operating costs reflect the recurring costs resulting from compliance with these regulations, and we do not anticipate material expenditures in excess of these amounts in the absence of future acquisitions or changes in regulation, or discovery of existing but unknown compliance issues. Additional proposals and proceedings that affect the oil and gas industries are regularly considered by Congress, the states, regulatory commissions and agencies, and the courts. We cannot predict when or whether any such proposals may become effective or the magnitude of the impact changes in laws and regulations may have on our business; however, additions or enhancements to the regulatory burden on our industry generally increase the cost of doing business and affect our profitability.

Our oil and gas exploration, production, and related operations are subject to extensive rules and regulations promulgated by federal, state, and local agencies. Failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil and gas industry increases our cost of doing business and affects our profitability. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws.

All of the jurisdictions in which we operate generally require permits for drilling operations, drilling bonds, and reports concerning operations and impose other requirements relating to the exploration and production of oil and gas. Such jurisdictions also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells and the spacing, plugging and abandonment of such wells. The statutes and regulations of certain jurisdictions also limit the rate at which oil and gas can be produced from our properties.

FERC regulates interstate natural gas transportation rates and terms of service, which affect the marketing of gas we produce, as well as the revenues we receive for sales of such production. Since the mid-1980s, FERC has issued various orders that have significantly altered the marketing and transportation of gas. These orders resulted in a fundamental restructuring of interstate pipeline sales and transportation services, including the unbundling by interstate pipelines of the sales, transportation, storage and other components of the city-gate sales services such pipelines previously performed. These FERC actions were designed to increase competition within all phases of the gas industry. The interstate regulatory framework may enhance our ability to market and transport our gas, although it may also subject us to greater competition and to the more restrictive pipeline imbalance tolerances and greater associated penalties for violation of such tolerances.

Our sales of oil and natural gas liquids are not presently regulated and are made at market prices. The price we receive from the sale of those products is affected by the cost of transporting the products to market. FERC has implemented regulations establishing an indexing methodology for interstate transportation rates for oil pipelines, which, generally, would index such rate to inflation, subject to certain conditions and limitations. We are not able to predict with any certainty what effect, if any, these regulations will have on us, but, other factors being equal, the regulations may, over time, tend to increase transportation costs which may have the effect of reducing wellhead prices for oil and natural gas liquids.

Under the EPAct 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional entities to FERC annual reporting and daily scheduled flow and capacity posting requirements, as described more fully in Item 1 above. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

Although FERC has not made any formal determinations with respect to any of our facilities, we believe that our natural gas gathering pipelines meet the traditional tests that FERC has used to determine if a pipeline is a gathering pipeline and are therefore not subject to FERC s jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation, however, and, over time, FERC s policy for determining which facilities it regulates has changed. In addition, the distinction between FERC-regulated transmission facilities, on the one hand, and gathering facilities, on the other, is a fact-based determination made by FERC on a case-by-case basis. If FERC were to consider the status of an individual facility and determine that the facility and/or services

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provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGA or the Natural Gas Policy Act of 1978 (NGPA). Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the rate established by FERC.

State regulation of gathering facilities includes safety, environmental and, in some circumstances, nondiscriminatory take requirements and in some instances complaint-based rate regulation. Our gathering operations may also be subject to state ratable take and common purchaser statutes, designed to prohibit discrimination in favor of one producer over another or one source of supply over another. State and local regulation may cause us to incur additional costs or limit our operations and can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies.

Our oil and gas operations are subject to stringent laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from operations.

Failure to comply with these laws and regulations may result in:

- the imposition of administrative, civil and/or criminal penalties;
- incurring investigatory or remedial obligations; and
- the imposition of injunctive relief, which could limit or restrict our operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Although we intend to be in compliance in all material respects with all applicable environmental laws and regulations, we cannot assure shareholders that we will be able to comply with existing or new regulations. In addition, the risk of accidental spills, leakages or other circumstances could expose us to extensive liability.

Under certain environmental laws that impose strict, joint and several liability, we could be held liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination, and regardless of whether current or prior operations were conducted in compliance with all applicable laws and consistent with accepted standards of practice at the time those actions were taken. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations. Such liabilities can be significant, and if imposed could have a material adverse effect on our financial condition or results of operations.

We are unable to predict the effect of additional environmental laws and regulations that may be adopted in the future, including whether any such laws or regulations would materially adversely increase our cost of doing business or affect operations in any area.

Our operations are subject to environmental and other government laws andregulations that are costly and could po

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Rate regulation may not allow us to recover the full amount of increases in our costs.

We have ownership interests in oil pipelines that are subject to regulation by FERC. Rates for service on our system are set using FERC s price indexing methodology. The indexing method currently allows a pipeline to increase its rates by a percentage factor equal to the change in the producer price index for finished goods plus 2.65 percent. When the index falls, we are required to reduce rates if they exceed the new maximum allowable rate. In addition, changes in the index might not be large enough to fully reflect actual increases in our costs.

FERC s indexing methodology is subject to review every five years. The current or any revised indexing formula could hamper our ability to recover our costs because: (1) the indexing methodology is tied to an inflation index; (2) it is not based on pipeline-specific costs; and (3) it could be reduced in comparison to the current formula. Any of the foregoing would adversely affect our revenues and cash flow. FERC could limit our pipeline s ability to set rates based on its costs, order our pipelines to reduce rates, require the payment of refunds or reparations to shippers, or any or all of these actions, which could adversely affect our financial position, cash flows, and results of operations. If FERC s ratemaking methodology changes, the new methodology could also result in tariffs that generate lower revenues and cash flow.

Based on the way our oil pipelines are operated, we believe that the only transportation on our pipelines that is subject to the jurisdiction of FERC is the transportation specified in the tariff we have on file with FERC. We cannot guarantee that the jurisdictional status of transportation on our pipelines and related facilities will remain unchanged, however. Should circumstances change, then currently non-jurisdictional transportation could be found to be FERC-jurisdictional. In that case, FERC s ratemaking methodologies may limit our ability to set rates based on our actual costs, may delay the use of rates that reflect increased costs, and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, results of operations and financial condition.

If our tariff rates are successfully challenged, we could be required to reduce our tariff rates, which would reduce our revenues.

Shippers on our pipelines are free to challenge, or to cause other parties to challenge or assist others in challenging, our existing or proposed tariff rates. If any party successfully challenges our tariff rates, the effect would be to reduce revenues.

Our sales of oil and natural gas, and any hedging activities related to such energy commodities, expose us to potential regulatory risks.

FERC, the FTC and the CFTC hold statutory authority to regulate certain segments of the physical and futures energy commodities markets relevant to our business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil and natural gas, and any hedging activities related to these commodities, we are required to observe and comply with these anti-fraud and anti-manipulation regulations. Failure to comply with such regulations, as interpreted and enforced, could materially and adversely affect our financial condition or results of operations.

We have identified material weaknesses in our internal controls that, if not properly corrected, could result in material misstatements in our financial statements.

Our management has identified material weaknesses in our internal control over financial reporting as of June 30, 2015. Further, we have determined that control deficiencies existed with respect to certain aspects of our historical financial reporting subsequent to the Merger, and accordingly, we have concluded that our reports subsequent to the Merger on disclosure controls and procedures may not have been correct and reports subsequent to the Merger on internal control over financial reporting and changes in internal control over financial reporting may have been incorrect. A material weakness is a deficiency, or combination of deficiencies in internal controls over financial reporting that results in a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

We did not maintain properly designed controls over the contemporaneous formal documentation that we had prepared subsequent to the Merger to support our initial designations of derivative financial instruments as cash flow hedges in connection with our crude oil and natural gas hedging program. Specifically, the controls in place subsequent to the Merger relating to the documentation of hedge designations were not properly designed to provide reasonable assurance that these derivative contracts would be properly recorded and disclosed in the financial statements in accordance with U.S. GAAP. As a result subsequent to the Merger, our controls failed to detect that our formal hedge documentation did not meet the technical requirements to qualify for cash flow hedge accounting treatment in accordance with ASC Topic 815, *Derivatives and Hedging*. The primary reason for this determination was that the formal hedge documentation lacked specificity of the hedged items and, therefore, the designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment. Effective June 30, 2015, management discontinued the use of hedge accounting on all derivative contracts and does not expect the material weakness associated with hedge accounting to recur. If, in the future, we were to begin to designate our derivatives as hedges we would need to enhance our controls regarding consideration of all sources of ineffectiveness.

In addition, we recently learned that, in 2007, 2009 and 2014, the Chief Executive Officer of our parent company Energy XXI Ltd borrowed funds from personal acquaintances or their affiliates, certain of whom provided the Company with services. We also learned that Norman Louie, one of the directors of our parent company, made a personal loan to Mr. Schiller in 2014 before Mr. Louie became a director of our parent. At the time the loan was made, Mr. Louie was a managing director at Mount Kellett Capital Management LP, which at the time, and as of June 30, 2015, owned a majority interest in Energy XXI M21K, in which our parent owned a 20% interest (and purchased the remaining 80% interest subsequent to June 30, 2015), and 6.3% of our parent s common stock. The loans made in 2014 are still outstanding. Since Mr. Schiller did not disclose the personal loans before they were made, our parent s board of directors has determined that he did not comply with the procedural requirements of the Company s Code of Business Conduct and Ethics. Upon learning of Mr. Schiller s personal loans from affiliates of service providers, our parent s board of directors engaged independent legal counsel to conduct an internal investigation, with the assistance of outside forensic accountants, to review these loans and vendor procurement processes across the organization, including EPL. Our parent s board of directors is still reviewing the results of the internal investigation. Although the internal investigation has not uncovered any illegal activity or any impact on parent or EPL s financial reporting or financial statements, we have concluded this non-compliance to be a material weakness in its control environment given the leadership position of this officer, the visibility and importance of his actions to the Company s overall system of controls and the significance with which the Company views this nondisclosure. As part of its review, our parent s board of directors has begun the process of designing and implementing additional controls and procedures, including, but not limited to, strengthening the vendor procurement procedures across the organization including EPL to address any potential conflicts of interest that could arise from Mr. Schiller s personal loans; revising our parent s Code of Business Conduct and Ethics to explicitly ban any such personal loans in the future; and implementing an enhanced comprehensive training program on our parent s Code of Business Conduct and Ethics.

If we are not able to remedy the control deficiencies in a timely manner, we may be unable to provide holders of our securities with the required financial information in a timely and reliable manner, either of which could subject us to litigation and regulatory enforcement actions.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the crude oil and natural gas that we produce.

The EPA has determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act (CAA). Among the EPA s rules regulating greenhouse gas emissions under the CAA, one requires a reduction in emissions of greenhouse gases from motor vehicles and requires preconstruction and operating permits for certain large stationary sources of such emissions. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified greenhouse gas emission sources in the United States, including petroleum refineries and certain onshore oil and natural gas production facilities. In addition, in January 2015, the Obama Administration announced its goal to reduce methane emissions from the oil and gas sector by 40% to 45% from 2012 emission levels by 2025. As part of this announcement, the EPA announced that it will issue a proposed rule in the summer of 2015 and a final rule in 2016 setting standards for methane and volatile organic compounds emissions from new and modified oil and gas production sources and natural gas processing and transmission sources.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances that correspond to their annual emissions of greenhouse gases. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal. As the number of emission allowances declines each year, the cost or value of such allowances is expected to escalate significantly.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. Our offshore operations are particularly at risk from severe climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

The adoption of financial reform legislation by Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us that participate in that market. This legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), was signed into law by President Obama on July 21, 2010 and requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require certain counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The final rules will be phased in over time according to a specified schedule which is dependent on the finalization of certain other rules to be promulgated jointly by the CFTC and the SEC. The Dodd-Frank Act and any new regulations could increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, natural gas liquids and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas liquids and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

Cyber incidents could result in information theft, data corruption, operational disruption, and/or financial loss.

The oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation, and for compliance reporting. The use of mobile communication devices has increased rapidly. Industrial control systems such as SCADA (supervisory control and data acquisition) now control large scale processes that can include multiple sites and long distances, such as power generation and transmission, communications and oil and gas pipelines.

We depend on digital technology, including information systems and related infrastructure, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimated quantities of oil and gas reserves and for many other activities related to our business. Our business partners, including vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology. The complexity of the technologies needed to extract oil and gas in increasingly difficult physical environments, such as ultra-deep trend, and global competition for oil and gas resources make certain information more attractive to thieves.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. Certain countries, including China, Russia and Iran, are believed to possess cyber warfare capabilities and are credited with attacks on American companies and government agencies. SCADA-based systems are potentially more vulnerable to cyber-attacks due to the increased number of connections with office networks and the internet.

Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations in the following ways, among others:

unauthorized access to seismic data, reserves information or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;
data corruption, communication interruption, or other operational disruption during drilling activities could result in a dry hole cost or even drilling incidents;
data corruption or operational disruption of production infrastructure could result in loss of production, or accidental discharge;
a cyber-attack on a vendor or service provider could result in supply chain disruptions which could delay or halt one of our major development projects, effectively delaying the start of cash flows from the project;

a cyber-attack on a third party gathering or pipeline service provider could prevent us from marketing our production, resulting in a loss of revenues;

a cyber-attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;

Cyber incidents could result in information theft, data corruption, operational disruption, and/or financial loss.

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a cyber-attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices, and reduced revenues;

a cyber-attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;

a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties; and

business interruptions could result in expensive remediation efforts, distraction of management, and damage to our reputation.

Although to date we have not experienced any losses relating to cyber-attacks, there can be no assurance that we will not suffer such losses in the future. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

The Budget for Fiscal Year 2016 sent to Congress by President Obama on February 2, 2015, among other proposed legislation, contains recommendations that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include (1) the repeal of the percentage depletion allowance for oil and natural gas properties, (2) the elimination of current deductions for intangible drilling and development costs, (3) the elimination of the deduction for certain domestic production activities, and (4) an extension of the amortization period for certain geological and geophysical expenditures. Several bills have been introduced in Congress that would implement these proposals. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

The information contained in Part I, Item 1, Business of this Form 10-K is incorporated herein by reference.

Item 3. *Legal Proceedings*

The information contained in Note 14, Commitments and Contingencies in the consolidated financial statements in Part II, Item 8 of this Form 10-K is incorporated herein by reference.

Item 4. *Mine Safety Disclosures*

Not applicable.

PART II

Item 5. ***Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Following the effective date of the Merger, we became an indirect, wholly owned subsidiary of Energy XXI and there is no longer a trading market for EPL common stock. As a result of the Merger, our common stock was suspended from trading on June 4, 2014 and removed from listing and registration on the New York Stock Exchange (the NYSE) on July 15, 2014.

Prior to the Merger, our common stock was listed on the NYSE under the symbol EPL. The following table sets forth, for the periods indicated, the range of the high and low sales prices of our common stock as reported by the NYSE.

	High ($)	Low ($)
2013		
First Quarter	29.18	22.53
Second Quarter	35.14	26.05
Third Quarter	38.32	28.75
Fourth Quarter	42.64	25.00
2014		
First Quarter	39.26	25.18
Second Quarter (through June 3, 2014)	39.31	36.85

On June 3, 2014, the last reported sales price of our common stock on the NYSE was $37.73 per share.

We have not paid cash dividends in the past on our common stock. The covenants in certain debt instruments to which we are a party, including the 8.25% senior notes due 2018 (the 8.25% Senior Notes) issued under an indenture dated February 14, 2011 (the 2011 Indenture), place certain restrictions and conditions on our ability to pay dividends. Any future cash dividends would depend on contractual limitations, future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

Item 6. ***Selected Financial Data***

Not applicable due to reduced disclosure format allowed for certain wholly-owned subsidiaries pursuant to General Instruction I(1)(a) and (b) of Form 10-K.

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion and analysis should be read in conjunction with Item 8, Financial Statements and Supplementary Data of this Form 10-K. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Known material factors that could cause or contribute to such differences include those discussed under Part I, Item 1A Risk Factors in this Form 10-K.

Restatement of Previously Issued Consolidated Financial Statements

Management s Discussion and Analysis of Financial Condition and Results of Operations have been updated to reflect the effects of the restatement described in Note 17 Restatement of Previously Issued Consolidated Financial Statements of Notes to Consolidated Financial Statements in this Form 10-K. We have also included our restated financial statements for the three unaudited quarters of fiscal 2015 following our fiscal year 2015 financial statements in Item 8, Financial Statements and Supplementary Data in this Form 10-K. In addition, we have included a discussion of restated revenues, related costs and income tax expense for the three unaudited quarters of 2015 following the discussion of our results of operations for our year ended June 30, 2015 compared to the year ended December 31, 2013.

In connection with preparing this Form 10-K, we determined that the contemporaneous formal documentation that we had prepared subsequent to the Merger to support our designations of derivative financial instruments as cash flow hedges in connection with our crude oil and natural gas hedging program did not meet the technical requirements to qualify for cash flow hedge accounting treatment in accordance with ASC Topic 815, *Derivatives and Hedging*. The primary reason for this determination was that the formal hedge documentation lacked specificity of the hedged items and, therefore, the designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment. Consequently, unrealized gains or losses resulting from those derivative financial instruments should have been recorded in our consolidated statements of operations as a component of earnings. Under the cash flow hedge accounting treatment applied subsequent to the Merger, we had recorded unrealized gains or losses resulting from changes in the fair value of our derivative financial instruments, net of the related tax impact, in accumulated other comprehensive income or loss until the production month when the associated hedge contracts were settled, at which time gains or losses associated with the settled contracts were reclassified to revenues.

This restatement, which impacts periods subsequent to the Merger, primarily reflects the recognition of gains and losses on derivative financial instruments previously included in accumulated other comprehensive income (loss) to gain (loss) on derivative financial instruments in earnings and the reclassification of amounts associated with settled contracts previously included in oil and gas sales revenues to gain (loss) on derivative financial instruments as a result of not qualifying for cash flow hedge accounting treatment as described above. For the quarters ending December 31, 2014 and March 31, 2015, the restatement also reflects resulting adjustments to net oil and natural gas properties, impairment of oil and natural gas properties and depreciation, depletion and amortization due to the previous inclusion of the value of the cash flow hedges in our full cost ceiling test, which is only permitted if the derivative instruments qualify for cash flow hedge accounting. Additionally, resulting adjustments to deferred income taxes and income tax expense (benefit) are also reflected in the restatement. While these non-cash adjustments impact revenues and net income (loss) for each period, as well as total stockholders equity, these adjustments do not impact the economics of the hedge transactions nor do they affect our liquidity.

Overview

We were incorporated as a Delaware corporation on January 29, 1998. We are an independent oil and natural gas exploration and production company. Our current operations are concentrated in the U.S. Gulf of Mexico shelf (the GoM shelf) focusing on state and federal waters offshore Louisiana, which we consider our core area. As of June 30, 2015, we had estimated proved reserves of 57.2 Mmboe, of which 67% were oil and 76% were proved developed. Of these proved developed reserves, 70% were oil reserves.

On June 3, 2014, Energy XXI, EGC, Merger Sub, and EPL, completed the transactions contemplated by the Merger Agreement, by and among Energy XXI, EGC, Merger Sub, and EPL, pursuant to which Merger Sub was merged with and into EPL with EPL continuing as the surviving corporation. Pursuant to the Merger Agreement, at the effective time of the Merger, the issued and outstanding shares of EPL common stock were converted, in the aggregate, into the Merger Consideration consisting of approximately 65% in cash and 35% in shares of Energy XXI Common Stock.

As a result of the Merger, the future strategy of the Company is determined by Energy XXI s Board of Directors. For the year ended June 30, 2015, our capital expenditures totaled approximately $271 million, of which approximately $186 million was spent on development of core properties and $27 million on exploration of core properties and $58 million on other assets. Our fiscal year 2016 capital budget is approximately $26 million, excluding potential capitalized general and administrative expenses. The budgeted capital is allocated to development activities, which are geared toward the improvement of existing production, the continued development of core fields, and the performance of necessary plugging, abandonment and other decommissioning activities.

Disposition

On June 30, 2015, we sold our interest in the East Bay field to Whitney Oil & Gas, LLC and Trimont Energy (NOW), LLC, for cash consideration of $21 million, plus the assumption of asset retirement obligations totaling approximately $55.1 million. The cash consideration is payable in two installments with $5 million received at closing and the remainder due on or before October 31, 2015. We retained a 5%

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overriding royalty interest (applicable only during calendar months if and when the WTI for such month averages over $65) on these assets for a period not to exceed 5 years from the closing date or $7 million whichever occurs first, and we also retained 50% of the deep rights associated with the East Bay field. Revenues and expenses related to the field were included in our results of operations through June 30, 2015. The proceeds were recorded as a reduction to our oil and natural gas properties with no gain or loss being recognized. The net reduction to the full cost pool related to this sale was $68.9 million.

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. Oil prices declined significantly during fiscal year 2015, and our ability to maintain current production levels could be impacted by continued downward pressure on oil prices. The posted price per barrel for West Texas intermediate light sweet crude oil, or WTI, for the period from July 1, 2014 to June 30, 2015 ranged from a high of $105.34 to a low of $43.46, a decrease of 58.7%, and the NYMEX natural gas price per MMBtu for the period July 1, 2014 to June 30, 2015 ranged from a high of $4.49 to a low of $2.49, a decrease of 44.5%. As of September 22, 2015, the spot market price for WTI was $45.83. The recent declines in oil prices have adversely affected our financial position and results of operations and the quantities of oil and natural gas reserves that we can economically produce. If we experience sustained periods of low prices for oil and natural gas, it will likely have a further material adverse effect on our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

Decreasing Service Costs. We have also seen a significant and continuing reduction in rig rates and drilling costs, which should allow us to spend less capital drilling our development wells than in prior periods. Jack-up rig rates, for example, have fallen by 35 50% in recent months and other service providers are similarly cutting their rates.

Ceiling Test Write-down. For the second, third and fourth quarters of our fiscal year ended June 30, 2015, we recognized ceiling test write-downs of our oil and natural gas properties of $690.3 million, $404.3 million and $584.2 million, respectively. The write-downs did not impact our cash flows from operating activities but did increase our net loss and reduce stockholders equity. Further ceiling test write-downs may be required if oil and natural gas prices remain low or decline further, unproved property values decrease, estimated proved reserve volumes are revised downward or the net capitalized cost of proved oil and gas properties otherwise exceeds the present value of estimated future net cash flows. Based on the average oil and natural gas price calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the previous 12 months ending September 30, 2015, we presently expect to incur further impairment of $300 million to $500 million in the first fiscal quarter of 2016. If the current low commodity price environment or downward trend in oil prices continues beyond first fiscal quarter of 2016, we could incur further impairment to our full cost pool in fiscal 2016 based on the average oil and natural gas price calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the previous 12-month period under the SEC pricing methodology.

