TRANS ENERGY INC
Form 10-Q
August 24, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2015

OR

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

For the transition period from __________ to __________

Commission File Number 0-23530

TRANS ENERGY, INC.

(Exact name of registrant as specified in its charter)

Nevada	**93-0997412**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

210 Second Street, P.O. Box 393, St. Marys, West Virginia 26170

(Address of principal executive offices)

Registrant s telephone number, including area code: (304) 684-7053

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the past 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 x No ¨

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

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

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

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	**Outstanding as of August 24, 2015**
Common Stock, $0.001 par value	15,144,477

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

TRANS ENERGY, INC. AND SUBSIDIARIES

Condensed Consolidated Balance Sheets

Unaudited

	June 30, 2015 Unaudited	December 31, 2014 Audited
ASSETS		
CURRENT ASSETS		
Cash	$ 998,830	$ 1,585,530
Accounts receivable, trade	4,808,362	4,248,152
Accounts receivable, related parties	18,500	18,500
Derivative assets	3,577,996	5,420,309
Advance royalties	227,633	68,133
Prepaid expenses	632,400	767,233
Deferred financing costs, net of amortization of $1,125,807 and $599,971, respectively	1,051,671	1,051,671
Total current assets	11,315,392	13,159,528
OIL AND GAS PROPERTIES, USING SUCCESSFUL EFFORTS ACCOUNTING		
Proved properties	84,852,988	88,194,425
Unproved properties	6,276,687	5,728,196
Pipelines	4,407,117	1,259,052
Accumulated depreciation, depletion and amortization	(21,113,333)	(17,731,699)
Oil and gas properties, net	74,423,459	77,449,974
PROPERTY AND EQUIPMENT, net of accumulated depreciation of $404,435 and $364,710, respectively	469,969	504,526
OTHER ASSETS		
Assets held for sale	14,164,597	14,301,375
Derivative assets		2,809,847
Deferred financing costs	2,629,178	3,155,014
Other assets	389,887	388,881
Total other assets	17,183,662	20,655,117
TOTAL ASSETS	$ 103,392,482	$ 111,769,145

See notes to unaudited condensed consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Condensed Consolidated Balance Sheets (continued)

Unaudited

	June 30, 2015 Unaudited	December 31, 2014 Audited
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable, trade	$ 878,323	$ 531,761
Accounts payable due to drilling operator	1,203,986	5,777,983
Accounts payable, related party	1,500	1,500
Accrued expenses	4,833,688	7,429,874
Environmental settlement and related costs	3,000,000	3,600,000
Revenue payable	17,979	25,019
Notes payable current	960,256	4,402
Total current liabilities	10,895,732	17,370,539
LONG-TERM LIABILITIES		
Notes payable, net	111,508,558	109,539,647
Asset retirement obligations	115,672	90,928
Environmental settlement and related costs	3,000,000	3,000,000
Commodity derivative liability	1,345,504	716,488
Deferred revenue	62,510	62,510
Total long-term liabilities	116,032,244	113,409,573
Total liabilities	126,927,976	130,780,112
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Preferred stock; 10,000,000 shares authorized at $0.001 par value; -0- shares issued and outstanding		
Common stock; 500,000,000 shares authorized at $0.001 par value; 15,146,477 and 14,578,467 shares issued, and 15,144,477 and 14,576,467 shares outstanding, respectively	15,146	14,578
Additional paid-in capital	45,611,641	44,323,190
Treasury stock, at cost, 2,000 shares	(1,950)	(1,950)
Accumulated deficit	(69,160,331)	(63,346,785)
Total stockholders equity (deficit)	(23,535,494)	(19,010,967)
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 103,392,482	$ 111,769,145

See notes to unaudited condensed consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Condensed Consolidated Statements of Operations (Unaudited)

