BLUE DOLPHIN ENERGY CO
Form 10-Q
November 16, 2015

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

FORM 10-Q

(Mark One)

þ Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended: September 30, 2015

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: 0-15905

BLUE DOLPHIN ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	73-1268729 (I.R.S. Employer Identification No.)

801 Travis Street, Suite 2100, Houston, Texas 77002
(Address of principal executive offices)

(713) 568-4725
(Registrant’s telephone number, including area code)

Indicate by check mark whether the registrant (1) 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 þ No o

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

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	o	Smaller reporting company	þ
(Do not check if a smaller reporting company)			

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

Number of shares of common stock, par value $0.01 per share outstanding as of November 16, 2015: 10,453,802

BLUE DOLPHIN ENERGY COMPANY & SUBSIDIARIES
FORM 10-Q REPORT INDEX

PART I FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

Blue Dolphin Energy Company & Subsidiaries

Consolidated Balance Sheets (Unaudited)

	September 30, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$1,518,359	$1,293,233
Restricted cash	5,834,197	1,008,514
Accounts receivable	7,833,519	8,340,303
Prepaid expenses and other current assets	1,045,893	771,458
Deposits	420,176	68,498
Inventory	5,620,827	3,200,651
Deferred tax assets, current portion, net	2,892,459	-
Total current assets	25,165,430	14,682,657
Total property and equipment, net	46,054,365	37,371,075
Restricted cash, noncurrent	11,277,441	-
Surety bonds	1,667,000	1,642,000
Debt issue costs, net	1,296,480	479,737
Trade name	303,346	303,346
Deferred tax assets, net	387,824	5,928,342
Total long-term assets	60,986,456	45,724,500
TOTAL ASSETS	$86,151,886	$60,407,157
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$16,459,787	$12,370,179
Accounts payable, related party	-	1,174,168
Asset retirement obligations, current portion	38,644	85,846
Accrued expenses and other current liabilities	2,005,206	2,783,704
Interest payable, current portion	57,140	56,039
Long-term debt, current portion	1,631,539	1,245,476
Deferred tax liabilities, net	-	168,236
Total current liabilities	20,192,316	17,883,648
Long-term liabilities:		
Asset retirement obligations, net of current portion	1,928,371	1,780,924
Deferred revenues and expenses	561,864	691,525
Long-term debt, net of current portion	28,948,021	10,808,803
Long-term interest payable, net of current portion	1,430,371	1,274,789
Total long-term liabilities	32,868,627	14,556,041

TOTAL LIABILITIES	53,060,943	32,439,689
Commitments and contingencies (Note 21)		
STOCKHOLDERS' EQUITY		
Common stock ($0.01 par value, 20,000,000 shares authorized;10,603,802 and 10,599,444 shares issued at September 30, 2015 and December 31, 2014, respectively)	106,038	105,995
Additional paid-in capital	36,738,737	36,718,781
Accumulated deficit	(2,953,832)	(8,057,308)
Treasury stock, 150,000 shares at cost	(800,000)	(800,000)
Total stockholders' equity	33,090,943	27,967,468
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$86,151,886	$60,407,157

See accompanying notes to consolidated financial statements.

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Blue Dolphin Energy Company & Subsidiaries

Consolidated Statements of Income (Unaudited)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
REVENUE FROM OPERATIONS				
Refined petroleum product sales	$ 54,924,070	$ 87,846,757	$ 174,830,292	$ 310,938,981
Tank rental revenue	286,892	282,516	860,676	847,548
Pipeline operations	45,925	56,900	119,882	178,793
Total revenue from operations	55,256,887	88,186,173	175,810,850	311,965,322
COST OF OPERATIONS				
Cost of refined products sold	48,415,627	82,781,856	151,604,774	289,819,720
Refinery operating expenses	2,953,528	2,496,514	8,420,650	8,092,738
Joint Marketing Agreement profit share	1,435,376	1,094,383	4,812,674	2,334,487
Pipeline operating expenses	63,099	50,100	170,582	139,542
Lease operating expenses	(1,143)	7,041	20,271	21,037
General and administrative expenses	312,365	253,437	1,058,267	1,049,981
Depletion, depreciation and amortization	414,837	393,871	1,217,005	1,175,643
Accretion expense	52,720	53,731	158,655	158,264
Total cost of operations	53,646,409	87,130,933	167,462,878	302,791,412
Income from operations	1,610,478	1,055,240	8,347,972	9,173,910
OTHER INCOME (EXPENSE)				
Easement, interest and other income	724,349	1,813	856,816	253,745
Interest expense	(382,191)	(214,407)	(1,322,562)	(675,586)
Loss on disposal of property and equipment	-	(4,400)	-	(4,400)
Total other income (expense)	342,158	(216,994)	(465,746)	(426,241)
Income before income taxes	1,952,636	838,246	7,882,226	8,747,669
Income tax expense	(688,403)	(22,199)	(2,778,750)	(298,792)
Net income	$ 1,264,233	$ 816,047	$ 5,103,476	$ 8,448,877
Income per common share				
Basic	$ 0.12	$ 0.08	$ 0.49	$ 0.81
Diluted	$ 0.12	$ 0.08	$ 0.49	$ 0.81

Weighted average number of common shares outstanding:				
Basic	10,453,802	10,446,218	10,451,168	10,439,684
Diluted	10,453,802	10,446,218	10,451,168	10,439,684

See accompanying notes to consolidated financial statements.

Blue Dolphin Energy Company & Subsidiaries

Consolidated Statements of Cash Flows (Unaudited)

	Nine Months Ended September 30,	
	2015	2014
OPERATING ACTIVITIES		
Net income	$5,103,476	$8,448,877
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation and amortization	1,217,005	1,175,643
Unrealized loss on derivatives	362,750	26,150
Deferred taxes	2,479,823	-
Amortization of debt issue costs	517,652	25,350
Accretion expense	158,655	158,264
Common stock issued for services	19,999	75,001
Loss on disposal of assets	-	4,400
Changes in operating assets and liabilities		
Accounts receivable	506,784	2,058,624
Prepaid expenses and other current assets	(274,435)	152,655
Deposits and other assets	(1,711,073)	(490,838)
Inventory	(2,420,176)	(2,879,729)
Accounts payable, accrued expenses and other liabilities	2,916,973	(5,144)
Accounts payable, related party	(1,174,168)	(1,857,964)
Net cash provided by operating activities	7,703,265	6,891,289
INVESTING ACTIVITIES		
Capital expenditures	(9,900,295)	(1,145,720)
Change in restricted cash for investing activities	(13,021,438)	-
Net cash used in investing activities	(22,921,733)	(1,145,720)
FINANCING ACTIVITIES		
Proceeds from issuance of debt	25,000,000	-
Payments on long-term debt	(9,474,720)	(6,103,131)
Proceeds from notes payable	3,000,000	2,000,000
Payments on notes payable	-	(216,182)
Change in restricted cash for financing activities	(3,081,686)	(678,498)
Net cash provided by (used in) financing activities	15,443,594	(4,997,811)
Net increase in cash and cash equivalents	225,126	747,758
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	1,293,233	434,717
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$1,518,359	$1,182,475
Supplemental Information:		
Non-cash operating activities		
Surety bond funded by seller of pipeline interest	$-	$850,000
Non-cash investing and financing activities:		
New asset retirement obligations	$-	$300,980

Financing of capital expenditures via capital lease	$-	$536,635
Interest paid	$959,665	$1,211,773
Income taxes paid	$139,500	$231,552

See accompanying notes to consolidated financial statements.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)

(1) Organization

Nature of Operations

Blue Dolphin Energy Company (http://www.blue-dolphin-energy.com, referred to herein, with its predecessors and subsidiaries, as "Blue Dolphin," "we," "us" and "our") is primarily an independent refiner and marketer of petroleum products. Our primary asset is a 15,000 bpd crude oil and condensate processing facility that is located in Nixon, Texas (the "Nixon Facility"). As part of our refinery business segment, we conduct petroleum storage and terminaling operations under third-party lease agreements at the Nixon Facility. We also own and operate pipeline assets and have leasehold interests in oil and gas properties. See "Note (4) Business Segment Information" of this report for further discussion of our business segments.

Structure and Management

We were formed as a Delaware corporation in 1986. We are currently controlled by Lazarus Energy Holdings, LLC ("LEH"), which owns approximately 81% of our common stock, par value $0.01 per share (the "Common Stock). LEH manages and operates all of our properties pursuant to an Operating Agreement (the "Operating Agreement"). Jonathan P. Carroll is Chairman of the Board of Directors (the "Board"), Chief Executive Officer and President of Blue Dolphin, as well as a majority owner of LEH. See "Note (10) Accounts Payable, Related Party," "Note (13) Long-Term Debt," and "Note (21) Commitments and Contingencies – Financing Agreements" of this report for additional disclosures related to the Operating Agreement, Jonathan P. Carroll, and LEH.

Our operations are conducted through the following operating subsidiaries:

- Lazarus Energy, LLC, a Delaware limited liability company ("LE");
- Lazarus Refining & Marketing, LLC, a Delaware limited liability company ("LRM");
- Blue Dolphin Pipe Line Company, a Delaware corporation;
- Blue Dolphin Petroleum Company, a Delaware corporation; and
- Blue Dolphin Services Co., a Texas corporation.

See "Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Owned and Leased Assets" of this report for additional information regarding our operating subsidiaries.

(2) Basis of Presentation

We have prepared our unaudited consolidated financial statements in accordance with U.S. generally accepted accounting principles ("GAAP"), as codified by the Financial Accounting Standards Board (the "FASB") in its Accounting Standards Codification ("ASC"), and pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC"). Our consolidated financial statements include Blue Dolphin and its subsidiaries. Significant intercompany transactions have been eliminated in the consolidation. In the opinion of management, such consolidated financial statements reflect all adjustments necessary to present fair consolidated statements of income, financial position and cash flows. We believe that the disclosures are adequate and the presented information is not misleading. This report has been prepared in accordance with the SEC's Form 10-Q instructions and therefore, certain information and footnote disclosures normally included in our annual audited financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to the SEC's rules and regulations.

(3) Significant Accounting Policies

The summary of significant accounting policies of Blue Dolphin is presented to assist in understanding our consolidated financial statements. Our consolidated financial statements and accompanying notes are representations of management who is responsible for its integrity and objectivity. These accounting policies conform to GAAP and have been consistently applied in the preparation of our consolidated financial statements.

Use of Estimates

We have made a number of estimates and assumptions related to the reporting of our consolidated assets and liabilities and to the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with GAAP. While we believe our current estimates are reasonable and appropriate, actual results could differ from those estimated.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

Cash and Cash Equivalents

Cash and cash equivalents represent liquid investments with an original maturity of three months or less. Cash balances are maintained in depository and overnight investment accounts with financial institutions that, at times, may exceed insured deposit limits. We monitor the financial condition of the financial institutions and have experienced no losses associated with these accounts. Cash and cash equivalents totaled $1,518,359 and $1,293,233 at September 30, 2015 and December 31, 2014, respectively.

Restricted Cash

Restricted cash totaled $5,834,197 and $1,008,514 at September 30, 2015 and December 31, 2014, respectively. Restricted cash, noncurrent totaled $11,277,441 and $0 at September 30, 2015 and December 31, 2014, respectively. Restricted cash primarily represents: (i) a construction contingency account under which Sovereign Bank, a Texas state bank ("Sovereign") will fund contingencies, (ii) a payment reserve account held by Sovereign as security for payments under a loan agreement, and (iii) a certificate of deposit held by Sovereign as security under a loan agreement. Restricted cash, noncurrent, represents a disbursement account under which Sovereign will make payments for construction related expenses to build new petroleum storage tanks. See "Note (13) Long-Term Debt" of this report for additional disclosures related to loan agreements with Sovereign.

Accounts Receivable, Allowance for Doubtful Accounts and Concentration of Credit Risk

Accounts receivable are customer obligations due under normal trade terms. The allowance for doubtful accounts represents our estimate of the amount of probable credit losses existing in our accounts receivable. We have a limited number of customers with individually large amounts due on any given date. Any unanticipated change in any one of these customers' credit worthiness or other matters affecting the collectability of amounts due from such customers could have a material adverse effect on our results of operations in the period in which such changes or events occur. We regularly review all of our aged accounts receivable for collectability and establish an allowance for individual customer balances as necessary.

Concentration of Risk

Bank Accounts

Financial instruments that potentially subject us to concentrations of risk consist primarily of cash, trade receivables and payables. We maintain our cash balances at financial institutions located in Houston, Texas. In the United States, the Federal Deposit Insurance Corporation (the "FDIC") insures certain financial products up to a maximum of $250,000 per depositor. We had cash balances in excess of the FDIC insurance limit per depositor in the amount of $18,017,488 and $1,113,977 at September 30, 2015 and December 31, 2014, respectively.

Significant Customers

Customers of our refined petroleum products include distributors, wholesalers, and refineries primarily in the lower portion of the Texas Triangle (the Houston - San Antonio - Dallas/Fort Worth area). We have bulk term contracts, including month-to-month, six months, and up to five year terms in place with most of our customers. Certain of our contracts require us to sell fixed quantities and/or minimum quantities of intermediate and finished petroleum products and many of these arrangements are subject to periodic renegotiation, which could result in us receiving higher or lower relative prices for our refined petroleum products. See “Note (15) Concentration of Risk” of this report for additional disclosures related to significant customers.

Inventory

The nature of our business requires us to maintain inventory, which primarily consists of refined petroleum products and chemicals. Inventory reflected for crude oil and condensate is nominal and represents line fill. Our overall inventory is valued at lower of cost or market with costs being determined by the average cost method. If the market value of our refined petroleum product inventories declines to an amount less than our average cost, we record a write-down of inventory and an associated adjustment to cost of refined products sold. See “Note (7) Inventory” of this report for additional disclosures related to our inventory.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

Derivatives

We are exposed to commodity prices and other market risks including gains and losses on certain financial assets as a result of our inventory risk management policy. Under our inventory risk management policy, Genesis Energy, LLC (“Genesis”) may, but is not required to, use commodity futures contracts to mitigate the change in value for certain of our refined petroleum product inventories subject to market price fluctuations. The physical inventory volumes are not exchanged and these contracts are net settled with cash.

Although these commodity futures contracts are not subject to hedge accounting treatment under FASB ASC guidance, we record the fair value of these Genesis hedges in our consolidated balance sheet each financial reporting period because of contractual arrangements with Genesis under which we are effectively exposed to the potential gains or losses. We recognize all commodity hedge positions as either current assets or current liabilities in our consolidated balance sheets and those instruments are measured at fair value. Changes in the fair value from financial reporting period to financial reporting period are recognized in our consolidated statements of income. Net gains or losses associated with these transactions are recognized within cost of refined products sold in our consolidated statements of income using mark-to-market accounting.

See “Note (19) Fair Value Measurement” and “Note (20) Inventory Risk Management” of this report for additional disclosures related to derivatives.

Property and Equipment

Refinery and Facilities

Additions to refinery and facilities are capitalized. Expenditures for repairs and maintenance are expensed as incurred and are included as operating expenses under the Operating Agreement. Management expects to continue making improvements to the Nixon Facility based on technological advances.

Refinery and facilities are carried at cost. Adjustment of the asset and the related accumulated depreciation accounts are made for refinery and facilities’ retirements and disposals, with the resulting gain or loss included in the consolidated statements of income. For financial reporting purposes, depreciation of refinery and facilities is computed using the straight-line method using an estimated useful life of 25 years beginning when the refinery and facilities are placed in service. We did not record any impairment of our refinery and facilities for the three and nine months ended September 30, 2015 and 2014.

Oil and Gas Properties

We account for our oil and gas properties using the full-cost method of accounting, whereby all costs associated with acquisition, exploration and development of oil and gas properties, including directly related internal costs, are capitalized on a cost center basis. Amortization of such costs and estimated future development costs are determined using the unit-of-production method. Our oil and gas properties had no production during the three and nine months ended September 30, 2015 and 2014. All leases associated with our oil and gas properties have expired.

Pipelines and Facilities

We record pipelines and facilities at cost less any adjustments for depreciation or impairment. Depreciation is computed using the straight-line method over estimated useful lives ranging from 10 to 22 years. In accordance with FASB ASC guidance on accounting for the impairment or disposal of long-lived assets, we periodically evaluate our long-lived assets for impairment. Additionally, we evaluate our long-lived assets when events or circumstances indicate that the carrying value of these assets may not be recoverable.

Construction in Progress

Construction in progress expenditures, which relate to construction ans refurbishment activities at the Nixon Facility, are capitalized as incurred. Depreciation begins once the asset is placed in service.

See “Note (8) Property, Plant and Equipment, Net” of this report for additional disclosures related to our refinery and facilities, oil and gas properties, pipelines and facilities, and construction in progress.