BOEM Bonding Requirements. In April 2015, we received letters from the BOEM stating that certain of our subsidiaries no longer qualify for waiver of certain supplemental bonding requirements for potential offshore decommissioning, plugging and abandonment liabilities. The letters notified us that certain of our subsidiaries must provide approximately $566.5 million in supplemental financial assurance and/or bonding for their offshore oil and gas leases, rights-of-way, and rights-of-use and easements. In June 2015, we reached agreements with the BOEM pursuant to which we provided $54.7 million of supplemental bonds issued to the BOEM, and the BOEM agreed to withdraw its orders with regard to supplemental bonding and postpone until November 15, 2015 the issuance of further requirements of us related to these supplemental bonding obligations. On June 30, 2015, we sold the East Bay field and the $566.5 million of requested supplemental bonding was reduced by approximately $178 million. On September 22, 2015, the BOEM issued Draft Guidance relating to supplemental bonding procedures that will, among other things, eliminate the waiver exemption currently allowed by BOEM with respect to supplemental bonding and, instead, broaden the self-insurance approach that would allow more operators on the OCS to seek self-insurance for a portion of their supplemental bond obligations, but only for an amount that is no more than 10% of such operators tangible net worth. Further, the Draft Guidance would implement a phased-in period for establishing compliance with supplemental bonding obligations, whereby operators may seek payment of estimated costs of decommissioning obligations owed under a tailored plan that is approved by the BOEM and requires payment of the supplemental bonding amount in three equal installment of one-third each, by no later than 120, 240 and 360 calendar days, respectively, from the date of BOEM approval of the tailored plan. We currently maintain approximately $58.3 million in lease and/or area bonds issued to the BOEM and approximately $122.5 million in bonds issued to predecessor third party assignors including certain state regulatory bodies of certain wells and facilities on leases pursuant to a contractual commitment made by us to those third parties at the time of assignment with respect to the eventual decommissioning of those wells and facilities. Thus, our total supplemental bonding is approximately $180.8 million, with an annual premium expense of $2.7 million. We are undertaking a number of initiatives to mitigate our potential additional bonding requirements resulting from any waiver disqualifications and any forthcoming requirement from the BOEM and to limit the amount of additional required supplemental bonding by ensuring we have received credit for all of the plugging and abandonment work completed to date, by accounting for recent asset divestitures and consequential reduction in related bonding requirements such as the June 2015 sale of our interest in the East Bay field, and by counting our existing bonds and letters of credit with third parties against the BOEM s various bonding requests. However, with respect to our existing bonds and letters of credit with third parties, we can provide no assurance that the BOEM will consider them when determining the total value of additional financial assurances and/or bonding we must provide. In addition, since June 2015, we have received additional letters from the BOEM in which the BOEM requests additional supplemental bonding for other certain properties previously exempt from supplemental bonding, generally as a result of exempt co-owners either losing their exemptions or no longer owning an interest in the property. Furthermore, we anticipate our supplemental bonding requirements to increase as we further develop or acquire additional properties subject to the BOEM s financial assurance requirements.

Although we believe we are currently in compliance with the supplemental bonding requirements, the BOEM may in the future continue to review our plugging, abandonment, decommissioning and removal obligations; re-evaluate the adequacy of our financial assurances; and require us to provide additional supplemental bonding or other surety for most or all of our properties. Furthermore, in addition to the Draft Guidance describing revised supplemental bonding procedures that may be used by the BOEM, the BOEM is actively seeking to bolster its financial assurance requirements mandated by rule for all companies operating in federal waters. The cost of compliance with our existing supplemental bonding requirements or any other changes to the BOEM s current NTL supplemental bonding requirements or supplemental bonding regulations applicable to us or our properties could be substantial and could materially and adversely affect our financial condition, cash flows, and results of operations. We can provide no assurance that we can continue to obtain bonds or other surety in all cases, and if we are unable to obtain the additional required bonds or assurances as requested, the BOEM may require any of our operations on federal leases to be suspended or terminated, and such action could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity. Please read Risk Factors We and our subsidiaries have been asked by the BOEM to obtain bonds or other surety in order to maintain compliance with BOEM regulations, which may be costly and could potentially reduce borrowings available under our revolving credit facility.

Oil Spill Response Plan. We maintain a Regional Oil Spill Response Plan (the Plan) that defines our response requirements, procedures and remediation plans in the event we have an oil spill. Oil Spill Response Plans are generally approved by the BSEE bi-annually, except when changes are required, in which case revised plans are required to be submitted for approval at the time changes are made. We believe the Plan specifications are consistent with the requirements set forth by the BSEE. Additionally, these plans are tested and drills are conducted periodically at all levels of the Company.

We have contracted with an emergency and 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 and has capabilities to simultaneously respond to multiple spills. CGA has chartered its marine equipment to the Marine Spill Response Corporation (MSRC), a private, not-for-profit marine spill response organization which is funded by the Marine Preservation Association, a member-supported, not-for-profit organization created to assist the

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petroleum and energy-related industries by addressing problems caused by oil spills on water. In the event of a spill, MSRC mobilizes appropriate equipment to CGA members. In addition, CGA maintains a contract with Airborne Support Inc., which provides aircraft and dispersant capabilities for CGA member companies.

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

Results of Operations

The Merger resulted in EPL becoming an indirect, wholly owned subsidiary of Energy XXI. Therefore, in the preparation of our financial statements, we have applied pushdown accounting, based on guidance from the Securities and Exchange Commission (SEC). Pushdown accounting refers to the use of the acquiring entity s basis of accounting in the preparation of the acquired entity s financial statements. As a result, our separate financial statements reflect the new basis of accounting recorded by Energy XXI upon acquisition. As such, in accordance with GAAP, due to our new basis of accounting, our financial statements include a black line denoting that our financial statements covering periods prior to the date of the Merger are not comparable to our financial statements as of and subsequent to the date of the Merger. References to the Predecessor Company refer to reporting dates of the Company through June 3, 2014, reflecting results of operations and cash flows of the Company prior to the Merger on our historical accounting basis; subsequent thereto, the Company is referred to as the Successor Company, reflecting the impact of pushdown accounting and the results of operations and cash flows of the Company subsequent to the Merger.

Energy XXI follows the full cost method of accounting for its oil and gas producing activities, while we had historically followed the successful efforts method of accounting. Subsequent to the Merger, we converted our accounting method from successful efforts to the full cost method of accounting to be consistent with Energy XXI s method of accounting pursuant to SEC guidance, which requires a reporting entity that follows the full cost method to apply that method to all of its operations and to the operations of its subsidiaries. Under GAAP, a change in accounting method is generally required to be applied retroactively in order to provide comparable historical period information to users of financial statements. However, due to the new basis of accounting established as a result of the Merger transaction and pushdown accounting, our financial statements are no longer comparable to those of prior periods and we have applied the full cost method of accounting on a prospective basis from the date of the Merger.

Energy XXI has a fiscal year end of June 30, while we historically had a fiscal year end of December 31. Subsequent to the Merger, we changed our fiscal year end to June 30 to be consistent with Energy XXI. Therefore, these financial statements include audited statements of operations, cash flows and stockholders equity using the successful efforts method of accounting applied to the historical basis in our assets and liabilities for the five months and three days ended June 3, 2014 and audited statements of operations, cash flows and stockholders equity using the full cost method of accounting applied to EPL s new basis in its assets and liabilities established in the Merger transaction for the twenty-seven days ended June 30, 2014, with a black line between the periods denoting that they are not comparable.

Prior to the Merger, we used the successful efforts method of accounting for oil and natural gas producing activities. Costs to acquire mineral interests in oil and natural gas properties, to drill and complete exploratory wells with found proved reserves, and to drill and complete development wells were capitalized. Exploratory drilling costs were initially capitalized, but charged to expense if and when a well was determined not to have reserves in commercial quantities. Geological and geophysical costs were charged to expense as incurred. Leasehold acquisition costs were capitalized as unproved properties. If proved reserves were discovered on undeveloped leases, the related leasehold costs were transferred to proved properties and amortized using the units of production method. For individual unevaluated properties with capitalized costs below a threshold amount, we allocated capitalized costs to earnings generally over the primary lease terms. Properties that were subject to amortization and those with capitalized costs greater than the threshold amount were assessed for impairment periodically. Capitalized costs of producing oil and natural gas properties were depreciated and depleted by the units-of-production method.

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Subsequent to the Merger, we adopted the full cost method of accounting for exploration and development activities. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves.

Under the full cost method, oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Costs excluded from depletion or amortization represent investments in unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the property has been evaluated. We also allocate a portion of our acquisition costs to unevaluated properties based on fair value. Costs are transferred to the full cost pool as the properties are evaluated or over the life of the reservoir.

As a result of pushdown accounting in connection with the Merger, the Predecessor Company s operations are deemed to have ceased on June 3, 2014 and the Successor Company began operations as of that date. In the following discussion, references to the combined operations for the six months ended June 30, 2014 combine the periods from January 1, 2014 through June 3, 2014 (reflecting the operations of the Predecessor Company) with the period from June 4, 2014 through June 30, 2014 (reflecting the operations of the Successor Company). The combined results of operations for the six months ended June 30, 2014 represent a non-GAAP financial measure due to the application of pushdown accounting and conversion to the full cost method of accounting for exploration and development activities. In addition, the consolidated financial statements of the Successor Company are not comparable to those of the Predecessor Company. However, the comparability of certain components of our operating results and key operating performance measures was not significantly impacted by the Merger, specifically those related to production, average oil and natural gas selling prices, revenues and lease operating expenses. Therefore, we believe that presenting the Successor Company s results of operations and cash flows with those of the Predecessor Company on a combined basis for the six months ended June 30, 2014 is useful when analyzing certain measures of our performance. For those items that are not comparable, we have included additional analysis to supplement the discussion.

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Year Ended June 30, 2015 Compared to Year Ended December 31, 2013

The following table represents information about our oil and natural gas operations.

	Year Ended June 30, 2015	Year Ended December 31, 2013
Net production (per day):		
Oil (Bbls)	18,289	16,938
Natural gas (Mcf)	43,734	32,863
Total (Boe)	25,578	22,415
Average sales prices:		
Oil (per Bbl)	$ 67.66	$ 104.01
Natural gas (per Mcf)	3.14	3.81
Gain on derivative financial instruments (per Boe)	4.29	
Total (per Boe)	58.04	84.18
Oil and natural gas revenues (in thousands):		
Oil	$ 451,676	$ 643,033
Natural gas	50,113	45,710
Gain on derivative financial instruments	40,082	
Total	541,871	688,743
Average costs (per Boe):		
LOE	$ 22.68	$ 20.27
Taxes, other than on earnings	0.87	1.40
General and administrative (G&A) expenses	3.78	3.44
Increase (decrease) in oil and natural gas revenues due to:		
Changes in prices of oil	$ (224,720)	
Changes in production volumes of oil	33,363	
Total decrease in oil sales	$ (191,357)	
Changes in prices of natural gas	$ (8,001)	
Changes in production volumes of natural gas	12,404	
Total increase in natural gas sales	$ 4,403	

Overview

Our operating results for the year ended June 30, 2015 compared to the year ended December 31, 2013, reflect an 8% increase in oil production and a 33% increase in natural gas production, resulting in a 14% increase in our overall production volumes. Our product mix for the year ended June 30, 2015 was 72% oil (including natural gas liquids) compared to 76% for the year ended December 31, 2013.

Revenue

Year Ended June 30,	Year Ended December	$ Change	% Change

	2015 (in thousands)	31, 2013 (in thousands)		
Oil and natural gas revenues	$ 501,789	$ 688,743	$ (186,954)	-27 %
Gain on derivative financial instruments	40,082		40,082	

For the year ended June 30, 2015, our oil and natural gas revenues decreased 27% as compared to the year ended December 31, 2013, due primarily to a 35% decrease in average selling prices for our oil partially offset by an 8% increase in oil production. Additionally, we had a 33% increase in natural gas production and partially offset by an 18% decrease in average selling prices for natural gas for the year ended June 30, 2015, as compared to the year ended December 31, 2013.

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Our overall average selling prices decreased by 31% for the year ended June 30, 2015 when compared to the year ended December 31, 2013. Average crude oil prices decreased $36.35 per barrel in fiscal 2015, resulting in lower revenues of approximately $224.7 million. Average natural gas prices decreased $0.67 per Mcf in fiscal 2015, resulting in lower revenues of approximately $8.0 million. Our hedging activities resulted in higher revenues of $40.1 million or $4.29 per BOE for the year ended June 30, 2015. Prior to the Merger, the Predecessor Company recorded gain (loss) on derivative financial instruments in Other income (expense).

Operating Expenses

Our operating expenses primarily consist of the following:

	Year Ended June 30, 2015	Year Ended December 31, 2013	$ Change	% Change
	(in thousands)			
LOE	$ 211,699	$ 165,841	$ 45,858	28 %
Exploration expenditures and dry hole costs(1)		26,555	NM	
Impairment of oil and natural gas properties(1)	1,678,804	2,937	NM	
Goodwill impairment	329,293		NM	
DD&A, including accretion expense(1)	338,353	228,658	NM	
G&A expenses	35,324	28,137	7,187	26 %
Taxes, other than on earnings	8,126	11,490	(3,364)	-29 %
Other	18	34,942	(34,924)	NM

NM Not meaningful.

(1) Exploration expenditures and dry hole costs, impairment of oil and natural gas properties, and DD&A, including accretion expense, are not comparable for the periods presented due to the conversion from successful efforts accounting to full cost accounting effective June 4, 2014. See *Discussion of Critical Accounting Policies*.

LOE increased for the year ended June 30, 2015, compared to the year ended December 31, 2013, primarily due to the acquisition of the EI Interests and SP49 Interests. LOE for the year ended June 30, 2015 also included non-routine costs associated with pipeline maintenance in two fields in addition to other non-routine workover and other expenses.

Under the full cost method, 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 unproved properties and excluding cash flows related to estimated abandonment costs) to our full cost pool 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 amount of the discounted cash flows. As a result of our ceiling test during the year ended June 30, 2015, we recognized ceiling test impairments of our oil and natural gas properties totaling $1.7 billion. Impairments for the year ended December 31, 2013 were determined under the successful efforts method and primarily related to reservoir performance at a gas well in one of our smaller producing fields. This field was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value during the year ended December 31, 2013.

During the year ended June 30, 2015, we recorded a non-cash goodwill impairment charge of $329.3 million to reduce the carrying value of goodwill to zero as of September 30, 2014. At September 30, 2014, we performed a goodwill impairment test after assessing relevant events and circumstances, primarily the decline in oil prices since June 30, 2014. In the first step of the goodwill impairment test, we determined that the fair value of our reporting unit was less than the carrying amount, including goodwill, primarily due to price deterioration in forward pricing curves and an increase in our weighted average cost of capital used to estimate fair value, both of which adversely impacted the fair value of our reserves. Therefore, we performed

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the second step of the goodwill impairment test, which led us to conclude that there would be no remaining implied fair value attributable to goodwill at September 30, 2014.

G&A expenses increased for the year ended June 30, 2015, as compared to the year ended December 31, 2013, primarily due to the cost of services allocated to us pursuant to an intercompany services and cost allocation agreement with an affiliate, Energy Services, which we entered into in connection with the Merger.

During the year ended December 31, 2013, we had other operating expenses of $34.9 million, primarily due to loss on abandonment activities totaling $27.2 million which primarily reflected an increase of $20.8 million in our asset retirement obligation liability related to our non-operated deepwater properties. Other operating expenses also included amortization expense related to our weather derivative of $8.0 million for the year ended December 31, 2013.

Other Income and Expense

Interest expense decreased approximately $1.1 million for the year ended June 30, 2015, as compared to the year ended December 31, 2013 due primarily to a decrease in our effective interest rate on the 8.25% Senior Notes from 9.1% to 5.8%, reflecting the impact of the fair value adjustment to the carrying amount of the 8.25% Senior Notes recorded in pushdown accounting. This decrease was partially offset by an increase in interest expense on our revolving credit sub-facility and our intercompany promissory note during fiscal year 2015.

Other income (expense) in the year ended December 31, 2013 included a net loss on derivative instruments of $32.4 million consisting of a loss of $20.9 million due to the change in fair value of derivative instruments which were to be settled in the future and a loss of $11.5 million on derivative instruments settled during the period primarily from the impact of higher oil prices on our oil fixed-price swaps. The Successor Company classifies gain (loss) on derivative financial instruments as a component of revenue.

Income Taxes

For the year ended June 30, 2015, we recorded income tax benefit of $459 million. Excluded from the income tax benefit is the effect of the goodwill impairment charge recorded in the first quarter of fiscal 2015. The effective income tax/(benefit) rate for the year ended June 30, 2015 was (21.7)% as compared to 36.8% for the year ended December 31, 2013. The variance in the tax rate is primarily due to the valuation allowance recorded as of June 30, 2015. In light of changes in our expectations regarding our future taxable income, consistent with the results of operations for the current year (heavily affected by impairments), we recorded a valuation allowance of $189.6 million at June 30, 2015. See Note 12, Income Taxes in of the consolidated financial statements in Part II, Item 8 of this Form 10-K for additional information.

Restated Quarterly Comparisons

The following table and subsequent section discuss the effect of the restatement for impacted line items on the consolidated statement of operations for the first three quarters in fiscal years 2015. Amounts related to derivatives previously classified in accumulated other comprehensive income (loss) have been reclassified to gain (loss) on derivative financial instruments. The total impact to the income statement is shown in Item 8. Financial Statements and Supplementary Data Restated Quarterly Financial Statements.

For the Quarter Ended

	September 30, 2014	December 31, 2014	March 31, 2015
Revenue Oil and natural gas:			
As previously reported	$ 173,720	$ 156,070	$ 87,253
Adjustments to revenue oil and natural gas	(1,839)	(23,237)	(1,830)
As restated	171,881	132,833	85,423

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	For the Quarter Ended		
	September 30, 2014	December 31, 2014	March 31, 2015
(Loss) gain on derivative financial instruments:			
As previously reported	$ (30)	$ (26)	$ (579)
Adjustments to (loss) gain on derivative financial instruments	21,887	22,288	(1,634)
As restated	21,857	22,262	(2,213)
Total Revenue:			
As previously reported	174,109	156,613	87,253
Adjustments to total revenue	20,018	(975)	(4,043)
As restated	194,127	155,638	83,210
Net Loss:			
As previously reported	(319,371)	(449,478)	(310,517)
Adjustments to net loss	13,015	(5,134)	14,884
As restated	(306,356)	(454,612)	(295,633)

Three months ended September 30, 2014 compared with three months ended September 30, 2013

Revenues

The restatement adjustment increased our consolidated revenues for the three months ended September 30, 2014 by $20.0 million. Our consolidated revenues increased $10.1 million in the first quarter of fiscal 2015 as compared to the same period in the prior fiscal year. Higher revenues were primarily due to the gain on derivative financial instruments and higher oil and natural gas sales volumes, partially offset by lower oil sales prices. Average oil prices decreased $11.82 per barrel in the first quarter of fiscal 2015, resulting in lower revenues of $19.0 million. Average natural gas prices increased $0.28 per Mcf during the first quarter of fiscal 2015 resulting in higher revenues of $0.9 million. Our hedging activities more than offset the impact of the decrease in oil prices resulting in higher revenues of $21.9 million or $9.69 per BOE. The gain on derivatives for the three months ended September 30, 2014 reflects a gain on settlements of our derivative contracts of approximately $1.09 per barrel of oil.

Income Tax Expense

The restatement adjustment increased our income tax expense for the three months ended September 30, 2014 by $7.0 million. Restated income tax expense increased by $13.9 million for the three months ended September 30, 2014 compared to the three months ended September 30, 2013. Our effective income tax rate for the three months ended September 30, 2014 was 35.9%, excluding the impact of the goodwill impairment charge during the period, which is not deductible for income tax purposes. Our effective income tax rate for the three months ended September 30, 2013 was 44.4%. The decrease in our effective income tax rate is primarily related to our estimated state income taxes.

Three months ended December 31, 2014 compared with three months ended December 31, 2013

Revenues

The restatement adjustment decreased our consolidated revenues for the three months ended December 31, 2014 by $1.0 million. Our consolidated revenues increased $13.0 million in the second quarter of fiscal 2015 as compared to the same period in the prior fiscal year. Higher revenues were primarily due to higher oil sales volumes and gain on derivative financial instruments, partially offset by lower commodity sales prices. Average oil prices decreased $23.57 per barrel in the second quarter of fiscal 2015, resulting in lower revenues of $32.8 million. Average natural gas prices decreased $0.39 per Mcf during the second quarter of fiscal 2015, resulting in lower revenues of $1.0 million. Our hedging activities partially offset the impact of the decrease in oil and natural gas prices resulting in higher revenues of $22.3 million or $9.71 per BOE. The gain on derivatives for the three months ended December 31, 2014 reflects a gain on settlements and monetization of our derivative contracts of approximately $16.28 per barrel of oil.

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Costs and Expenses and Other (Income) Expense

The restatement adjustment increased our costs and expenses for the three months ended December 31, 2014 by $7.4 million. Restated costs and expenses increased $728.1 million in the second quarter of fiscal 2015 as compared to the same period in the prior fiscal year, principally due to the restated impairment of oil and gas properties of $690.3 million.

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 unproved properties and excluding cash flows related to estimated abandonment costs) to our full cost pool 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. As a result of our ceiling test at December 31, 2014, we recognized a restated ceiling test impairment of our oil and natural gas properties totaling $690.3 million. The restatement adjustment increased our impairment of oil and natural gas properties during the three months ended December 31, 2014 by $7.4 million.

Income Tax Expense

The restatement adjustment increased our income tax benefit for the three months ended December 31, 2014 by $3.3 million. Restated income tax benefit increased $245.1 million in the second quarter of fiscal 2015 compared to the three months ended December 31, 2013. The effective income tax/(benefit) rate for the second quarter of fiscal 2015 was (35.6)% as compared to (32.2)% for the three months ended December 31, 2013. The increase in the tax rate is primarily due to two elements: (i) the increase in pre-tax net loss and (ii) an increase in common permanent difference items.

Six months ended December 31, 2014 compared with six months ended December 31, 2013

Revenues

The restatement adjustment increased our consolidated revenues for the six months ended December 31, 2014 by $19.0 million. Our restated consolidated revenues increased $23.2 million in the first six months of fiscal 2015 as compared to the six months ended December 31, 2013. Higher revenues were primarily due gain on derivative financial instruments and higher oil sales volumes, partially offset by lower oil sales prices. Average oil prices decreased $18.28 per barrel in the first six months of fiscal 2015, resulting in lower revenues of $54.8 million. Average natural gas prices decreased $0.04 per Mcf in the first six months of fiscal 2015, resulting in lower revenues of $0.2 million. Our hedging activities partially offset the impact of the decrease in oil and natural gas prices resulting in higher revenues of $44.1 million or $9.70 per BOE. The gain on derivatives for the six months ended December 31, 2014 reflects a gain on settlements and monetization of our derivative contracts of approximately $8.77 per barrel of oil.

Costs and Expenses and Other (Income) Expense

The restatement adjustment increased our costs and expenses for the six months ended December 31, 2014 by $7.4 million. Restated costs and expenses increased $1,061.6 million in the second quarter of fiscal 2015 as compared to the same period in the prior fiscal year, principally due to the restated impairment of oil and gas properties of $690.3 million and the goodwill impairment charge of $329.3 million.