	For the Three Months Ended June 30, 2015	For the Three Months Ended June 30, 2014	For the Six Months Ended June 30, 2015	For the Six Months Ended June 30, 2014
OPERATING REVENUES				
Oil and gas sales	$ 3,620,627	$ 8,432,592	$ 8,005,664	$ 18,149,015
Gas transportation, gathering, and processing	41,173	22,830	83,889	77,619
Other income	4,137	1,303	5,914	6,433
Total operating revenues	3,665,937	8,456,725	8,095,467	18,233,067
OPERATING COSTS AND EXPENSES				
Production costs	4,140,778	3,489,282	7,177,964	6,745,232
Depreciation, depletion, amortization and accretion	2,588,627	2,248,970	4,391,457	4,360,695
Selling, general and administrative	1,844,624	1,534,477	3,025,454	2,982,296
Total operating costs and expenses	8,574,029	7,272,729	14,594,875	14,088,223
(Loss) gain on sale of assets		(298)		207,097
(LOSS) INCOME FROM OPERATIONS	(4,908,092)	1,183,698	(6,499,408)	4,351,941
OTHER INCOME (EXPENSES)				
Interest income	540	585	1,081	1,494
Interest expense	(3,047,743)	(9,674,758)	(6,163,480)	(13,805,951)
(Loss) gain on derivative assets	(526,920)	(2,459,436)	6,848,261	(3,025,628)
Total other income (expenses)	(3,574,123)	(12,133,609)	685,862	(16,830,085)
NET LOSS BEFORE INCOME TAXES	(8,482,215)	(10,949,911)	(5,813,546)	(12,478,144)
INCOME TAX				
NET LOSS	$ (8,482,215)	$ (10,949,911)	$ (5,813,546)	$ (12,478,144)
NET LOSS PER SHARE BASIC AND DILUTED	$ (0.56)	$ (0.81)	$ (0.39)	$ (0.92)
WEIGHTED AVERAGE SHARES BASIC AND DILUTED	15,118,455	13,590,048	15,004,377	13,553,423

See notes to unaudited condensed consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Six Months Ended June 30, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (5,813,546)	$ (12,478,144)
Adjustments to reconcile net loss to net cash used by operating activities:		
Depreciation, depletion, amortization and accretion	3,421,359	4,360,695
Amortization of financing costs and debt discount	970,098	8,426,119
Share-based compensation	692,003	483,216
Professional fees paid by common stock issuance	270,000	
(Gain) loss on sale of assets		(207,097)
Interest and legal expense added to principal		1,818,240
Unrealized loss on commodity derivative assets	5,281,176	2,575,581
Realized (gain) loss on commodity derivative assets	(12,129,437)	450,047
Changes in operating assets and liabilities:		
Accounts receivable, trade	4,569,227	(2,962,965)
Accounts receivable due from operator, net		(704,677)
Prepaid expenses and other current assets	(24,667)	(3,239,585)
Other assets	(1,006)	(990)
Accounts payable and accrued expenses	(2,249,624)	230,583
Accounts payable due to operator	2,426,003	
Environmental settlement and related costs	(600,000)	
Revenue payable	(7,040)	(60,248)
Net cash used by operating activities	(3,195,454)	(1,309,225)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Proceeds from sale of assets		15,259,543
Expenditures for oil and gas properties	(193,597)	(16,008,089)
Expenditures for property and equipment	(5,168)	(2,087)
Net cash used by investing activities	(198,765)	(750,633)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Financing costs paid		(4,298,647)
Payments on notes payable	(569,497)	(98,699,723)
Proceeds from notes payable	3,050,000	103,093,750
Stock options exercised	327,016	223,746
Net cash provided by financing activities	2,807,519	319,126
NET CHANGE IN CASH	(586,700)	(1,740,732)

CASH, BEGINNING OF PERIOD		1,585,530		2,727,832
CASH, END OF PERIOD	$	998,830	$	987,100
SUPPLEMENTAL DISCLOSURES FOR CASH FLOW INFORMATION:				
CASH PAID FOR:				
Interest	$	6,163,479	$	5,648,315
Income taxes				
Non-cash investing and financing activities:				
Accrued expenditures for oil and gas properties	$	(4,573,997)	$	(3,443,366)
Increase in asset retirement obligation	$	24,744	$	24,744

See notes to unaudited condensed consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements (Unaudited)

NOTE 1 BASIS OF FINANCIAL STATEMENT PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