Intangibles – Other

We have an acquisition-related intangible asset consisting of the Blue Dolphin trade name in the amount of $303,346. We have determined our trade name to have an indefinite useful life. We account for other intangible assets under FASB ASC guidance related to intangibles, goodwill and other. Under the guidance, we test intangible assets with indefinite lives annually for impairment. Management performed its regular annual impairment testing of trade name in the fourth quarter of 2014. Upon completion of that testing, we determined that no impairment was necessary as of December 31, 2014.

Debt Issue Costs

We have debt issue costs related to certain refinery and facilities debt. Debt issue costs are capitalized and amortized over the term of the related debt using the straight-line method, which approximates the effective interest method. When a loan is paid in full, any unamortized financing costs are removed from the related asset accounts and expensed as interest expense. See "Note (9) Debt Issue Costs" of this report for additional disclosures related to debt issue costs.

Revenue Recognition

Refined Petroleum Products Revenue

We sell jet fuel in nearby markets, and our intermediate products, including liquefied petroleum gas, naphtha, heavy oil-based mud blendstock ("HOBM"), and atmospheric gas oil ("AGO"), to wholesalers and nearby refineries for further blending and processing. Revenue from refined petroleum products sales is recognized when title passes. Title passage occurs when refined petroleum products are sold or delivered in accordance with the terms of the respective sales agreements. Revenue is recognized when sales prices are fixed or determinable and collectability is reasonably assured.

Customers assume the risk of loss when title is transferred. Transportation, shipping, and handling costs incurred are included in cost of refined products sold. Excise and other taxes that are collected from customers and remitted to governmental authorities are not included in revenue.

Tank Rental Revenue

Tank rental fees are invoiced monthly in accordance with the terms of the related lease agreement and recognized in revenue as earned.

Easement Revenue

Land easement revenue is recognized monthly as earned and is included in other income.

Pipeline Transportation Revenue

Revenue from our pipeline operations is derived from fee-based contracts and is typically based on transportation fees per unit of volume transported multiplied by the volume delivered. Revenue is recognized when volumes have been physically delivered for the customer through the pipeline.

Deferred Revenue

On February 5, 2014, we entered into an Asset Sale Agreement (the “Purchase Agreement”) with WBI Energy Midstream, LLC, a Colorado limited liability company (“WBI”), whereby we reacquired WBI’s 1/6th interest in the Blue Dolphin Pipeline System, the Galveston Area Block 350 Pipeline, and the Omega Pipeline (the “Pipeline Assets”) effective October 31, 2013. Pursuant to the Purchase Agreement, WBI paid us $100,000 in cash, and a surety company $850,000 in cash as collateral for supplemental pipeline bonds for our benefit in exchange for the payment and discharge of any and all payables, claims, and obligations related to the Pipeline Assets. We recorded the amount received for our benefit for the supplemental pipeline bonds as deferred revenue. The deferred revenue is being recognized on a straight-line basis through December 31, 2018, the expected retirement date of the assets that the supplemental pipeline bonds secure.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

Income Taxes

We account for income taxes under FASB ASC guidance related to income taxes, which requires recognition of income taxes based on amounts payable with respect to the current year and the effects of deferred taxes for the expected future tax consequences of events that have been included in our financial statements or tax returns. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial accounting and tax basis of assets and liabilities, as well as for operating losses and tax credit carryforwards using enacted tax rates in effect for the year in which the differences are expected to reverse.

As of each reporting date, management considers new evidence, both positive and negative, to determine the realizability of deferred tax assets. Management considers whether it is more likely than not that some portion or all of the deferred tax assets will be realized, which is dependent upon the generation of future taxable income prior to the expiration of any net operating loss (“NOL”) carryforwards. When management determines that it is more likely than not that a tax benefit will not be realized, a valuation allowance is recorded to reduce deferred tax assets.

The guidance also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, as well as guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosures, and transition.

See “Note (17) Income Taxes” of this report for further information related to income taxes.

Impairment or Disposal of Long-Lived Assets

In accordance with FASB ASC guidance on accounting for the impairment or disposal of long-lived assets, we periodically evaluate our long-lived assets for impairment. Additionally, we evaluate our long-lived assets when events or circumstances indicate that the carrying value of these assets may not be recoverable. The carrying value is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset or group of assets. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset or group of assets is recognized. Significant management judgment is required in the forecasting of future operating results that are used in the preparation of projected cash flows and, should different conditions prevail or judgments be made, material impairment charges could be necessary.

Asset Retirement Obligations

FASB ASC guidance related to asset retirement obligations (“AROs”) requires that a liability for the discounted fair value of an ARO be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted towards its future value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Management has concluded that there is no legal or contractual obligation to dismantle or remove the refinery and facilities. Further, management believes that these assets have indeterminate lives under FASB ASC guidance for estimating AROs because dates or ranges of dates upon which we would retire these assets cannot reasonably be estimated at this time. When a date or range of dates can reasonably be estimated for the retirement of these assets, we will estimate the cost of performing the retirement activities and record a liability for the fair value of that cost using present value techniques.

We recorded an ARO liability related to future asset retirement costs associated with dismantling, relocating, or disposing of our offshore platform, pipeline systems, and related onshore facilities, as well as for plugging and abandoning wells and restoring land and sea beds. We developed these cost estimates for each of our assets based upon regulatory requirements, structural makeup, water depth, reservoir characteristics, reservoir depth, equipment demand, current retirement procedures, and construction and engineering consultations. Because these costs typically extend many years into the future, estimating future costs are difficult and require management to make judgments that are subject to future revisions based upon numerous factors, including changing technology, political, and regulatory environments. We review our assumptions and estimates of future abandonment costs on an annual basis.

See “Note (12) Asset Retirement Obligations” of this report for additional information related to our AROs.

Computation of Earnings Per Share

We apply the provisions of FASB ASC guidance for computing earnings per share ("EPS"). The guidance requires the presentation of basic EPS, which excludes dilution and is computed by dividing net income available to common stockholders by the weighted-average number of shares of common stock outstanding for the period. The guidance requires dual presentation of basic EPS and diluted EPS on the face of our consolidated statements of income and requires a reconciliation of the numerators and denominators of basic EPS and diluted EPS. Diluted EPS is computed by dividing net income available to common stockholders by the diluted weighted average number of common shares outstanding, which includes the potential dilution that could occur if securities or other contracts to issue shares of common stock were converted to common stock that then shared in the earnings of the entity.

The number of shares related to options, warrants, restricted stock, and similar instruments included in diluted EPS is based on the "Treasury Stock Method" prescribed in FASB ASC guidance for computation of EPS. This method assumes theoretical repurchase of shares using proceeds of the respective stock option or warrant exercised, and, for restricted stock, the amount of compensation cost attributed to future services that has not yet been recognized and the amount of any current and deferred tax benefit that would be credited to additional paid-in-capital upon the vesting of the restricted stock, at a price equal to the issuer's average stock price during the related earnings period. Accordingly, the number of shares includable in the calculation of EPS in respect of the stock options, warrants, restricted stock, and similar instruments is dependent on this average stock price and will increase as the average stock price increases. See "Note (18) Earnings Per Share" for additional information related to EPS.

Stock-Based Compensation

In accordance with FASB ASC guidance for stock-based compensation, share-based payments to personnel, including grants of restricted stock units, are measured at fair value as of the date of grant and are expensed in our consolidated statements of income over the service period (generally the vesting period).

Treasury Stock

We account for treasury stock under the cost method. When treasury stock is re-issued, the net change in share price subsequent to acquisition of the treasury stock is recognized as a component of additional paid-in-capital in our consolidated balance sheets. See "Note (14) Treasury Stock" for additional disclosures related to treasury stock.

Reclassification

We have reclassified certain insignificant prior period amounts related to our tank rental revenue to conform to our 2015 presentation.

New Pronouncements Issued but Not Yet Effective

FASB issues an Accounting Standards Update ("ASU") to communicate changes to the FASB ASC, including changes to non-authoritative SEC content. The following are recently issued, but not yet effective, accounting standards that may have an effect on our consolidated financial position, results of operations, or cash flows:

- Revenue from Contracts with Customers ("ASU 2014-09") – In May 2014, FASB issued ASU 2014-09, which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services.

In August 2015, FASB issued Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, which defers the effective date of ASU 2014-09 for all entities by one year. The effective date for public business entities is annual reporting periods beginning after December 15, 2017. Public business entities would apply the new revenue standard to interim reporting periods after December 15, 2017. As such, for a public business entity with a calendar year-end, ASU 2014-09 would be effective on January 1, 2018, for both its interim and annual reporting periods. This represents a one-year deferral from the original effective date. The new effective date guidance allows early adoption for all entities as of the original effective date (December 15, 2016). We are evaluating the impact that adoption of this guidance will have on the determination or reporting of our financial results.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

- Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15") – In August 2014, FASB issued ASU 2014-15, which requires management to perform interim and annual assessments of an entity's ability to continue as a going concern for a one year period subsequent to the date of the financial statements. An entity must provide certain disclosures if conditions or events raise substantial doubt about the entity's ability to continue as a going concern. The guidance is effective for all entities for the first annual period ending after December 15, 2016 and interim periods thereafter, with early adoption permitted. We do not anticipate adoption of this guidance to have a material effect on our consolidated financial statements.

- Inventory (Topic 330): Simplifying the Measurement of Inventory ("ASU 2015-11") – In July 2015, FASB issued ASU 2015-11. Current guidance requires an entity to measure inventory at the lower of cost or market. Market could be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. Under ASU 2015-11, an entity should measure inventory at the lower of cost or net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. Amendments under ASU 2015-11 more closely align the measurement of inventory in GAAP with the measurement of inventory in International Financial Reporting Standards. For public business entities, ASU 2015-11 is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. ASU 2015-11 should be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. We do not anticipate adoption of this guidance to have a material effect on our consolidated financial statements.

- Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03") – In April 2015, FASB issued ASU 2015-03, which requires debt issue costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying value of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issue costs are not affected by ASU 2015-03. The amendments in this ASU are effective retrospectively for fiscal years, and interim periods within those years, beginning after December 15, 2015. Early adoption is permitted. We do not anticipate adoption of this guidance to have a material effect on our consolidated financial statements.

- Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements ("ASU 2015-15") – In August 2015, FASB issued ASU 2015-15, which amends ASU 2015-03 by clarifying the presentation and subsequent measurement of debt issuance costs associated with lines of credit. These costs may be presented as an asset and amortized ratably over the term of the line of credit arrangement, regardless of whether there are outstanding borrowings on the arrangement. The effective date will be the first quarter of fiscal year 2016 and will be applied retrospectively. We do not anticipate adoption of this guidance to have a material effect on our consolidated financial statements.

Other new pronouncements issued but not effective until after September 30, 2015 are not expected to have a material impact on our financial position, results of operations or liquidity.

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Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

(4) Business Segment Information

We have two reportable business segments: (i) Refinery Operations and (ii) Pipeline Transportation. Business activities related to our Refinery Operations business segment are conducted at the Nixon Facility. Business activities related to our Pipeline Transportation business segment are primarily conducted in the Gulf of Mexico through our Pipeline Assets and leasehold interests in oil and gas properties.

Business segment information for the three months ended September 30, 2015 and 2014 (and at September 30, 2015 and 2014), was as follows:

	Three Months Ended September 30, 2015 Segment				Three Months Ended September 30, 2014 Segment			
	Refinery Operations	Pipeline Transportation	Corporate & Other	Total	Refinery Operations	Pipeline Transportation	Corporate & Other	Total
Revenue from operations	$55,210,962	$45,925	$-	$55,256,887	$88,129,273	$56,900	$-	$88,186,17
Less: cost of operations(1)	(51,444,705)	(114,675)	(236,816)	(51,796,196)	(85,261,533)	(110,872)	(274,674)	(85,647,0
Other non-interest income(2)	-	62,500	660,000	722,500	-	-	-	-
Adjusted EBITDA	3,766,257	(6,250)	423,184	4,183,191	2,867,740	(53,972)	(274,674)	2,539,094
Less: JMA Profit Share(3)	(1,435,376)	-	-	(1,435,376)	(1,094,383)	-	-	(1,094,38
EBITDA	$2,330,881	$(6,250)	$423,184		$1,773,357	$(53,972)	$(274,674)	
Depletion, depreciation and amortization				(414,837)				(393,871
Interest expense, net				(380,342)				(212,594
Income before income taxes				1,952,636				838,246
Income tax expense				(688,403)				(22,199
Net income				$1,264,233				$816,047
	$3,640,801	$-	$-	$3,640,801	$815,849	$-	$-	$815,849

Capital expenditures								
Identifiable assets(4)	$79,442,106	$3,303,803	$3,405,977	$86,151,886	$57,520,835	$2,998,619	$523,533	$61,042,98

(1) Operation cost within the Refinery Operations and Pipeline Transportation segments includes related general, administrative, and accretion expenses. Operation cost within Corporate and Other includes general and administrative expenses associated with corporate maintenance costs, such as accounting fees, director fees, and legal expense.
(2) Other non-interest income reflects FLNG easement revenue and the Grynberg Settlement Agreement. See "Part 1, Item 1. Financial Statements - Note (21) Commitments and Contingencies – FLNG Master Easement Agreement and Grynberg Settlement Agreement" of this report for further discussion related to FLNG and Grynberg.
(3) The Joint Marketing Agreement profit share (the "JMA Profit Share") represents the GEL Profit Share plus the Performance Fee for the period pursuant to the Joint Marketing Agreement. See "Note (21) Commitments and Contingencies – Genesis Agreements" and "Part 1, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Relationship with Genesis" of this report for further discussion related to the Joint Marketing Agreement.
(4) Identifiable assets contain related legal obligations of each business segment including cash, accounts receivable, and recorded net assets.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

Business segment information for the nine months ended September 30, 2015 and 2014 (and at September 30, 2015 and 2014), was as follows:

	Nine Months Ended September 30, 2015 Segment				Nine Months Ended September 30, 2014 Segment			
	Refinery Operations	Pipeline Transportation	Corporate & Other	Total	Refinery Operations	Pipeline Transportation	Corporate & Other	To
Revenue from operations	$175,690,968	$119,882	$-	$175,810,850	$311,786,529	$178,793	$-	$311,96
Less: cost of operations(1)	(160,208,576)	(296,291)	(928,331)	(161,433,198)	(297,956,882)	(355,645)	(973,154)	(299,2
Other non-interest income(2)	-	187,500	660,000	847,500	-	208,333	-	208,33
Adjusted EBITDA	15,482,392	11,091	(268,331)	15,225,152	13,829,647	31,481	(973,154)	12,88
Less: JMA Profit Share(3)	(4,812,674)	-	-	(4,812,674)	(2,334,487)	-	-	(2,334
EBITDA	$10,669,718	$11,091	$(268,331)		$11,495,160	$31,481	$(973,154)	
Depletion, depreciation and amortization				(1,217,005)				(1,175
Interest expense, net				(1,313,247)				(630,1
Income before income taxes				7,882,226				8,747,
Income tax expense				(2,778,750)				(298,7
Net income				$5,103,476				$8,448,
Capital expenditures	$9,900,295	$-	$-	$9,900,295	$1,145,720	$-	$-	$1,145,
Identifiable assets(4)	$79,442,106	$3,303,803	$3,405,977	$86,151,886	$57,520,835	$2,998,619	$523,533	$61,04

(1)

Operation cost within the Refinery Operations and Pipeline Transportation segments includes related general, administrative, and accretion expenses. Operation cost within Corporate and Other includes general and administrative expenses associated with corporate maintenance costs, such as accounting fees, director fees, and legal expense.

(2) Other non-interest income reflects FLNG easement revenue and the Grynberg Settlement Agreement. See “Part 1, Item 1. Financial Statements - Note (21) Commitments and Contingencies – FLNG Master Easement Agreement and Grynberg Settlement Agreement” of this report for further discussion related to FLNG and Grynberg.

(3) The JMA Profit Share represents the GEL Profit Share plus the Performance Fee for the period pursuant to the Joint Marketing Agreement. See “Note (21) Commitments and Contingencies – Genesis Agreements” and “Part 1, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Relationship with Genesis” of this report for further discussion related to the Joint Marketing Agreement.

(4) Identifiable assets contain related legal obligations of each business segment including cash, accounts receivable, and recorded net assets.