Income Tax Expense

The restatement adjustment decreased our income tax benefit for the six months ended December 31, 2014 by $3.8 million. Restated income tax benefit increased by $231.3 million in the first six months of fiscal 2015 compared to the six months ended December 31, 2013. The effective income tax/(benefit) rate (excluding the discrete item from pre-tax book loss) for the first six months of fiscal 2015 was (35.5)% as compared to (33.6)% for the six months ended December 31, 2013. The increase in the tax rate is primarily due to two elements: (i) the increase in pre-tax net loss and (ii) an increase in common permanent difference items.

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Three months ended March 31, 2015 compared with three months ended March 31, 2014

Revenues

The restatement adjustment decreased our consolidated revenues for the three months ended March 31, 2015 by $4.0 million. Our consolidated revenues decreased $76.3 million in the third quarter of fiscal 2015 as compared to the three months ended March 31, 2014. Lower revenues were primarily due to lower commodity sales prices, partially offset by higher sales volumes. Average oil prices decreased $52.90 per barrel in the third quarter of fiscal 2015, resulting in lower revenues of $77.4 million. Average natural gas prices decreased $2.42 per Mcf during the third quarter of fiscal 2015, resulting in lower revenues of $6.0 million. Our hedging activities resulted in lower revenues of $2.2 million or $0.96 per BOE.

Costs and Expenses and Other (Income) Expense

The restatement adjustment decreased our costs and expenses for the three months ended March 31, 2015 by $26.8 million. Restated costs and expenses increased $436.2 million in the third quarter of fiscal 2015 as compared to the three months ended March 31, 2014, principally due to the restated impairment of oil and gas properties of $404.3 million.

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 unproved properties and excluding cash flows related to estimated abandonment costs) to our full cost pool 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. As a result of our ceiling test at March 31, 2015, we recognized a restated ceiling test impairment of our oil and natural gas properties totaling $404.3 million. The restatement adjustment decreased our impairment of oil and natural gas properties during the three months ended March 31, 2015 by $26.6 million.

Income Tax Expense

The restatement adjustment decreased our income tax benefit for the three months ended March 31, 2015 by $8.5 million. We recorded restated income tax benefit of $182.0 million in the third quarter of fiscal 2015 compared to income tax expense of $7.6 million in the three months ended March 31, 2014. The effective income tax (benefit) rate for the third quarter of fiscal 2015 was (38.1%) as compared to 36.4% for three months ended March 31, 2014. The increase in the tax rate is primarily due to an increase in common permanent difference items.

Nine months ended March 31, 2015 compared with nine months ended March 31, 2014

Revenues

The restatement adjustment increased our consolidated revenues for the nine months ended March 31, 2015 by $15.0 million. Our restated consolidated revenues decreased $53.1 million in the first nine months of fiscal 2015 as compared to the nine months ended March 31, 2014. Lower revenues were primarily due to lower commodity sales prices partially offset by higher sales volumes and gain on derivative financial instruments. Average oil prices decreased $29.27 per barrel in the first nine months of fiscal 2015, resulting in lower revenues of $130.6 million. Average natural gas prices decreased $0.83 per Mcf during the first nine months of fiscal 2015, resulting in lower revenues of $6.9 million. Our hedging activities partially offset the impact of the decrease in oil and natural gas prices resulting in higher revenues of $41.9 million or $6.12 per BOE. The gain on derivatives for the nine months ended March 31, 2015 reflects a gain on settlements and monetization of our derivative contracts of approximately $5.97 per barrel of oil.

Costs and Expenses and Other (Income) Expense

The restatement adjustment decreased our costs and expenses for the nine months ended March 31, 2015 by $19.4 million. Restated costs and expenses increased $1,497.8 million in the first nine months of fiscal 2015 as compared to the nine months ended March 31, 2014, principally due to the impairment of oil and gas properties and the impairment of goodwill.

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As a result of our ceiling test at March 31, 2015, we recognized a restated ceiling test impairment of our oil and natural gas properties totaling $1,094.6 million during the nine months ended March 31, 2015. The restatement adjustment decreased our impairment of oil and natural gas properties during the nine months ended March 31, 2015 by $19.4 million.

Income Tax Expense

The restatement adjustment decreased our income tax benefit for the nine months ended March 31, 2015 by $12.3 million. We recorded restated income tax benefit of $420.0 million in the first nine months of fiscal 2015 compared to income tax expense of $0.9 million in the nine months ended March 31, 2014. The effective income tax (benefit) rate (excluding the discrete item from pre-tax book loss) for the first nine months of fiscal 2015 was (36.6%) as compared to 101.3% for the nine months ended March 31, 2014. The decrease in the tax rate is primarily due to changes in common permanent difference items.

Results of Operations   Restated Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

The following table represents information about our oil and natural gas operations.

	Period from June 4, 2014 through June 30, 2014 (Restated)	Period from January 1, 2014 through June 3, 2014	Non-GAAP Combined Results for the Six Months Ended June 30, 2014 (Restated)	Six Months Ended June 30, 2013
Net production (per day):				
Oil (Bbls)	19,113	16,922	17,285	17,591
Natural gas (Mcf)	26,410	26,502	26,487	34,352
Total (Boe)	23,515	21,339	21,700	23,316
Average sales prices:				
Oil (per Bbl)	$100.48	$99.73	$99.87	$106.79
Natural gas (per Mcf)	4.62	4.98	4.92	3.86
Loss on derivative financial instruments (per BOE)	(15.71)		(2.82)	
Total (per Boe)	71.15	85.28	82.74	86.25
Oil and natural gas revenues (in thousands):				
Oil	$57,613	$254,827	$312,440	$340,003
Natural gas	3,658	19,945	23,603	23,982
Loss on derivative financial instruments	(11,079)		(11,079)	
Total	50,192	274,772	324,964	363,985
Average costs (per Boe):				
LOE	$25.16	$22.44	$22.93	$19.99
Taxes, other than on earnings	1.21	1.36	1.33	1.33

General and administrative (G&A) expenses	3.71	15.96	13.76	3.44
Increase (decrease) in oil and natural gas revenues due to:				
Changes in prices of oil			$(22,032)	
Changes in production volumes of oil			(5,531)	
Total decrease in oil sales			$(27,563)	
Changes in prices of natural gas			$6,046	
Changes in production volumes of natural gas			(6,425)	
Total decrease in natural gas sales			$(379)	

Results of Operations Restated Six Months Ended June 30,2014 Compared to Six Months Ended June 30, 2013

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Overview

Our operating results for the six months ended June 30, 2014, compared to the six months ended June 30, 2013, reflect a 2% decrease in oil production and a 23% decrease in natural gas production, resulting in a 7% decrease in our overall production volumes. Our product mix for the six months June 30, 2014 was 80% oil (including natural gas liquids) compared to 75% for the six months ended June 30, 2013.

Revenue

	Period from June 4, 2014 through June 30, 2014 (Restated)	Period from January 1, 2014 through June 3, 2014	Non-GAAP Combined Results for the Six Months Ended June 30, 2014 (Restated)	Six Months Ended June 30, 2013	$ Change	% Change
	(in thousands)	(in thousands)				
Oil and natural gas revenues	$ 61,271	$ 274,772	$ 336,043	$ 363,985	$ (27,942)	-8 %
Gain (loss) on derivative financial instruments	(11,079)		(11,079)		(11,079)	

For the six months ended June 30, 2014, our oil and natural gas revenues decreased 8% as compared to the six months ended June 30, 2013, due primarily to a decrease of 6% in average selling prices for our oil. The decrease in our oil and natural gas revenues also reflects the 2% decrease in oil production and 23% decrease in natural gas production, partially offset by a 27% increase in average selling prices for natural gas in the six months ended June 30, 2014, as compared to the six months ended June 30, 2013. In addition, revenues for the period from June 4, 2014 through June 30, 2014 and the non-GAAP combined revenues for the six months ended June 30, 2014 include a reduction of $11.1 million due to loss on derivative financial instruments.

Our overall production volumes decreased by 7% for the six months ended June 30, 2014 when compared to the six months ended June 30, 2013. During the first two months of 2014, we experienced significant weather-related downtime, which negatively impacted the average oil production for the period. Our GoM shelf production decreased 6% in the six months ended June 30, 2014, as compared to the six months ended June 30, 2013, due primarily to a decrease in production in our West Delta field, which was partially offset by an increase in production in our Ship Shoal 208 area and production from the acquired interests in the Eugene Island and South Pass 49 fields.

Operating Expenses

Our operating expenses primarily consisted of the following:

	Period from June 4,	Period from January	Non-GAAP Combined Results for	Six Months Ended	$ Change	% Change

	2014 through June 30, 2014	1, 2014 through June 3, 2014	the Six Months Ended June 30, 2014	June 30, 2013		
	(in thousands)	(in thousands)				
LOE	$ 17,746	$72,302	$ 90,048	$84,372	$5,676	7 %
Exploration expenditures and dry hole costs(1)		26,239	NM	8,463		
Impairments(1)		61	NM	2,171		
DD&A, including accretion expense(1)	24,797	96,898	NM	112,056		
G&A expenses	2,617	51,434	54,051	14,501	39,550	273 %
Taxes, other than on earnings	850	4,384	5,234	5,599	(365)	-7 %
Other		44	44	6,543	(6,499)	-99 %

NM Not meaningful.

(1) Exploration expenditures and dry hole costs, impairments, and DD&A, including accretion expense, are

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not comparable for the periods presented due to the conversion from successful efforts accounting to full cost accounting effective June 4, 2014. See *Discussion of Critical Accounting Policies*.

LOE increased for the six months ended June 30, 2014, compared to the six months ended June 30, 2013, primarily due to employee severance costs of $3.4 million related to the Merger. LOE for the six months ended June 30, 2014 also included approximately $3.2 million of non-routine workover expenses as compared to $6.0 million for the six months ended June 30, 2013.

Exploration expenditures and dry hole costs for the period from January 1, 2014 through June 3, 2014 include dry hole costs totaling approximately $14.8 million, primarily associated with an exploratory drilling operation which reached its target depth in June 2014 and was determined to be unsuccessful. In addition, exploration expenditures and dry hole costs for the period from January 1, 2014 through June 3, 2014 include seismic expense of $2.4 million and other exploratory costs totaling approximately $9.0 million, primarily associated with our geological and geophysical staff, including non-cash share-based compensation due to accelerated vesting of outstanding stock options and restricted shares at the time of the Merger totaling approximately $3.9 million. During the six months ended June 30, 2013, we recorded approximately $3.7 million of dry hole costs associated with an exploratory drilling operation during the quarter ended June 30, 2013. In addition, exploration expenditures and dry hole costs for six months ended June 30, 2013 include seismic expense of $1.2 million and other exploratory costs totaling approximately $3.6 million, primarily associated with our geological and geophysical staff. Prior to adopting the full cost method of accounting, our exploratory expenditures and dry hole costs could vary significantly depending on the amount of capital expenditures dedicated to exploration activities and the level of success we achieved in exploratory drilling activities.

G&A expenses increased for the six months ended June 30, 2014, as compared to the six months ended June 30, 2013, primarily due to expenses related to the Merger, including third party legal and financial advisory costs totaling approximately $11.2 million, non-cash share-based compensation due to accelerated vesting of outstanding stock options and restricted shares at the time of the Merger totaling approximately $11.8 million, employee severance costs of approximately $8.7 million and the impact of employee bonuses approved in connection with the Merger of approximately $5.1 million.

During the six months ended June 30, 2013, we recorded loss on abandonment activities totaling $5.4 million and amortization expense related to our weather derivative of $1.3 million in other operating expenses.

Other Income and Expense

Interest expense for the period from June 4, 2014 to June 30, 2014 includes interest on our 8.25% Senior Notes and borrowings on the revolving credit sub-facility as described in *Liquidity and Capital Resources*. For the period January 1, 2014 through June 3, 2014 and the six months ended June 30, 2013, our interest expense included interest on our 8.25% Senior Notes and interest on borrowings on our prior senior credit facility.

Other income (expense) for the period January 1, 2014 through June 3, 2014 includes a net loss on derivative instruments of $19.4 million consisting of a loss of $26.4 million on derivative instruments settled during the period primarily from the impact of higher oil prices on our oil fixed-price swaps and a gain of $7.0 million due to the change in fair value of derivative instruments which were to be settled in the future. Other income (expense) in the six months ended June 30, 2013 includes a net gain on derivative instruments of $23.0 million consisting of a gain of $27.3 million due to the change in fair value of derivative instruments which were to be settled in the future and a loss of $4.3 million on derivative instruments settled during the period primarily from the impact of higher oil prices on our oil fixed-price swaps.

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Results of Operations Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

The following table represents information about our oil and natural gas operations.

	Year Ended December 31, 2013	2012
Net production (per day):		
Oil (Bbls)	16,938	10,398
Natural gas (Mcf)	32,863	17,852
Total (Boe)	22,415	13,373
Average sales prices[1]:		
Oil (per Bbl)	$ 104.01	$ 106.08
Natural gas (per Mcf)	3.81	2.89
Total (per Boe)	84.18	86.33
Oil and natural gas revenues (in thousands):		
Oil	$ 643,033	$ 403,663
Natural gas	45,710	18,866
Total	688,743	422,529
Impact of derivatives instruments settled during the period:		
Oil (per Bbl)	$ (1.78)	$ (0.88)
Natural gas (per Mcf)	(0.04)	(0.07)
Average costs (per Boe):		
LOE	$ 20.27	$ 19.38
Depreciation, depletion and amortization (DD&A)	24.49	23.21
Accretion of liability for asset retirement obligations	3.46	3.18
Taxes, other than on earnings	1.40	2.66
General and administrative (G&A) expenses	3.44	4.74
Increase (decrease) in oil and natural gas revenues due to:		
Changes in prices of oil	$ (7,879)	
Changes in production volumes of oil	247,249	
Total decrease in oil sales	$ 239,370	
Changes in prices of natural gas	$ 6,017	
Changes in production volumes of natural gas	20,827	
Total increase in natural gas sales	$ 26,844	

Overview

Our operating results for the year ended December 31, 2013, compared to the year ended December 31, 2012, reflect a 63% increase in oil production and an 84% increase in natural gas production. Our product mix for the year ended December 31, 2013 was 76% oil (including natural gas liquids) compared to 78% for the year ended December 31, 2012, resulting in a 68% increase in our overall production volumes for the year ended December 31, 2013 when compared to the year ended December 31, 2012.

Revenue and Net Income

	Years Ended December 31,			
	2013	2012	$ Change	% Change
	(in thousands)			
Oil and natural gas revenues	$ 688,743	$ 422,529	$ 266,214	63 %
Net income	85,274	58,810	26,464	45 %

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For the year ended December 31, 2013, our oil and natural gas revenues increased 63% as compared to the year ended December 31, 2012, due primarily to the 63% increase in oil production, partially offset by slightly lower average selling prices for our oil. The increase in our oil and natural gas revenues also reflects the 84% increase in natural gas production and a 32% increase in average selling prices for natural gas in the year ended December 31, 2013, as compared to the year ended December 31, 2012.

Our GoM shelf production, excluding production from properties acquired in the acquisition of the 100% membership interests of Hilcorp Energy GOM, LLC in October 2012 (the Hilcorp Properties), increased 29% in the year ended December 31, 2013, as compared to the year ended December 31, 2012, due primarily to production increases in our West Delta, South Pass 49 and Main Pass fields partially offset by production declines in our South Timbalier area. Production from the Hilcorp Properties increased our production rate by approximately 5,902 Boe per day in the year ended December 31, 2013, compared to results for the year ended December 31, 2012, which include production from the Hilcorp Properties only for the period from November 1 to December 31, 2012, reflecting a 1,488 Boe per day impact on the production rate in the prior period.

In addition to the items addressed above, our net income for the year ended December 31, 2013 included a gain on sale of assets of $28.7 million, primarily from the sale of the interests in the Bay Marchand field; a loss on abandonment activities of $27.2 million; interest expense of $52.4 million and a net loss on derivative instruments of $32.4 million. Our net income for the year ended December 31, 2012 reflected a loss on abandonment activities of $2.4 million; interest expense of $28.6 million and a net loss on derivative instruments of $13.3 million.

For the years ended December 31, 2013 and 2012, our effective income tax rate was 36.8% and 33.7%, respectively, and the income tax expense that we recorded was all deferred. For the year ended December 31, 2012 the income tax expense that we recorded was reduced due to applying the change in our estimated effective income tax rate to our net deferred tax liabilities. The change in our estimated effective income tax rate from 37.3% in 2011 to 36.4% in 2012 was primarily related to estimated state income taxes.

Operating Expenses

Our operating expenses primarily consisted of the following:

	Years Ended December 31,			
	2013	2012	$ Change	% Change
	(in thousands)			
LOE	$ 165,841	$ 94,850	$ 70,991	75 %
Exploration expenditures and dry hole costs	26,555	18,799	7,756	41 %
Impairments	2,937	8,883	(5,946)	-67 %
DD&A, including accretion expense	228,658	129,146	99,512	77 %
G&A expenses	28,137	23,208	4,929	21 %
Taxes, other than on earnings	11,490	13,007	(1,517)	-12 %
Other	34,942	4,678	30,264	647 %

LOE increased for the year ended December 31, 2013, compared to the year ended December 31, 2012, primarily due to the acquisition of the Hilcorp Properties. LOE for the year ended December 31, 2013 also included approximately $8.2 million of non-routine workover expenses.

Exploration expenditures and dry hole costs increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily reflecting costs associated with the increased size of our geological and geophysical staff. We also had increases in seismic expense and dry hole costs. For the year ended December 31, 2013, seismic expense, was $12.3 million compared to $10.6 million for the year ended December 31, 2012. Our seismic expense for the year ended December 31, 2013 related primarily to the 3-D seismic agreements negotiated during the year. Our seismic expense for the year ended December 31, 2012 related to area-wide 2-D and 3-D seismic purchases. For the year ended December 31, 2013, we recorded approximately $5.5 million of dry hole costs, primarily associated with an exploratory drilling operation during the year which was unsuccessful. For the year ended December 31, 2012, we recorded approximately $4.2 million of dry hole costs, primarily associated with two exploratory wells which reached their target depths in January 2012 and were determined to be unsuccessful and an unsuccessful exploratory portion of a well that was successfully completed in a development zone.

Impairments for the year ended December 31, 2013 were primarily related to reservoir performance at a gas well in one of our smaller producing fields. This field was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value during the year ended December 31, 2013. Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices, which affected three of our natural gas producing fields and reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that were expiring in 2013 for which we had no development plans.

DD&A increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily due to the increase in production associated with the acquisition of the Hilcorp Properties.

G&A expenses increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily as a result of higher professional fees related to the expansion of our asset base following the acquisition of the Hilcorp Properties and an increase in non-cash share-based compensation. G&A per Boe for the year ended December 31, 2013, as compared to the year ended December 31, 2012, declined significantly because of the increase in production primarily from the Hilcorp Properties.

Taxes, other than on earnings, were lower in the year ended December 31, 2013, as compared to the year ended December 31, 2012. The decrease was primarily related to severance taxes and a decrease in production from state leases (which is subject to a severance tax regime).

Other operating expenses increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily as a result of an increase in loss on abandonment activities and amortization of the premium paid for our weather derivative. During the year ended December 31, 2013, we recorded loss on abandonment activities totaling $27.2 million and amortization expense related to our weather derivative of $8.0 million. During the year ended December 31, 2012, we recorded loss on abandonment activities totaling $2.4 million and amortization expense related to our weather derivative of $2.4 million. For the year ended December 31, 2013, our loss on abandonment activities primarily reflected an increase of $20.8 million in our asset retirement obligation liability related to our non-operated deepwater properties.

Other Income and Expense

Interest expense increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012. The increase in our interest expense was due to the full year of interest on our 8.25% Senior Notes issued in connection with the acquisition of the Hilcorp Properties and borrowings on our prior senior credit facility for the year ended December 31, 2013. For the year ended December 31, 2012, our interest expense included interest on our 8.25% Senior Notes and interest on borrowings on the prior senior credit facility beginning in late October 2012 in connection with the acquisition of the Hilcorp Properties.

Other income (expense) in the year ended December 31, 2013 included a net loss on derivative instruments of $32.4 million consisting of a loss of $20.9 million due to the change in fair value of derivative instruments to be settled in the future and a loss of $11.5 million on derivative instruments settled during the period primarily from the impact of higher oil prices on our oil fixed-price swaps. Other income (expense) in the year ended December 31, 2012 includes a net loss on derivative instruments of $13.3 million consisting of a loss of $9.5 million due to the change in fair market value of derivative instruments and a loss of $3.8 million on derivative instruments settled during the period primarily from the impact of higher oil prices during 2012 on our oil fixed-price swaps.

Liquidity and Capital Resources

Overview

As of June 30, 2015, we had $150 million in borrowings outstanding under the First Lien Credit Agreement, as amended, to which we are a party with EGC. Currently, we fund our operations primarily through cash flows from operating activities and advances from EGC. Future cash flows are subject to a number of variables, including the level of crude oil and natural gas production and prices. Oil prices declined severely during the second quarter of our fiscal year 2015, with continued lower prices throughout the second half of fiscal year 2015. These lower commodity prices have negatively impacted revenues, earnings and cash flows, and sustained low oil and natural gas prices could have a material and adverse effect on our liquidity position.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon oil and natural gas prices, the success of our development activities, our ability to maintain and grow reserves and our ability to refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by the results of our operations, economic and capital market conditions, oil and natural gas prices and other factors, many of which are beyond our control. For example, constraints in the credit markets may increase the rates we are charged for utilizing these markets. Based on our current production levels and prices for oil and natural gas, our liquidity and capital resource alternatives may not be sufficient to meet our funding requirements through June 30, 2016, without additional advances from EGC, further reductions in capital expenditures or sales of non-core assets by us or EGC. If we are unable to generate sufficient cash flow to service our debt or meet our debt obligations as they become due, we will have to take certain actions described in greater detail in Risk Factors We may not be able to generate sufficient cash flows to service all of our indebtedness and may be forced to take other actions in order to satisfy our obligations under our indebtedness, which may not be successful.

Based on projected market conditions and commodity prices, we currently expect that we will be in compliance with covenants under our credit agreement for the near term; however, a protracted period of low commodity prices could cause us to not be in compliance with certain financial covenants under our credit agreements in future periods, including prior to June 30, 2016. Our parent and EGC intend to support us financially to enable us to meet our ongoing obligations and comply with our covenants. However, in the event that we are unable to comply with these covenants, a breach of the covenants under our revolving credit sub-facility would cause a default under such facility, potentially resulting in acceleration of all amounts outstanding under our revolving credit sub-facility. If the lenders under our credit facility were to accelerate the indebtedness under our revolving credit facility as a result of such defaults, such acceleration could cause a cross-default or cross-acceleration of all of our other outstanding indebtedness, as well as all of EGC s and our parent s other outstanding indebtedness. As of June 30, 2015, EGC and our parent had outstanding indebtedness of $3,916 million, excluding all of our indebtedness. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding, we may not have sufficient liquidity to repay all of our outstanding indebtedness.