The accompanying unaudited interim condensed consolidated financial statements have been prepared by Trans Energy, Inc. (Trans Energy, we, our, us, or the Company), in accordance with accounting principles generally accepted in the United State of America (GAAP) for interim financial information and with the instructions to Form 10-Q and Rule 8-03 of Regulation S-X. Accordingly, they do not include certain information and footnote disclosures normally included in a full set of financial statements prepared in accordance with GAAP. The information furnished in the interim condensed consolidated financial statements includes normal recurring adjustments and reflects all adjustments, which, in the opinion of management, are necessary for a fair presentation of such financial statements. Although management believes the disclosures and information presented are adequate to make the information not misleading, these interim consolidated financial statements should be read in conjunction with our most recent audited consolidated financial statements and notes thereto included in our December 31, 2014 Annual Report on Form 10-K. Operating results for the six months ended June 30, 2015 are not necessarily indicative of the results that may be expected for the year ending December 31, 2015.

Significant Accounting Policies

The accounting policies followed by the Company are set forth in Note 1 to the Company s consolidated financial statements in the 2014 Form 10-K, and are supplemented by the notes to the unaudited condensed consolidated financial statements in this report.

Nature of Operations and Organization

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil and natural gas. Our operations are presently focused in the State of West Virginia.

Principles of Consolidation

The unaudited consolidated financial statements include Trans Energy and our wholly-owned subsidiaries, Prima Oil Company, Inc. (Prima), Ritchie County Gathering Systems, Inc., Tyler Construction Company, Inc., American Shale Development, Inc. (American Shale or ASD), and Tyler Energy, Inc., and interests with joint venture partners, which are accounted for under the proportional consolidation method. All significant inter-company balances and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Our financial statements are based on a number of significant estimates, including oil and gas reserve quantities which are the basis for the calculation of depreciation, depletion, amortization, and impairment of oil and gas properties, timing and costs associated with our asset retirement obligations, estimates of fair value of derivative instruments and estimates used in stock-based compensation calculations. Reserve estimates are by their nature inherently imprecise.

Financing Costs

In connection with obtaining the Morgan Stanley financing in May 2014 and subsequent borrowings, we incurred fees and expenses of $4,806,656. These fees and expenses were recorded as financing costs and are being amortized over the life of the loan using the straight-line method, which approximates the effective interest method.

Amortization of financing costs for the three months ended June 30, 2015 and 2014 were $485,049 and $3,123,838, respectively. Amortization of financing costs for the six months ended June 30, 2015 and 2014 were $970,098 and $3,328,323, respectively. Our policy is to recognize twelve months of future deferred financing cost amortization as a current asset and the remaining balance of deferred financing costs as other assets in the condensed consolidated balance sheets.

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Property and Equipment

Property and equipment are recorded at cost. Depreciation on vehicles, machinery and equipment is computed using the straight-line method over expected useful lives of five to ten years. Additions are capitalized and maintenance and repairs are charged to expense as incurred.

Oil and Gas Properties

Trans Energy uses the successful efforts method of accounting for oil and gas producing activities. Under the successful efforts method, costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells and asset retirement costs are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed as incurred.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved properties are amortized based on Trans Energy s experience of successful drilling and average holding period. Capitalized costs of producing oil and gas properties, after considering estimated dismantlement and abandonment costs and estimated salvage values, are depreciated and depleted by the unit-of-production method. Depreciation on pipelines and related equipment, including compressors, is computed using the straight-line method over the expected useful lives of ten to twenty-five years.

On the sale or retirement of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized.

On the sale of an entire interest in an unproved property for cash or cash equivalent, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually.

If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Impairments

Generally accepted accounting principles require that long- lived assets (including oil and gas properties) and certain identifiable intangibles are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The Company, at least annually, reviews its proved oil and gas properties for impairment by comparing the carrying value of its properties to the properties undiscounted estimated future net cash flows. Estimates of future oil and gas prices, operating costs, and production are utilized in determining undiscounted future net cash flows. The estimated future production of oil and gas reserves is based upon the Company s independent reserve engineer s estimate of proved reserves, which includes assumptions regarding field decline rates and future prices and costs. For properties where the carrying value exceeds undiscounted future net cash flows, the Company recognizes as impairment the difference between the carrying value and fair market value of the properties.

No impairments were recorded through June 30, 2015 or 2014.