(5) Prepaid Expenses and Other Current Assets

Prepaid expenses and other current assets consisted of the following:

	September 30, 2015	December 31, 2014
Prepaid related party operating expenses	$712,688	$-
Prepaid insurance	196,305	156,558
Unrealized hedging gains	133,150	495,900
Prepaid listing fees	3,750	15,000
Prepaid professional fees	-	104,000
	$1,045,893	$771,458

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

(6) Deposits

Deposits consisted of the following:

	September 30, 2015	December 31, 2014
Construction deposits	$300,000	$-
Equipment deposits	100,463	48,785
Utility deposits	10,250	10,250
Rent deposits	9,463	9,463
	$420,176	$68,498

(7) Inventory

Inventory consisted of the following:

	September 30, 2015	December 31, 2014
HOBM	$ 3,044,646	$ 124,176
Jet fuel	1,557,847	2,631,546
AGO	403,875	224,007
Naphtha	362,049	194,688
Chemicals	216,208	-
Crude oil and condensate	19,041	19,041
Propane	12,817	-
LPG mix	4,344	7,193
	$ 5,620,827	$ 3,200,651

(8) Property, Plant and Equipment, Net

Property, plant and equipment, net, consisted of the following:

	September 30, 2015	December 31, 2014
Refinery and facilities	$39,969,028	$36,462,451
Pipelines and facilities	2,127,207	2,127,207
Onshore separation and handling facilities	325,435	325,435
Land	602,938	602,938
Other property and equipment	644,795	597,064

	43,669,403	40,115,095
Less: Accumulated depletion, depreciation, and amortization	(5,803,580)	(4,586,575)
	37,865,823	35,528,520
Construction in progress	8,188,542	1,842,555
	$46,054,365	$37,371,075

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Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

(9) Debt Issue Costs

Debt issue costs, net of accumulated amortization, totaled $1,296,480 and $479,737 at September 30, 2015 and December 31, 2014, respectively. Debt issue costs at September 30, 2015 related to loan agreements with Sovereign. Debt issue costs at December 31, 2014 related to a loan agreement with American First National Bank.

Accumulated amortization totaled $22,781 and $211,244 at September 30, 2015 and December 31, 2014, respectively. Amortization expense, which is included in interest expense, was $17,086 and $8,450 for the three months ended September 30, 2015 and 2014, respectively. Amortization expense was $517,652 and $25,350 for the nine months ended September 30, 2015 and 2014, respectively. Amortization expense for the nine months ended September 30, 2015 included $456,287 related to writing off debt issue costs associated with the refinance of debt owed to American First National Bank.

See "Note (13) Long-Term Debt" of this report for additional disclosures related to the loan agreements with Sovereign and American First National Bank.

(10) Accounts Payable, Related Party

LEH manages and operates all of our properties pursuant to the Operating Agreement. For services rendered, LEH receives reimbursements and fees as follows:

- Reimbursements – For management and operation of all properties excluding the Nixon Facility, LEH is reimbursed at cost for all reasonable expenses incurred while performing the services. Unsettled reimbursements are reflected within either prepaid expenses or accounts payable, related party in our consolidated balance sheets. Amounts reimbursed to LEH are reflected in the appropriate asset or expense accounts in our consolidated statements of income.

- Fees – For management and operation of the Nixon Facility, LEH receives fees: (i) in the form of weekly payments from GEL TEX Marketing, LLC ("GEL") not to exceed $750,000 per month, (ii) $0.25 for each barrel processed at the Nixon Facility up to a maximum quantity of 10,000 barrels per day determined on a monthly basis, and (iii) $2.50 for each barrel processed at the Nixon Facility in excess of 10,000 barrels per day determined on a monthly basis. In the normal course of business, we make estimates and assumptions related to amounts expensed for fees since actual amounts can vary depending upon production volumes. We then use the cumulative catch-up method to account for revisions in estimates, which may result in prepaid expenses or accounts payable, related party on our consolidated balance sheets. Amounts expensed as fees are reflected as refinery operating expenses in our consolidated statements of income.

At September 30, 2015, we were in a prepaid position with respect to fees and reimbursements under the Operating Agreement. Prepaid related party operating expenses totaled $712,688 and $0 at September 30, 2015 and December 31, 2014, respectively. Accounts payable, related party totaled $0 and $1,174,168 at September 30, 2015 and December 31, 2014, respectively.

For the three months ended September 30, 2015 and 2014, refinery operating expenses totaled $2,953,528 (approximately $2.66 per barrel of throughput) and $2,496,514 (approximately $2.94 per barrel of throughput), respectively. For the nine months ended September 30, 2015 and 2014, refinery operating expenses totaled $8,420,650 (approximately $2.73 per barrel of throughput) and $8,092,738 (approximately $2.78 per barrel of throughput), respectively.

The Operating Agreement expires upon the earliest to occur of: (a) the date of the termination of the Joint Marketing Agreement pursuant to its terms, (b) August 12, 2018, or (c) upon written notice of either party to the Operating Agreement of a material breach of the Operating Agreement by the other party.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

(11) Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities consisted of the following:

	September 30, 2015	December 31, 2014
Excise and income taxes payable	$1,489,921	$1,228,411
Other payable	175,634	149,962
Genesis JMA Profit Share payable	162,470	521,739
Property taxes	92,002	-
Board of director fees payable	85,179	345,000
Transportation and inspection	-	190,000
Unearned revenue	-	252,500
Insurance	-	96,092
	$2,005,206	$2,783,704

(12) Asset Retirement Obligations

Refinery and Facilities

Management has concluded that there is no legal or contractual obligation to dismantle or remove the refinery and facilities. Management believes that the refinery and facilities have indeterminate lives under FASB ASC guidance for estimating AROs because dates or ranges of dates upon which we would retire these assets cannot reasonably be estimated at this time. When a date or range of dates can reasonably be estimated for the retirement of these assets, we will estimate the cost of performing the retirement activities and record a liability for the fair value of that cost using present value techniques.

Pipelines and Facilities and Oil and Gas Properties

We have AROs associated with the dismantlement and abandonment in place of our pipelines and facilities, as well as the plugging and abandonment of our oil and gas properties. We recorded a discounted liability for the fair value of an ARO with a corresponding increase to the carrying value of the related long-lived asset at the time the asset was installed or placed in service. We amortize the amount added to property and equipment and recognize accretion expense in connection with the discounted liability over the remaining life of the asset.

Plugging and abandonment costs for oil and gas properties and pipelines are recorded as information becomes available from operators to substantiate actual and/or probable costs. Abandonment costs that exceed the asset's ARO liability are recorded as abandonment expense during the period incurred. For the three and nine months ended September 30, 2015 and 2014, we did not incur any abandonment expense related to our oil and gas properties.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

AROs on a roll-forward basis were as follows:

	September 30, 2015	December 31, 2014
Asset retirement obligations, at the beginning of the period	$1,866,770	$1,597,661
New asset retirement obligations and adjustments	49	300,980
Liabilities settled	(58,459)	(243,866)
Accretion expense	158,655	211,995
	1,967,015	1,866,770
Less: current portion of asset retirement obligations	(38,644)	(85,846)
Long-term asset retirement obligations, at the end of the period	$1,928,371	$1,780,924

The WBI transaction resulted in a $300,980 increase in our AROs related to the Pipeline Assets, which represents the fair value of the liability, and increased accretion expense throughout the remaining useful life of certain of the Pipeline Assets. For additional information related to the WBI Transaction, see "Note (3) Significant Accounting Policies – Revenue Recognition – Deferred Revenue" and "Note (21) Commitments and Contingencies – Supplemental Pipeline Bonds" of this report.

(13) Long-Term Debt

Long-term debt consisted of the following:

	September 30, 2015	December 31, 2014
Term Loan Due 2034	$24,822,362	$-
Term Loan Due 2016	3,000,000	-
Notre Dame Debt	1,300,000	1,300,000
Term Loan Due 2017	1,109,962	1,638,898
Capital Leases	347,236	466,401
Refinery Note	-	8,648,980
	30,579,560	12,054,279
Less: current portion of long-term debt	(1,631,539)	(1,245,476)
	$28,948,021	$10,808,803

Term Loan Due 2034

We entered into a Loan and Security Agreement with Sovereign on June 22, 2015, as administrative agent and lender pursuant to a term loan in the principal amount of $25.0 million (the "Term Loan Due 2034"). The Term Loan Due 2034 matures in June 2034, has a monthly payment of principal and interest of $185,289, and accrues interest at a rate based on the Wall Street Journal Prime Rate plus 2.75%. Pursuant to a construction rider in the Term Loan Due 2034, proceeds available for use were placed in a disbursement account whereby Sovereign makes payments for construction related expenses. Amounts held in the disbursement account are reflected as restricted cash and restricted cash, noncurrent in our consolidated balance sheets. The principal balance outstanding on the Term Loan Due 2034 was $24,822,362 and $0 at September 30, 2015 and December 31, 2014, respectively. Interest was accrued on the Term Loan Due 2034 in the amount of $33,102 and $0 at September 30, 2015 and December 31, 2014, respectively.

As a condition of the Term Loan Due 2034, Jonathan P. Carroll was required to guarantee repayment of funds borrowed and interest accrued under the loan. For his personal guarantee, we entered into a Guaranty Fee Agreement with Jonathan P. Carroll whereby he receives a contingent fee equal to 2.00% per annum, paid monthly, of the outstanding principal balance owed under the Term Loan Due 2034. For the three and nine months ended September 30, 2015 and 2014, guaranty fees related to the Term Loan Due 2034 totaled $142,002. There were no guaranty fees paid in 2014 related to the Term Loan Due 2034. Guaranty fees are recognized monthly as incurred and are included in other income as interest expense. LEH, LRM and Blue Dolphin also guaranteed the Term Loan Due 2034. See "Note (10) Accounts Payable, Related Party" of this report for additional disclosures related to LEH.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

Proceeds of the Term Loan Due 2034 were used to refinance approximately $8.5 million of debt owed to American First National Bank under the Refinery Note. Remaining proceeds are being used primarily to construct new petroleum storage tanks. The Term Loan Due 2034 is secured by: (i) a first lien on all Nixon Facility business assets (excluding accounts receivable and inventory), (ii) assignment of all Nixon Facility contracts, permits, and licenses, (iii) absolute assignment of Nixon Facility rents and leases, including tank rental income, (iv) a $1.0 million payment reserve account held by Sovereign, and (v) a pledge of $5.0 million of a life insurance policy on Jonathan P. Carroll. The Term Loan Due 2034 contains representations and warranties, affirmative, restrictive, and financial covenants, as well as events of default which are customary for credit facilities of this type.

Term Loan Due 2016

We entered into a Loan and Security Agreement with Sovereign as lender on June 22, 2015, for a term note in the principal amount of $3,000,000 (the “Term Loan Due 2016”). The Term Loan Due 2016 was amended on November 10, 2015, pursuant to a Loan Modification Agreement (the "November Loan Modification Agreement"). Under the November Loan Modification Agreement, the due date was extended to November 2016. The Term Loan Due 2016 accrues interest at the greater of the Wall Street Journal Prime Rate plus 2.75% or 6.00%. The Term Loan Due 2016 requires payment of interest with full payment of the outstanding principal due at maturity. The principal balance outstanding on the Term Loan Due 2016 was $3,000,000 and $0 at September 30, 2015 and December 31, 2014, respectively. Interest was accrued on the Term Loan Due 2016 in the amount of $15,500 and $0 at September 30, 2015 and December 31, 2014, respectively.

As a condition of the Term Loan Due 2016, Jonathan P. Carroll was required to guarantee repayment of funds borrowed and interest accrued under the loan. For his personal guarantee, we entered into a Guaranty Fee Agreement with Jonathan P. Carroll whereby he receives a contingent fee equal to 2.00% per annum, paid monthly, of the outstanding principal balance owed under the Term Loan Due 2016. For the three and nine months ended September 30, 2015 and 2014, guaranty fees related to the Term Loan Due 2016 totaled $16,500. There were no guaranty fees paid in 2014 related to the Term Loan Due 2016. Guaranty fees are recognized monthly as incurred and are included in other income as interest expense. LE and Blue Dolphin also guaranteed the Term Loan Due 2016.

Proceeds of the Term Loan Due 2016 were used to purchase idle refinery equipment for the Nixon Facility. The Term Loan Due 2016 is secured by: (i) a first lien on the equipment that was purchased, (ii) a $1.5 million certificate of deposit at Sovereign, (iii) assignment of an easement agreement on land in Freeport, Texas (iv) a second lien on all LRM assets (excluding accounts receivable and inventory), and (v) a second lien and deed of trust on the Nixon Facility. The Term Loan Due 2016 contains representations and warranties, affirmative, restrictive, and financial covenants, as well as events of default which are customary for credit facilities of this type.

Notre Dame Debt

We entered into a loan with Notre Dame Investors, Inc. as evidenced by a Promissory Note in the original principal amount of $8.0 million, which is currently held by John Kissick (the “Notre Dame Debt”). The Notre Dame Debt matures in January 2017, and accrues interest at a rate of 16.00%. The principal balance outstanding on the Notre Dame Debt was $1,300,000 at September 30, 2015 and December 31, 2014. Interest was accrued on the Notre Dame Debt in the amount of $1,430,371 and $1,274,789 at September 30, 2015 and December 31, 2014, respectively.

The Notre Dame Debt is secured by a Deed of Trust, Security Agreement and Financing Statements (the “Subordinated Deed of Trust”), which encumbers the Nixon Facility and general assets of LE. There are no financial maintenance covenants associated with the Notre Dame Debt. Pursuant to a Subordination Agreement dated June 22, 2015, the holder of the Notre Dame Debt agreed to subordinate its interest and liens on the Nixon Facility and general assets of LE first in favor of Sovereign as holder of the Term Loan Due 2034 and second in favor of GEL. See “Note (21) Commitments and Contingencies” of this report for additional disclosures related to the Genesis Agreements.

Term Loan Due 2017

We entered into a Loan and Security Agreement with Sovereign on May 2, 2014, for a term loan facility in the principal amount of $2.0 million (the “Term Loan Due 2017”). The Term Loan Due 2017 was amended on March 25, 2015, pursuant to a Loan Modification Agreement (the “March Loan Modification Agreement”). Under the March Loan Modification Agreement, the interest rate was modified to be the greater of the U.S. Prime Rate plus 2.75% or 6.00% and the due date was extended to March 2017. Pursuant to the March Loan Modification Agreement, the monthly payment due under the Term Loan Due 2017 is $61,665 plus interest. The principal balance outstanding on the Term Loan Due 2017 was $1,109,962 and $1,638,898 at September 30, 2015 and December 31, 2014, respectively. Interest was accrued on the Term Loan Due 2017 in the amount of $5,550 and $8,470 at September 30, 2015 and December 31, 2014, respectively.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

As a condition of the Term Loan Due 2017, Jonathan P. Carroll was required to guarantee repayment of funds borrowed and interest accrued under the loan. For his personal guarantee, we entered into a Guaranty Fee Agreement with Jonathan P. Carroll whereby he receives a contingent fee equal to 2.00% per annum, paid monthly, of the outstanding principal balance owed under the Term Loan Due 2017. For the three and nine months ended September 30, 2015 and 2014, guaranty fees related to the Term Loan Due 2017 totaled $6,506. There were no guaranty fees paid in 2014 related to the Term Loan Due 2017. Guaranty fees are recognized monthly as incurred and are included in other income as interest expense.

The proceeds of the Term Loan Due 2017 were used primarily to finance costs associated with refurbishment of the Nixon Facility's naphtha stabilizer and depropanizer units. The Term Loan Due 2017 is: (i) subject to a financial maintenance covenant pertaining to debt service coverage ratio and (ii) secured by the assignment of certain leases of LRM and assets of LEH. See "Note (10) Accounts Payable, Related Party" of this report for additional disclosures related to LEH.

Capital Leases

We entered into a 36 month "build-to-suit" capital lease on August 7, 2014, for the purchase of new boiler equipment for the Nixon Facility. The equipment was delivered in December 2014 and the cost was added to construction in progress. Once placed in service, the equipment will be reclassified to refinery and facilities and depreciation will begin. The capital lease requires a quarterly payment in the amount of $42,996. Capital lease obligations totaled $347,236 and $466,401 at September 30, 2015 and December 31, 2014, respectively. Interest was accrued on capital leases in the amount of $2,988 and $0 at September 30, 2015 and December 31, 2014, respectively.

The following is a summary of equipment held under long-term capital leases:

	September 30, 2015	December 31, 2014
Boiler equipment	$538,598	$538,598
Less: accumulated depreciation	-	-
	$538,598	$538,598

Refinery Note

We entered into a Loan Agreement with First International Bank on September 29, 2008, in the principal amount of $10.0 million (the "Refinery Note"). The Refinery Note was subsequently acquired by American First National Bank. The Refinery Note matured in October 2028 and accrued interest at a rate based on the U.S. Prime Rate plus 2.25%. The principal balance outstanding on the Refinery Note was $0 and $8,648,980 at September 30, 2015 and December 31, 2014, respectively. Interest was accrued on the Refinery Note in the amount of $0 and $47,569 at September 30, 2015 and December 31, 2014, respectively. All amounts due and outstanding under the Refinery Note were repaid in June 2015.