In light of current commodity prices and our substantial leverage position, our parent continues to analyze a variety of transactions and mechanisms designed to reduce debt, including the retirement or purchase of outstanding debt securities, including our outstanding debt securities, through cash purchases in open market purchases and/or exchanges for equity or other securities of the Company through privately negotiated transactions or otherwise and opportunistic acquisitions. Such transactions, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors and there can be no assurance that we will take any of these actions.

Our Indebtedness and Available Credit

Revolving Credit Sub-Facility. During March 2015, the Tenth Amendment to the First Lien Credit Agreement dated as of March 3, 2015 (the Tenth Amendment) became effective. Pursuant to the terms of the Tenth Amendment, the lenders under the First Lien Credit Agreement reduced the borrowing base for EGC from $1,500 to $500 million, of which such amount $150 million is the borrowing base for EPL (the

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Revolving Credit Sub-Facility). The maturity date of the First Lien Credit Agreement is April 9, 2018, provided that certain conditions are met; however, the maturity of the revolving credit facility will accelerate if EGC s 9.25% Senior Notes are not retired or refinanced by May 15, 2017 or the 8.25% Senior Notes are not retired or refinanced by July 15, 2017. Additionally, we entered into a $325 million secured second lien promissory note between us, as the maker, and EGC, as the payee (the Promissory Note) on March 12, 2015. Proceeds from the Promissory Note were used to repay a like amount of the outstanding borrowings under the Revolving Credit Sub-Facility. As of June 30, 2015, we have fully utilized amounts available under our Revolving Credit Sub-Facility. For more information on our Revolving Credit Sub-Facility and the Promissory Note, see Note 8, Indebtedness in Part II, Item 8 of this Form 10-K.

Additionally, as of July 31, 2015, EGC and EPL entered into the Eleventh Amendment and Waiver to the First Lien Credit Agreement (the Eleventh Amendment), which waives certain provisions of the First Lien Credit Agreement to permit certain transactions entered into by other subsidiaries of Energy XXI. Further, the Eleventh Amendment temporarily increased the letter of credit commitment amount within the facility from $300 million to a maximum amount of $305 million through August 31, 2015, after which it reduced back to $300 million.

The First Lien Credit Agreement, as amended, requires EGC and EPL to maintain certain financial covenants separately for so long as the 8.25% Senior Notes remain outstanding. EGC is subject to the following financial covenant on a consolidated basis: a minimum current ratio of no less than 1.0 to 1.0. In addition, EGC is subject to the following financial covenants on a stand-alone basis: (a) a consolidated maximum net first lien leverage ratio of 1.25 to 1.0 and (b) a consolidated maximum net secured leverage ratio of no more than 3.75 to 1.0. In addition, EPL is subject to the following financial covenants on a stand-alone basis: (a) a consolidated maximum first lien leverage ratio of 1.25 to 1.0 and (b) a consolidated maximum secured leverage ratio of no more than 3.75 to 1.0. If the EPL Notes are no longer outstanding and certain other conditions are met, EGC and EPL will be subject to the following financial covenants on a consolidated basis: (a) a consolidated maximum net first lien leverage ratio of 1.25 to 1.0, (b) a consolidated maximum net secured leverage ratio of no more than 3.75 to 1.0, provided that if the 8.25% Senior Notes are refinanced with new secured debt, the liens of which are junior in priority to the Revolving Credit Facility indebtedness, then the maximum ratio permitted would be 4.25 to 1.0, and (c) a minimum current ratio of no less than 1.0 to 1.0.

As of June 30, 2015, we were in compliance with all covenants under the First Lien Credit Agreement, other than with respect to the sale of interests in the East Bay field. Since required lender consent to the specific terms of the transaction had not been obtained, EGC and EPL were in technical default under the First Lien Credit Agreement at June 30, 2015. On July 14, 2015, we obtained a waiver to this event of default, which waiver required EGC to deposit $21 million into an account subject to a control agreement in favor of the administrative agent under the First Lien Credit Agreement. Such amount will remain on deposit until the next redetermination of the borrowing base, unless used to repay a borrowing base deficiency. Upon the next redetermination, any amounts remaining in the account will be used to make an immediate payment toward any borrowing base deficiency at the time of such redetermination, and so long as no event of default shall have occurred, any amount remaining after payment in full of any borrowing base deficiency shall be released and paid to EGC. Based on projected market conditions and commodity prices, we currently expect that we will be in compliance with covenants under our credit agreement for the near term; however, a protracted period of low commodity prices could cause us to not be in compliance with certain financial covenants under our credit agreements in future periods, including prior to June 30, 2016. Our parent and EGC intend to support us financially to enable us to meet our ongoing obligations and comply with our covenants.

As a result of EGC s reduction in borrowing base availability to $500 million and the resulting increased asset coverage for the Revolving Credit Facility, we do not currently anticipate any further borrowing base reductions in connection with our semi-annual borrowing base redeterminations. However, it is possible if commodity prices were to decline significantly from current levels, EGC s borrowing base and our borrowing base under the Revolving Credit

Sub-Facility may be further reduced, which would impact the working capital available to fund our capital spending program. In addition, we would be required to repay any outstanding indebtedness in excess of any reduced borrowing base.

8.25% Senior Notes. The 8.25% Senior Notes consist of $510.0 million in aggregate principal amount issued under an indenture dated February 14, 2011 (the 2011 Indenture). The 8.25% Senior Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest due semi-annually, in arrears, on February 15th and August 15th of each year. The 8.25% Senior Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured senior basis initially by each of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries). The 8.25% Senior Notes will mature on February 15, 2018. As of June 30, 2015, we were in compliance with all of the covenants under the 2011 Indenture.

On April 18, 2014, we entered into a supplemental indenture (the Supplemental Indenture) to the 2011 Indenture, by and among us, the guarantors party thereto, and U.S. Bank National Association, as trustee, governing the 8.25% Senior Notes. We entered into the Supplemental Indenture after the receipt of the requisite consents from the holders of the 8.25% Senior Notes in accordance with the Supplemental Indenture. The Supplemental Indenture amended the terms of the 2011 Indenture governing the 8.25% Senior Notes to waive our obligation to make and consummate an offer to repurchase the 8.25% Senior Notes at 101% of the principal amount thereof plus accrued and unpaid interest. We paid an aggregate cash payment of $1.2 million (equal to $2.50 per $1,000 principal amount of 8.25% Senior Notes for which consents were validly delivered and unrevoked). The 8.25% Senior Notes are callable at 104.125% starting February 15, 2015 with such premium declining to zero by February 15, 2017.

For more information regarding our outstanding indebtedness, see Note 8, Indebtedness, to our consolidated financial statements contained in Part II, Item 8 of this Form 10-K.

BOEM Bonding Requirements

As a lessee and operator of oil and natural gas leases on the federal OCS, we currently maintain approximately $58.3 million in lease and/or area bonds issued to the BOEM and approximately $122.5 million in bonds issued to predecessor third party assignors including certain state regulatory bodies of certain wells and facilities on leases pursuant to a contractual commitment made by us to those third parties at the time of assignment with respect to the eventual decommissioning of those wells and facilities. Thus, our total supplemental bonding is approximately $180.8 million, with an annual premium expense of $2.7 million. In April 2015, we received letters from the BOEM stating that certain of our subsidiaries no longer qualify for waiver of certain supplemental bonding requirements for potential offshore decommissioning, plugging and abandonment liabilities. The letters notified us that certain of our subsidiaries must provide approximately $566.5 million in supplemental financial assurance and/or bonding for their offshore oil and gas leases, rights-of-way, and rights-of-use and easements. In June 2015, we reached agreements with the BOEM pursuant to which we provided $54.7 million of supplemental bonds issued to the BOEM (which is reflected in the $58.3 million in lease and/or area bonds discussed above), and the BOEM agreed to withdraw its orders with regard to supplemental bonding and postpone until November 15, 2015 the issuance of further requirements of us related to these supplemental bonding obligations. On June 30, 2015, we sold the East Bay field and the $566.5 million of requested supplemental bonding was reduced by approximately $178 million.

On September 22, 2015, the BOEM issued Draft Guidance relating to supplemental bonding procedures that will, among other things, eliminate the waiver exemption currently allowed by BOEM with respect to supplemental bonding and, instead, broaden the self-insurance approach that would allow more operators on the OCS to seek self-insurance for a portion of their supplemental bond obligations, but only for an amount that is no more than 10% of such operators tangible net worth. Further, the Draft Guidance would implement a phased-in period for establishing compliance with supplemental bonding obligations, whereby operators may seek payment of estimated costs of decommissioning obligations owed under a tailored plan that is approved by the BOEM and requires payment of the supplemental bonding amount in three equal installment of one-third each, by no later than 120, 240 and 360 calendar days, respectively, from the date of BOEM approval of the tailored plan. Furthermore, with issuance of an ANPR in August 2014, the BOEM is actively seeking to bolster its financial assurance requirements mandated by rule for all companies operating in federal waters.

The BOEM may in the future continue to review our plugging, abandonment, decommissioning and removal obligations; re-evaluate the adequacy of our financial assurances; and require us to provide additional supplemental bonding or other surety for most or all of our properties. With respect to our existing bonds and letters of credit with third parties, we can provide no assurance that the BOEM will consider them when determining the total value of additional financial assurances and/or bonding we must provide. In addition, since June 2015, we have received additional letters from the BOEM in which the BOEM requests additional supplemental bonding for other certain properties previously exempt from supplemental bonding. Furthermore, we anticipate our supplemental bonding requirements to increase as we further develop or acquire additional properties subject to the BOEM s financial assurance requirements. The cost of compliance with our existing supplemental bonding requirements or any changes to the BOEM s current NTL supplemental bonding requirements or supplemental bonding regulations applicable to us or our properties could be substantial and could materially and adversely affect our financial condition, cash flows, and results of operations. In addition, we may be required to provide letters of credit to support the issuance of such bonds or other surety. Such letters of credit would likely be issued under our credit facility and would reduce the amount of borrowings available under such facility in the amount of any such letter of credit obligations. We can provide no assurance that we can continue to obtain bonds or other surety in all cases or that we will have sufficient availability under our credit facility to support such supplemental bonding requirements.

Capital Expenditures

For fiscal 2015, our capital expenditures totaled approximately $271 million, of which approximately $186 million was spent on development of our core properties, $27 million on exploration of core properties and $58 million on other assets. Our initial fiscal year 2016 capital budget is expected to be approximately $26 million. The budgeted capital is allocated to development activities, which are geared toward the improvement of existing production, the continued development of core fields, and the performance of necessary plugging, abandonment and other decommissioning activities. Based on our outlook of commodity prices and our estimated production, we expect to fund our fiscal year 2016 capital expenditures with cash flow from operations, borrowings and equity investments from EGC. If oil and natural gas prices remain at current levels or continue to decline, we may be required to reduce our capital expenditure budget for fiscal year 2016 and future years, which in turn may affect our liquidity and results of operations in future periods. If our cash flows from operations and availability of funding from EGC are not sufficient to fund our capital program, we may further reduce our capital spending or otherwise fund our capital needs with proceeds from the sale of non-core assets. Our capital expenditures and the scope of our drilling activities for fiscal year 2016 may change as a result of several factors, including, but not limited to, changes in oil and natural gas sales prices, costs of drilling and completion operations and drilling results and changes in the borrowing base under the First Lien Credit Agreement and available funding from EGC.

Disposition

On June 30, 2015, we sold our interest in the East Bay field for cash consideration of $21 million plus the assumption of asset retirement obligations totaling approximately $55.1 million. The cash consideration is payable in two installments with $5 million received at closing and the remainder due on or before October 31, 2015. We retained a 5% overriding royalty interest (applicable only during calendar months if and when the WTI for such month averages over $65) on these assets for a period not to exceed 5 years from the closing date or $7 million whichever occurs first, and we also retained 50% of the deep rights associated with the East Bay field.

We may decide to divest of certain non-core assets from time to time. There can be no assurance any such potential transactions will prove successful. We cannot provide any assurance that we will be able to sell these assets on satisfactory terms, if at all.

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Analysis of Cash Flows for the Year ended June 30, 2015 compared to the Year ended December 31, 2013

The following table sets forth our cash flows:

	Year Ended June 30, 2015	Year Ended December 31, 2013
	(In thousands)	
Net cash provided by operating activities	$ 126,007	$ 387,559
Net cash used in investing activities	(294,257)	(306,339)
Net cash provided by (used in) financing activities	162,866	(73,929)

The decrease in our fiscal year 2015 cash flows from operating activities primarily reflects decreases in revenues due to the decrease in oil prices and changes in working capital during the year ended June 30, 2015, as compared to the year ended December 31, 2013.

Net cash used in investing activities decreased for the year ended June 30, 2015, as compared to the year ended December 31, 2013, primarily due to the decrease in capital expenditures and property acquisitions.

Net cash provided by financing activities during the year ended June 30, 2015 reflects $165.8 million in advances from EGC. Net cash used in financing activities during the year ended December 31, 2013 primarily reflected repayments of $65.0 million borrowed under our prior senior credit facility as well as $9.6 million for purchases of shares of our common stock (which were held as treasury shares) pursuant to our repurchase program.

We have not paid any cash dividends in the past on our common stock. The covenants in certain debt instruments to which we are a party, including the 2011 Indenture governing the 8.25% Senior Notes, place certain restrictions and conditions on our ability to pay dividends. Any future cash dividends would depend on contractual limitations, future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

Analysis of Cash Flows for the Six months ended June 30, 2014 compared to the Six Months ended June 30, 2013

The following table sets forth our cash flows:

	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Six Months Ended June 30, 2013
	(In thousands)	(In thousands)	
Net cash provided by operating activities	$ 22,209	$ 105,122	$ 192,476
Net cash used in investing activities	(200,929)	(258,714)	(154,969)
Net cash provided by (used in) financing activities	(15,729)	344,830	(35,143)

The decrease in our 2014 cash flows from operating activities primarily reflects decreases in revenues due to the decrease in the average selling prices for our oil and the decrease in our oil and natural gas production during the six months ended June 30, 2014, as compared to the six months ended June 20, 2013.

Net cash used in investing activities increased for the six months ended June 30, 2014, as compared to the six months ended June 30, 2013. The increase in net cash used during the six months ended June 30, 2014, as compared to the six months ended June 30, 2013, reflects our acquisition of the SP49 Interests and the EI Interests and increased exploration and development expenditures in 2014. In addition, net cash used in investing activities during the six months ended June 30, 2013 is net of the $51.7 million in proceeds from the sale of the BM Interests.

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Net cash provided by financing activities during the six months ended June 30, 2014 primarily reflects borrowings of $345.0 million under our prior senior credit facility. Net cash used in financing activities during the six months ended June 30, 2013 reflects repayments of $30.0 million on our prior senior credit facility and $5.1 million for settlements of purchases of shares of our common stock (which were kept as treasury shares) pursuant to our repurchase program.

Analysis of Cash Flows for the Year Ended December 31, 2013 compared to the Year Ended December 31, 2012

The following table sets forth our cash flows:

	Years Ended December 31,	
	2013	2012
	(In thousands)	
Net cash provided by operating activities	$ 387,559	$ 213,871
Net cash used in investing activities	(306,339)	(764,965)
Net cash provided by (used in) financing activities	(73,929)	472,487

The increase in our 2013 cash flows from operating activities primarily reflected increases in revenues due to the increase in our oil and natural gas production during the year ended December 31, 2013, as compared to the year ended December 31, 2012.

Net cash used in investing activities decreased for the year ended December 31, 2013, as compared to the year ended December 31, 2012. Net cash used during the year ended December 31, 2013, related to an increase in exploration and development expenditures of $137.2 million compared to the year ended December 31, 2012, which was consistent with our increased capital expenditures budget for 2013. In addition, net cash used in investing activities during the year ended December, 2013 was net of the $51.7 million in proceeds from the sale of interests in the Bay Marchand field partially offset by property acquisitions, while the year ended December 31, 2012 included the acquisition of the Hilcorp Properties and interests in the South Timbalier 41 field.

Net cash used in financing activities during the year ended December 31, 2013 primarily reflected repayments of $65.0 million borrowed under our prior senior credit facility as well as $9.6 million for purchases of shares of our common stock (which were held as treasury shares) pursuant to our repurchase program. Net cash provided by financing activities during the year ended December 31, 2012 reflected $294.3 million of net cash proceeds from the issuance of the 8.25% Senior Notes in connection with the acquisition of the Hilcorp Properties (including $4.8 million of accrued interest included in the purchase price of the 8.25% Senior Notes) and $215.0 million in borrowings under our prior senior credit facility, partially offset by repayments of $20.0 million on our prior senior credit facility, expenditures of $8.5 million for financing costs primarily associated with our prior senior credit facility and offering expenses associated with our 8.25% Senior Notes issued in connection with the Hilcorp Properties and $8.8 million for settlements of purchases of shares of our common stock (which were kept as treasury shares) pursuant to our repurchase program.

Disclosures about Contractual Obligations and Commercial Commitments

The following table aggregates the contractual commitments and commercial obligations which affect our financial condition and liquidity position as of June 30, 2015.

	Payments Due by Period				
	Total	Less than 1 Year	1 3 Years	3 5 Years	More than 5 years
	(in thousands)				
Long-term debt	$ 988,364	$ 3,364	$ 660,000	$ 325,000	$
Interest on indebtedness	206,739	80,106	118,508	8,125	
Operating leases	3,460	1,231	1,552	677	
Asset retirement obligations (discounted)(1)	240,362	38,056	38,059	20,094	144,153
Drilling rig commitments(2)	4,704	4,704			

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	Payments Due by Period				
	Total	Less than 1 Year	1 3 Years	3 5 Years	More than 5 years
	(in thousands)				
Performance bond premiums(3)	13,365	2,673	5,346	5,346	
Total contractual obligations	$1,456,994	$130,134	$823,465	$359,242	$144,153

(1) See Note 7 Asset Retirement Obligations of Notes to Consolidated Financial Statements in this Form 10-K for details of asset retirement obligations. The obligations reflected above are discounted. In addition, the table above does not include performance bonds totaling $180.8 million which support our asset retirement obligations.

(2) See Note 14 Commitments and Contingencies to our Consolidated Financial Statements in this Form 10-K for discussion of these commitments.

(3) See Note 14 Commitments and Contingencies to our Consolidated Financial Statements in this Form 10-K. As of June 30, 2015, our total annual premium expense for supplemental bonding totaled $2.7 million.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet transactions which may give rise to material off-balance sheet liabilities. As of June 30, 2015, the material off-balance sheet transactions entered into by us include drilling rig contracts and operating lease agreements. See contractual obligations table above. Other than the off-balance sheet transactions listed above, we have no other transactions, arrangements or relationships with other persons that are reasonably likely to materially affect our liquidity or availability of our requirements for capital resources.

Critical Accounting Policies

We have identified the following policies as critical to the understanding of our financial condition and results of operations. This is not a comprehensive list of all of our accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by U.S. GAAP, with no need for management s judgment in selecting their application. There are also areas in which management s judgment in selecting any available alternative would not produce a materially different result. However, certain accounting policies are important to the portrayal of our financial condition and results of operations and require management s most subjective or complex judgments. In applying those policies, management uses its judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on historical experience, observation of trends in the industry, and information available from other outside sources, as appropriate. Our critical accounting policies and estimates are set forth below. Certain of these accounting policies and estimates are particularly sensitive because of their complexity and the possibility that future events affecting them may differ materially from our management s current judgment. Our most sensitive estimate affecting our financial statements are our oil and gas reserves, which are highly sensitive to changes in oil and gas prices that have been volatile in recent years. Although decreases in oil and gas prices are partially offset by our hedging program, to the extent reserves are adversely impacted by reductions in oil and gas prices, we could experience increased depreciation, depletion and amortization expense in future periods.

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

Proved Oil and Gas Reserves. Proved oil and gas reserves are currently defined by the SEC as those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered from existing wells with existing equipment and operating methods. Although our internal and external engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires the engineers to make a number of assumptions based on professional judgment. Estimated reserves are often subject to future revisions, certain of which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions in reserve quantities. Reserve revisions will inherently lead to adjustments of DD&A rates. We cannot predict the types of reserve revisions that will be required in future periods.

Oil and Natural Gas Properties. Oil and natural gas exploration and production companies choose from two acceptable methods of accounting for oil and gas properties, the successful efforts method, which is the method we used prior to the Merger, and the full cost method, which we adopted subsequent to the Merger to be consistent with Energy XXI s method of accounting. The most significant difference between the two methods relates to the accounting treatment of drilling costs incurred on unsuccessful exploratory wells (dry holes) and exploration costs.

Full Cost Method. Under the full cost method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves. Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Oil and natural gas property costs excluded represent investments in unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the property has been evaluated. We also allocate a portion of our acquisition costs to unevaluated properties based on relative value. Costs are transferred to the full cost pool as the properties are evaluated or over the life of the reservoir.

Under the full cost method of accounting, we evaluate the impairment of our evaluated oil and natural gas properties through the use of a ceiling test as prescribed by SEC Regulation S-X Rule 4-10. Future production volumes from oil and natural gas properties are a significant factor in determining the full cost ceiling limitation of capitalized costs. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. Such cost estimates related to future development costs of proved oil and natural gas reserves could be subject to revisions due to changes in regulatory requirements, technological advances and other factors which are difficult to predict. For the second, third and fourth quarters of fiscal year 2015, we recognized ceiling test write-downs of our oil and natural gas properties totaling $1,678.8 million.

Successful Efforts Method. Under the successful efforts method of accounting for oil and natural gas producing activities, costs to acquire mineral interests in oil and natural gas properties, to drill and complete exploratory wells that found proved reserves, and to drill and complete development wells were capitalized. Exploratory drilling costs were initially capitalized, but charged to expense if and when the well was determined not to have found reserves in commercial quantities. Under this method, exploratory well costs were capitalized beyond one year if (a) we found a sufficient quantity of reserves to justify its completion as a producing well and (b) we were making sufficient progress assessing the reserves and the

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economic and operating viability of the project; otherwise, these costs were expensed. Geological and geophysical costs were charged to expense as incurred. We allocated the capitalized cost of producing oil and gas properties to earnings through DD&A on a field-by-field basis as production occurred. Seismic, geological and geophysical, and delay rental expenditures were expensed as incurred.

We segregated the capitalized costs and recorded DD&A for capitalized property costs separately using the units-of-production method based on the ratio of (1) actual volumes in barrel equivalents produced to (2) total proved developed reserve volumes in barrel equivalents (those proved reserves recoverable through existing wells with existing equipment and operating methods), or total proved reserve volumes in barrel equivalents in the case of leasehold costs. Each period, this ratio, referred to as the DD&A rate, was applied to the applicable capitalized asset cost category, resulting in allocation of the cost of our oil and natural gas properties over the periods during which they produced revenues. Because we converted our natural gas reserves and production into barrel equivalents using six thousand cubic feet of natural gas equal to one barrel of oil, which was based on the relative energy content of natural gas and oil, the margin between the revenues realized per barrel equivalent unit of production sold compared to the DD&A recorded per unit of production varied significantly as the mix of production varied and the relative prices of natural gas and oil varied.