Derivatives

We may enter into derivative commodity contracts at times to manage or reduce commodity price risk related to our production. Derivatives and embedded derivatives, if applicable, are measured at fair value and recognized in the consolidated balance sheets as assets or liabilities. Derivatives are classified in the consolidated balance sheets as current or non-current based on whether net-cash settlement is expected to be required within 12 months of the balance sheet date. These commodity contracts are not designated as cash flow hedges, so changes in the fair value are recognized immediately in other income (expense) in the consolidated statement of operations. The pricing models used for valuation often incorporate significant estimates and assumptions, which may impact the level of precision in the financial statements.

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Notes Payable

We record notes payable at fair value and recognize interest expense for accrued interest payable under the terms of the agreements. Principal and interest payments due within one year are classified as current, whereas principal and interest payments for periods beyond one year are classified as long term.

Asset Retirement Obligations

We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. These obligations include dismantlement, plugging and abandonment of oil and gas wells and associated pipelines and equipment. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depleted over the estimated useful life of the related asset which has been determined to be 40 years for Marcellus Shale wells.

The following is a description of the changes to our asset retirement obligations for the six months ended June 30:

	2015	2014
Asset retirement obligations at beginning of period	$ 90,928	$ 41,440
Liabilities incurred during the period	22,744	22,744
Accretion expense	2,000	2,000
Asset retirement obligations at end of period	$ 115,672	$ 66,184

At June 30, 2015 and December 31, 2014, our current portion of the asset retirement obligation was $0.

Income Taxes

At June 30, 2015, the Company had net operating loss carry forwards (NOLs) for future years of approximately $61.5 million. These NOLs will expire at various dates through 2033. There is no current tax provision for the three or six months ended June 30, 2014 due to a net operating loss for the period. No tax benefit has been recorded in the consolidated financial statements for the remaining NOLs or Alternative Minimum Tax (AMT) credit since the potential tax benefit is offset by a valuation allowance of the same amount. Utilization of the NOLs could be limited if there is a substantial change in ownership of the Company and is contingent on future earnings.

We have provided a valuation allowance equal to 100% of the total net deferred asset in recognition of the uncertainty regarding the ultimate amount of the net deferred tax asset that will be realized.

The Company has no material unrecognized tax benefits. No tax penalties or interest expense were accrued as of June 30, 2015 or December 31, 2014 or paid during the periods then ended. We file tax returns in the United States and states in which we have operations and are subject to taxation. Tax years subsequent to 2010 remain open to examination by U.S. federal and state tax jurisdictions, however prior year net operating losses remain open for examination.

Revenue and Cost Recognition

We recognize gas revenues upon delivery of the gas to the customers pipeline from our pipelines when recorded as received by the customer s meter. We recognize oil revenues when pumped and metered by the customer. We use the sales method to account for sales and imbalances of natural gas. Under this method, revenues are recognized based on actual volumes sold to purchasers. The volumes sold may differ from the volumes to which we are entitled based on our interest in the properties. These differences create imbalances which are recognized as a liability only when the imbalance exceeds the estimate of remaining reserves. We had no material imbalances as of June 30, 2015 and December 31, 2014. Costs associated with production are expensed in the period incurred.

Revenue payable represents cash received but not yet distributed to third parties.

Transportation revenue is recognized when earned and we have a contractual right to receive payment.

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On January 1, 2013, the Company adopted new authoritative accounting guidance issued by the Financial Accounting Standards Board (FASB), which enhanced disclosures by requiring an entity to disclose information about netting arrangements, including rights of offset, to enable users of its financial statements to understand the effect of those arrangements on its financial position and provided clarification as to the specific instruments that should be considered in these disclosures. These pronouncements were issued to facilitate comparison between financial statements prepared on the basis of GAAP and International Financial Reporting Standards. These disclosures are effective for annual and interim reporting periods beginning on or after January 1, 2013, and are to be applied retrospectively for all comparative periods presented. See Note 9 - Derivative and Hedging Financial Instruments for tabular presentation of the Company s gross and net derivative positions.