(14) Treasury Stock

At September 30, 2015 and December 31, 2014, we had 150,000 shares of treasury stock.

(15) Concentration of Risk

Key Supplier

Under the Crude Oil and Supply Throughput Services Agreement dated August 12, 2011 (the “Crude Supply Agreement”), GEL is our exclusive supplier of crude oil and condensate. We have the ability to purchase crude oil and condensate from other suppliers with the prior consent of GEL. The initial term was to expire on August 12, 2014. However, on October 30, 2013, we entered into a Letter Agreement Regarding Certain Advances and Related Agreements with GEL and Milam Services, Inc. (“Milam”)(the “October 2013 Letter Agreement”), effective October 24, 2013. In accordance with the terms of the October 2013 Letter Agreement, we agreed not to terminate the Crude Supply Agreement and GEL agreed to automatically renew the Crude Supply Agreement at the end of the initial term for successive one year periods until August 12, 2019, unless sooner terminated by GEL with 180 days prior written notice.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

Significant Customers

For the three months ended September 30, 2015, we had 5 customers that accounted for approximately 81% of our refined petroleum products sales. These 5 customers represented approximately $5.7 million in accounts receivable at September 30, 2015. For the three months ended September 30, 2014, we had 3 customers that accounted for approximately 71% of our refined petroleum products sales. These 3 customers represented approximately $6.4 million in accounts receivable at September 30, 2014.

For the nine months ended September 30, 2015, we had 3 customers that accounted for approximately 55% of our refined petroleum products sales. These 3 customers represented approximately $4.4 million in accounts receivable at September 30, 2015. For the nine months ended September 30, 2014, we had 4 customers that accounted for approximately 84% of our refined petroleum products sales. These 4 customers represented approximately $7.7 million in accounts receivable at September 30, 2014.

Refined Petroleum Product Sales

All of our refined petroleum products are currently sold in the United States. The following table summarizes total refined petroleum product sales by distillation (from light to heavy):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2015		2014		2015		2014	
LPG mix	$617,715	1.1 %	$146,452	0.2 %	$909,207	0.5 %	$670,473	0.2 %
Naphtha	11,218,381	20.4 %	19,195,974	21.8 %	38,048,064	21.8 %	73,061,235	23.5 %
Jet fuel	17,782,534	32.4 %	25,978,551	29.6 %	51,713,507	29.6 %	65,616,193	21.1 %
NRLM	-	0.0 %	-	0.0 %	-	0.0 %	62,729,476	20.2 %
HOBM	9,609,536	17.5 %	22,094,185	25.1 %	40,640,975	23.2 %	29,321,261	9.4 %
Reduced Crude	50,407	0.1 %	-	0.0 %	50,407	0.0 %	-	0.0 %
AGO	15,645,497	28.5 %	20,431,595	23.3 %	43,468,132	24.9 %	79,540,343	25.6 %
	$54,924,070	100.0 %	$87,846,757	100.0 %	$174,830,292	100.0 %	$310,938,981	100.0 %

On May 31, 2014, we ceased production of NRLM, a transportation-related diesel fuel product. On June 1, 2014, we began producing HOBM, a non-transportation lubricant blend product. The shift in product slate from NRLM to HOBM was the result of the Environmental Protection Agency's (the "EPA's") phased-in requirements for small refineries to reduce the sulfur content in transportation-related diesel fuel, such as NRLM, to a maximum of 15 ppm sulfur by June 1, 2014. "Topping units," like the Nixon Facility, typically lack a desulfurization process unit to lower sulfur content levels within the range required by the EPA's recently implemented fuel quality standards, and integration of such a unit generally requires additional permitting and significant capital upgrades. We can produce and sell a low sulfur diesel as a feedstock to other refineries and blenders in the United States and as a finished petroleum product to other countries.

(16) Leases

Our company headquarters is located in downtown Houston, Texas. We lease 13,878 square feet of office space, 7,389 square feet of which is used and paid for by LEH. The office lease has a 10 year term expiring in 2017, includes free rent periods and escalating rent payment provisions, and requires payment of a portion of related actual operating expenses. Rent expense is recognized on a straight-line basis. For the three months ended September 30, 2015 and 2014, rent expense totaled $29,857 and $26,129, respectively. For the nine months ended September 30, 2015 and 2014, rent expense totaled $112,746 and $77,787, respectively.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

(17) Income Taxes

Income Tax Expense

Our income tax expense consisted of the following:

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Current:				
Federal	$(37,620)	$(1,395)	$(122,863)	$(152,759)
State	(36,102)	(20,804)	(148,656)	(146,033)
Deferred:				
Federal	(614,681)	-	(2,507,231)	-
State	-	-	-	-
	$(688,403)	$(22,199)	$(2,778,750)	$(298,792)

The state of Texas has a Texas margins tax ("TMT"), which is a form of business tax imposed on gross margin to replace the state's prior franchise tax structure. Although TMT is imposed on an entity's gross margin rather than on its net income, certain aspects of TMT make it similar to an income tax.

Deferred Income Taxes

Under Section 382 of the Internal Revenue Code of 1986, as amended ("IRC Section 382"), a corporation that undergoes an "ownership change" is subject to limitations on its use of pre-change NOL carryforwards to offset future taxable income. Within the meaning of IRC Section 382, an "ownership change" occurs when the aggregate stock ownership of certain stockholders (generally 5% shareholders, applying certain look-through rules) increases by more than 50 percentage points over such stockholders' lowest percentage ownership during the testing period (generally three years). In general, the annual use limitation equals the aggregate value of common stock at the time of the ownership change multiplied by a specified tax-exempt interest rate. We experienced ownership changes in 2005 in connection with a series of private placements, and in 2012 as a result of a reverse acquisition. The 2012 ownership change will subject NOL carryforwards to an annual use limitation, which will significantly reduce our ability to use them to offset taxable income in periods following the 2012 ownership change. The amount of NOLs subject to such limitations is approximately $18.7 million. As a result of the limitation under IRC Section 382, the annual use limitation is $638,196 per year, the effect of which will result in approximately $6.7 million in NOL carryforwards expiring unused.

At September 30, 2015, approximately $3.3 million of net deferred tax asset remained available for future use, reflecting use of approximately $5.4 million of net operating loss carryforwards through the period. At September 30, 2015, approximately $9.6 million of NOLs generated prior to the 2012 ownership change remain available for future use. At September 30, 2015, approximately $7.9 million of NOLs generated subsequent to the 2012 ownership change remained available for future use and are not subject to an annual use limitation under IRC Section 382.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting and income tax purposes. The following table shows significant components of our deferred tax assets and liabilities:

	September 30, 2015	December 31, 2014
Deferred tax assets:		
Net operating loss and capital loss carryforwards	$8,221,505	$10,067,144
Start-up costs (Nixon Facility)	1,545,033	1,648,036
Asset retirement obligations liability/deferred revenue	859,819	869,821
AMT credit and other	236,389	85,467
Total deferred tax assets	10,862,746	12,670,468
Deferred tax liabilities:		
Fair market value adjustments	(46,116)	(46,116)
Unrealized hedges	(45,271)	(168,606)
Basis differences in property and equipment	(5,220,754)	(4,425,318)
Total deferred tax liabilities	(5,312,141)	(4,640,040)
Deferred tax assets, net	5,550,605	8,030,428
Valuation allowance	(2,270,322)	(2,270,322)
	$3,280,283	$5,760,106

The following table shows our current and noncurrent deferred tax assets (liabilities):

	September 30, 2015	December 31, 2014
Current deferred tax liabilities	$5,162,781	$(168,236)
Noncurrent deferred tax assets, net	387,824	8,198,664
Deferred tax assets, net	5,550,605	8,030,428
Valuation allowance	(2,270,322)	(2,270,322)
	$3,280,283	$5,760,106

Valuation Allowance

As of each reporting date, management considers new evidence, both positive and negative, that could impact management's view with regard to future realization of deferred tax assets. As of September 30, 2015 and December 31, 2014, management determined that sufficient positive evidence existed to conclude that it was more likely than not that net deferred tax assets of approximately $3.3 million and $5.8 million, respectively, were realizable, and as a result, reflected a valuation allowance accordingly.

Uncertain Tax Positions

We have adopted the provisions of the FASB ASC guidance on accounting for uncertainty in income taxes. The guidance clarifies the accounting for uncertainty in income taxes recognized in an enterprise’s financial statements. The guidance also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The standard also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

As part of this guidance, we record income tax related interest and penalties, if applicable, as a component of the provision for income tax benefit (expense). However, there were no amounts recognized relating to interest and penalties in the consolidated statements of income for the three and nine months ended September 30, 2015 and 2014. Furthermore, none of our federal and state income tax returns are currently under examination by the Internal Revenue Service ("IRS") or state authorities. As of September 30, 2015, fiscal years 2011 and later remain subject to examination by the IRS and fiscal years 2009 and later remain subject to examination by the state of Texas. We believe there are no uncertain tax positions for both federal and state income taxes.

(18) Earnings Per Share

The following table provides reconciliation between basic and diluted income per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income	$1,264,233	$816,047	$5,103,476	$8,448,877
Basic and diluted income per share	$0.12	$0.08	$0.49	$0.81
Basic and Diluted				
Weighted average number of shares of common stock outstanding and potential dilutive shares of common stock	10,453,802	10,446,218	10,451,168	10,439,684

Diluted EPS is computed by dividing net income available to common stockholders by the weighted average number of shares of common stock outstanding. Diluted EPS for the three and nine months ended September 30, 2015 and 2014 was the same as basic EPS as there were no stock options or other dilutive instruments outstanding.

(19) Fair Value Measurement

We have determined the fair value of certain assets and liabilities through the application of fair value measurements and disclosures, which establishes a framework for measuring fair value. We are subject to gains or losses on certain financial assets based on our various agreements and understandings with Genesis. Pursuant to these agreements and understandings, Genesis may execute the purchase and sale of certain financial instruments for the purpose of economically hedging certain commodity price risks associated with our refined petroleum products and, over time, this program may also include mitigating certain risks associated with the purchase of crude oil and condensate. These financial instruments are direct contractual obligations of Genesis and not us. However, under our agreement with Genesis, we financially benefit from any gains and financially bear any losses associated with the purchase and/or sale of such financial instruments by Genesis. Because such instruments represent embedded derivatives for the purpose of financial reporting, we account for such embedded derivatives in our financial records by utilizing the market approach when measuring fair value of our financial instruments (typically in current assets and/or liabilities, as discussed below). The market approach uses prices and other relevant information generated by such market transactions executed on our behalf involving identical or comparable assets or liabilities.

Generally accepted accounting principles establish a framework for measuring the fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The fair value hierarchy consists of the following three levels:

Level 1	Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.
Level 2	Inputs are quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable and market-corroborated inputs, which are derived principally from or corroborated by observable market data.
Level 3	Inputs are derived from valuation techniques in which one or more significant inputs or value drivers are unobservable and cannot be corroborated by market data or other entity-specific inputs.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

The carrying amounts of accounts receivable, accounts payable, and accrued liabilities approximated their fair values at September 30, 2015 and December 31, 2014 due to their short-term maturities. The fair value of our short and long-term debt at September 30, 2015 and December 31, 2014 was $30,579,560 and $12,054,279, respectively. The fair value of our debt was determined using a Level 3 hierarchy.

The following table represents our assets and liabilities measured at fair value on a recurring basis as of September 30, 2015 and December 31, 2014 and the basis for the measurement:

	Fair Value Measurement at September 30, 2015 Using			
Financial assets (liabilities):	Carrying Value at September 30, 2015	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity contracts	$133,150	$133,150	$-	$ -

	Fair Value Measurement at December 31, 2014 Using			
Financial assets (liabilities):	Carrying Value at December 31, 2014	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity contracts	$495,900	$495,900	$-	$ -

Carrying amounts of commodity contracts executed by Genesis are reflected as other current assets or other current liabilities in our consolidated balance sheets.

(20) Inventory Risk Management

Under our inventory risk management policy, Genesis may, but is not required to, use commodity futures contracts to mitigate the change in value for certain of our refined petroleum product inventories subject to market price fluctuations in our inventory. The physical inventory volumes are not exchanged, and these contracts are net settled by Genesis with cash.

The fair value of these contracts is reflected in our consolidated balance sheets and the related net gain or loss is recorded within cost of refined products sold in our consolidated statements of income. Quoted prices for identical assets or liabilities in active markets (Level 1) are considered to determine the fair values for the purpose of marking to market the financial instruments at each period end.

Commodity transactions are executed by Genesis to minimize transaction costs, monitor consolidated net exposures, and allow for increased responsiveness to changes in market factors. Genesis may, but is not required to, initiate an economic hedge on our refined petroleum products when our inventory levels exceed targeted levels (currently 1.5 days production). Although the decision to enter into a futures contract is made solely by Genesis, Genesis typically confers with management as part of Genesis' decision making process.

Due to mark-to-market accounting during the term of the commodity contracts, significant unrealized non-cash net gains and losses could be recorded in our results of operations. Additionally, Genesis may be required to collateralize any mark-to-market losses on outstanding commodity contracts.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

As of September 30, 2015, we had the following obligations based on futures contracts of refined petroleum products and crude oil that were entered into as economic hedges through Genesis. The information presents the notional volume of open commodity instruments by type and year of maturity (volumes in barrels):

	Notional Contract Volumes by Year of Maturity		
Inventory positions (futures):	2015	2016	2017
Refined petroleum products and crude oil - net short positions	155,000	-	-

The following table provides the location and fair value amounts of derivative instruments that are reported in our consolidated balance sheets at September 30, 2015 and December 31, 2014:

		Fair Value	
Asset Derivatives	Balance Sheets Location	September 30, 2015	December 31, 2014
Commodity contracts	Prepaid expenses and other current assets (accrued expenses and other current liabilities)	$ 133,150	$ 495,900

The following table provides the effect of derivative instruments in our consolidated statements of income for the three months ended September 30, 2015 and 2014:

		Gain (Loss) Recognized Three Months Ended September 30,		Nine Months Ended September 30,	
Derivatives	Statements of Operations Location	2015	2014	2015	2014
Commodity contracts	Cost of refined products sold	$2,205,291	$396,271	$1,762,582	$(12,438)

(21) Commitments and Contingencies

Operating Agreement

See "Note (10) Accounts Payable, Related Party" of this report for additional disclosures related to the Operating Agreement.

Genesis Agreements

We were previously subject to three agreements with Genesis and its affiliates. Under the Construction and Funding Agreement, Milam committed funding for the Nixon Facility's start-up refurbishment. Payments under the Construction and Funding Agreement began in the first quarter of 2012, when the Nixon Facility was placed in service. As a result of our repayment of amounts due to Milam under the Construction and Funding Agreement in May 2014, we now receive up to 80% of the Gross Profits as our Profit Share under the Joint Marketing Agreement.

Our relationship with Genesis and its affiliates is currently governed by two agreements, as follows:

Joint Marketing Agreement – Under the Joint Marketing Agreement, we, along with GEL, jointly market and sell the output produced at the Nixon Facility and share the Gross Profits (as defined below) from such sales. GEL is responsible for all product transportation scheduling; we are responsible for entering into contracts with customers for the purchase and sale of output produced at the Nixon Facility and handling all billing and invoicing relating to the same. All payments for the sale of output produced at the Nixon Facility are made directly to GEL as collection agent and all customers must satisfy GEL's customer credit approval process. Subject to certain amendments and clarifications (as described below), the Joint Marketing Agreement also provides for the sharing of "Gross Profits" (defined as the total revenue from the sale of output from the Nixon Facility minus the cost of crude oil and condensate pursuant to the Crude Supply Agreement). As a result of our repayment of amounts due to Milam under the Construction and Funding Agreement in May 2014, certain aspects related to the distribution of Gross Profits under the Joint Marketing Agreement no longer apply. Key applicable provisions are as follows:

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

- We are entitled to receive weekly payments to cover direct expenses in operating the Nixon Facility (the "Operations Payments") in an amount not to exceed $750,000 per month plus the amount of any accounting fees, if incurred, not to exceed $50,000 per month. We assigned our rights to weekly payments and reimbursement of accounting fees under the Joint Marketing Agreement to LEH pursuant to the Operating Agreement. If Gross Profits are insufficient to cover Operations Payments, then GEL may: (i) reduce Operations Payments by an amount representing the difference between the Operations Payments and the Gross Profits for such monthly period, or (ii) provide the Operations Payments with such Operations Payments being considered deficit amounts owing to GEL. If Gross Profits are negative, then we are not entitled to receive Operations Payments and GEL may recoup any losses sustained by a special allocation of 80% of Gross Profits until such losses are covered in full, after which the prevailing Gross Profits allocation shall be reinstated; and

- GEL is entitled to receive an administrative fee in the amount of $150,000 per month relating to the performance of its obligations under the Joint Marketing Agreement (the "Performance Fee"). GEL shall be paid 30% of the remaining Gross Profit up to $600,000 (the "Threshold Amount") as the GEL Profit Share and we shall be paid 70% of the remaining Gross Profit as our Profit Share. Any amount of remaining Gross Profit that exceeds the Threshold Amount for such calendar month shall be paid to GEL and us in the following manner: (i) GEL shall be paid 20% of the remaining Gross Profits over the Threshold Amount as the GEL Profit Share and (ii) we shall be paid 80% of the remaining Gross Profits over the Threshold Amount as our Profit Share. The GEL Profit Share plus the Performance Fee are collectively referred to in this report as the JMA Profit Share.