Under the successful efforts method, we measured impairments of our oil and natural gas properties based on the estimated fair value of oil and natural gas properties on a field-by-field basis based on the requirements of ASC Topic 360, Property, Plant and Equipment (ASC 360). We evaluated our capitalized oil and natural gas property costs for potential impairment when circumstances indicated that the carrying value may not be recoverable. Because we accumulated capitalized costs, and calculated DD&A, separately on a property by property (generally analogous to a field or a lease) basis, for our proved oil and natural gas properties under the successful efforts method of accounting, we performed impairment assessments on a property by property basis. The need to test a property for impairment was based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserve volumes, actual operating and development costs in excess of expected amounts, changes in estimates of future operating and capital expenditure requirements, or other changes to contracts or environmental regulations. Our impairment tests made use of long-term sales price assumptions for oil and natural gas. A significant amount of judgment and uncertainty was involved in performing impairment evaluations because major inputs to the computation were based on our estimates of future events, including projections of future oil and natural gas sales prices, amounts of recoverable oil and natural gas reserves, timing of future production, future costs to develop and produce our oil and natural gas and discount factors. Our assessment of possible impairment of proved oil and natural gas properties was based on our best estimate of future prices, costs and expected net future cash flows by property. An impairment loss was indicated if undiscounted net future cash flows were less than the carrying value of a property. The impairment expense was measured as the shortfall between the net book value of the property and its estimated fair value measured based on the discounted net future cash flows from the property. Actual prices, costs, and net future cash flows may have varied from our estimates. Our discount rate may not have accurately reflected economic conditions.

For individual unevaluated properties (those with no corresponding proved reserves) with capitalized cost below a threshold amount, we allocated capitalized costs to earnings generally over the primary lease terms. We believed this method provided a reasonable estimate of the amount of capitalized costs of unevaluated properties which would prove unproductive over the primary lease terms. Properties that were subject to amortization and those with capitalized costs greater than the threshold amount were assessed for impairment periodically. If we found oil and natural gas reserves sufficient to justify development of the property, we reclassified the net capitalized cost of the unproved property to proved properties and DD&A was recorded on the units-of-production basis described above. If our efforts did not result in proved oil and natural gas reserves, the related net capitalized costs are charged to earnings as impairment expense.

Business Combinations. For properties acquired in a business combination, we allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes are recorded for any differences between the assigned values and tax basis of assets and liabilities. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. Any excess of amounts assigned to assets and liabilities over the purchase price is recorded as a gain on bargain purchase. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and natural gas properties. To estimate the fair values of these properties, we prepare estimates of oil and natural gas reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

Estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Goodwill. Goodwill has an indefinite useful life and is not amortized, but rather is tested for impairment at least annually during the fiscal third quarter, unless events occur or circumstances change between annual tests that would more likely than not reduce the fair value of a related reporting unit below its carrying value. Impairment occurs when the carrying amount of goodwill exceeds its implied fair value. Goodwill arose in fiscal 2014 with pushdown accounting associated with the Merger.

At September 30, 2014, we conducted a qualitative goodwill impairment assessment by examining relevant events and circumstances that could have a negative impact on our goodwill, such as macroeconomic conditions, industry and market conditions, cost factors that have a negative effect on earnings and cash flows, overall financial performance, dispositions and acquisitions, and any other relevant events or circumstances. After assessing the relevant events and circumstances for the qualitative impairment assessment, we determined that performing a quantitative goodwill impairment test was necessary. In the first step of the goodwill impairment test, we determined that the fair value of our reporting unit was less than its carrying amount, including goodwill, primarily due to price deterioration in forward pricing curves for oil and natural gas and an increase in our weighted average cost of capital, both factors which adversely impacted the fair value of our estimated reserves. Therefore, we performed the second step of the goodwill impairment test, which led us to conclude that there would be no remaining implied fair value attributable to goodwill. As a result, we recorded a goodwill impairment charge of $329.3 million to reduce the carrying value of goodwill to zero at September 30, 2014.

Asset Retirement Obligations. Our investment in oil and gas properties includes an estimate of the future cost associated with dismantlement, abandonment and restoration of our properties. The present value of the future costs are added to the capitalized cost of our oil and gas properties and recorded as a long-term or current liability. The capitalized cost is included in oil and natural gas properties cost that are depleted over the life of the assets. The estimation of future costs associated with dismantlement, abandonment and restoration requires the use of estimated costs in future periods that, in some cases, will not be incurred until a number of years in the future. Such cost estimates could be subject to revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors that are difficult to predict.

Derivative Instruments. We utilize derivative instruments in the form of natural gas and crude oil put, swap and collar arrangements and combinations of these instruments in order to manage the price risk associated with future crude oil and natural gas production. Derivative instruments are recorded at fair value and included as either assets or liabilities in the consolidated balance sheets. Subsequent to the Merger, we designated the majority of our derivative instruments as cash flow hedges. However, in connection with preparing our Form 10-K for the year ended June 30, 2015, we determined that the contemporaneous formal documentation that we had prepared to support our designations of derivative financial instruments as cash flow hedges related to our crude oil and natural gas hedging program did not meet the technical requirements to qualify for cash flow hedge accounting treatment in accordance with ASC Topic 815, *Derivatives and Hedging*. The primary reason for this determination was that the formal hedge documentation lacked specificity of the hedged items and, therefore, the designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment. Accordingly, our currently outstanding derivative contracts are not accounted for as cash flow hedges. Therefore, changes in fair value of these outstanding derivative financial instruments are recognized in earnings and included in gain (loss) on derivative financial instruments as a component of revenues in the accompanying consolidated statements of operations.

Prior to the Merger, we did not designate derivative instruments as hedges. Gains and losses resulting from changes in the fair value of derivative instruments were recorded in other income (expense). Gains and losses related to contract settlements were also recorded in other income (expense).

Income Taxes. Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and natural gas properties and derivative instruments for financial reporting purposes and income tax purposes. Changes in the financial accounting method for derivative instruments caused no changes in previous tax filings or deferred tax balances related to these instruments. For financial reporting purposes, all exploratory and development expenditures are capitalized and depreciated, depleted and amortized on the unit-of-production method. For income tax purposes, only the equipment and leasehold costs relative to successful wells are capitalized and recovered through depreciation or depletion. Generally, most other exploratory and development costs are charged to expense as incurred; however, we may use certain provisions of the Internal Revenue Code which allow capitalization of intangible drilling costs where management deems appropriate.

When recording income tax expense, certain estimates are required to be made by management due to timing and to the impact of future events on when income tax expenses and benefits are recognized by us. As a result of changes in our expectations regarding our future taxable income, consistent with the results of operations for the current year (heavily affected by impairments), we recorded a valuation allowance of $189.6 million at June 30, 2015. We recorded this valuation allowance against our net deferred tax assets due to our judgment that a portion of our existing U.S. federal and State of Louisiana net operating loss (NOL) carryforwards are not, on a more-likely-than-not basis, likely recoverable in future years. We continue to evaluate the need for the valuation allowance based on current and expected taxable income and other factors, and adjust it accordingly.

Share-Based Compensation. Compensation cost for equity awards is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which an employee is required to provide service in exchange for the award. Compensation cost for liability awards is based on the fair value of the vested award at the end of each reporting period.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers* (ASU 2014-09). ASU 2014-09 provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and will supersede most current revenue recognition guidance. ASU No. 2014-09 is effective for annual periods beginning after December 15, 2017, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). Early adoption is permitted for annual periods beginning after December 15, 2016, and interim periods therein. We are evaluating the impact of the pending adoption of ASU No. 2014-09 on our financial position and results of operations and have not yet determined the method that will be adopted.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15, *Disclosure of Uncertainties about an Entity s Ability to Continue as a Going Concern* (ASU 2014-15). ASU 2014-15 requires management to assess an entity s ability to continue as a going concern and to provide related footnote disclosures in certain circumstances. The standard is effective for annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016, with early adoption

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permitted. We are currently evaluating the provisions of ASU 2014-15 and assessing the impact, if any, it may have on our consolidated financial statements.

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, *Interest Imputation of Interest (Subtopic 835-30)* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The ASU is effective for public entities for annual periods beginning after December 15, 2015, and interim periods within those annual reporting periods. Early adoption is permitted for financial statements that have not been previously issued. The guidance will be applied on a retrospective basis. We are currently evaluating the provisions of ASU 2015-03 and assessing the impact it will have on our consolidated financial position and footnote disclosures.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

General

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 which 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, 2015, 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 such as the recent declines adversely affect our revenues, cash flows and profitability.

Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. We have incurred debt under the borrowing base of our Revolving Credit Sub-Facility. This borrowing base is subject to periodic redetermination based in part on changing expectations of future prices. Recently, commodity prices have deteriorated materially. As a result of the reduction in EGC s borrowing base availability to $500 million and the resulting increased asset coverage for the Revolving Credit Facility, we do not currently anticipate any further borrowing base reductions in connection with the semi-annual borrowing base redeterminations. However, it is possible if commodity prices were to decline significantly from current levels, the borrowing base under the Revolving Credit Facility may be further reduced, which would require EGC and us to repay that portion, if any, of our outstanding indebtedness under the facility in excess of the new borrowing base. 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 also use financially settled crude oil and natural gas puts, put spreads, swaps, zero-cost collars and three-way collars. 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 subsequent to the Merger.

With a financially settled purchased put, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the hedged price of the transaction. A put spread is a combination of a bought put and a sold put. If the settlement price is below the sold put strike price, we receive the difference between the two strike prices. If the settlement price is below the bought put strike price but above the sold put strike price, we receive the difference between the bought put strike price and the

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settlement price. There is no settlement if the underlying price settles above the bought put strike price. With a swap, the counterparty is required to make a payment to us if the settlement price for a settlement period is below the hedged price for the transaction, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the hedged price for the transaction. With a zero-cost 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. A three-way collar is a combination of options consisting of a sold call, a purchased put and a sold put. The sold call establishes a maximum price we will receive for the volumes under contract. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be the reference price (i.e., NYMEX WTI and/or BRENT, IPE) plus the difference between the purchased put and the sold put strike price.

At June 30, 2015, our crude oil contracts outstanding were in a liability position of $1.1 million. A 10% increase in crude oil prices would reduce the fair value by approximately $3.5 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $1.8 million. At June 30, 2015, our natural gas contract outstanding was in an asset position of $1.0 million. A 10% increase in natural gas prices would reduce the fair value by approximately $0.2 million, while a 10% decrease in natural gas prices would increase the fair value by approximately $0.2 million. These fair value changes assume volatility based on prevailing market parameters at June 30, 2015. Our ultimate realized gain or loss with respect to commodity price fluctuations will depend on the future exposures that arise during the period, our hedging strategies at the time and commodity prices at the time.

For a complete discussion of our derivative financial instruments, see Note 10, Derivative Instruments and Hedging Activities and Note 11, Fair Value Measurements, of the consolidated financial statements in Part II, Item 8 of this Form 10-K.

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 Revolving Credit Sub-Facility. As of June 30, 2015, total debt included $150.0 million of floating-rate debt. As a result, our period-end interest costs will fluctuate based on short-term interest rates on approximately 15% of our total debt outstanding as of June 30, 2015. A 10% change in floating interest rates on period-end floating debt balances would change annual interest expense by approximately $28,125. We currently have no interest rate hedge positions in place to reduce our exposure to changes in interest rates. However, to reduce our future exposure to changes in interest rates, we may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues.

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* The financial statements for the periods ended September 30, 2013, December 31, 2013, and March 31, 2014 are not restated. Prior to the Merger, EPL did not designate derivative contracts as cash flow hedges, therefore no restatement required for those periods.

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is a process designed by management, under the supervision of our principal executive and principal financial officers, and effected by our Board of Directors, management and other personnel, 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 in the U.S. (U.S. GAAP) and includes those policies and procedures that:

Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management, under the supervision and participation of our principal executive officer and our principal financial officer, assessed the effectiveness of our internal control over financial reporting as of June 30, 2015. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013).*

Prior to the issuance of this Form 10-K, management determined that the contemporaneous formal documentation that we had prepared to support our designations of derivative financial instruments as cash flow hedges in connection with our crude oil and natural gas hedging program did not meet the technical requirements to qualify for cash flow hedge accounting treatment in accordance with ASC Topic 815, Derivatives and Hedging. The primary reason for this determination was that the formal hedge documentation lacked specificity of the hedged items and, therefore, the designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment. Accordingly, we restated our consolidated balance sheet as of June 30, 2014, our consolidated statements of operations, consolidated statements of cash flows, and consolidated statements of stockholders equity (deficit) for period from June 4, 2014 to June 30, 2014, and restated quarterly financial information for the quarters ended September 30, 2014, December 31, 2014 and March 31, 2015. Management evaluated the impact of this restatement on our assessment of our internal control over financial reporting. Management has concluded that the controls in place relating to the documentation of hedge designations were not properly designed to provide reasonable assurance that these derivative contracts would be properly recorded and disclosed in the financial statements in accordance with U.S. GAAP; and, that this represents a material weakness in our internal control over financial reporting as of June 30, 2015. As a result of the assessment performed and the material weakness noted, management has concluded that our internal control over financial reporting was not effective as of June 30, 2015. Further, we have determined that these control deficiencies existed with respect to certain aspects of our historical financial reporting as of June 30, 2014 and, accordingly, we have concluded that our prior disclosures regarding the sufficiency of our disclosure controls, internal controls and changes in internal controls may not have been correct.

In addition, we recently learned that, in 2007, 2009 and 2014, the Chief Executive Officer of our parent company Energy XXI Ltd borrowed funds from personal acquaintances or their affiliates, certain of whom provided the Company with services. We also learned that Norman Louie, one of the directors of our parent company, made a personal loan to Mr. Schiller in 2014 before Mr. Louie became a director of our parent. At the time the loan was made, Mr. Louie was a managing director at Mount Kellett Capital Management LP,

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which at the time, and as of June 30, 2015, owned a majority interest in Energy XXI M21K, an equity method investee of Energy XXI, and 6.3% of Energy XXI s common stock. The loans made in 2014 are still outstanding. Since Mr. Schiller did not disclose the personal loans before they were made, our parent s board of directors has determined that he did not comply with the procedural requirements of the Company s Code of Business Conduct and Ethics. Upon learning of Mr. Schiller s personal loans from affiliates of service providers, our parent s board of directors engaged independent legal counsel to conduct an internal investigation, with the assistance of outside forensic accountants, to review these loans and vendor procurement processes across the organization, including EPL. Our parent s board of directors is still reviewing the results of the internal investigation. Although the internal investigation has not uncovered any illegal activity or any impact on parent or EPL s financial reporting or financial statements, we have concluded this non-compliance to be a material weakness in its control environment given the leadership position of this officer, the visibility and importance of his actions to the Company s overall system of controls and the significance with which the Company views this nondisclosure. As part of its review, our parent s board of directors has begun the process of designing and implementing additional controls and procedures, including, but not limited to, strengthening the vendor procurement procedures across the organization including EPL to address any potential conflicts of interest that could arise from Mr. Schiller s personal loans; revising our parent s Code of Business Conduct and Ethics to explicitly ban any such personal loans in the future; and implementing an enhanced comprehensive training program on our parent s Code of Business Conduct and Ethics.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholder
EPL Oil & Gas, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheet of EPL Oil & Gas, Inc. and subsidiaries (the Company) as of June 30, 2015 and the related consolidated statements of operations, stockholders equity (deficit), and cash flows for the year then ended. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of EPL Oil & Gas, Inc. and subsidiaries at June 30, 2015, and the results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ BDO USA, LLP

Houston, Texas
October 12, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
EPL Oil & Gas, Inc.

We have audited the accompanying consolidated balance sheet of EPL Oil & Gas, Inc. and subsidiaries (the Company) as of June 30, 2014, and the related consolidated statements of operations, stockholders equity, and cash flows for the periods from June 4, 2014 to June 30, 2014 and from January 1, 2014 to June 3, 2014. The Company s management is responsible for these consolidated financial statements. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of EPL Oil & Gas, Inc. and subsidiaries as of June 30, 2014, and the consolidated results of their operations and their cash flows for the periods from June 4, 2014 to June 30, 2014 and from January 1, 2014 to June 3, 2014, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP

Houston, Texas
September 23, 2014, except for the effects of the
restatement disclosed in Note 17, as to
which the date is October 12, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of EPL Oil & Gas, Inc.:

In our opinion, the consolidated statements of operations, of changes in stockholders equity and of cash flows for each of two years in the period ended December 31, 2013 present fairly, in all material respects, the financial position of EPL Oil & Gas, Inc. and its subsidiaries at December 31, 2013, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

New Orleans, Louisiana
February 27, 2014

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EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	SUCCESSOR COMPANY	
	June 30, 2015	June 30, 2014 (Restated)
ASSETS		
Current assets:		
Cash and cash equivalents	$217	$5,601
Trade accounts receivable net	71,323	72,301
Derivative financial instruments	888	
Deferred tax asset		24,587
Restricted cash	6,024	
Prepaid expenses	1,831	26,521
Total current assets	80,283	129,010
Property and equipment, net full cost method of accounting, including $435.4 million and $908.5 million of unevaluated properties not being amortized at June 30, 2015 and 2014, respectively	1,415,025	3,205,187
Goodwill		329,293
Restricted cash		6,023
Other assets and debt issuance costs, net of accumulated amortization	1,039	317
Total assets	$1,496,347	$3,669,830
LIABILITIES AND STOCKHOLDERS EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$24,548	$92,981
Due to EGC	170,728	4,960
Accrued expenses	95,981	161,518
Asset retirement obligations	38,056	39,831
Derivative financial instruments	1,057	26,440
Current maturities of long-term debt	3,364	
Total current liabilities	333,734	325,730
Long-term debt, less current maturities	689,459	1,025,566
Promissory note payable to EGC	325,000	
Asset retirement obligations	202,306	232,864
Deferred tax liabilities		483,810
Derivative financial instruments		2,140
Other		6
Total liabilities	1,550,499	2,070,116
Commitments and contingencies (Note 14)		
Stockholders equity (deficit):		

Preferred stock, par value $0.001 per share. Authorized 1,000,000 shares; no shares issued and outstanding at June 30, 2015 and 2014		
Common stock, par value $0.001 per share. Authorized 75,000,000 shares; shares issued and outstanding: 1,000 at June 30, 2015 and 2014		
Additional paid-in capital	1,599,341	1,599,341
Retained earnings (accumulated deficit)	(1,653,493)	373
Total stockholders equity (deficit)	(54,152)	1,599,714
Total liabilities and stockholders equity (deficit)	$1,496,347	$3,669,830

See accompanying notes to consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES CONSOLIDATED BALANCE SHEETS (In thousands, except share da 153

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EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (In thousands, except per share data)

	SUCCESSOR COMPANY		PREDECESSOR COMPANY		
	Year Ended June 30, 2015	Period from June 4, 2014 through June 30, 2014 (Restated)	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012
Revenue:					
Oil and natural gas	$501,789	$61,271	$274,772	$688,743	$422,529
Gain (loss) on derivative financial instruments	40,082	(11,079)			
Other	932	332	1,628	4,295	1,104
Total revenue	542,803	50,524	276,400	693,038	423,633
Costs and expenses:					
Lease operating	211,699	17,746	72,302	165,841	94,850
Transportation	3,035	299	1,475	3,568	615
Exploration expenditures and dry hole costs			26,239	26,555	18,799
Impairment of oil and natural gas properties	1,678,804		61	2,937	8,883
Goodwill impairment	329,293				
Depreciation, depletion and amortization	314,953	22,775	85,127	200,359	113,581
Accretion of liability for asset retirement obligations	23,400	2,022	11,771	28,299	15,565
General and administrative	35,324	2,617	51,434	28,137	23,208
Taxes, other than on earnings	8,126	850	4,384	11,490	13,007
Gain on sales of assets				(28,681)	
Other	18		44	34,942	4,678
Total costs and expenses	2,604,652	46,309	252,837	473,447	293,186
Income (loss) from operations	(2,061,849)	4,215	23,563	219,591	130,447
Other income (expense):					
Interest income	18	4	17	99	136
Interest expense	(51,258)	(3,627)	(22,621)	(52,368)	(28,568)
Loss on derivative instruments			(19,420)	(32,361)	(13,305)

Total other expense	(51,240)	(3,623)	(42,024)	(84,630)	(41,737)
Income (loss) before income taxes	(2,113,089)	592	(18,461)	134,961	88,710
Income tax expense (benefit)	(459,223)	219	4,495	49,687	29,900
Net income (loss)	$(1,653,866)	$373	$(22,956)	$85,274	$58,810
Basic earnings (loss) per share			$(0.59)	$2.18	$1.50
Diluted earnings (loss) per share			$(0.59)	$2.15	$1.50
Weighted average common shares used in computing earnings (loss) per share:					
Basic			38,730	38,730	38,885
Diluted			38,730	39,236	39,034

See accompanying notes to consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF OPERATIONS (In thousands, e 155

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EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY (DEFICIT) (In thousands)

See accompanying notes to consolidated financial statements.

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EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (In thousands)

	SUCCESSOR COMPANY		PREDECESSOR COMPANY		
	Year Ended June 30, 2015	Period from June 4, 2014 through June 30, 2014 (Restated)	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012
Cash flows from operating activities:					
Net income (loss)	$(1,653,866)	$373	$(22,956)	$85,274	$58,810
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation, depletion and amortization	314,953	22,775	85,127	200,359	113,581
Accretion of liability for asset retirement obligations	23,400	2,022	11,771	28,299	15,565
Change in fair value of derivative financial instruments	(11,106)	9,528	(6,996)	20,884	9,491
Non-cash compensation			19,704	7,344	4,717
Deferred income taxes	(459,223)	219	4,495	49,687	29,900
Exploration expenditures			14,825	5,520	4,227
Impairment of oil and natural gas properties	1,678,804		61	2,937	8,883
Goodwill impairment	329,293				
Amortization of premium, discount and deferred financing costs on debt	(10,996)	(841)	2,359	5,396	2,556
Gain on sales of assets				(28,681)	
Other			(573)	27,235	2,448
Changes in operating assets and liabilities:					
Trade accounts receivable	20,205	18,238	(21,106)	(1,916)	(33,547)
Prepaid expenses and other assets	25,008	3,274	(1,881)	2,871	1,192
Accounts payable and accrued expenses	(77,209)	(29,592)	52,932	35,658	31,477
Asset retirement obligation settlements	(53,256)	(3,787)	(32,640)	(53,308)	(35,429)
Net cash provided by operating activities	126,007	22,209	105,122	387,559	213,871
Cash flows provided by (used in) investing activities:					
Property acquisitions	(350)	(141,886)	(60,495)	(27,560)	(578,372)
Deposit for Nexen Acquisition				(7,040)	

Capital expenditures	(298,849)	(58,976)	(197,968)	(322,040)	(184,850)
Other property and equipment additions	(58)	(67)	(251)	(2,016)	(1,743)
Proceeds from sale of assets	5,000			52,317	
Net cash used in investing activities	(294,257)	(200,929)	(258,714)	(306,339)	(764,965)

See accompanying notes to consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF CASH FLOWS (In thousands)

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(In thousands)

	SUCCESSOR COMPANY		PREDECESSOR COMPANY		
	Year Ended June 30, 2015	Period from June 4, 2014 through June 30, 2014 (Restated)	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012
Cash flows provided by (used in) financing activities:					
Proceeds from indebtedness	$	$475,000	$345,000	$	$509,313
Repayments of indebtedness	(325,000)	(475,000)		(65,000)	(20,000)
Proceeds from intercompany promissory note	325,000				
Payments on put financing	(1,751)				
Advances from (to) EGC	165,768	(15,729)			
Deferred financing costs	(1,151)		(170)	(674)	(8,469)
Purchase of shares into treasury				(9,640)	(8,798)
Exercise of stock options				1,385	441
Net cash provided by (used in) financing activities	162,866	(15,729)	344,830	(73,929)	472,487
Net increase (decrease) in cash and cash equivalents	(5,384)	(194,449)	191,238	7,291	(78,607)
Cash and cash equivalents at beginning of period	5,601	200,050	8,812	1,521	80,128
Cash and cash equivalents at end of period	$217	$5,601	$200,050	$8,812	$1,521
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:					
Non-cash investing information:					
Capital contribution from EGC	$	$95,000	$	$	$
Derivative instruments premium financing	5,115				
Changes in capital expenditures accrued in accounts payable	(80,984)	(27,404)	40,884	13,819	27,621
	(64,295)				

Non-cash change related to property disposition					
Non-cash changes in asset retirement obligations	52,842		7,415	25,773	23,518
Cash paid during the period for:					
Interest	$52,146	$1,559	$23,185	$47,339	$21,129

See accompanying notes to consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies

EPL Oil & Gas, Inc. (referred to herein as we, our, us, EPL or the Company) was incorporated as a Delawa corporation on January 29, 1998 and is a wholly-owned subsidiary of Energy XXI Gulf Coast, Inc. (EGC), a Delaware corporation and indirect wholly-owned subsidiary of Energy XXI Ltd, an exempted company under the laws of Bermuda and our ultimate parent company (Energy XXI or parent). We operate as an independent oil and natural gas exploration and production company based in Houston, Texas. Effective September 1, 2012, we changed our legal corporate name from Energy Partners, Ltd. to EPL Oil & Gas, Inc. through a short-form merger pursuant to Section 253 of the General Corporation Law of the State of Delaware.