Share-Based Compensation

Trans Energy estimates the fair value of each stock option award at the grant date by using the Black-Scholes option pricing model. The model employs various assumptions, based on management s best estimates at the time of the grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the award. We have utilized historical data and analyzed current information to reasonably support these assumptions. The fair value of restricted stock awards is determined based on the fair market value of our common stock on the date of the grant.

We recognize share-based compensation expense on a straight-line basis over the requisite service period for the entire award. As a result of stock and option transactions, we recorded total share-based compensation of $136,225 and $284,675 for the three months ended June 30, 2015 and 2014, respectively. We also recorded total share-based compensation of $692,003 and $483,216 for the six months ended June 30, 2015 and 2014, respectively.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board (the FASB) issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) (ASU 2014-09). ASU 2014-09 is intended to improve the financial reporting requirements for revenue from contracts with customers by providing a principle based approach. The core principal of the standard is that revenue should be recognized when the transfer of promised goods or services is made in an amount that the entity expects to be entitled to in exchange for the transfer of goods and services. ASU 2014-09 also requires disclosures enabling users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The original effective date for financial statements issued by public companies was for annual reporting periods beginning after December 15, 2016. In July 2015, the FASB deferred the effective date for annual reporting periods beginning after December 15, 2017 (including interim reporting periods within those periods). Early adoption is permitted to the original effective date. The Company is currently evaluating the potential impact of ASU 2014-09 on the financial statements.

In April 2015 the Financial Accounting Standards Board issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs (ASU 2015-03). This standard amends the existing guidance to require that debt issuance costs be presented in the balance sheet as a deduction from the carrying amount of the related debt liability instead of as a deferred charge. ASU No. 2015-03 is effective on a retrospective basis for annual reporting periods beginning after December 15, 2015, but early adoption is permitted. The Company is currently evaluating the effect that the adoption of this standard will have on its financial statements and related disclosures.

The Company has reviewed all other recently issued accounting standards in order to determine their effects, if any, on the consolidated financial statements. Based on that review, the Company believes that none of these standards will have a significant effect on current or future earnings or results of operations.

NOTE 2   OPERATIONS

We have incurred net losses for the three months and six months ended June 30, 2015 of $(8,482,215) and $(5,813,546), respectively. Although our current and prior year-to-date revenues were not sufficient to cover our operating costs and interest expense, we are focusing on drilling Marcellus Shale wells which, based upon projections, are expected to increase our cash flow. If our cash flows from operations are not sufficient to meet liquidity requirements, we may need to sell assets, obtain additional financing or issue equity.

Our net losses and cash flows used in operating and investing activities during the six months ended June 30, 2015 were primarily due to a gain on commodity derivatives as well as an increase in accounts payable and accrued expenses. Our net losses and cash flows used in operating and investing activities during the six months ended June 30, 2014 were funded using net proceeds from notes payable to Chambers and Morgan Stanley (see Note 8), in addition to proceeds from the sale of certain oil and gas properties (see Note 6).

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NOTE 3 ACCOUNTS PAYABLE DUE TO DRILLING OPERATOR

We have historically been the drilling operator for wells drilled on our behalf in which we own a working interest. In 2012, another working interest owner became the drilling operator for wells in which we own a working interest. We owed the drilling operator $1,203,986 and $5,777,983 for charges incurred, but not paid, as of June 30, 2015 and December 31, 2014, respectively. The amount due to the operator reported at December 31, 2014 has been reduced for consideration received from the Republic purchase and sale agreement, which is to be paid in the form of a credit against the expenses incurred by Republic Energy Ventures on behalf of American Shale (See Note 6). The amount due to the operator reported at June 30, 2015 and December 31, 2014, is net of a $0 and $708,467 credit, respectively, related to intercompany charges related to employee salary reimbursements, travel expenses, and lease costs.

NOTE 4 OIL AND GAS PROPERTIES

Total reductions and additions for oil and gas properties for the three months ended June 30, 2015 and 2014 were $(6,914,445) and $14,021,282, respectively. Total additions for oil and gas properties for the six months ended June 30, 2015 and 2014 were $193,597 and $16,008,089, respectively. The reduction reported at June 30, 2015 is the result of the sale of a partial interest in unproved property to Republic Energy Operating, LLC on April 27, 2015 (See Note 8). Depreciation, depletion, and amortization expenses on oil and gas properties were $2,083,871 and $2,148,847 for the three months ended June 30, 2015 and 2014, respectively. Depreciation, depletion, and amortization expenses on oil and gas properties were $3,381,134 and $4,238,454 for the six months ended June 30, 2015 and 2014, respectively.