  The Joint Marketing Agreement contains negative covenants that restrict our actions under certain circumstances. For example, we are prohibited from making any modifications to the Nixon Facility or entering into any contracts with third-parties that would materially affect or impair GEL's or its affiliates' rights under the agreements set forth above. The Joint Marketing Agreement had an initial term of three years expiring on August 12, 2014. In accordance with the terms of the October 2013 Letter Agreement, we agreed not to terminate the Joint Marketing Agreement and GEL agreed to automatically renew the Joint Marketing Agreement at the end of the initial term for successive one year periods until August 12, 2019, unless sooner terminated by GEL with 180 days prior written notice; and

Crude Supply Agreement – Under the Crude Supply Agreement, GEL is our exclusive supplier of crude oil and condensate. We have the ability to purchase crude oil and condensate from other suppliers with the prior consent of GEL. GEL supplies crude oil and condensate to us at cost plus freight expense and any costs associated with GEL's hedging. All crude oil and condensate supplied to us pursuant to the Crude Supply Agreement is paid for pursuant to the terms of the Joint Marketing Agreement as described above. In addition, GEL has a first right of refusal to use three petroleum storage tanks at the Nixon Facility during the term of the Crude Supply Agreement. Subject to certain termination rights, the Crude Supply Agreement had an initial term of three years expiring on August 12, 2014. In accordance with the terms of the October 2013 Letter Agreement, we agreed not to terminate the Crude Supply Agreement and GEL agreed to automatically renew the Crude Supply Agreement at the end of the initial term for successive one year periods until August 12, 2019, unless sooner terminated by GEL with 180 days prior written notice.

Pursuant to a Letter Agreement Regarding Subordination of GEL Transaction Documents dated June 4, 2015, we, among other things, assigned our rights to payments under the Joint Marketing Agreement and Crude Supply Agreement as collateral in favor of Sovereign as lender and lienholder pursuant to the Term Loan Due 2034. See "Note (13) Long-Term Debt" of this report for further discussion related to the Term Loan Due 2034.

FLNG Master Easement Agreement

Pursuant to a Master Easement Agreement dated December 11, 2013, we provide FLNG Land II, Inc., a Delaware corporation ("FLNG") with: (i) uninterrupted pedestrian and vehicular ingress and egress to and from State Highway 332, across certain of our property to certain property of FLNG (the "Access Easement") and (ii) a pipeline easement and right of way across certain of our property to certain property owned by FLNG (the "Pipeline Easement" and together with the Access Easement, the "Easements"). Under the agreement, FLNG will make payments to us in the amount of $500,000 in October of each year through 2019. Thereafter, FLNG will make payments to us in the amount of $10,000 in October of each year for so long as FLNG desires to use the Access Easement.

Blue Dolphin Energy Company & Subsidiaries
Notes to Consolidated Financial Statements (Unaudited) - Continued

Supplemental Pipeline Bonds

We are required to satisfy supplemental pipeline bonding requirements of the Bureau of Ocean Energy Management (“BOEM”) with regard to certain pipelines that we operate in federal waters of the Gulf of Mexico. These supplemental pipeline bonding requirements are intended to secure our performance of plugging and abandonment obligations with respect to these pipelines. Once plugging and abandonment work has been completed, the collateral backing the supplemental pipeline bonds will be released.

In August 2006, we secured a $700,000 supplemental pipeline bond for Right-of-Way Number OCS-G 01381. On February 5, 2014, we entered into a Purchase Agreement whereby we reacquired WBI’s 1/6th interest in the Pipeline Assets effective October 31, 2013. Pursuant to the Purchase Agreement, WBI paid us $100,000 in cash, and a surety company $850,000 in cash as collateral for supplemental pipeline bonds for our benefit in exchange for the payment and discharge of any and all payables, claims, and obligations related to the Pipeline Assets. The $850,000 in cash was used to: (i) increase the supplemental pipeline bond for Right-of-Way Number OCS-G 01381 by $205,000, and (ii) secure a $645,000 supplemental pipeline bond for Right-of-Way Number OCS-G 08606.

In December 2014, we completed plugging and abandonment work for Right-of-Way Number OCS-G 08606. In February 2015, we requested that BOEM release the cash-backed collateral for this supplemental pipeline bond. Although BOEM indicated that the bond was cancelled, as of the date of this report we were awaiting release of the collateral. There can be no assurance that BOEM will not require additional supplemental pipeline bonds related to our other pipeline right-of-ways.

Financing Agreements

See “Note (13) Long-Term Debt” of this report for additional disclosures related to financing agreements.

Grynberg Settlement Agreement

During the third quarter of 2015, management reevaluated its estimated zero gain contingency related to a nearly two decades-old case involving Jack J. Grynberg and several defendants in the oil and gas industry, including Blue Dolphin Pipe Line Company (the “Grynberg Matter”). New developments in the Grynberg Matter resulted in a final Mutual Release Agreement and Withdrawal of All Qui Tam Claims (the “Grynberg Settlement Agreement”) in the amount of $725,073 (the “Settlement Amount”). The Settlement Amount represents 50% of a $1,371,723 November 2006 summary judgment in our favor plus 1.5% interest. We received the Settlement Amount on October 16, 2015. Our proceeds from the Settlement Agreement were reduced by accrued fees outstanding to our legal counsel in the amount of $135,273. Based on management’s assessment, we recognized a gain recorded in other income related to the Grynberg Matter of $660,000 (the Settlement Amount less additional legal fees of approximately $65,000).

Legal Matters

From time to time we are subject to various lawsuits, claims, mechanics liens, and administrative proceedings that arise out of the normal course of business. Management does not believe that liens, if any, will have a material adverse effect on our results of operations.

Health, Safety and Environmental Matters

All of our operations and properties are subject to extensive federal, state, and local environmental, health, and safety regulations governing, among other things, the generation, storage, handling, use and transportation of petroleum and hazardous substances; the emission and discharge of materials into the environment; waste management; characteristics and composition of jet fuel and other products; and the monitoring, reporting and control of greenhouse gas emissions. Our operations also require numerous permits and authorizations under various environmental, health, and safety laws and regulations. Failure to obtain and comply with these permits or environmental, health, or safety laws generally could result in fines, penalties or other sanctions, or a revocation of our permits.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion of our financial condition and results of operations should be read in conjunction with the unaudited consolidated financial statements and accompanying notes included hereto, as well as the risk factors and audited and unaudited consolidated financial statements and accompanying notes thereto included in our previously filed Annual Report on Form 10-K for the year ended December 31, 2014 and our Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2015 and June 30, 2015. In this report, the words “Blue Dolphin,” “we,” “us” and “our” refer to Blue Dolphin Energy Company and its subsidiaries.

Forward Looking Statements

As provided by the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, certain statements included throughout this Quarterly Report on Form 10-Q for the three and nine months ended September 30, 2015, and in particular under the sections entitled “Part I, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Part II, Item 1A. Risk Factors” are forward-looking statements that represent management’s beliefs and assumptions based on currently available information. Forward-looking statements relate to matters such as our industry, business strategy, goals and expectations concerning our market position, future operations, margins, profitability, capital expenditures, liquidity and capital resources and other financial and operating information. We have used the words “anticipate,” “assume,” “believe,” “budget,” “continue,” “could,” “estimate,” “intend,” “may,” “plan,” “potential,” “predict,” “project,” “will,” “future” and similar terms and phrases to identify forwar statements.

Forward-looking statements reflect our current expectations regarding future events, results or outcomes. These expectations may or may not be realized. Some of these expectations may be based upon assumptions or judgments that prove to be incorrect. In addition, our business and operations involve numerous risks and uncertainties, many of which are beyond our control, which could result in our expectations not being realized, or materially affect our financial condition, results of operations and cash flows.

Actual events, results and outcomes may differ materially from our expectations due to a variety of factors. Although it is not possible to identify all of these factors, they include, among others, the following:

Risks Related to Our Business and Industry

- dangers inherent in oil and gas operations that could cause disruptions and expose us to potentially significant losses, costs or liabilities and reduce our liquidity;
- geographic concentration of our assets, which creates a significant exposure to the risks of the regional economy;
- competition from companies having greater financial and other resources;
- laws and regulations regarding personnel and process safety, as well as environmental, health, and safety, for which failure to comply may result in substantial fines, criminal sanctions, permit revocations, injunctions, facility shutdowns, and/or significant capital expenditures;
- insurance coverage that may be inadequate or expensive;
- related party transactions with Lazarus Energy Holdings, LLC (“LEH”) and its affiliates, which may cause conflicts of interest;
- capital needs for which our internally generated cash flows and other sources of liquidity may not be adequate; and
- our ability to use net operating loss (“NOL”) carryforwards to offset future taxable income for U.S. federal income tax purposes, which are subject to limitation.

Risks Related to Our Refinery Operations Business Segment

- volatility of refining margins;
- volatility of crude oil, other feedstocks, refined petroleum products, and fuel and utility services;
- potential downtime at the Nixon Facility, which could result in lost margin opportunity, increased maintenance expense, increased inventory, and a reduction in cash available for payment of our obligations;
- loss of market share by a key customer or consolidation among our customer base;
- failure to grow or maintain the market share for our refined petroleum products;
- our reliance on third-parties for the transportation of crude oil and condensate into and refined petroleum products out of the Nixon Facility;
- interruptions in the supply of crude oil and condensate sourced in the Eagle Ford Shale;
- changes in the supply/demand balance in the Eagle Ford Shale that could result in lower refining margins;

- hedging of our refined petroleum products and crude oil and condensate inventory, which may limit our gains and expose us to other risks;
- our dependence on Genesis Energy, LLC ("Genesis") and its affiliates for crude oil and condensate sourcing, inventory risk management, hedging, and refined petroleum product marketing;
- loss of executive officers or key employees, as well as a shortage of skilled labor or disruptions in our labor force, which may make it difficult to maintain productivity;
- our dependence on LEH for financing and management of our properties; and
- regulation of greenhouse gas emissions, which could increase our operational costs and reduce demand for our products.

Risks Related to Our Pipelines and Oil and Gas Properties

- asset retirement obligations ("AROs") for our pipelines and facilities assets and oil and gas properties.

Any one of these factors or a combination of these factors could materially affect our future results of operations and could influence whether any forward-looking statements ultimately prove to be accurate. Our forward-looking statements are not guarantees of future performance, and actual results and future performance may differ materially from those suggested in any forward-looking statements. We do not intend to update these statements unless we are required to do so.

Overview

Blue Dolphin Energy Company (http://www.blue-dolphin-energy.com) is primarily an independent refiner and marketer of petroleum products. Our primary asset is a 15,000 barrels per day ("bpd") crude oil and condensate processing facility that is located in Nixon, Texas (the "Nixon Facility"). As part of our refinery operations business segment, we conduct petroleum storage and terminaling operations under third-party lease agreements at the Nixon Facility. We also own and operate pipeline assets and have leasehold interests in oil and gas properties.

Structure and Management

We were formed as a Delaware corporation in 1986. We are currently controlled by LEH, which owns approximately 81% of our common stock, par value $0.01 per share (the "Common Stock). Jonathan P. Carroll is Chairman of the Board of Directors (the "Board"), Chief Executive Officer, and President of Blue Dolphin, as well as a majority owner of LEH. LEH manages and operates all of our properties pursuant to an Operating Agreement (the "Operating Agreement"). See "Part I, Item 1. Financial Statements – Note (10) Accounts Payable, Related Party, Note (13) Long-Term Debt, and Note (21) Commitments and Contingencies – Financing Agreements" of this report for additional disclosures related to the Operating Agreement, Jonathan P. Carroll, and LEH.

Our operations are conducted through the following operating subsidiaries:

- Lazarus Energy, LLC, a Delaware limited liability company;
- Lazarus Refining & Marketing, LLC, a Delaware limited liability company;
- Blue Dolphin Pipe Line Company, a Delaware corporation;
- Blue Dolphin Petroleum Company, a Delaware corporation; and
- Blue Dolphin Services Co., a Texas corporation.

See "Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Owned and Leased Assets" of this report for additional information regarding our operating subsidiaries.

Refinery Operations

The Nixon Facility occupies approximately 56 acres in Nixon, Texas and currently consists of a distillation unit, naphtha stabilizer unit, depropanizer unit, approximately 120,000 barrels (“bbls”) of crude oil and condensate storage capacity, approximately 178,000 bbls of refined petroleum product storage capacity, and related loading and unloading facilities and utilities. We are in the process of expanding the Nixon Facility by constructing an additional 500,000 bbls of petroleum storage tanks. (See discussion within this section of the report related to our business strategy.)

With a current capacity of 15,000 bpd, the Nixon Facility is considered a “topping unit” because it is primarily comprised of a crude distillation unit, the first stage of the crude oil refining process. The Nixon Facility’s current level of complexity allows us to refine crude oil and condensate into finished and intermediate petroleum products. Our jet fuel is sold in nearby markets, and our intermediate products, including liquefied petroleum gas (“LPG”), naphtha, heavy oil-based mud blendstock (“HOBM”), and atmospheric gas oil (“AGO”) are sold to wholesalers and nearby refineries for further blending and processing. The Nixon Facility uses light crude oil and condensate sourced in the Eagle Ford Shale as feedstock.

In June 2015, we announced plans to expand the Nixon Facility in three phases that include: (i) constructing more than 500,000 bbls of petroleum storage tanks, (ii) purchasing and redeploying idle refinery equipment, and (iii) obtaining additional financing for further expansion projects. Potential benefits of the Nixon Facility expansion plan include:

- generating additional revenue from leasing product and crude storage to third parties;
- having crude and product storage to support refinery throughput of up to 30,000 bbls per day; and
- increasing the processing capacity and complexity of the Nixon Facility.

Through the third quarter of 2015, we: (i) completed refurbishment of the naphtha stabilizer and depropanizer units, which will improve the overall quality of the naphtha that we produce and help increase the capacity utilization rate of the Nixon Facility, (ii) purchased idle refinery equipment, including, among others, a Merox unit, vacuum tower, prefrac tower unit, and LPG fractionator, which will, over time, be refurbished, and (iii) continued debottlenecking efforts, which improve production and efficiency. (See Refinery Throughput and Production Data under Refinery Operations Business Segment Results for more information.)

The below diagram represents a high level overview of the current crude oil and condensate refining process at the Nixon Facility.

Pipeline Transportation

Our pipeline transportation operations are conducted in the Gulf of Mexico and involve the gathering and transportation of oil and natural gas for producers/shippers operating in the vicinity of our pipelines, as well as the ownership of leasehold interests in oil and natural gas properties.

Owned and Leased Assets

We own, lease, and have leasehold interests in the following properties:

Property	Operating Subsidiary	Description	Business Segment	Owned / Leased	Location
Nixon Facility (56 acres)	Lazarus Energy, LLC Lazarus Refining & Marketing, LLC	Petroleum Processing Petroleum Storage and Terminaling	Refinery Operations	Owned	Nixon, Texas
Freeport Facility (193 acres)	Blue Dolphin Pipe Line Company	Pipeline Operations	Pipeline Transportation	Owned	Freeport, Texas
Pipelines and Oil and Gas Properties	Blue Dolphin Pipe Line Company Blue Dolphin Petroleum Company	Exploration and Production	Pipeline Transportation	Owned/ Leasehold Interests	Gulf of Mexico
Corporate Headquarters	Blue Dolphin Services Co.	Administrative Services	Corporate and Other	Leased	Houston, Texas

Major Influences on Results of Operations

Our earnings and cash flows from our refinery operations business segment are primarily affected by the relationship between refined petroleum product prices and the prices for crude oil and other feedstocks. Crude oil refining is primarily a margin-based business, and in order to increase profitability, it is important for the refinery to maximize the yields of higher value finished and intermediate products and to minimize the costs of feedstock and operating expenses. Our cost to acquire crude oil and condensate and the price for which our refined petroleum products are ultimately sold depend on several factors, many of which are beyond our control, including the supply of, and demand for, crude oil and refined petroleum products, which depend on changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, production levels, availability of and access to transportation infrastructure, the availability of imports, the marketing of competitive fuel, and governmental regulations, among other factors.