On June 3, 2014, Energy XXI, EGC, Clyde Merger Sub, Inc., a wholly owned subsidiary of EGC (Merger Sub), and EPL, completed the transactions contemplated by the Agreement and Plan of Merger, dated as of March 12, 2014 (as amended, the Merger Agreement), by and among Energy XXI, EGC, Merger Sub, and EPL, pursuant to which Merger Sub was merged with and into EPL with EPL continuing as the surviving corporation (the Merger). Pursuant to the Merger Agreement, at the effective time of the Merger (the Effective Time), the issued and outstanding shares of EPL common stock, par value $0.001 per share (EPL Common Stock), were converted, in the aggregate, into the right to receive merger consideration (the Merger Consideration) consisting of approximately 65% in cash and 35% in shares of common stock of Energy XXI, par value $0.005 per share (Energy XXI Common Stock). See Note 4, Common Stock for more information regarding the Merger Consideration.

Our current operations are concentrated in the U.S. Gulf of Mexico shelf (the GoM shelf) focusing on state and federal waters offshore Louisiana, which we consider our core area. We have focused on acquiring and developing assets in this region, because the region is characterized by established exploitation, development and exploration opportunities in both productive horizons and deeper geologic formations.

A summary of acquisition and disposition activity during 2015, 2014 and 2013 is as follows (purchase prices are before economic effective date adjustments):

On June 30, 2015, we sold our interest in the East Bay field to Whitney Oil & Gas, LLC and Trimont Energy (NOW), LLC, for cash consideration of approximately $21 million;
On June 3, 2014, we acquired from Energy XXI GOM, LLC, a Delaware limited liability company and wholly-owned subsidiary of Energy XXI (Energy XXI GOM), an asset package consisting of certain shallow water GoM shelf oil and natural gas interests in our South Pass 49 field for $230 million;
On January 15, 2014, we acquired 100% working interest of certain shallow-water central GoM shelf oil and natural gas assets comprised of five leases in the Eugene Island 258/259 field for $70.4 million;
On September 26, 2013, we acquired an asset package consisting of certain GoM shelf oil and natural gas interests in the West Delta 29 field for $21.8 million; and
On April 2, 2013, we sold certain shallow water GoM shelf oil and natural gas interests located within the non-operated Bay Marchand field for total consideration of $62.8 million.

See Note 3, Acquisitions and Disposition for more information regarding these transactions.

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below.

Basis of Presentation. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (U.S. GAAP) and include the accounts of EPL and our wholly-owned subsidiaries. All significant intercompany accounts and transactions are eliminated in consolidation. Our interests in oil and natural gas exploration and production ventures and partnerships are proportionately consolidated.

The Merger resulted in EPL becoming an indirect, wholly owned subsidiary of Energy XXI. Therefore, in the preparation of our financial statements, we have applied pushdown accounting, based on guidance from the Securities and Exchange Commission (SEC). Pushdown accounting refers to the use of the acquiring entity s basis of accounting in the preparation of the acquired entity s financial statements. As a result, our separate financial statements reflect the new basis of accounting recorded by Energy XXI upon acquisition. As such, in accordance with U.S. GAAP, due to our new basis of accounting, our financial statements include a black line denoting that our financial statements covering periods prior to the date of the Merger are not comparable to our financial statements as of and subsequent to the date of the Merger. References to the Predecessor Company refer to reporting dates of the Company through June 3, 2014, reflecting results of operations and cash flows of the Company prior to the Merger on our historical accounting basis; subsequent thereto, the Company is referred to as the Successor Company, reflecting the impact of pushdown accounting and the results of operations and cash flows of the Company subsequent to the Merger. See Note 2, Pushdown Accounting for more information regarding these transactions.

Energy XXI follows the full cost method of accounting for its oil and gas producing activities, while we had historically followed the successful efforts method of accounting. Subsequent to the Merger, we converted our accounting method from successful efforts to the full cost method of accounting to be consistent with Energy XXI s method of accounting pursuant to SEC guidance, which requires a reporting entity that follows the full cost method to apply that method to all of its operations and to the operations of its subsidiaries. Under U.S. GAAP, a change in accounting method is required to be applied retroactively in order to provide comparable historical period information to users of financial statements. However, due to the new basis of accounting established as a result of the Merger transaction and pushdown accounting, our financial statements are no longer comparable to those of prior periods and we have applied the full cost method of accounting on a prospective basis from the date of the Merger.

Energy XXI has a fiscal year end of June 30, while we historically had a fiscal year end of December 31. Subsequent to the Merger, we changed our year end to June 30 to be consistent with Energy XXI. Therefore, these financial statements include audited statements of operations, cash flows and stockholders equity using the successful efforts method of accounting applied to our historical basis in our assets and liabilities for the five months and three days ended June 3, 2014 and audited statements of operations, cash flows and stockholders equity using the full cost method of accounting applied to EPL s new basis in its assets and liabilities established in the Merger transaction for the twenty-seven days ended June 30, 2014, with a black line between the periods denoting that they are not comparable.

We have restated consolidated financial statements issued subsequent to the Merger to reflect the recognition of gains and losses on derivative financial instruments previously included in accumulated other comprehensive income (loss) as gain (loss) on derivative financial instruments in earnings as a component of revenues and the reclassification of amounts associated with settled contracts previously included in oil and gas sales revenues to gain (loss) on derivative financial instruments as a result of not qualifying for cash flow hedge accounting treatment. The restatement also reflects resulting adjustments to net oil and natural gas properties, impairment of oil and natural gas properties and depreciation, depletion and amortization due to the previous inclusion of the value of the cash flow hedges in our full cost ceiling test, which is only permitted if the derivative instruments qualify for cash flow hedge accounting. Additionally, resulting adjustments to

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EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

deferred income taxes and income tax expense (benefit) are also reflected in the restatement. See Note 17 Restatement of Previously Issued Consolidated Financial Statements for details of the impact of the restatement.

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

Cash and Cash Equivalents. We consider all highly liquid investments, with maturities of 90 days or less when purchased, to be cash and cash equivalents.

Restricted Cash. We maintain restricted escrow funds in trusts as required by certain contractual arrangements. Amounts on deposit in trust accounts are reflected in Restricted cash on our consolidated balance sheets.

Accounts Receivable and Allowance for Doubtful Accounts. Accounts receivable are stated at historical carrying amount net of allowance for doubtful accounts. We establish provisions for losses on accounts receivable if it is determined that collection of all or a part of an outstanding balance is not probable. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2015 and 2014, no allowance for doubtful accounts was necessary.

Oil and Natural Gas Properties. As described above, subsequent to the Merger, we adopted the full cost method of accounting for exploration and development activities. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves.

Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Costs excluded from depletion or amortization represent investments in unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the property has been evaluated. We also allocate a portion of our acquisition costs to unevaluated properties based on fair value. Costs associated with unevaluated properties are transferred to evaluated properties upon the earlier of 1) a determination as to whether there are any proved reserves related to the properties, or 2) ratably over a period of time of not more than four years.

We evaluate the impairment of our evaluated oil and natural gas properties through the use of a ceiling test as prescribed by SEC Regulation S-X Rule 4-10. Future production volumes from oil and natural gas properties are a significant factor in determining the full cost ceiling limitation of capitalized costs. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural

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EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. Such cost estimates related to future development costs of proved oil and natural gas reserves could be subject to revisions due to changes in regulatory requirements, technological advances and other factors which are difficult to predict.

Prior to the Merger, we used the successful efforts method of accounting for oil and natural gas producing activities. Costs to acquire mineral interests in oil and natural gas properties, to drill and complete exploratory wells that find proved reserves, and to drill and complete development wells were capitalized. Exploratory drilling costs were initially capitalized, but charged to expense if and when the well was determined not to have found reserves in commercial quantities. We may have capitalized exploratory well costs beyond one year if (a) we found a sufficient quantity of reserves to justify its completion as a producing well and (b) we were making sufficient progress assessing the reserves and the economic and operating viability of the project; otherwise, these costs were expensed. Geological and geophysical costs were charged to expense as incurred.

Leasehold acquisition costs were capitalized as unproved properties. If proved reserves were discovered on undeveloped leases, the related leasehold costs were transferred to proved properties and amortized using the units of production method. For individual unevaluated properties with capitalized costs below a threshold amount, we allocated capitalized costs to earnings generally over the primary lease terms. Properties that were subject to amortization and those with capitalized costs greater than the threshold amount were assessed for impairment periodically. Capitalized costs of producing oil and natural gas properties were depreciated and depleted by the units-of-production method.

We evaluated our capitalized costs of proved oil and natural gas properties for potential impairment when circumstances indicated that the carrying values may not have been recoverable. The need to test a property for impairment was based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserve volumes, actual operating and development costs in excess of expected amounts, changes in estimates of future operating and capital expenditure requirements, or other changes to contracts, environmental regulations or tax laws. The calculation was performed on a field-by-field basis, utilizing our current estimates of future revenues and operating expenses. In the event net undiscounted cash flow was less than the carrying value, an impairment loss was recorded based on the present value of expected future net cash flows over the economic lives of the reserves.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depletion, depreciation and amortization were eliminated from the property accounts, along with the related asset retirement obligations, unless retained by us, and the resulting gain or loss was recognized in earnings.

Depreciation, Depletion and Amortization. Subsequent to the Merger, the depreciable base for oil and natural gas properties includes the sum of all capitalized costs net of accumulated depreciation, depletion, amortization and impairment (DD&A), estimated future development costs and asset retirement costs not included in oil and natural gas properties, less costs excluded from amortization. The depreciable base of oil and natural gas properties is amortized using the unit-of-production method over total proved reserves.

Weather Based Insurance Linked Securities. We obtain Weather Based Insurance Linked Securities (Securities), to mitigate potential loss to our oil and natural gas properties from hurricanes in the Gulf of Mexico. These Securities provide for payments of negotiated amounts should a pre-defined category hurricane pass within specific pre-defined areas encompassing our oil and natural gas producing fields. Since these Securities were obtained to mitigate potential loss due to hurricanes in the Gulf of Mexico, the majority of the premiums associated with these Securities are charged to expense during the period associated with the hurricane season, typically June 1 to November 30. The amortization of insurance premiums for these Securities is recorded as a component of our lease operating expense.

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EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

Other Property and Equipment. Other property and equipment include data processing and telecommunications equipment, office furniture and equipment, vehicle and leasehold improvements and other fixed assets. These items are recorded at cost and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets, which ranges from three to five years. Repairs and maintenance costs are expensed in the period incurred.

Business Combinations. For properties acquired in a business combination, we allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes are recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. Any excess of amounts assigned to assets and liabilities over the purchase price is recorded as a gain on bargain purchase. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and natural gas properties. To estimate the fair values of these properties, we prepare estimates of crude oil and natural gas reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Goodwill. Goodwill has an indefinite useful life and is not amortized, but rather is tested for impairment at least annually during the third quarter, unless events occur or circumstances change between annual tests that would more likely than not reduce the fair value of a related reporting unit below its carrying value. Impairment occurs when the carrying amount of goodwill exceeds its implied fair value. We recorded goodwill as of June 3, 2014 as a result of pushdown accounting in conjunction with the Merger. At September 30, 2014, we conducted a qualitative goodwill impairment assessment and after assessing the relevant events and circumstances, we determined that performing a quantitative goodwill impairment test was necessary. Therefore, we performed steps one and two of the goodwill impairment test, which led us to conclude that there would be no remaining implied fair value attributable to goodwill.

As a result, we recorded a goodwill impairment charge of $329.3 million to reduce the carrying value of goodwill to zero at September 30, 2014. See Note 2, Pushdown Accounting for more information.

Derivative Instruments. We utilize derivative instruments in the form of natural gas and crude oil put, swap and collar arrangements and combinations of these instruments in order to manage the price risk associated with future crude oil and natural gas production. Derivative financial instruments are recorded at fair value and included as either assets or liabilities in the consolidated balance sheets. We net derivative assets and liabilities for counterparties where we have a legal right of offset. Any premiums paid or financed on derivative financial instruments are capitalized as part of the derivative assets or derivative liabilities, as appropriate, at the time the premiums are paid or financed.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

Subsequent to the Merger, we designated the majority of our derivative instruments as cash flow hedges. However, in connection with preparing our Form 10-K for the year ended June 30, 2015, we determined that the contemporaneous formal documentation that we had prepared subsequent to the Merger to support our designations of derivative financial instruments as cash flow hedges related to our crude oil and natural gas hedging program did not meet the technical requirements to qualify for cash flow hedge accounting treatment in accordance with ASC Topic 815, *Derivatives and Hedging*. The primary reason for this determination was that the formal hedge documentation lacked specificity of the hedged items and, therefore, the designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment. Accordingly, our currently outstanding derivative contracts are not accounted for as cash flow hedges. Therefore, subsequent to the Merger, changes in fair value of these outstanding derivative financial instruments are recognized in earnings and included in gain (loss) on derivative financial instruments as a component of revenues in the accompanying consolidated statements of operations of the Successor Company.

Additionally, we concluded that certain of our previously issued consolidated financial statements should no longer be relied upon and would need to be restated. This Form 10-K for the year ended June 30, 2015 includes (1) a restated balance sheet as of June 30, 2014, (2) a restated consolidated statement of operations, consolidated statements of cash flows, and consolidated statements of stockholders equity (deficit) for the period from June 4, 2014 through June 30, 2014, and (3) restated quarterly consolidated financial statements for the quarters ended September 30, 2014, December 31, 2014, and March 31, 2015. See Note 17, Restatement of Previously Issued Consolidated Financial Statements and Note 18, Interim Financial Information for more information concerning these restatements.

Prior to the Merger, we did not designate derivative instruments as hedges. Gains and losses resulting from changes in the fair value of derivative instruments were recorded in other income (expense). Gains and losses related to contract settlements were also recorded in other income (expense).

Debt Issuance Costs. Cost incurred in connection with the issuance of long-term debt are capitalized and amortized to interest expense over the scheduled maturity of the debt utilizing the interest method.

Asset Retirement Obligations. Our investment in oil and natural gas properties includes an estimate of the future cost associated with dismantlement, abandonment and restoration of our properties. The present value of the future costs are added to the capitalized cost of our oil and natural gas properties and recorded as a long-term or current liability. The capitalized cost is included in oil and natural gas properties that are depleted over the life of the assets. The estimation of future costs associated with dismantlement, abandonment and restoration requires the use of estimated costs in future periods that, in some cases, will not be incurred until a substantial number of years in the future. Such cost estimates could be subject to revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors which may be difficult to predict.

Revenue Recognition. We recognize oil and natural gas revenue when the product is delivered at the contracted sales price, title is transferred and collectability is reasonable assured. We have elected the entitlements method to account for gas production imbalances. Gas imbalances occur when we sell more or less than our entitled ownership percentage of total gas production. Any amount received in excess of our share is treated as a liability. If we receive less than our entitled share the underproduction is recorded as a receivable. The amounts of imbalances were not material at June 30, 2015 and 2014.

General and Administrative Expense. Under the full cost method of accounting, the portion of our general and administrative expense that is directly identified with our acquisition, exploration and development activities is capitalized as part of our oil and natural gas properties. These capitalized costs include salaries, employee benefits, costs of consulting services, and other direct costs incurred to support those employees directly involved in acquisition, exploration and development activities. The capitalized costs do not include costs related to production operations, general corporate overhead or similar activities. We began capitalizing

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

general and administrative expenses on July 1, 2015. Our capitalized general and administrative expense directly related to our acquisition, exploration and development activities for the year ended June 30, 2015 was $15.5 million.

Share-Based Compensation. Compensation cost for equity awards is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which an employee is required to provide service in exchange for the award. Compensation cost for liability awards is based on the fair value of the vested award at the end of each reporting period.

Income Taxes. Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and natural gas properties and derivative instruments for financial reporting purposes and income tax purposes. For financial reporting purposes, all exploratory and development expenditures are capitalized and depreciated, depleted and amortized on the unit-of-production method. For income tax purposes, only the equipment and leasehold costs relative to successful wells are capitalized and recovered through depreciation or depletion. Generally, most other exploratory and development costs are charged to expense as incurred; however, we may use certain provisions of the Internal Revenue Code which allow capitalization of intangible drilling costs where management deems appropriate.

When recording income tax expense, certain estimates are required to be made by management due to timing and to the impact of future events on when income tax expenses and benefits are recognized by us. We periodically evaluate any tax operating loss and other carryforwards to determine whether a gross tax asset, as well as a valuation allowance, should be recognized in our consolidated financial statements. As a result of changes in our expectations regarding our future taxable income, consistent with net losses recorded during the current year, we recorded a valuation allowance of $189.6 million at June 30, 2015. We recorded this increase to our valuation allowance against our net deferred tax assets due to our judgment that a portion of our existing U.S. federal and State of Louisiana net operating loss (NOL) carryforwards are not, on a more-likely-than-not basis, likely recoverable in future years. We continue to evaluate the need for the valuation allowance based on current and expected taxable income and other factors, and adjust it accordingly.

Accrued Expenses. As of June 30, 2015, our accrued expenses included accrued exploration costs, development costs and lease operating expenses totaling approximately $50.9 million, other accrued expenses of $19.2 million and interest payable of approximately $25.9 million. As of June 30, 2014, our accrued expenses included accrued exploration costs, development costs and lease operating expenses totaling approximately $127.6 million, other accrued expenses of $18.1 million and interest payable of approximately $15.8 million.

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). ASU 2014-09 provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and will supersede most current revenue recognition guidance. ASU No. 2014-09 is effective for annual periods beginning after December 15, 2017, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). We are evaluating the impact of the pending adoption of ASU No. 2014-09 on our financial position and results of operations and have not yet determined the method that will be adopted.

In August 2014, the FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity s Ability to Continue as a Going Concern* (ASU 2014-15). ASU 2014-15 requires management to assess an entity s ability to continue as a going concern and to provide related footnote disclosures in certain circumstances. The standard is effective for annual periods ending after December 15, 2016, and interim periods within annual

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

periods beginning after December 15, 2016, with early adoption permitted. We are currently evaluating the provisions of ASU 2014-15 and assessing the impact, if any, it may have on our consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-03, *Interest Imputation of Interest (Subtopic 835-30)* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The ASU is effective for public entities for annual periods beginning after December 15, 2015, and interim periods within those annual reporting periods. Early adoption is permitted for financial statements that have not been previously issued. The guidance will be applied on a retrospective basis. We are currently evaluating the provisions of ASU 2015-03 and assessing the impact it may have on our consolidated financial position.

(2) Pushdown Accounting

As described in Note 1, Organization and Summary of Significant Accounting Policies the Merger resulted in EPL becoming an indirect, wholly owned subsidiary of Energy XXI. Therefore, we have applied pushdown accounting, based on guidance from the SEC. The following table reflects the impact on our condensed consolidated balance sheet of the pushdown accounting adjustments required to reflect the fair value of our assets acquired and liabilities assumed by Energy XXI in the Merger:

	PREDECESSOR COMPANY June 3, 2014	PUSHDOWN ADJUSTMENTS	SUCCESSOR COMPANY June 3, 2014
ASSETS			
Current assets:			
Cash and cash equivalents	$ 200,050	$	$ 200,050
Trade accounts receivable net	91,813	1,194	93,007
Deferred tax asset	8,405	16,182	24,587
Prepaid expenses	9,729	80	9,809
Total current assets	309,997	17,456	327,453
Property and equipment, net of accumulated depreciation, depletion and amortization	1,969,382	972,510	2,941,892
Goodwill		329,293	329,293
Restricted cash	6,023		6,023
Fair value of commodity derivative instruments	27		27
Deferred financing costs	9,002	(9,002)	

Other assets	1,175		1,175
Total assets	$ 2,295,606	$ 1,310,257	$ 3,605,863
LIABILITIES AND STOCKHOLDERS EQUITY			
Current liabilities:			
Accounts payable	$ 61,938	$ 2,058	$ 63,996
Accrued expenses	230,086		230,086
Asset retirement obligations	39,859	3,758	43,617
Fair value of commodity derivative instruments	22,625		22,625
Total current liabilities	354,508	5,816	360,324
Long-term debt	973,440	52,967	1,026,407
Asset retirement obligations	220,302	9,453	229,755
Deferred tax liabilities	126,764	356,827	483,591

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(2) Pushdown Accounting (continued)

	PREDECESSOR COMPANY June 3, 2014	PUSHDOWN ADJUSTMENTS	SUCCESSOR COMPANY June 3, 2014
Fair value of commodity derivative instruments	$ 1,439	$	$ 1,439
Other	803	(797)	6
Total liabilities	1,677,256	424,266	2,101,522
Commitments and contingencies			
Stockholders equity:			
Preferred stock, par value $0.001 per share.			
Common stock, par value $0.001 per share.	41	(41)	
Additional paid-in capital	538,844	965,497	1,504,341
Treasury stock, at cost	(38,794)	38,794	
Retained earnings	118,259	(118,259)	
Total stockholders equity	618,350	885,991	1,504,341
Total liabilities and stockholders equity	$ 2,295,606	$ 1,310,257	$ 3,605,863

In accordance with the acquisition method of accounting, the purchase price established in the Merger has been allocated to the assets acquired and liabilities assumed based on their estimated fair values on the acquisition date. The fair value estimates were based on, but not limited to quoted market prices, where available; expected future cash flows based on estimated reserve quantities; estimated costs to produce and develop reserves; current replacement cost for similar capacity for certain fixed assets; market rate assumptions for contractual obligations; appropriate discount rates and growth rates; and crude oil and natural gas forward prices. Deferred income taxes have been recognized based on the estimated fair value adjustments to net assets using a 37 percent tax rate, which reflected the 35 percent federal statutory rate and a 2 percent weighted-average of the applicable statutory state tax rates (net of federal benefit). The excess of the total consideration over the estimated fair value of the amounts initially assigned to the identifiable assets acquired and liabilities assumed has been recorded as goodwill. Goodwill recorded in connection with the acquisition is not deductible for income tax purposes.