NOTE 5 ASSETS AND LIABILITIES HELD FOR SALE

On April 3, 2015, we and our wholly owned subsidiaries American Shale and Prima, along with Republic Energy Ventures, LLC, Republic Partners VIII, LLC, Republic Partners VI, LP, Republic Partners VII, LLC, and Republic Energy Operating, LLC (collectively, the Sellers) entered into a Purchase and Sale Agreement (the PSA), pursuant to which the Sellers agreed to sell certain interests located in Wetzel County, West Virginia, including 5,159 net acres held by the Company and the Company s interest in twelve Marcellus producing wellbores, to TH Exploration, LLC (Buyer). The Company expected to receive approximately $47.0 million at closing, net of funds used to repurchase assets that are to be included in the sale. The Company expected to ultimately receive approximately $71.3 million in connection with the sale of its assets and the overriding royalty interests that were to be repurchased and included in the sale. The incremental funds were expected to be received upon the successful resolution of certain quiet title actions that are currently ongoing and the release of funds would be held in escrow for a time following the closing.

The PSA contained customary representations, warranties and indemnities among the parties and the closing contemplated by the PSA was subject to the satisfaction of certain customary conditions as described therein. Additionally, the PSA provided the Buyer with the opportunity to terminate the agreement and receive its deposit plus reimbursement for diligence expenses in the event that certain conditions are not met.

The foregoing descriptions of the PSA and the consideration payable hereunder do not purport to be complete and are qualified in their entirety by reference to the complete text of the PSA, a copy of which is attached hereto as exhibit 99.1.

On July 30, 2015, the Buyer elected to formally extend the expiration date of the PSA until August 14, 2015 (the Extension Period). During the Extension Period, the Buyer provided notice to the Company that the PSA would terminate on August 13, 2015. The Company believes that the PSA terminated as a result of such notice. No assets were sold under the PSA. See Note 15 Subsequent Events related to sale assets.

Total assets held for sale as of June 30, 2015 and December 31, 2014 were $14,164,597 and $14,301,375, respectively.

NOTE 6 SALE OF OIL AND GAS PROPERTIES

On January 24, 2013, we closed the sale of our interests in certain non-core assets for approximately $2.6 million of net cash proceeds. The interests sold consisted of our working interest in all existing shallow wells, but we retained an overriding royalty interest of approximately 2.5% on most of the wells. The purchaser assumed the role of operator with respect to approximately 300 wellbores, and has commenced a workover program with respect to a number of the existing wells. The wells produced at a rate of approximately 800 Mcfe per day as of December 31, 2012, which was the effective date for the transaction.

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Additionally, we granted the purchaser the right to drill wells in or above conventional shallow Devonian formations, for leases where we currently hold rights to such depths. We did not farm out any of our rights to drill in deeper formations such as the Rhinestreet, Marcellus or Utica. We retained up to a 5% overriding royalty interest on any such wells drilled, depending on the net revenue interest.

On December 13, 2013, the Company and Republic closed a transaction pursuant to a Purchase and Sale Agreement (the PSA) dated September 30, 2013. The Company owned 1,114.8 lease acres of the total 4,650 lease acres and leasehold working interests in certain partially completed well sites, located in Tyler County, West Virginia. At closing, the Company received cash of approximately $10.6 million of the total purchase price of $36.3 million, net of holdback. A total of 118.6 lease acres were excluded from the sale (39.8 lease acres net to the Company) due to incurable title defects. An additional 135.5 lease acres (30.7 lease acres net to the Company) were excluded from the sale due to curable title defects, which were cured and an additional $0.2 million was due and payable to the Company, as of December 31, 2013, per the terms of the PSA. In February 2014, the Company received $489,608 related to curable title defects. The proceeds were applied to a receivable of $230,064 recorded at December 31, 2013. The remaining $259,544 was reported, net of expenses, as gain on sale of assets in 2014.