Crude oil and refined petroleum product prices are also affected by other factors, such as local and general market conditions and the operating levels of competing refineries. Crude oil costs and the prices of refined petroleum products have historically been subject to wide fluctuations. An expansion or upgrade of our competitors' facilities, price volatility, international political and economic developments, and other factors beyond our control are likely to continue to play an important role in crude oil refining industry economics. Moreover, the refining industry typically experiences seasonal fluctuations in demand for refined petroleum products, such as increases in the demand for gasoline during the summer driving season and for home heating oil during the winter. These factors can impact, among other things, the level of inventories in the market, resulting in price volatility and a negative impact on product margins. In addition to current market conditions, there are long-term factors that may impact the demand for refined petroleum products. These factors include mandated renewable fuels standards, proposed climate change laws and regulations, and increased mileage standards for vehicles.

Relationship with LEH

LEH manages and operates all of our properties pursuant to the Operating Agreement. For services rendered, LEH receives reimbursements and fees. We currently rely on our profit share and LEH to fund our working capital requirements. During months in which we receive no profit share distribution, LEH may, but is not required to, fund our operating losses. See “Part I, Item 1. Financial Statements – Note (10) Accounts Payable, Related Party and Note (13) Long-Term Debt for additional disclosures related to the Operating Agreement and LEH.

Relationship with Genesis

We were previously subject to three agreements with Genesis and its affiliates. Under the Construction and Funding Agreement, Milam Services, Inc. (“Milam”) committed funding for the Nixon Facility’s start-up refurbishment. Payments under the Construction and Funding Agreement began in the first quarter of 2012, when the Nixon Facility was placed in service. As a result of our repayment of amounts due to Milam under the Construction and Funding Agreement in May 2014, we now receive up to 80% of the Gross Profits as our Profit Share under the Joint Marketing Agreement. In addition, Milam is obligated to release all liens on the Nixon Facility.

Our relationship with Genesis and its affiliates is currently governed by two agreements, as follows:

Joint Marketing Agreement – Under the Joint Marketing Agreement, we, together with GEL, jointly market and sell the output produced at the Nixon Facility and share the Gross Profits (as defined below) from such sales. GEL is responsible for all product transportation scheduling; we are responsible for entering into contracts with customers for the purchase and sale of output produced at the Nixon Facility and handling all billing and invoicing relating to the same. All payments for the sale of output produced at the Nixon Facility are made directly to GEL as collection agent and all customers must satisfy GEL's customer credit approval process. Subject to certain amendments and clarifications (as described below), the Joint Marketing Agreement also provides for the sharing of "Gross Profits" (defined as the total revenue from the sale of output from the Nixon Facility minus the cost of crude oil and condensate pursuant to the Crude Supply Agreement). As a result of our repayment of amounts due to Milam under the Construction and Funding Agreement in May 2014, certain aspects related to the distribution of Gross Profits under the Joint Marketing Agreement no longer apply. Key applicable provisions are as follows:

- We are entitled to receive weekly payments to cover direct expenses in operating the Nixon Facility (the "Operations Payments") in an amount not to exceed $750,000 per month plus the amount of any accounting fees, if incurred, not to exceed $50,000 per month. We assigned our rights to weekly payments and reimbursement of accounting fees under the Joint Marketing Agreement to LEH pursuant to the Operating Agreement. If Gross Profits are insufficient to cover Operations Payments, then GEL may: (i) reduce Operations Payments by an amount representing the difference between the Operations Payments and the Gross Profits for such monthly period, or (ii) provide the Operations Payments with such Operations Payments being considered deficit amounts owing to GEL. If Gross Profits are negative, then we are not entitled to receive Operations Payments and GEL may recoup any losses sustained by a special allocation of 80% of Gross Profits until such losses are covered in full, after which the prevailing Gross Profits allocation shall be reinstated; and

- GEL is entitled to receive an administrative fee in the amount of $150,000 per month relating to the performance of its obligations under the Joint Marketing Agreement (the "Performance Fee"). GEL shall be paid 30% of the remaining Gross Profit up to $600,000 (the "Threshold Amount") as the GEL Profit Share and we shall be paid 70% of the remaining Gross Profit as our Profit Share. Any amount of remaining Gross Profit that exceeds the Threshold Amount for such calendar month shall be paid to GEL and us in the following manner: (i) GEL shall be paid 20% of the remaining Gross Profits over the Threshold Amount as the GEL Profit Share and (ii) we shall be paid 80% of the remaining Gross Profits over the Threshold Amount as the our Profit Share. The GEL Profit Share plus the Performance Fee are collectively referred to in this report as the Joint Marketing Agreement Profit Share (the "JMA Profit Share").

  The Joint Marketing Agreement contains negative covenants that restrict our actions under certain circumstances. For example, we are prohibited from making any modifications to the Nixon Facility or entering into any contracts with third-parties that would materially affect or impair GEL's or its affiliates' rights under the agreements set forth above. The Joint Marketing Agreement had an initial term of three years expiring on August 12, 2014. In accordance with the terms of the October 2013 Letter Agreement, we agreed not to terminate the Joint Marketing Agreement and GEL agreed to automatically renew the Joint Marketing Agreement at the end of the initial term for successive one year periods until August 12, 2019, unless sooner terminated by GEL with 180 days prior written notice; and

Crude Supply Agreement – Under the Crude Supply Agreement, GEL is our exclusive supplier of crude oil and condensate. We have the ability to purchase crude oil and condensate from other suppliers with the prior consent of GEL. GEL supplies crude oil and condensate to us at cost plus freight expense and any costs associated with GEL's hedging. All crude oil and condensate supplied to us pursuant to the Crude Supply Agreement is paid for pursuant to the terms of the Joint Marketing Agreement as described above. In addition, GEL has a first right of refusal to use three petroleum storage tanks at the Nixon Facility during the term of the Crude Supply Agreement. Subject to certain termination rights, the Crude Supply Agreement had an initial term of three years expiring on August 12, 2014. In accordance with the terms of the October 2013 Letter Agreement, we agreed not to terminate the Crude Supply Agreement and GEL agreed to automatically renew the Crude Supply Agreement at the end of the initial term for successive one year periods until August 12, 2019, unless sooner terminated by GEL with 180 days prior written notice.

Pursuant to a Letter Agreement Regarding Subordination of GEL Transaction Documents dated June 4, 2015, we, among other things, assigned our rights to payments under the Joint Marketing Agreement and Crude Supply Agreement as collateral in favor of Sovereign Bank, a Texas state bank ("Sovereign"), as lender and lienholder pursuant to that certain Loan and Security Agreement between us and Sovereign dated June 22, 2015 in the principal amount of \$25.0 million (the "Term Loan Due 2034"). See "Part I, Item 1. Financial Statements - Note (13) Long-Term Debt" of this report for further discussion related to the Term Loan Due 2034.

Results of Operations

We have two reportable business segments: (i) Refinery Operations and (ii) Pipeline Transportation. Business activities related to our Refinery Operations business segment are conducted at the Nixon Facility and represent approximately 99% of our operations. Business activities related to our Pipeline Transportation business segment are primarily conducted in the Gulf of Mexico through our pipeline assets and leasehold interests in oil and gas properties and represent less than 1% of our operations.

Management uses generally accepted accounting principles ("GAAP") and certain non-GAAP performance measures to assess our results of operations. In this Results of Operations section, we first review non-GAAP performance measures followed by a review of Refinery Operations business segment results. We conclude this Results of Operations section by reviewing our consolidated results, which include our Pipeline Transportation business segment.

Non-GAAP Performance Measures

Definitions

Certain performance measures used by management to assess our operating results and the effectiveness of our business segments are considered non-GAAP performance measures. These performance measures may differ from similar calculations used by other companies within the petroleum industry, thereby limiting their usefulness as a comparative measure. Below are definitions of non-GAAP performance measures used by management:

• Adjusted Earnings Before Interest, Income Taxes and Depreciation ("EBITDA") – Reflects EBITDA before an adjustment for the JMA Profit Share. The JMA Profit Share, which is an indirect operating expense, represents the GEL Profit Share plus the Performance Fee for the period pursuant to the Joint Marketing Agreement.

– Refinery Operations Adjusted EBITDA – Reflects adjusted EBITDA for our refinery operations business segment.

– Total Adjusted EBITDA – Reflects adjusted EBITDA for our refinery operations and pipeline transportation business segments, as well as corporate and other.

• EBITDA – Reflects earnings before: (i) interest income (expense), (ii) income taxes, and (iii) depreciation and amortization.

– Refinery Operations EBITDA – Reflects EBITDA for our refinery operations business segment.

– Total EBITDA – Reflects EBITDA for our refinery operations and pipeline transportation business segments, as well as corporate and other.

• Refinery Operating Income – Reflects refined petroleum product sales less direct operating costs (including cost of refined products sold and refinery operating expenses) and the JMA profit share.

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

Refinery Operations Adjusted EBITDA. For the Current Quarter, refinery operations adjusted EBITDA was \$3,766,257 compared to refinery operations adjusted EBITDA of \$2,867,740 for the Prior Quarter. This represented an increase in refinery operations adjusted EBITDA of \$898,517 for the Current Quarter compared to the Prior Quarter. The increase in refinery operations adjusted EBITDA between the periods was primarily the result of an increase in refinery sales volumes and refinery throughput.

Total Adjusted EBITDA. For the Current Quarter, we had total adjusted EBITDA of $4,183,191 compared to total adjusted EBITDA of $2,539,094 for the Prior Quarter. This represented an increase in total adjusted EBITDA of $1,644,097 for the Current Quarter compared to the Prior Quarter. The increase in total adjusted EBITDA between the periods was primarily the result of increases in refinery sales volumes and refinery throughput, as well as recognition of a one-time gain of $660,000 related to settlement proceeds from a nearly two decades-old case involving Jack J. Grynberg and several defendants in the oil and gas industry, including Blue Dolphin Pipe Line Company (the "Grynberg Matter").

Refinery Operations EBITDA. For the Current Quarter, refinery operations EBITDA was $2,330,881 compared to refinery operations EBITDA of $1,773,357 for the Prior Quarter. This represented an increase in refinery operations EBITDA of $557,524 for the Current Quarter compared to the Prior Quarter. The increase in refinery operations EBITDA between the periods was primarily the result of increases in refinery sales volumes and refinery throughput.

Total EBITDA. For the Current Quarter, we had total EBITDA of $2,747,815 compared to total EBITDA of $1,444,711 for the Prior Quarter. This represented an increase in total EBITDA of $1,303,104 for the Current Quarter compared to the Prior Quarter. The increase in total EBITDA between the periods was primarily the result of increases in refinery sales volumes and refinery throughput, as well as recognition of a one-time gain of $660,000 related to the Grynberg Matter.

Refinery Operating Income. Refinery operating income totaled $2,119,539 for the Current Quarter compared to $1,474,004 for the Prior Quarter, representing an increase of $645,535. The increase in refinery operating income between the periods was primarily the result of increases in refinery sales volumes and refinery throughput.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Refinery Operations Adjusted EBITDA. For the Current Nine Months, refinery operations adjusted EBITDA was $15,482,392 compared to refinery operations adjusted EBITDA of $13,829,647 for the Prior Nine Months. This represented an increase in refinery operations adjusted EBITDA of $1,652,745 for the Current Nine Months compared to the Prior Nine Months. The increase in refinery operations adjusted EBITDA between the periods was primarily the result of increases in refinery sales volumes and refinery throughput.

Total Adjusted EBITDA. For the Current Nine Months, we had total adjusted EBITDA of $15,225,152 compared to total adjusted EBITDA of $12,887,974 for the Prior Nine Months. This represented an increase in total adjusted EBITDA of $2,337,178 for the Current Nine Months compared to the Prior Nine Months. The increase in total adjusted EBITDA between the periods was primarily the result of increases in refinery sales volumes and refinery throughput, as well as recognition of a one-time gain of $660,000 related to the Grynberg Matter.

Refinery Operations EBITDA. For the Current Nine Months, refinery operations EBITDA was $10,669,718 compared to refinery operations EBITDA of $11,495,160 for the Prior Nine Months. This represented a decrease in refinery operations EBITDA of $825,442 for the Current Nine Months compared to the Prior Nine Months. The decrease in refinery operations EBITDA between the periods was the result of a significant increase in the cost of the JMA Profit Share, which offset increases in refinery sales volumes and refinery throughput. GEL became entitled to receive the JMA Profit Share in May 2014 as a result of our repayment of amounts due under the Construction and Funding Agreement. The JMA Profit Share for the Current Nine Months, totaling $4,812,674, represented expenses for the entire nine month period while the JMA Profit Share for the Prior Nine Months, totaling $2,334,487, represented expenses for five months out of the nine month period.

Total EBITDA. We had total EBITDA of $10,412,478 for the Current Nine Months compared to total EBITDA of $10,553,487 for the Prior Nine Months, which was relatively flat between the periods. Total EBITDA between the periods would have been higher were it not for the $2,478,187 increase in the JMA Profit Share.

Refinery Operating Income. Refinery operating income totaled $9,992,194 for the Current Nine Months compared to $10,692,036 for the Prior Nine Months, representing a decrease of $699,842. The decrease in refinery operating income between the periods was the result of a significant increase in the cost of the JMA Profit Share, which offset increases in refinery sales volumes and refinery throughput. GEL became entitled to receive the JMA Profit Share in May 2014 as a result of our repayment of amounts due under the Construction and Funding Agreement. The JMA Profit Share for the Current Nine Months, totaling $4,812,674, represented expenses for the entire nine month period while the JMA Profit Share for the Prior Nine Months, totaling $2,334,487, represented expenses for five months out of the nine month period.

Non-GAAP Reconciliations

Adjusted EBITDA and EBITDA. EBITDA should be considered in conjunction with net income and other performance measures such as operating cash flows. Following is a reconciliation of adjusted EBITDA and EBITDA by business segment for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30, 2015 Segment				Three Months Ended September 30, 2014 Segment			
	Refinery Operations	Pipeline Transportation	Corporate & Other	Total	Refinery Operations	Pipeline Transportation	Corporate & Other	Total
Revenue from operations	$55,210,962	$45,925	$-	$55,256,887	$88,129,273	$56,900	$-	$88,186,173
Less: cost of operations(1)	(51,444,705)	(114,675)	(236,816)	(51,796,196)	(85,261,533)	(110,872)	(274,674)	(85,647,079)
Other non-interest income(2)	-	62,500	660,000	722,500	-	-	-	-
Adjusted EBITDA	3,766,257	(6,250)	423,184	4,183,191	2,867,740	(53,972)	(274,674)	2,539,094
Less: JMA Profit Share(3)	(1,435,376)	-	-	(1,435,376)	(1,094,383)	-	-	(1,094,383)
EBITDA	$2,330,881	$(6,250)	$423,184	$2,747,815	$1,773,357	$(53,972)	$(274,674)	$1,444,711
Depletion, depreciation and amortization				(414,837)				(393,871)
Interest expense, net				(380,342)				(212,594)
Income before income taxes				1,952,636				838,246
Income tax expense				(688,403)				(22,199)
Net income				$1,264,233				$816,047

	Nine Months Ended September 30, 2015 Segment				Nine Months Ended September 30, 2014 Segment			
	Refinery Operations	Pipeline Transportation	Corporate & Other	Total	Refinery Operations	Pipeline Transportation	Corporate & Other	Total
Revenue from operations	$175,690,968	$119,882	$-	$175,810,850	$311,786,529	$178,793	$-	$311,965,3
	(160,208,576)	(296,291)	(928,331)	(161,433,198)	(297,956,882)	(355,645)	(973,154)	(299,285

Less: cost of operations(1)								
Other non-interest income(2)	-	187,500	660,000	847,500	-	208,333	-	208,333
Adjusted EBITDA	15,482,392	11,091	(268,331)	15,225,152	13,829,647	31,481	(973,154)	12,887,97
Less: JMA Profit Share(3)	(4,812,674)	-	-	(4,812,674)	(2,334,487)	-	-	(2,334,48
EBITDA	$10,669,718	$11,091	$(268,331)	$10,412,478	$11,495,160	$31,481	$(973,154)	$10,553,48
Depletion, depreciation and amortization				(1,217,005)				(1,175,64
Interest expense, net				(1,313,247)				(630,175
Income before income taxes				7,882,226				8,747,669
Income tax expense				(2,778,750)				(298,792
Net income				$5,103,476				$8,448,87

(1) Operation cost within the Refinery Operations and Pipeline Transportation segments includes related general, administrative, and accretion expenses. Operation cost within Corporate and Other includes general and administrative expenses associated with corporate maintenance costs, such as accounting fees, director fees, and legal expense.

(2) Other non-interest income reflects FLNG easement revenue and the Grynberg Settlement Agreement. See “Part 1, Item 1. Financial Statements - Note (21) Commitments and Contingencies – FLNG Master Easement Agreement and Grynberg Settlement Agreement” of this report for further discussion related to FLNG and Grynberg.