On April 2, 2013, we sold certain shallow water GoM shelf oil and natural gas interests located within the non-operated Bay Marchand field to Chevron U.S.A. Inc. (Chevron) with an effective date of January 1, 2013. In September 2014, we were informed by Chevron that the final settlement statement did not reflect a portion of production in the months of January 2013 and February 2013 totaling to approximately $2.1 million. After review of relevant supporting documents, we agreed to reimburse Chevron approximately $2.1 million. This resulted in an increase in liabilities assumed by Energy XXI in the Merger and a corresponding increase in goodwill of approximately $2.1 million; accordingly the June 30, 2014 condensed consolidated balance sheet has been retrospectively adjusted to increase the value of goodwill.

ASC 350, *Intangibles Goodwill and Other* (ASC 350), requires that intangible assets with indefinite lives, including goodwill, be evaluated for impairment on an annual basis or more frequently if events occur or circumstances change that could potentially result in impairment. Our annual goodwill impairment test is performed during the third quarter each fiscal year.

Impairment testing for goodwill is performed at the reporting unit level. We have only one reporting unit, which includes all of our oil and natural gas properties. Accordingly, all of our goodwill, as well as all of our other assets and liabilities, are included in our single reporting unit.

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(2) Pushdown Accounting (continued)

At September 30, 2014, we conducted a qualitative goodwill impairment assessment by examining relevant events and circumstances that could have a negative impact on our goodwill, such as macroeconomic conditions, industry and market conditions, cost factors that have a negative effect on earnings and cash flows, overall financial performance, dispositions and acquisitions, and any other relevant events or circumstances. After assessing the relevant events and circumstances for the qualitative impairment assessment, we determined that performing a quantitative goodwill impairment test was necessary. In the first step of the goodwill impairment test, we determined that the fair value of our reporting unit was less than the carrying amount, including goodwill, primarily due to price deterioration in forward pricing curves for oil and natural gas and an increase in our weighted average cost of capital used to estimate fair value, both factors which adversely impacted the fair value of our estimated reserves. Therefore, we performed the second step of the goodwill impairment test, which led us to conclude that there was no remaining implied fair value attributable to goodwill. As a result, we recorded a goodwill impairment charge of $329.3 million to reduce the carrying value of goodwill to zero at September 30, 2014.

In estimating the fair value of our reporting unit and our estimated reserves, we used an income approach which estimated fair value primarily based on the anticipated cash flows associated with our estimated reserves, discounted using a weighted average cost of capital rate based on market participant data. The estimation of the fair value of our reporting unit includes the use of significant inputs not observable in the market, such as estimates of reserves quantities, the weighted average cost of capital (discount rate), future pricing beyond a certain period and estimated future capital and operating costs. The use of these unobservable inputs results in the fair value estimate being classified as a Level 3 measurement. Although we believe the assumptions and estimates used in the fair value calculation of our reporting unit are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions.

The fair value measurements of the oil and natural gas properties and the asset retirement obligations included in other long-term liabilities were based, in part, on significant inputs not observable in the market and thus represent Level 3 measurements. The fair value measurement of long-term debt was based on prices obtained from a readily available pricing source and thus represents a Level 2 measurement.

(3) Acquisitions and Dispositions

Sale of interests in the East Bay field

On June 30, 2015, we sold our interest in the East Bay field to Whitney Oil & Gas, LLC and Trimont Energy (NOW), LLC, for cash consideration of $21 million plus the assumption of asset retirement obligations estimated at $55.1 million. The cash consideration is payable in two installments with $5 million received at closing and the remainder due on or before October 31, 2015. We retained a 5% overriding royalty interest (applicable only during calendar months if and when the WTI for such month averages over $65) on these assets for a period not to exceed 5 years from the closing date or $7 million whichever occurs first, and we also retained 50% of the deep rights associated with the East Bay field. Revenues and expenses related to the field were included in our results of operations through June 30, 2015. The proceeds were recorded as a reduction to our oil and natural gas properties with no gain or loss being recognized. The net reduction to the full cost pool related to this sale was $68.9 million.

The South Pass 49 Transfer

On June 3, 2014, Energy XXI GOM, LLC transferred an asset package consisting of certain shallow-water GoM shelf oil and natural gas interests in our South Pass 49 field (the SP49 Interests) to us for $230.0 million to reflect an economic effective date of June 1, 2014 (the SP49 Transfer). We estimate that the proved reserves as of the June 1, 2014 economic effective date totaled approximately 11.3 Mmboe, of which 74% were oil and 73% were proved developed reserves. Prior to the SP49 Transfer, we owned a 43.5% working interest in certain of these assets, and Energy XXI owned a 56.5% working interest in certain of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(3) Acquisitions and Dispositions (continued)

these assets as well as 100% interest in additional assets in the field. As a result of the SP49 Transfer, we have become the sole working interest owner of the South Pass 49 field. We financed the SP49 Acquisition with borrowings of approximately $135 million under our credit facility and a $95 million capital contribution from EGC. See Note 8, Indebtedness for more information regarding our credit facility.

The following table summarizes the estimated values of assets acquired and liabilities assumed in the transfer.

(In thousands)	June 1, 2014
Oil and natural gas properties	$ 231,271
Asset retirement obligations	(1,086)
Net assets acquired	$ 230,185

The Nexen Acquisition

On January 15, 2014, we acquired from Nexen Petroleum Offshore U.S.A., Inc. (Nexen) a 100% working interest of certain shallow-water central GoM shelf oil and natural gas assets for $70.4 million, subject to customary adjustments to reflect the September 1, 2013, economic effective date (the Nexen Acquisition). The assets we acquired comprise five leases in the Eugene Island 258/259 field (the EI Interests). Estimated proved reserves as of the September 1, 2013 effective date consist of approximately 2.6 Mmboe of proved developed producing reserves, about 91% of which is oil. The Nexen Acquisition was financed with borrowings under our senior secured credit facility with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender, and the other lender parties thereto (as amended and restated, the Prior Senior Credit Facility).

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects final adjustments to purchase price provided for by the purchase and sale agreement of approximately of $5.7 million to reflect an economic effective date of September 1, 2013.

(In thousands)	September 1, 2013
Oil and natural gas properties	$ 82,897
Asset retirement obligations	(18,165)
Net assets acquired	$ 64,732

The West Delta 29 Acquisition

On September 26, 2013, we acquired from W&T Offshore, Inc. (W&T) an asset package consisting of certain GoM shelf oil and natural gas interests in the West Delta 29 field (the WD29 Interests) for $21.8 million in cash, subject to customary adjustments to reflect an economic effective date of January 1, 2013 (the WD29 Acquisition). We estimate that the proved reserves as of the January 1, 2013 economic effective date totaled approximately 0.7 Mmboe, of which 95% were oil and 58% were proved developed reserves. The WD29 Acquisition was funded with a portion of the proceeds from the sale of the BM Interests held by the qualified intermediary as described below.

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(3) Acquisitions and Dispositions (continued)

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects final adjustments to purchase price provided for by the purchase and sale agreement of approximately $7.1 million to reflect an economic effective date of January 1, 2013.

(In thousands)	January 1, 2013
Oil and natural gas properties	$ 16,544
Asset retirement obligations	(1,398)
Net assets acquired	$ 15,146

Sale of Non-Operated Bay Marchand Asset

On April 2, 2013, we sold certain shallow water GoM shelf oil and natural gas interests located within the non-operated Bay Marchand field (the BM Interests) to the property operator for $51.5 million in cash and the buyer s assumption of liabilities recorded on our balance sheet of $11.3 million resulting in total consideration of $62.8 million, subject to customary adjustments to reflect the January 1, 2013 economic effective date. Our results for the year ended December 31, 2013 reflect a pre-tax gain of $28.1 million from this sale.

The following table summarizes the carrying amount of the net assets sold and reflects final adjustments to the sale price provided for by the purchase and sale agreement of approximately $0.7 million to reflect the economic effective date of January 1, 2013.

(In thousands)	January 1, 2013
Oil and natural gas properties	$ 35,298
Asset retirement obligations	(3,959)
Other liabilities	(7,311)
Net assets sold	$ 24,028

The cash proceeds from this sale of assets were held on deposit with a qualified intermediary in contemplation of a potential tax-deferred exchange of properties and classified as restricted cash at June 30, 2013. On September 26, 2013, we used $16.5 million of these proceeds to fund the WD29 Acquisition (defined and described above), which was a qualifying purchase for tax-deferral purposes. On September 29, 2013, the underlying escrow agreement expired, and the remaining amount of the deposit became unrestricted.

We have accounted for our acquisitions using the acquisition method of accounting for business combinations, and therefore we have estimated the fair value of the assets acquired and the liabilities assumed as of their respective acquisition dates. In the estimation of fair value, management uses various valuation methods including (i) comparable company analysis, which estimates the value of the acquired properties based on the implied valuations of other similar operations; (ii) comparable asset transaction analysis, which estimates the value of the acquired operations based upon publicly announced transactions of assets with similar characteristics; (iii) comparable merger transaction analysis, which, much like comparable asset transaction analysis, estimates the value of operations based upon publicly announced transactions with similar characteristics, except that merger analysis analyzes public to public merger transactions rather than solely asset transactions; and (iv) discounted cash flow analysis. The fair value is based on subjective estimates and assumptions, which are inherently subject to significant uncertainties which are beyond our control. These assumptions represent Level 3 inputs, as further discussed in Note 11, Fair Value Measurements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(3) Acquisitions and Dispositions (continued)

Results of Operations and Pro Forma Information

Revenues and lease operating expenses attributable to acquired interests and properties were as follows:

	Year Ended June 30, 2015	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013
	(In thousands)		(In thousands)	
SP49 Interests:				
Revenues	$ 44,702	$ 5,126	$	$
Lease operating expenses	$ 8,039	$ 600	$	$
EI Interests:				
Revenues	$ 30,521	$ 4,379	$ 17,565	$
Lease operating expenses	$ 21,469	$ 1,151	$ 7,264	$
WD29 Interests:				
Revenues	$ 10,943	$ 1,232	$ 5,681	$ 3,011
Lease operating expenses	$ 710	$ 12	$ 89	$ 44

We have determined that the presentation of net income attributable to the acquired interests and properties is impracticable due to the integration of the related operations upon acquisition. We incurred fees of approximately $0.3 million related to the SP49 Acquisition which were included in general and administrative expenses in the accompanying consolidated statement of operations for the period June 4, 2014 through June 30, 2014. We incurred fees of approximately $0.1 million related to the Nexen Acquisition which were included in general and administrative expenses in the accompanying consolidated statement of operations for the period January 1, 2014 through June 3, 2014.

The following supplemental unaudited pro forma information presents consolidated results of operations as if the WD 29 Acquisition, the Nexen Acquisition and the SP49 Transfer had occurred on July 1, 2012. In addition, this unaudited information has been prepared to reflect the Merger and pushdown accounting as if it occurred on July 1, 2012. The supplemental unaudited pro forma information was derived from a) our historical condensed consolidated statements of operations and b) unaudited revenues and direct operating expenses of the SP49 Interests, WD29 Interests and the EI Interests as derived from the records of the applicable seller provided to us in connection with the acquisitions. This information does not purport to be indicative of results of operations that would have occurred had the transactions occurred on July 1, 2012, nor is such information indicative of any expected future results of operations.

The most significant pro forma adjustments for the period from January 1, 2014 through June 3, 2014 and the year ended December 31, 2013, were the following:

a. Exclude $26.3 million and $0.8 million, respectively, of our exploration costs, impairment expense and gain on sales of assets accounted for under the successful efforts method of accounting to correspond with the full cost method of accounting.
b. Increase DD&A expense by $35.6 million and $129.6 million, respectively, for our properties to correspond with the full cost method of accounting.
c. Decrease interest expense $5.6 million and $13.3 million, respectively, to reflect non-cash premium amortization due to the adjustment to fair value associated with the $510 million face value of our 8.25% Senior Notes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(3) Acquisitions and Dispositions (continued)

	PRO FORMA Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013
	(in thousands, except per share data)	
	(Unaudited)	
Revenue	$ 303,742	$ 823,436
Net income (loss)	(9,244)	73,794
Basic earnings (loss) per share	(0.24)	1.88
Diluted earnings (loss) per share	(0.24)	1.86

(4) Common Stock

The Merger became effective on June 3, 2014. For each share of our common stock held, shareholders had the right to elect to receive $39.00 in cash or 1.669 shares of Energy XXI common stock or a combination of $25.35 in cash and 0.584 of a share of Energy XXI common stock. As a result of the Merger our securities were suspended from trading on June 4, 2014. Our common stock was then removed from listing and registration on the New York Stock Exchange (the NYSE) on July 15, 2014. However, in connection with the Merger, 1,000 shares were issued to EGC and remain outstanding.

In August 2011, the former Board of Directors of EPL authorized a program for the repurchase of our outstanding common stock for up to an aggregate cash purchase price of $20.0 million and increased the program to $40.0 million in May 2012. In July 2013, the former Board of Directors increased the program to $80.0 million. Through December 31, 2013, we executed trades to repurchase 1,799,000 shares at an aggregate cash purchase price of approximately $29.7 million. Such shares were held in treasury and could be used to provide available shares for possible resale in future public or private offerings and our employee benefit plans. The repurchases were carried out in accordance with certain volume, timing and price constraints imposed by the SEC rules applicable to such transactions. In July 2013, our Prior Senior Credit Facility was amended to increase the limit applicable to certain restricted payments, which includes share repurchases, permitted by the agreement. Our treasury shares were retired in connection with the Merger.

Covenants in certain debt instruments to which we are a party, including the indenture related to our 8.25% Senior Notes, place certain restrictions and conditions on our ability to pay dividends on our common stock.

(5) Earnings Per Share

The following table sets forth the calculation of basic and diluted weighted average shares outstanding and earnings per share for the indicated periods.

	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012
		(in thousands, except per share data)	
Income (numerator):			
Net income (loss)	$ (22,956)	$ 85,274	$ 58,810
Net income attributable to participating securities		(943)	(455)
Net income (loss) attributable to common shares	$ (22,956)	$ 84,331	$ 58,355
Weighted average shares (denominator):			
Weighted average shares basic	38,730	38,730	38,885
Dilutive effect of stock options		506	149
Weighted average shares diluted	38,730	39,236	39,034
Basic earnings (loss) per share	$ (0.59)	$ 2.18	$ 1.50
Diluted earnings (loss) per share	$ (0.59)	$ 2.15	$ 1.50

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EPL OIL & GAS, INC. AND SUBSIDIARIES

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(5) Earnings Per Share (continued)

The following table indicates the number of shares underlying outstanding stock-based awards excluded from the computation of dilutive weighted average shares because their effect was antidilutive for the periods indicated.

	Period from January 1, 2014 through June 3, 2014	Year Ended December 31,	
		2013	2012
	(in thousands)	(in thousands)	
Weighted average shares	941	273	687

(6) Property and Equipment

The following table summarizes our property and equipment.

	June 30,	
	2015	2014
	(In thousands)	
Proved oil and natural gas properties	$2,993,012	$2,316,306
Unevaluated oil and natural gas properties	435,429	908,483
Other	3,116	3,173
Less: accumulated depreciation, depletion, amortization and impairment	(2,016,532)	(22,775)
Total property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$1,415,025	$3,205,187

Substantially all of our oil and natural gas properties serve as collateral under our credit facility. At June 30, 2015 and 2014, we did not have any exploratory projects that were suspended for a period greater than one year. Our investment in unevaluated properties primarily relates to the fair value of unproved oil and gas properties determined during the Merger. Costs associated with unevaluated properties are transferred to evaluated properties upon the earlier of 1) a determination as to whether there are any proved reserves related to the properties, or 2) amortization over a period of time of not more than four years.

The following table summarizes an aging of total costs related to unevaluated properties excluded from the amortization base as of June 30, 2015 *(in thousands).*

	Net Costs Incurred During the	Balance as of June 30, 2015

	Period from June 4, 2014 through June 30, 2014	Year Ended June 30, 2015	
Unevaluated Properties (acquisition costs)	$ 435,429	$	$ 435,429

Under the full cost method of accounting at the end of each financial reporting period, we compare the present value of estimated future net cash flows from proved reserves (computed using the unweighted arithmetic average of the first-day-of-the-month historical price, net of applicable differentials, for each month within the previous 12-month period discounted at 10%, plus the lower of cost or fair market value of unproved properties and excluding cash flows related to estimated abandonment costs) to the net full cost pool of oil and natural gas properties, net of related deferred income taxes. We refer to this comparison as a ceiling test. If the net capitalized costs of these oil and natural gas properties exceed the estimated discounted future net cash flows, we are required to write-down the value of our oil and natural gas properties to the value of the discounted cash flows. For the year ended June 30, 2015, our ceiling test computations resulted in impairment of our oil and natural gas properties totaling $1,678.8 million. If the current low commodity price environment or downward trend in oil prices continues, there is a reasonable likelihood that

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(6) Property and Equipment (continued)

we could incur further impairment to our full cost pool in fiscal 2016 based on the average oil and natural gas price calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the previous 12-month period under the SEC pricing methodology.

Under the successful efforts method of accounting, we recognized impairments of $0.1 million, $2.9 million and $8.9 million in the period from January 1, 2014 through June 3, 2014 and the years ended December 31, 2013, and 2012, respectively. Impairments for the year ended December 31, 2013 were primarily related to reservoir performance at a gas well in one of our smaller producing fields. This field was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value. Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices affecting certain of our natural gas producing fields and to reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that are expiring in 2013 for which we had no development plans.

(7) Asset Retirement Obligations

The following table reconciles the beginning and ending aggregate recorded amount of our asset retirement obligations (ARO).

	Year Ended June 30, 2015	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013
	(in thousands)		(in thousands)	
Beginning of period total	$ 272,695	$ 260,161	$ 255,450	$ 235,110
Accretion expense	23,400	2,022	11,771	28,299
Liabilities assumed in acquisitions		1,088	18,165	23,541
Pushdown accounting fair value adjustment		13,211		
Liabilities incurred	3,448			1,187
Revisions	49,394		7,415	24,586
Liabilities associated with assets sold	(55,319)			(3,965)
Liabilities settled	(53,256)	(3,787)	(32,640)	(53,308)
End of period total	240,362	272,695	260,161	255,450
Less: End of period, current portion	(38,056)	(39,831)	(39,859)	(51,601)

End of period, noncurrent portion	$ 202,306	$ 232,864	$ 220,302	$ 203,849

The fair value adjustment recorded in pushdown accounting resulted from conforming to Energy XXI s inflation and discount rate assumptions.

We revise our estimates of ARO as information about material changes to the liability becomes known. For the year ended June 30, 2015, we recorded revisions due to an increase in decommissioning cost estimates identified as part of our review of our supplemental bonding requirements. During the year ended December 31, 2013, our revisions included an increase to our estimated ARO of $20.8 million related to our only remaining four non-producing wellbores in our non-operated deepwater properties. These deepwater abandonment costs were primarily attributable to changes in regulatory interpretations and enforcement by the Bureau of Safety and Environmental Enforcement (BSEE) in the deepwater that increased the required scope of work. As a result, we recorded an associated $20.8 million loss on abandonment activities, which is included in Other costs and expenses in our consolidated statements of operations for the year ended December 31, 2013.

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(8) Indebtedness

The following table sets forth our indebtedness.

	June 30, 2015	June 30, 2014
	(In thousands)	
8.25% senior notes due 2018[1]	$539,459	$550,566
Revolving credit sub-facility	150,000	475,000
Derivative instruments premium financing	3,364	
Long term debt	692,823	1,025,566
Less: current maturities of long-term debt	(3,364)	
Long-term debt, less current maturities	$689,459	$1,025,566
Promissory note payable to EGC	325,000	
Noncurrent portion of indebtedness including promissory note payable to EGC	$1,014,459	$1,025,566

(1) Includes unamortized premium on the 8.25% Senior Notes.

Maturities of long-term debt as of June 30, 2015 are as follows (*in thousands*):

Twelve Months Ending June 30,	
2016	$ 3,364
2017	
2018	660,000
2019	325,000
	988,364
Add: Debt premium	29,459
Total debt	$ 1,017,823

Revolving Credit Sub-Facility

On March 3, 2015, EGC and EPL entered into the Tenth Amendment (the Tenth Amendment) to their second amended and restated First Lien Credit Agreement in connection with the issuance of $1.45 billion in aggregate principal amount of EGC s 11.0% senior secured second lien notes due 2020 (the 11.0% Notes). Pursuant to the terms of the Tenth Amendment, the lenders under the First Lien Credit Agreement reduced the borrowing base for EGC to $500.0 million, of which such amount $150.0 million is the borrowing base for EPL under the sub-facility established for EPL under the First Lien Credit Agreement (Revolving Credit Sub-Facility). The borrowing bases are to remain effective until the next redetermination thereof under the terms of the First Lien Credit Agreement. In addition to the reduction of the borrowing base, under the Tenth Amendment, the following changes, among others, to the First Lien Credit Agreement were effective:

addition of provisions to permit EGC to make a loan to us in the amount of $325 million using proceeds from the incurrence of additional permitted second lien or third lien indebtedness of EGC and for us to secure such loan by providing liens on substantially all of our assets that are second in priority to the liens of the lenders under the First Lien Credit Agreement pursuant to the terms of an intercreditor agreement and restricting the transfer of EGC s rights in respect of such loan or making any prepayment or otherwise making modifications of the terms of such arrangements;

change in the definition of the stated maturity date of the First Lien Credit Agreement so that it accelerates from April 9, 2018 (the scheduled date of maturity) to a date 210 days prior to the date of maturity of EGC s outstanding 9.25% unsecured notes due December 2017 if such notes are not prepaid, redeemed or refinanced prior to such prior date, or to a date 210 days prior to the date of maturity of the 8.25% Senior Notes in February 2018 if such notes are not prepaid, redeemed or

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(8) Indebtedness (continued)

refinanced prior to such prior date, or otherwise to a date that is 180 days prior to the date of maturity of any other permitted second lien or permitted third lien indebtedness or certain permitted unsecured indebtedness or any refinancings of such indebtedness if such indebtedness would come due prior to April 9, 2018;

elimination, addition, or modification of certain financial covenants;

setting the applicable commitment fee under the First Lien Credit Agreement at 0.50% and providing that outstanding amounts drawn under the First Lien Credit Agreement bear interest at either the applicable London Interbank Offered Rate (LIBOR), plus applicable margins ranging from 2.75% to 3.75% or an alternate base rate based on the federal funds effective rate plus applicable margins ranging from 1.75% to 2.75%;

increase of the threshold requirement for oil and gas properties required to be secured by mortgages to 90% of the value of EGC and its subsidiaries (other than our properties until we become guarantors of the EGC indebtedness under the First Lien Credit Agreement) proved reserves and proved developed producing reserves, but allowing the threshold for our properties (until we become guarantors of the EGC indebtedness under the First Lien Credit Agreement) to remain at 85%;

addition of certain further restrictions on the prepayment and repayment of outstanding note indebtedness of EGC and its subsidiaries, including the prohibition on using proceeds from credit extensions under the First Lien Credit Agreement for any such prepayment or repayment and the requirement that EGC have net liquidity at the time thereof of at least $250 million;

modification to the restricted payment covenant to substantially limit the ability of EGC to make distributions and dividends to parent entities, provided that a distribution of the Grand Isle gathering system and related equipment and other assets was permitted;

qualification on the ability of EGC and its subsidiaries to refinance outstanding indebtedness by requiring that EGC have pro forma net liquidity of $250 million at the time of such refinancing; and

modification of the asset disposition covenant to require lender consent for any such disposition that would have the effect of reducing the borrowing base by more than $5 million in the aggregate; provided, however, that such provision was expressly deemed not to be applicable to certain sales relating to the Grand Isle gathering system that are the subject of current marketing efforts of EGC, as long as EGC and its subsidiaries meet certain obligations, such as, among others, maintaining the proceeds from such sales in accounts that are subject to the liens of the lenders.