On May 21, 2014 (Funding Date), American Shale entered into a purchase and sale agreement (the Republic PSA) with its joint venture partner, Republic Energy Ventures (Republic). Under the Republic PSA, for $15 million, American Shale sold (i) an undivided interest across all of its undeveloped leasehold amounting to approximately 2,239 net acres, (ii) an over-riding royalty interest of 1.5% in all of its leasehold in Wetzel County, West Virginia, and (iii) an over-riding royalty interest of 1.0% in six (6) wells that were being drilled in Marshall County, West Virginia. The consideration was in the form of a credit against expenses incurred by Republic on behalf of American Shale. American Shale reserved the right to receive 25% of the net profits earned by Republic on the assets sold. American Shale had the option to repurchase the undivided interest across all of its undeveloped leasehold, plus the over-riding royalty interest in its Wetzel County leasehold, for $15 million if (i) such payment is made within six (6) months of the Funding Date, or (ii) a purchase and sale agreement that would allow for such repayment by American Shale was signed within such period and the transaction contemplated therein closed prior to December 31, 2014. American Shale did not exercise the option to repurchase the royalty interest and the sale was recognized as a gain on sale of assets at December 31, 2014.

As part of the Republic PSA, Republic also agreed to amend the Amended Joint Development Agreement with American Shale (the AJDA). Under the revised AJDA, Republic agreed to fund all costs associated with new leasehold acquisitions subsequent to April 1, 2014. American Shale has the right to buy a 25% interest in any such leasehold at Republic s cost, plus 12% interest, in the event that Republic sells its interest in the leasehold or permits a third party to drill a well on the leasehold.

On December 24, 2014, American Shale closed a transaction pursuant to a Purchase and Sale Agreement (the PSA) executed as of December 24, 2014 with Wellbore Capital, LLC, a Delaware limited liability company (Wellbore). Pursuant to the PSA, the Sellers granted to Wellbore overriding royalty interests in certain leases (the Oil and Gas Properties) located in Wetzel and Marion Counties, West Virginia (collectively, the ORRI). Under the PSA, the purchase price for the ORRI was $11.0 million, of which the Company received approximately $10.7 million in cash at closing. The PSA provides Wellbore the right to sell its interests in the ORRI to a third party acquiror in the event that Sellers sell all of their interests in the oil and gas properties to such acquiror. If such sale occurs prior to December 31, 2017, Wellbore alternatively has the right to require Sellers to repurchase the ORRI for a certain return on its investment in the ORRI.

NOTE 7 ENVIRONMENTAL SETTLEMENT AND RELATED COSTS

On September 28 and December 17, 2012, the U.S. Environmental Protection Agency (EPA) issued to the Company seven administrative compliance orders and a request for information. The orders and request related to our compliance with Clean Water Act (CWA) permitting requirements at seven pond and/or well site locations in Marshall and Wetzel Counties, West Virginia and concerned the alleged discharge of dredged and/or fill material into waters of the United States. On August 25, 2014, Trans Energy entered into a civil Consent Decree with the EPA with respect to the CWA matter and related issues that were discovered based upon an internal audit. Fines associated with the Consent Decree amount to $3,000,000.

As part of the Consent Decree, Trans Energy is required to perform certain restoration activities at affected pond, well pad and access roads at multiple sites. We have preliminarily estimated the cost of early components of restoration over all the sites involved to be an additional $3,000,000, net to Trans Energy. Overall costs may range as high as $9,000,000. The restoration will be performed during the 2015, 2016 and 2017 construction seasons. Our estimate of costs to us will be refined, and may increase or decrease as we submit work plans to the EPA for approval to perform these restoration activities. Additionally, we are exploring avenues to offset some costs to the extent they are reimbursable through our joint venture agreements and the purchase or trading of wetland credits.

On October 1, 2014, Trans Energy pleaded guilty to three misdemeanor charges related to Unauthorized Discharge into a Water of the United States in violation of the Clean Water Act. In connection with this plea, the Company agreed to pay a $600,000 fine and was placed on probation for a period of two years.

As a result of this plea and the previously disclosed settlement agreement, all civil and criminal matters arising out of the EPA s investigation and complaints arising out of the ponds in Marshall and Wetzel Counties West Virginia have been resolved.