(3) The JMA Profit Share represents the GEL Profit Share plus the Performance Fee for the period pursuant to the Joint Marketing Agreement. See “Part 1, Item 1. Financial Statements - Note (21) Commitments and Contingencies” and “Part 1, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Relationship with Genesis” of this report for further discussion of the Joint Marketing Agreement.

Refinery Operating Income. The following table provides a reconciliation of refinery operating income to refined product sales, cost of refined products sold, refinery operating expenses, and JMA Profit Share for the periods indicated. For a reconciliation of refined petroleum product sales to total revenue from operations for our consolidated operations, see "Part I, Item 1. Financial Statements – Consolidated Statements of Income" of this report.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Total refined petroleum product sales	$54,924,070	$87,846,757	$174,830,292	$310,938,981
Less: Cost of refined petroleum products sold	(48,415,627)	(82,781,856)	(151,604,774)	(289,819,720)
Less: Refinery operating expenses	(2,953,528)	(2,496,514)	(8,420,650)	(8,092,738)
Refinery operating income before JMA Profit Share	3,554,915	2,568,387	14,804,868	13,026,523
Less: JMA Profit Share	(1,435,376)	(1,094,383)	(4,812,674)	(2,334,487)
Refinery operating income	$2,119,539	$1,474,004	$9,992,194	$10,692,036
Total refined petroleum product sales (bbls)	1,035,275	823,399	2,958,865	2,818,270

Refinery Operations Business Segment Results

Definitions

For our refinery operations business segment results, we refer to certain refinery throughput and production data in the explanation of our period over period changes in results of operations. Below are general definitions of what each item includes and represents:

- Operating Days – The number of days in a period in which the Nixon Facility operated. Downtime is excluded from operating days.

- Downtime – Scheduled or unscheduled periods in which the Nixon Facility is not operable. Downtime may be required for a variety of reasons, including maintenance, inspection and equipment repair, voluntary regulatory compliance measures, and cessation or suspension by regulatory authorities. The safe and reliable operation of the Nixon Facility is key to our financial performance and results of operations. Downtime may result in lost margin opportunity, increased maintenance expense, and a reduction in cash available for payment of our obligations.

- Total Refinery Throughput – Refers to the volume processed as input through the Nixon Facility. Refinery throughput includes crude oil and condensate and other feedstocks.

- Total Refinery Production – Refers to the volume processed as output through the Nixon Facility. Refinery production includes finished petroleum products, such as jet fuel, and intermediate petroleum products, such as LPG, naphtha, HOBM and AGO.

- Capacity Utilization Rate –A percentage measure that indicates the amount of available capacity that is being used at the Nixon Facility. The rate is calculated by dividing total refinery throughput on a bpd basis or total refinery production on a bpd basis by the total capacity of the Nixon Facility, which is currently 15,000 bpd.

Refinery Throughput and Production Data

Following are refinery operational metrics for the Nixon Facility:

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating Days	87	78	257	252
Downtime	5	14	16	21
Total refinery throughput				
bbls	1,109,411	849,402	3,086,749	2,909,669
bpd	12,752	10,890	12,011	11,546
Total refinery production				
bbls	1,084,246	831,771	3,024,579	2,855,054
bpd	12,463	10,664	11,769	11,330
Capacity utilization rate				
refinery throughput	85.0 %	72.6 %	80.1 %	77.0 %
refinery production	83.1 %	71.1 %	78.5 %	75.5 %

Note: The difference between total refinery throughput (volume processed as input) and total refinery production (volume processed as output) represents refinery fuel and energy use.

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

Operating Days. The Nixon Facility operated for a total of 87 days in the Current Quarter compared to operating for a total of 78 days in the Prior Quarter.

Downtime. The Nixon Facility experienced 5 days of downtime in the Current Quarter compared to 14 days of downtime in the Prior Quarter. Downtime in both the Current Quarter and Prior Quarter related to unscheduled maintenance.

Total Refinery Throughput. For the Current Quarter, the Nixon Facility processed 1,109,411 bbls, or 12,752 bpd, of crude oil and condensate compared to 849,402 bbls, or 10,890 bpd, of crude oil and condensate for the Prior Quarter. Total refinery throughput increased 260,009 bbls, or approximately 31%, for the Current Quarter compared to the Prior Quarter, which represented an increase of 1,862 bpd. Total refinery throughput increased as a result of: (i) less downtime in the Current Quarter compared to the Prior Quarter, (ii) debottlenecking efforts in the Current Quarter, and (iii) completion of refurbishment of key components of the naphtha stabilizer and depropanizer units late in the Current Quarter, all of which contributed to an increase in average refinery throughput for the Current Quarter.

Total Refinery Production. For the Current Quarter, the Nixon Facility produced 1,084,246 bbls, or 12,463 bpd, of refined petroleum products compared to 831,771 bbls, or 10,664 bpd, of refined petroleum products for the Prior Quarter. Total refinery production increased 252,475 bbls, or approximately 30%, for the Current Quarter compared to the Prior Quarter, which represented an increase of 1,799 bpd. Total refinery production increased as a result of: (i) less downtime in the Current Quarter compared to the Prior Quarter, (ii) debottlenecking efforts in the Current Quarter, and (iii) completion of refurbishment of key components of the naphtha stabilizer and depropanizer units late in the Current Quarter, all of which contributed to an increase in average refinery production for the Current Quarter.

Capacity Utilization Rate. The capacity utilization rate for refinery throughput for the Current Quarter was 85.0% compared to 72.6% for the Prior Quarter, reflecting an increase of approximately 17%. The capacity utilization rate for refinery production for the Current Quarter was 83.1% compared to 71.1% for the Prior Quarter, also reflecting an increase of approximately 17%. Capacity utilization rates increased as a result of: (i) less downtime in the Current Quarter compared to the Prior Quarter, (ii) debottlenecking efforts in the Current Quarter, and (iii) completion of refurbishment of key components of the naphtha stabilizer and depropanizer units late in the Current Quarter, all of which contributed to an increase in average refinery throughput and average refinery production for the Current Quarter.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Operating Days. The Nixon Facility operated for a total of 257 days in the Current Nine Months and for a total of 252 days in the Prior Nine Months.

Downtime. The Nixon Facility experienced 16 days of downtime in the Current Nine Months compared to 21 days of downtime in the Prior Nine Months. Downtime in the Current Nine Months and Prior Nine Months related to both scheduled and unscheduled maintenance.

Total Refinery Throughput. For the Current Nine Months, the Nixon Facility processed 3,086,749 bbls, or 12,011 bpd, of crude oil and condensate compared to 2,909,669 bbls, or 11,546 bpd, of crude oil and condensate for the Prior Nine Months. Total refinery throughput increased 177,080 bbls, or approximately 6%, for the Current Nine Months, which represented an increase of 465 bpd. The nominal increase in total refinery throughput in the Current Nine Months compared to the Prior Nine Months was a result of debottlenecking efforts and less downtime.

Total Refinery Production. For the Current Nine Months, the Nixon Facility produced 3,024,579 bbls, or 11,769 bpd, of refined petroleum products compared to 2,855,054 bbls, or 11,330 bpd, of refined petroleum products for the Prior Nine Months. Total refinery production increased 169,525 bbls, or approximately 6%, for the Current Nine Months compared to the Prior Nine Months, which represented an increase of 439 bpd. The nominal increase in total refinery production in the Current Nine Months compared to the Prior Nine Months was a result of debottlenecking efforts and less downtime.

Capacity Utilization Rate. The capacity utilization rate for refinery throughput for the Current Nine Months was 80.1% compared to 77.0% for the Prior Nine Months, reflecting a nominal increase of approximately 4%. The capacity utilization rate for refinery production for the Current Nine Months was 78.5% compared to 75.5% for the Prior Nine Months, also reflecting a nominal increase of approximately 4%. The slight increases in capacity utilization rates in the Current Nine Months compared to the Prior Nine Months was a result of improvements in total refinery throughput and total refinery production.

Refined Petroleum Product Sales Summary

See “Part 1, Item 1. Financial Statements - Note (15) Concentration of Risk” of this report for a discussion of refined petroleum product sales.

Refined Petroleum Product Economic Hedges

Operation cost within our refinery operations business segment includes the effect of economic hedges on our refined petroleum product inventories. For the Current Quarter, our refinery operations business segment recognized a realized gain of $2,101,041 and an unrealized gain of $104,250. For the Prior Quarter, our refinery operations business segment recognized a realized gain of $466,821 and an unrealized loss of $70,550. For the Current Nine Months, our refinery operations business segment recognized a realized gain of $2,125,332 and an unrealized loss of $362,750. For the Prior Nine Months, our refinery operations business segment recognized a realized gain of $13,712 and an unrealized loss of $26,150.

Consolidated Results

Definitions

For our consolidated results, we refer to our consolidated statements of income in the explanation of our period over period changes in results of operations. We have reclassified certain prior period amounts to conform to our 2015 presentation. Below are general definitions of what each item includes and represents:

- Revenue from Operations – Primarily consists of refined petroleum product sales, but also includes tank rental and pipeline transportation revenue. Excise and other taxes that are collected from customers and remitted to governmental authorities are not included in revenue.

- Cost of Refined Products Sold – Primarily includes purchased crude oil and condensate costs, as well as transportation, freight and storage costs.

- Refinery Operating Expenses – Reflect the direct operating expenses of the Nixon Facility, including direct costs of labor, maintenance materials and services, chemicals and catalysts and utilities. Represent fees paid to LEH to manage and operate the Nixon Facility pursuant to the Operating Agreement.

- JMA Profit Share – Represents the GEL Profit Share plus the Performance Fee for the period pursuant to the Joint Marketing Agreement.

- General and Administrative Expenses – Primarily include corporate costs, such as accounting and legal fees, office lease expenses, and administrative expenses.

- Depletion, Depreciation and Amortization –Capital and intangible assets are depreciated or amortized based on the straight-line method over the estimated useful life of the related asset.

- Easement, Interest and Other Income – Reflects income related to: (i) the FLNG Master Easement Agreement, which is recorded as land easement revenue and recognized monthly as earned and (ii) the Grynberg Matter, which was recorded as other non-recurring income in the three months ended September 30, 2015 (the "Current Quarter").

- Income Tax Expense – Includes federal and state taxes currently payable and deferred taxes arising from temporary differences between income for financial reporting and income tax purposes.

- Net Income – Represents total revenue from operations less total cost of operations, total other expense, and income tax expense.

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

Total Revenue from Operations. For the Current Quarter we had total revenue from operations of $55,256,887 compared to total revenue from operations of $88,186,173 for the three months ended September 30, 2014 (the "Prior Quarter"). The approximate 37% decrease in total revenue from operations was primarily the result of a significant decrease in commodity prices in the Current Quarter compared to the Prior Quarter. The majority of our revenue in the Current Quarter came from refined petroleum product sales, which generated revenue of $54,924,070, or more than 99% of total revenue from operations, compared to $87,846,757, or more than 99% of total revenue from operations, in the Prior Quarter. We recognized $286,892 in tank rental revenue in the Current Quarter compared to $282,516 in the Prior Quarter. Tank rental revenue was relatively flat between the Current Quarter and Prior Quarter.

Cost of Refined Products Sold. Cost of refined products sold was $48,415,627 for the Current Quarter compared to $82,781,856 for the Prior Quarter. The approximate 42% decrease in cost of refined products sold was primarily the result of a significant decrease in commodity prices in the Current Quarter compared to the Prior Quarter.

Refinery Operating Expenses. We recorded refinery operating expenses of $2,953,528 in the Current Quarter compared to $2,496,514 in the Prior Quarter, an increase of approximately 18%. Refinery operating expenses per barrel of throughput were $2.66 in the Current Quarter compared to $2.94 in the Prior Quarter. The decrease in refinery operating expenses per barrel of throughput was a result of an increase in total refinery throughput between the periods. See "Part I, Item 1. Financial Statements – Note (10) Accounts Payable, Related Party of this report for additional disclosures related to the Operating Agreement.

JMA Profit Share. The JMA Profit Share was $1,435,376 and $1,094,383 for the Current Quarter and Prior Quarter, respectively. GEL became entitled to receive the JMA Profit Share in May 2014 as a result of our repayment of amounts due under the Construction and Funding Agreement.

General and Administrative Expenses. We incurred general and administrative expenses of $312,365 in the Current Quarter compared to $253,437 in the Prior Quarter. The approximate 23% increase in general and administrative expenses in the Current Quarter compared to the Prior Quarter was primarily related an increase in environmental compliance costs.

Depletion, Depreciation and Amortization. We recorded depletion, depreciation and amortization expenses of $414,837 in the Current Quarter compared to $393,871 in the Prior Quarter. The approximate 5% increase in depletion, depreciation and amortization expenses for the Current Quarter compared to the Prior Quarter primarily related to additional depreciable refinery assets that were placed in service.

Easement, Interest and Other Income – We recorded $724,349 in easement, interest and other income for the Current Quarter compared to $1,813 in the Prior Quarter. The significant increase primarily stemmed from recognition of a one-time gain of $660,000 related to the Grynberg Matter.

Income Tax Expense. We recognized an income tax expense of $688,403 in the Current Quarter, which primarily related to deferred federal income taxes, compared to an income tax expense of $22,199 in the Prior Quarter. See "Part I, Item 1. Financial Statements – Note (17) Income Taxes" for additional disclosures related to income taxes.

Net Income. For the Current Quarter, we reported net income of $1,264,233, or income of $0.12 per share, compared to net income of $816,047, or income of $0.08 per share, for the Prior Quarter. The $0.04 per share increase in net income between the periods was the result of increases in refinery sales volumes and easement, interest and other income related to the Grynberg Matter, which were offset by an increase in the JMA Profit Share.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Total Revenue from Operations. For the nine months ended September 30, 2015 (the "Current Nine Months"), we had total revenue from operations of $175,810,850 compared to total revenue from operations of $311,965,322 for the nine months ended September 30, 2014 (the "Prior Nine Months"). The approximate 44% decrease in total revenue from operations was primarily the result of a significant decrease in commodity prices in the Current Nine Months compared to the Prior Nine Months. The majority of our revenue in the Current Nine Months came from refined petroleum product sales, which generated revenue of $174,830,292, or more than 99% of total revenue from operations, compared to $310,938,981, or more than 99% of total revenue from operations, in the Prior Nine Months. We recognized $860,676 in tank rental revenue in the Current Nine Months compared to $847,548 in the Prior Nine Months. Tank rental revenue was relatively flat between the Current Nine Months and Prior Nine Months.

Cost of Refined Products Sold. Cost of refined products sold was $151,604,774 for the Current Nine Months compared to $289,819,720 for the Prior Nine Months. The approximate 48% decrease in cost of refined products sold was primarily the result of a significant decrease in commodity prices in the Current Nine Months compared to the Prior Nine Months.

Refinery Operating Expenses. We recorded refinery operating expenses of $8,420,650 in the Current Nine Months compared to $8,092,738 in the Prior Nine Months, an increase of approximately 4%. Refinery operating expenses per barrel of throughput were $2.73 in the Current Nine Months compared to $2.78 in the Prior Nine Months. The decrease in refinery operating expenses per barrel of throughput was a result of an increase in total refinery throughput between the periods. See "Part I, Item 1. Financial Statements – Note (10) Accounts Payable, Related Party of this report for additional disclosures related to the Operating Agreement.

JMA Profit Share. The JMA Profit Share was $4,812,674 and $2,334,487 for the Current Nine Months and Prior Nine Months, respectively. GEL became entitled to receive the JMA Profit Share in May 2014 as a result of our repayment of amounts due under the Construction and Funding Agreement. The JMA Profit Share for the Current Nine Months represented expenses for the entire nine month period while the JMA Profit Share for the Prior Nine Months represented expenses for five months out of the nine month period.

General and Administrative Expenses. We incurred general and administrative expenses of $1,058,267 in the Current Nine Months compared to $1,049,981 in the Prior Nine Months. General and administration expense between the periods was relatively flat.

Depletion, Depreciation and Amortization. We recorded depletion, depreciation and amortization expenses of $1,217,005 in the Current Nine Months compared to $1,175,643 in the Prior Nine Months. The nearly 4% increase in depletion, depreciation and amortization expenses for the Current Nine Months compared to the Prior Nine Months primarily related to additional depreciable refinery assets that were placed in service.

Easement, Interest and Other Income – We recorded $856,816 in easement, interest and other income for the Current Nine Months compared to $253,745 in the Prior Nine Months. The significant increase primarily stemmed from recognition of a one-time gain related to the Grynberg Matter.