The First Lien Credit Agreement, as amended, requires EPL and EGC to maintain certain financial covenants separately for so long as the 8.25% Senior Notes remain outstanding. We are currently subject to the following financial covenants on a stand-alone basis: (a) a consolidated maximum first lien leverage ratio of 1.25 to 1.0 and (b) a consolidated maximum secured leverage ratio of no more than 3.75 to 1.0. If the 8.25% Senior Notes are no longer outstanding and certain other conditions are met, EPL and EGC will be subject to the following financial covenants on a consolidated basis: (a) a consolidated maximum net first lien leverage ratio of 1.25 to 1.0, (b) a consolidated maximum net secured leverage ratio of no more than 3.75 to 1.0, provided that if the 8.25% Senior Notes are refinanced with new secured debt, the liens of which are junior in priority to the revolving credit facility indebtedness, then the maximum ratio permitted would be 4.25 to 1.0, and (c) a minimum current ratio of no less than 1.0 to 1.0.

Our Revolving Credit Sub-Facility restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. As of June 30, 2015, we were in compliance with all covenants under the First Lien Credit Agreement, other than with respect to the sale of interests in the East Bay field. Since required lender consent to the specific terms of the transaction had not been obtained, EGC and EPL were in technical default under the First Lien Credit Agreement at June 30,

EPL OIL & GAS, INC. AND SUBSIDIARIES

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(8) Indebtedness (continued)

2015. On July 14, 2015, we obtained a waiver to this event of default, which waiver required EPL to deposit $21 million into an account subject to a control agreement in favor of the administrative agent under the First Lien Credit Agreement. Such amount will remain on deposit until the next redetermination of the borrowing base, unless used to repay a borrowing base deficiency. Upon the next redetermination, any amounts remaining in the account will be used to make an immediate payment toward any borrowing base deficiency at the time of such redetermination, and so long as no event of default shall have occurred, any amount remaining after payment in full of any borrowing base deficiency shall be released and paid to EGC. As of June 30, 2015, we had $150.0 million in borrowings under the Revolving Credit Sub-Facility fully utilizing the amounts available under our Revolving Credit Sub-Facility.

As of July 31, 2015, EGC and EPL entered into the Eleventh Amendment and Waiver to the First Lien Credit Agreement (the Eleventh Amendment), which waives certain provisions of the First Lien Credit Agreement to permit EGC to acquire the remaining equity interests of M21K, LLC. Further, the Eleventh Amendment temporarily increased the letter of credit commitment amount within the facility from $300 million to a maximum amount of $305 million through August 31, 2015, after which it reduced back to $300 million.

Based on projected market conditions and commodity prices, we currently expect that we will be in compliance with covenants under our credit agreement for the near term; however, a protracted period of low commodity prices could cause us to not be in compliance with certain financial covenants under our credit agreements in future periods, including prior to June 30, 2016. Our parent and EGC intend to support us financially to enable us to meet our ongoing obligations and comply with our covenants. However, in the event that we are unable to comply with these covenants, a breach of the covenants under the First Lien Credit Agreement would cause a default under such facility, potentially resulting in acceleration of all amounts outstanding under the First Lien Credit Agreement. If the lenders under our credit facility were to accelerate the indebtedness under the First Lien Credit Agreement as a result of such defaults, such acceleration could cause a cross-default or cross-acceleration of all of our other outstanding indebtedness. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding, we may not have sufficient liquidity to repay all of our outstanding indebtedness.

Promissory Note

On March 12, 2015, in connection with EGC s issuance of the 11.0% Notes**,** we entered into a $325.0 million secured second lien promissory note between us, as the maker, and EGC, as the payee (the Promissory Note). Proceeds from the Promissory Note were used to repay a like amount of the outstanding borrowings under the Revolving Credit Sub-Facility. The Promissory Note bears interest at an annual rate of 10%, has a maturity date of October 9, 2018, and is secured by a second priority lien on certain of our assets that secure the obligations under the First Lien Credit Agreement. EGC may release the collateral securing the Promissory Note at any time. The note has not been, and will not be, registered under the Securities Act of 1933, as amended or the securities laws of any other jurisdiction. We have an option to prepay this note in whole or in part at any time, without penalty or premium. The note bears interest from the date of issuance with interest due quarterly, in arrears, on January 5th, April 5th, July 5th, and October 5th, beginning September 5, 2015.

8.25% Senior Notes

The 8.25% senior notes consist of $510.0 million in aggregate principal amount ($539.5 million carrying value at June 30, 2015) of our 8.25% senior notes due 2018 (the 8.25% Senior Notes) issued under an Indenture dated February 14, 2011 (the 2011 Indenture). The 8.25% Senior Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest due semi-annually, in arrears, on February 15th and August 15th of each year. The 8.25% Senior Notes are fully and unconditionally guaranteed, jointly and

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EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(8) Indebtedness (continued)

severally, on an unsecured senior basis initially by each of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries). The 8.25% Senior Notes will mature on February 15, 2018. As a result of pushdown accounting, the effective interest rate on the 8.25% Senior Notes is approximately 5.8%. We issued the 8.25% Senior Notes in two different private placements, described below.

On February 14, 2011, we issued the $210.0 million in aggregate principal amount of our 8.25% senior notes due 2018 (the 2011 Senior Notes) under the 2011 Indenture. We used the net proceeds from the offering of the 2011 Senior Notes of $202.0 million, after deducting the initial purchasers discount and offering expenses payable by us, to acquire an asset package for a purchase price of $200.7 million, before adjustments to reflect an economic effective date of January 1, 2011.

On October 25, 2012, we issued the $300.0 million in aggregate principal amount of our 2012 Senior Notes under an Indenture dated as of October 25, 2012 (the 2012 Indenture). We used the net proceeds from the offering of the 2012 Senior Notes of $289.5 million, after deducting the initial purchasers discount, to fund a portion of the acquisition of 100% of the membership interests of Hilcorp Energy GOM, LLC (the Hilcorp Acquisition). The purchase price of the 2012 Senior Notes included $4.8 million of accrued interest for the period from August 15, 2012 to October 25, 2012, which we recorded as interest payable.

The 2012 Senior Notes were offered in a private placement only to qualified institutional buyers under Rule 144A promulgated under the Securities Act of 1933, as amended (the Securities Act), or to persons outside of the United States in compliance with Regulation S promulgated under the Securities Act. The 2012 Senior Notes had terms that were substantially identical to the terms of our 2011 Senior Notes. Pursuant to a registration rights agreement executed as part of the sale of the 2012 Senior Notes, we issued publicly registered additional notes under our 2011 Indenture in exchange for the 2012 Senior Notes. As a result of this exchange offer, 100% in aggregate principal amount of the 2012 Senior Notes was exchanged for the notes under the 2011 Indenture, effective as of June 10, 2013. All of the 8.25% Senior Notes are now issued under the 2011 Indenture, regardless of which private placement they were issued under.

On April 18, 2014, we entered into a supplemental indenture (the Supplemental Indenture) to the 2011 Indenture, by and among us, the guarantors party thereto, and U.S. Bank National Association, as trustee (the 8.25% Senior Notes Trustee), governing our 8.25% Senior Notes. We entered into the Supplemental Indenture after the receipt of consents from the requisite holders of the 8.25% Senior Notes in accordance with the terms and conditions of the Consent Solicitation Statement dated April 7, 2014, pursuant to which Energy XXI had solicited consents (the Consent Solicitation) from the holders of the 8.25% Senior Notes to make certain proposed amendments to certain definitions set forth in the Indenture (the Proposed COC Amendments), as reflected in the Supplemental Indenture. The Consent Solicitation was made as permitted by the Merger Agreement. On April 18, 2014, Energy XXI had received valid consents from holders of an aggregate principal amount of $484.1 million of the 8.25% Senior Notes and those consents had not been revoked prior to the Consent Time. As a result, the requisite holders of the 8.25% Senior Notes had consented to the Proposed COC Amendments, upon the terms and subject to the conditions set forth in the

Consent Solicitation Statement. Accordingly, we, the guarantors party thereto and the Trustee entered into the Supplemental Indenture. Subject to the terms and conditions set forth in the Statement, Energy XXI paid an aggregate cash payment equal to $2.50 per $1,000 principal amount of 8.25% Senior Notes for which consents to the Proposed COC Amendments were validly delivered and unrevoked.

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(8) Indebtedness (continued)

On or after February 15, 2015, we may on any one or more occasions redeem all or a part of the 8.25% Senior Notes upon not less than 30 nor more than 60 days notice, at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest and special interest, if any, on the notes redeemed, to the applicable date, if redeemed during the twelve-month period beginning on February 15 of the years indicated below, subject to the rights of holders of notes on the relevant record date to receive interest on the relevant interest payment date:

Year	Percentage
2015	104.125 %
2016	102.063 %
2017 and thereafter	100.000 %

Any such redemption and notice may, in our discretion, be subject to the satisfaction of one or more conditions, precedent, including, but not limited to, the occurrence of a change of control. Unless we default in the payment of the redemption price, interest will cease to accrue on the 8.25% Senior Notes or portions thereof called for redemption on the applicable redemption date.

If we experience a change of control (as defined in the 2011 Indenture), each holder of the 8.25% Senior Notes will have the right to require us to repurchase all or any part (equal to $2,000 or an integral multiple of $1,000 in excess thereof) of the 8.25% Senior Notes at a price in cash equal to 101% of the aggregate principal amount of the 8.25% Senior Notes repurchased, plus accrued and unpaid interest to the date of repurchase. If we engage in certain asset sales, within 360 days of such sale, we generally must use the net cash proceeds from such sales to repay outstanding senior secured debt (other than intercompany debt or any debt owed to an affiliate), to acquire all or substantially all of the assets, properties or capital stock of one or more companies in our industry, to make capital expenditures or to invest in our business. When any such net proceeds that are not so applied or invested exceed $20.0 million, we must make an offer to purchase the 8.25% Senior Notes and other pari passu debt that is subject to similar asset sale provisions in an aggregate principal amount equal to the excess net cash proceeds. The purchase price of each 8.25% Senior Note (or other pari passu debt) so purchased will be 100% of its principal amount, plus accrued and unpaid interest to the repurchase date, and will be payable in cash.

The 2011 Indenture, among other things, limits our ability to: (i) declare or pay dividends, redeem subordinated debt or make other restricted payments; (ii) incur or guarantee additional debt or issue preferred stock; (iii) create or incur liens; (iv) incur dividend or other payment restrictions affecting restricted subsidiaries; (v) consummate a merger, consolidation or sale of all or substantially all of our assets; (vi) enter into sale-leaseback transactions, (vii) enter into transactions with affiliates; (viii) transfer or sell assets; (ix) engage in business other than our current business and reasonably related extensions thereof; or (x) issue or sell capital stock of certain subsidiaries. These covenants are subject to a number of important exceptions and qualifications set forth in the 2011 Indenture.

(9) Concentrations

Significant Customers

We had oil and natural gas sales to three customers accounting for 58%, 20% and 20%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended June 30, 2015. We had oil and natural gas sales to three customers accounting for 55%, 23% and 11%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the period from June 4, 2014 through June 30, 2014. We had oil and natural gas sales to three customers accounting for 52%, 23% and 10%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the period from January 1, 2014 through June 3, 2014. We had oil and natural gas sales to three customers accounting for 63%, 24% and 6%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2013. We had oil and natural gas sales to three customers

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(9) Concentrations (continued)

accounting for 45%, 31% and 11%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2012. We also sell our production to a number of other customers, and we believe that those customers, along with other purchasers of oil and natural gas, would purchase all or substantially all of our production in the event that these customers curtailed their purchases.

Accounts Receivable

Substantially all of our accounts receivable result from oil and natural gas sales and joint interest billings to third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions.

Derivative Instruments

Derivative instruments also expose us to credit risk in the event of nonperformance by counterparties. Generally, these contracts are with major investment grade financial institutions and other substantive counterparties. We believe that our credit risk related to the futures and swap contracts is no greater than the risk associated with the primary contracts and that the elimination of price risk through our hedging activities reduces volatility in our reported consolidated results of operations, financial position and cash flows from period to period and lowers our overall business risk.

Cash and Cash Equivalents

We are subject to concentrations of credit risk with respect to our cash and cash equivalents, which we attempt to minimize by maintaining our cash and cash equivalents with major high credit quality financial institutions. At times cash balances may exceed limits federally insured by the Federal Deposit Insurance Corporation.

Geographic Concentration

Virtually all of our current operations and proved reserves are concentrated in the Gulf of Mexico region. Therefore, we are exposed to operational, regulatory and other risks associated with the Gulf of Mexico, including the risk of adverse weather conditions. We maintain insurance coverage against some, but not all, of the operating risks to which our business is exposed.

(10) Derivative Instruments and Hedging Activities

We enter into derivative instruments to reduce exposure to fluctuations in the price of oil and natural gas for a portion of our production. Our fixed-price swaps fix the sales price for a limited amount of our production and, for the contracted volumes, eliminate our ability to benefit from increases in the sales price of the production. Derivative instruments are carried at their fair value on the consolidated balance sheets as Derivative financial instruments. Prior to the Merger, we did not designate derivative instruments as hedges. All gains and losses due to changes in fair market value and contract settlements were recorded in Gain (loss) on derivative instruments in Other income (expense) in the consolidated statements of operations.

Subsequent to the Merger, we designated our derivative financial instruments as cash flow hedges, however, in connection with preparing this Form 10-K for the year ended June 30, 2015, we determined that the contemporaneous formal documentation that we had historically prepared to support our initial designations of derivative financial instruments as cash flow hedges related to our crude oil and natural gas hedging program did not meet the technical requirements to qualify for cash flow hedge accounting treatment in accordance with ASC Topic 815, *Derivatives and Hedging*. The primary reason for this determination was that the formal hedge documentation lacked specificity of the hedged items and, therefore, the designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment. Accordingly, our current portfolio of derivative contracts are not accounted for as hedges. Therefore, changes in fair value of

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(10) Derivative Instruments and Hedging Activities (continued)

these outstanding derivative financial instruments are recognized in earnings subsequent to the Merger and are included in gain (loss) on derivative financial instruments as a component of revenues in the accompanying consolidated statements of operations.

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 hedging arrangements helps to limit the downside risk of adverse price movements, they may also limit future gains from favorable price movements.

In connection with the Merger, Energy XXI assumed our existing hedges with contract terms beginning in June 2014 through December 2015. Our oil contracts were primarily swaps and benchmarked to Argus-LLS and Brent. During the quarter ended December 31, 2014, we monetized all the calendar 2015 Brent swap contracts, keeping one natural gas contract intact.

The following table sets forth our derivative instrument outstanding as of June 30, 2015:

Oil Contracts

Remaining Contract Term		Type of Contract	Index	Volume (MBbls)	Weighted Average Contract Price Sub Floor	Floor	Ceiling
July 2015	December 2015	Three-Way Collars	ARGUS-LLS	2,024	$32.73	$45.00	$75.45

Gas Contracts

Remaining Contract Term		Type of Contract	Index	Volume (MMBtu)	Swap Fixed Price ($/Mmbtu)
July 2015	December 2015	Fixed Price Swaps	NYMEX-HH	791	$ 4.31

The effect of derivative financial instruments on our condensed consolidated statements of operations was as follows:

	SUCCESSOR COMPANY	PREDECESSOR COMPANY

	Year Ended June 30, 2015	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Years Ended December 31, 2013	2012
Gain (loss) on derivative financial instruments					
Cash settlements, net of purchased put premium amortization	24,417	(1,551)	(26,416)	(11,477)	(3,814)
Proceeds from monetizations	4,559				
Unrealized change in fair value	11,106	(9,528)	6,996	(20,884)	(9,491)
Total gain (loss) on derivative financial instruments	40,082	(11,079)	(19,420)	(32,361)	(13,305)

We monitor the creditworthiness of our counterparties. However, we are not able to predict sudden changes in counterparties creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices, and could incur a loss. At June 30, 2015, we had no deposits for collateral with our counterparties.

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(11) Fair Value Measurements

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

Level 1 quoted prices in active markets for identical assets or liabilities.

Level 2 inputs other than quoted prices that are observable for an asset or liability. These include: quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability; and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market-corroborated inputs).

Level 3 unobservable inputs that reflect our own expectations about the assumptions that market participants would use in measuring the fair value of an asset or liability.

As of June 30, 2015 and 2014, we held certain financial assets and liabilities that are required to be measured at fair value on a recurring basis, primarily our commodity derivative instruments. We estimate 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 LIBOR rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published issuer-weighted corporate default rates. These price inputs are quoted prices for assets and liabilities similar to those held by us and meet the definition of Level 2 inputs within the fair value hierarchy.

The following table sets forth our derivative financial instruments that are accounted for at fair value on a recurring basis.

	June 30, 2015	June 30, 2014
	(in thousands)	
Assets:		
Current	$ 888	$
Noncurrent		
Total gross fair value	888	
Less: counterparty off-set		
Total net fair value	$ 888	$
Liabilities:		

Current	$ 1,057	$ 26,440
Noncurrent		2,140
Total gross fair value	1,057	28,580
Less: counterparty off-set		
Total net fair value	$ 1,057	$ 28,580

The carrying values reported in the consolidated balance sheets for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short term maturities of these instruments. The fair value for the 8.25% Senior Notes is based on quoted prices, which are Level 1 inputs within the fair

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(11) Fair Value Measurements (continued)

value hierarchy. The carrying value of the Revolving Credit Sub-Facility approximates its fair value because the interest rates are variable and reflective of market rates, which are Level 2 inputs within the fair value hierarchy.

The following table sets forth the carrying values and estimated fair values of our long-term indebtedness.

	June 30, 2015 (In thousands)		June 30, 2014	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
8.25% Senior Notes	$ 539,459	$ 306,000	$ 550,566	$ 545,700
Revolving credit sub-facility	150,000	150,000	475,000	475,000
Intercompany Promissory Note	325,000	325,000		
Total	$ 1,014,459	$ 781,000	$ 1,025,566	$ 1,020,700

The 8.25% Senior Notes contain an option to redeem up to 35% of the aggregate principal amount of the notes outstanding with the net cash proceeds of certain equity offerings. This option is considered an embedded derivative and is classified as a Level 3 financial instrument for which the estimated fair value at June 30, 2015 and 2014 is not material.

Under the successful efforts method of accounting, our assessment of possible impairment of proved oil and natural gas properties was based on our best estimate of future prices, costs and expected net future cash flows by property (generally analogous to a field or lease). An impairment loss was indicated if undiscounted net future cash flows were less than the carrying value of a property. The impairment expense was measured as the shortfall between the net book value of the property and its estimated fair value, which was measured based on the discounted net future cash flows from the property. The inputs used to estimate the fair value of our oil and natural gas properties were based on our estimates of future events, including projections of future oil and natural gas sales prices, amounts of recoverable oil and natural gas reserves, timing of future production, future costs to develop and produce our oil and natural gas and discount factors. These inputs were Level 3 inputs within the fair value hierarchy. Impairments for the year ended December 31, 2013 were primarily related to reservoir performance at a gas well in one of our smaller producing fields. This field was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value. Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices, which affected three of our natural gas producing fields and reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write downs of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that were expiring in 2013 for which we had no development plans.

As addressed in Note 2, Pushdown Accounting, and Note 3, Acquisitions, we apply fair value concepts in estimating and allocating the fair value of assets acquired and liabilities assumed by Energy XXI in the Merger and assumed in acquisitions in accordance with acquisition accounting for business combinations. The inputs to the estimated fair values of assets acquired and liabilities assumed are described in Notes 2 and 3.

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EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(12) Income Taxes

We are a (U.S.) Delaware company and, as a result of the Merger, a direct subsidiary of EGC. We are a member of a consolidated group of corporations for U.S. federal income tax purposes where Energy XXI, Inc., (the U.S. Parent) is the parent entity. Energy XXI Ltd (the Foreign Parent) indirectly owns 100% of U.S. Parent, but is not a member of the U.S. consolidated group. We operate through our various subsidiaries in the United States as they apply to our current ownership structure. ASC Topic 740 provides that the income tax amounts presented in the separate financial statements of a subsidiary entity that is a member of a consolidated group should be based upon a reasonable allocation of the income tax amounts of that group. We allocate income tax expense/benefit and deferred tax items between affiliates as if each affiliate prepared a separate U.S. income tax return for the reporting period. We have recorded no income tax-related intercompany balances with affiliates.

The restatement (discussed in Note 17) did not require us to amend any previous income tax filings as the changes in the financial accounting method for derivatives and the resulting effect on depletion, depreciation, and amortization had no effect on taxable income (or loss) as determined for any year. Deferred tax balances related to the changes in balance sheet carrying amounts for derivative instruments and oil and gas properties were revised as required by the adjustments to pre-tax book income.

Changes in our expectations regarding our future taxable income, consistent with net losses recorded during the current fiscal year (that are heavily influenced by oil and gas property impairments), caused us to record a valuation allowance of $189.6 at June 30, 2015. We recorded this valuation allowance against our net deferred tax assets due to our judgment that a portion of our existing U.S. federal and State of Louisiana net operating loss (NOL) carryforwards are not, on a more-likely-than-not basis, likely recoverable in future years. We continue to evaluate the need for the valuation allowance based on current and expected taxable income and other factors, and adjust it accordingly.

The components of our income tax provision (benefit) (reflecting pushdown accounting as described in Notes 1 and 2) are as follows (in thousands):

	Year Ended June 30, 2015	Period from June 4, 2014 through June 30, 2014 (Restated)	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012
	(In thousands)		(In thousands)		
Deferred:					