Income Tax Expense. We recognized an income tax expense of $2,778,750 in the Current Nine Months compared to an income tax expense of $298,792 in the Prior Nine Months. The significant increase in income tax expense between the periods was the result of deferred income taxes in 2015. In 2014, our deferred tax assets were fully reserved due to the uncertainty of their use. As a result, there was no comparable deferred tax expense for the Prior Nine Months. We recorded a valuation allowance to reduce deferred tax assets at the end of 2014. See "Part I, Item 1. Financial Statements – Note (17) Income Taxes" for additional disclosures related to income taxes.

Net Income. For the Current Nine Months we reported net income of $5,103,476, or income of $0.49 per share, compared to net income of $8,448,877, or income of $0.81 per share, for the Prior Nine Months. The $0.32 per share decrease in net income between the periods was related to increases in the JMA Profit Share and income tax expense, which were partially offset by an increase is refinery sales volume.

Liquidity and Capital Resources

Sources and Uses of Cash

LEH manages and operates all of our properties pursuant to the Operating Agreement. For services rendered, LEH receives reimbursements and fees. We rely on our profit share distribution under the Joint Marketing Agreement and LEH to fund our working capital requirements. During months in which we receive no profit share distribution under the Joint Marketing Agreement, LEH may, but is not required to, fund our operating losses. Amounts funded by LEH are reflected in accounts payable, related party in our consolidated balance sheets. At September 30, 2015 and December 31, 2014, we had cash and cash equivalents of $1,518,359 and $1,293,233, respectively.

In the normal course of business, we make estimates and assumptions related to amounts expensed for fees under the Operating Agreement since actual amounts can vary depending upon production volumes. We then use the cumulative catch-up method to account for revisions in estimates, which may result in prepaid expenses or accounts payable, related party on our consolidated balance sheets. At September 30, 2015, we were in a prepaid position with respect to fees and reimbursements under the Operating Agreement. Prepaid related party operating expenses totaled $712,688 and $0 at September 30, 2015 and December 31, 2014, respectively. Accounts payable, related party totaled $0 and $1,174,168 at September 30, 2015 and December 31, 2014, respectively. See “Part I, Item 1. Financial Statements – Note (10) Accounts Payable, Related Party of this report for additional disclosures related to the Operating Agreement and related party operating expenses.

We believe that our business strategy will be sufficient to support our operations for the next 12 months. In June 2015, we announced plans to expand the Nixon Facility in three phases that include: (i) constructing more than 500,000 bbls of petroleum storage tanks, (ii) purchasing and redeploying idle refinery equipment, and (iii) obtaining additional financing for further expansion projects. Potential benefits of the Nixon Facility expansion plan include:

- generating additional revenue from leasing product and crude storage to third parties;
- having crude and product storage to support refinery throughput of up to 30,000 bbls per day; and
- increasing the processing capacity and complexity of the Nixon Facility.

Through the third quarter of 2015, we: (i) completed refurbishment of the naphtha stabilizer and depropanizer units, which will improve the overall quality of the naphtha that we produce and help increase the capacity utilization rate of the Nixon Facility, (ii) purchased idle refinery equipment, including, among others, a Merox unit, vacuum tower, prefrac tower unit, and LPG fractionator, which will, over time, be refurbished, and (iii) continued debottlenecking efforts, which improve production and efficiency.

Execution of our business strategy depends on several factors, including our future performance, levels of accounts receivable, inventories, accounts payable, capital expenditures, adequate access to credit, and the financial flexibility to attract long-term capital on satisfactory terms. These factors may be impacted by general economic, political, financial, competitive, and other factors beyond our control. There can be no assurance that our business strategy will achieve the anticipated outcomes, or that LEH will continue to fund our working capital requirements during months in which we have operational losses. In the event our business strategy is unsuccessful, or our working capital requirements are not funded by our profit share distribution or LEH, we may experience a significant and material adverse effect on our operations, liquidity, and financial condition. See “Part I, Item 1A. Risk Factors” of our annual report on Form 10-K for the year ended December 31, 2014 for risk factors related to working capital, liquidity and Nixon Facility downtime.

Cash Flow

Our cash flow from operations for the periods indicated was as follows:

	For Three Months Ended September 30,		For Nine Months Ended September 30,	
	2015	2014	2015	2014
Cash flow from operations				
Adjusted income from continuing operations	$2,231,898	$1,347,049	$9,859,360	$9,913,685
Change in assets and current liabilities	137,620	(478,606)	(2,156,095)	(3,022,396)
Total cash flow from operations	2,369,518	868,443	7,703,265	6,891,289
Cash inflows (outflows)				
Proceeds from issuance of long-term debt	-	-	25,000,000	-
Payments on long term debt	(403,561)	(156,230)	(9,474,720)	(6,103,131)
Change in restricted cash for investing activities	478,562	-	(13,021,438)	-
Capital expenditures	(3,640,801)	(815,849)	(9,900,295)	(1,145,720)
Proceeds from notes payable	-	-	3,000,000	2,000,000
Payments on notes payble	-	(153,699)	-	(216,182)
Change in restricted cash for financing activities	206,127	(1,389)	(3,081,686)	(678,498)
Total cash outflows	(3,359,673)	(1,127,167)	(7,478,139)	(6,143,531)
Total change in cash flows	$(990,155)	$(258,724)	$225,126	$747,758

For the Current Quarter, we experienced positive flow from operations of $2,369,518 compared to positive cash flow from operations of $868,443 for the Prior Quarter, reflecting an increase of $1,501,075. For the Current Nine Months, we experienced positive cash flow from operations of $7,703,265 compared to positive cash flow from operations of $6,891,289 for the Prior Nine Months, reflecting an increase of $811,976. The increase in cash flow from operations between both reporting periods was primarily related to a significant increase in restricted cash for financing activities, which is primarily being used for construction related activities at the Nixon Facility. During the Prior Nine Months we used approximately $5.7 million of our available cash to repay GEL for amounts due under the Construction and Funding Agreement, which resulted in GEL receiving the JMA Profit Share. During the Current Nine Months, the JMA Profit Share was $4,812,674, which increased our cost of operations and reduced our cash flow.

Working Capital

We had working capital of $4,973,144 consisting of $25,165,430 in total current assets and $20,192,316 in total current liabilities, at September 30, 2015. Comparatively, we had a working capital deficit of $3,200,991, consisting of $14,682,657 in total current assets and $17,883,648 in total current liabilities, at December 31, 2014. As of September 30, 2015, we recognized approximately $2.9 million of deferred tax assets that we expect to use over the next twelve months as current rather than long-term. For the nine month period, the $8,174,135 improvement in working capital between the periods primarily related to the change in our deferred tax assets, as well as increases in restricted cash, inventory and accounts payable, related party.

Capital Spending

Capital expenditures in the Current Quarter totaled $3,640,801 compared to $815,849 in the Prior Quarter. Capital expenditures in the Current Nine Months totaled $9,900,295 compared to $1,145,720 in the Prior Nine Months. Capital spending primarily related to investments in the Nixon Facility. During the Current Quarter, we completed refurbishment of key components of the naphtha stabilizer and depropanizer units and continued with construction of new petroleum storage tanks. We are funding capital expenditures at the Nixon Facility primarily through borrowings.

In June 2015, proceeds of the Term Loan Due 2034 were used to refinance approximately $8.5 million of debt owed to American First National Bank. Remaining proceeds are being used primarily to construct new petroleum storage tanks and expand the Nixon Facility. Also in June 2015, we entered into a Loan and Security Agreement with Sovereign as lender for a term loan in the principal amount of $3.0 million (the “Term Loan Due 2016”). Proceeds of the Term Loan Due 2016 were used to purchase idle refinery equipment for the Nixon Facility.

We entered into a 36 month "build-to-suit" capital lease in August 2014, for the purchase of new boiler equipment for the Nixon Facility. The boiler equipment was delivered in December 2014.

In May 2014, we entered into a Loan and Security Agreement with Sovereign for a term loan in the principal amount of $2.0 million (the "Term Loan Due 2017"). Proceeds of the Term Loan Due 2017 were used primarily to finance costs associated with refurbishment of the Nixon Facility's naphtha stabilizer and depropanizer units.

Indebtedness

The principal balance outstanding on our short and long-term debt obligations was as follows:

	September 30, 2015	December 31, 2014
Long-term debt		
Term Loan Due 2034	$24,822,362	$-
Term Loan Due 2016	3,000,000	-
Notre Dame Debt	1,300,000	1,300,000
Term Loan Due 2017	1,109,962	1,638,898
Capital Leases	347,236	466,401
Refinery Note	-	8,648,980
	$30,579,560	$12,054,279

See "Part I, Item 1. Financial Statements – Note (13) Long-Term Debt" of this report for additional disclosures related to long-term debt obligations.

Critical Accounting Policies

Long-Lived Assets

Refinery and Facilities. Additions to refinery and facilities are capitalized. Expenditures for repairs and maintenance are included as operating expenses under the Operating Agreement and covered by LEH (see "Part I, Item 1. Financial Statements – Note (10) Accounts Payable, Related Party of this report for additional disclosures related to the Operating Agreement). Management expects to continue making improvements to the Nixon Facility based on technological advances.

Refinery and facilities are carried at cost. Adjustment of the asset and the related accumulated depreciation accounts are made for refinery and facilities' retirements and disposals, with the resulting gain or loss included in the consolidated statements of income. For financial reporting purposes, depreciation of refinery and facilities is computed using the straight-line method using an estimated useful life of 25 years beginning when the refinery and facilities are placed in service. We did not record any impairment of our refinery and facilities for the three and nine months ended September 30, 2015 and 2014.

Pipelines and Facilities Assets. We record pipelines and facilities at cost less any adjustments for depreciation or impairment. Depreciation is computed using the straight-line method over estimated useful lives ranging from 10 to 22 years. In accordance with FASB ASC guidance on accounting for the impairment or disposal of long-lived assets, assets are grouped and evaluated for impairment based on the ability to identify separate cash flows generated therefrom.

Construction in Progress. Construction in progress expenditures, which relate to construction and refurbishment activities at the Nixon Facility, are capitalized as incurred. Depreciation begins once the asset is placed in service.

Revenue Recognition

We sell jet fuel in nearby markets, and our intermediate products, including LPG, naphtha, HOBM, and AGO, to wholesalers and nearby refineries for further blending and processing. Revenue from refined petroleum product sales is recognized when title passes. Title passage occurs when refined petroleum products are sold or delivered in accordance with the terms of the respective sales agreements. Revenue is recognized when sales prices are fixed or determinable and collectability is reasonably assured.

Customers assume the risk of loss when title is transferred. Transportation, shipping and handling costs incurred are included in cost of refined products sold. Excise and other taxes that are collected from customers and remitted to governmental authorities are not included in revenue.

Tank rental fees are invoiced monthly in accordance with the terms of the related lease agreement and recognized in revenue as earned. Land easement revenue is recognized monthly as earned and included in other income.

Revenue from our pipeline operations is derived from fee-based contracts and is typically based on transportation fees per unit of volume transported multiplied by the volume delivered. Revenue is recognized when volumes have been physically delivered for the customer through the pipeline.

Asset Retirement Obligations

FASB ASC guidance related to AROs requires that a liability for the discounted fair value of an ARO be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted towards its future value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Management has concluded that there is no legal or contractual obligation to dismantle or remove the refinery and facilities. Further, management believes that these assets have indeterminate lives under FASB ASC guidance for estimating AROs because dates or ranges of dates upon which we would retire these assets cannot reasonably be estimated at this time. When a date or range of dates can reasonably be estimated for the retirement of these assets, we will estimate the cost of performing the retirement activities and record a liability for the fair value of that cost using present value techniques.

We recorded an ARO liability related to future asset retirement costs associated with dismantling, relocating or disposing of our offshore platform, pipeline systems and related onshore facilities, as well as plugging and abandoning wells and restoring land and sea beds. We developed these cost estimates for each of our assets based upon regulatory requirements, structural makeup, water depth, reservoir characteristics, reservoir depth, equipment demand, current retirement procedures, and construction and engineering consultations. Because these costs typically extend many years into the future, estimating future costs are difficult and require management to make judgments that are subject to future revisions based upon numerous factors, including changing technology, political, and regulatory environments. We review our assumptions and estimates of future abandonment costs on an annual basis.

Income Taxes

We account for income taxes under FASB ASC guidance related to income taxes, which requires recognition of income taxes based on amounts payable with respect to the current year and the effects of deferred taxes for the expected future tax consequences of events that have been included in our financial statements or tax returns. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial accounting and tax basis of assets and liabilities, as well as for operating losses and tax credit carryforwards using enacted tax rates in effect for the year in which the differences are expected to reverse.

As of each reporting date, management considers new evidence, both positive and negative, to determine the realizability of deferred tax assets. Management considers whether it is more likely than not that some portion or all of the deferred tax assets will be realized, which is dependent upon the generation of future taxable income prior to the expiration of any NOL carryforwards. When management determines that it is more likely than not that a tax benefit will not be realized, a valuation allowance is recorded to reduce deferred tax assets.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income prior to the expiration of any NOL carryforwards.

The guidance also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, as well as guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosures, and transition.

See “Part I, Item 1. Financial Statements - Note (17) Income Taxes” of this report for further information related to income taxes.

Recently Adopted Accounting Guidance

The guidance issued by the FASB during the three and nine months ended September 30, 2015 is not expected to have a material effect on our consolidated financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not applicable.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our disclosure controls and procedures, as defined in Exchange Act Rules 13a-15(e) and 15d-15(e), require us to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms, and information required to be disclosed in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of the end of the period covered by this report, we carried out an evaluation under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”). Although we have made improvements, our disclosure controls and procedures were ineffective as of September 30, 2015, reflecting the following material weaknesses:

- Inadequate personnel resources to handle complex accounting transactions, which can result in errors related to the recording, disclosure and presentation of consolidated financial information in quarterly, annual and other filings;
- Lack of formally documented accounting policies and procedures; and
- Inadequate personnel resources to ensure a complete segregation of duties within the accounting function.

The effectiveness of any system of controls and procedures is subject to certain limitations, and, as a result, there can be no assurance that our controls and procedures will detect all errors or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system will be attained.

Changes in Internal Control over Financial Reporting

We have taken a number of steps toward remediating noted material weakness related to the lack of formally documented accounting policies and procedures. During the three months ended September 30, 2015, we completed phase two internal control testing. During the nine months ended September 30, 2015, we:

- developed and implemented a monthly accounting close checklist;
- instituted a formal process to ensure manual journal entries are reviewed and approved by someone other than the preparer;
- developed a written capitalization policy for fixed assets and reviewed the policy with our external tax consultant;
- created a framework to document our internal controls, developed a plan for current year testing, and completed phase one testing of our internal controls framework;
- reviewed results of our internal controls testing with our independent registered public accounting firm; and
- reported internal control testing results to the Audit Committee of the Board.

We believe that, to date, we have made significant progress towards remediating identified significant deficiencies and material weaknesses in our internal controls over financial reporting. Although we plan to continue with our efforts to fully remediate the identified material weaknesses during the fourth quarter of 2015, there can be no assurance that our corrective actions will be sufficient or fully effective, or that we will not discover additional material weaknesses in our internal controls over financial reporting in the future.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time we are subject to various lawsuits, claims, liens and administrative proceedings that arise out of the normal course of business. Vendors have placed mechanic's liens on certain of our assets primarily as protection during construction activities. Management does not believe that such liens will have a material adverse effect on our results of operations.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, careful consideration should be given to the risk factors discussed under "Part I, Item 1A. Risk Factors" and elsewhere in our previously filed annual report on Form 10-K for the year ended December 31, 2014. These risks and uncertainties could materially and adversely affect our business, financial condition and results of operations. Our operations could also be affected by additional factors that are not presently known to us or by factors that we currently consider immaterial to our business. There have been no material changes in our assessment of our risk factors from those set forth in our previously filed annual report on Form 10-K for the year ended December 31, 2014.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

See "Part I, Item. 1. Financial Statements – Note (13) Long-Term Debt" of this report for disclosures related to potential defaults on debt.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

(a) Exhibits:

The following exhibits are filed herewith:

No.	Description
31.1	Jonathan P. Carroll Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Tommy L. Byrd Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Jonathan P. Carroll Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Tommy L. Byrd Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.CAL	XBRL Calculation Linkbase Document.
101.LAB	XBRL Label Linkbase Document.
101.PRE	XBRL Presentation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.

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SIGNATURES

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

BLUE DOLPHIN ENERGY COMPANY
(Registrant)

Date: November 16, 2015	By:	/s/ JONATHAN P. CARROLL Jonathan P. Carroll Chairman of the Board, Chief Executive Officer, President, Assistant Treasurer and Secretary (Principal Executive Officer)
Date: November 16, 2015	By:	/s/ TOMMY L. BYRD Tommy L. Byrd Chief Financial Officer, Treasurer and Assistant Secretary (Principal Financial Officer)