NOTE 8 NOTES PAYABLE

On April 26, 2012 American Shale closed a Credit Agreement transaction (hereafter the Chambers Credit Agreement) with several banks and other financial institutions or entities that from time-to-time will be parties to the Chambers Credit Agreement (the Lenders), and Chambers Energy Management, LP as the administrative agent (Agent or Chambers).

The Chambers Credit Agreement was originally for a notional amount of $50 million, which was received at closing net of a $3 million Original Issue Discount (OID) and a $50,000 administrative fee due annually. These OID costs were netted against notes payable and were being amortized over the life of the loan using the straight-line method, which approximated the effective interest method. For the six months ended June 30, 2015 and 2014, $0 and $1,189,400 of the OID was amortized as interest expense, respectively.

On February 28, 2013, American Shale, the Lenders and the Agent amended and restated the Chambers Credit Agreement in order to facilitate an increase in the principal amount of the borrowings under the facility to $75 million. The additional funds were received February 28, 2013. The other terms of the Chambers Credit Agreement were unchanged.

Interest was due monthly at 10% plus the greater of 1% or the 3 month LIBOR rate (11% at time of payoff). Principal was due at maturity, February 28, 2015. We had to pay interest through April 26, 2014, on any principal prepayments with respect to the original $50 million loan at the time of the prepayment prior to April 26, 2014. American Shale was obligated to pay a Termination Fee with respect to the $25 million loan upon the earliest to occur of (i) a Change of Control, (ii) repayment in full of the loans under the Chambers Credit Agreement and (iii) certain defaults under the Chambers Credit Agreement related to seeking relief from creditors or generally being unable to repay debts as they come due. The Termination Fee was defined as $12.5 million less all interest payments actually made with respect to the $25 million loan prior to such date.

The Company estimated its liability related to the Termination Fee to be approximately $6.8 million ($12.5 million gross fee, less $5.7 million in interest payments) (the Termination Fee Liability).

The Termination Fee Liability was recorded on the Company s condensed consolidated balance sheet as an addition to the related debt balance, offset by an equal debt discount of $6.8 million (the Termination Fee Debt Discount). The Termination Fee Debt Discount was being amortized to interest expense through the expected payment date of February 28, 2015; however, such amortization was accelerated upon payment of the Termination Fee in conjunction with the Morgan Stanley Credit Agreement. At repayment of the loan, the Termination Fee was computed to be $9,077,778. For the three months ended June 30, 2015 and 2014, the Company recorded interest expense of $0 and $3,104,200 of amortization related to the Termination Fee, respectively. For the six months ended June 30, 2015 and 2014, the Company recorded interest expense of $0 and $3,940,689 of amortization related to the Termination Fee, respectively.

During the three months ended June 20, 2015 and 2014 the Company recorded interest of $0 and $278,821 related to the amortization of the Termination Fee Debt Discount. For the six months ended June 30, 2015 and 2014, the Company recorded interest of $0 and $1,115,280 related to the amortization of the Termination Fee Debt

The Chambers Credit Agreement included a contingent interest provision that added 1% of the outstanding principal amount of the loan to the loan balance for any quarter in which American Shale s Consolidated Leverage Ratio exceeded certain levels. American Shale s Consolidated Leverage Ratio exceeded the allowed level at September 30, 2012, and quarterly thereafter. Therefore, the contingent interest provision had been applied and $1,149,969 was added to the principal balance and interest expense in 2014 (through the date of the repayment).

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On May 21, 2014, American Shale entered into a credit agreement (the Morgan Stanley Credit Agreement) by and among American Shale, several lenders (the Lenders), and Morgan Stanley Capital Group Inc. as the administrative agent (Agent). Trans Energy is a guarantor of the Morgan Stanley Credit Agreement as is Prima, another of our wholly owned subsidiaries. The Morgan Stanley Credit Agreement provides that the Lenders will lend American Shale up to $200 million, including an initial draw of $102.5 million plus a PIK fee of $593,750, a contingent committed amount of $47.5 million and an uncommitted amount of $50 million (the Loans). The initial draw under the facility was used primarily to repay all of the outstanding debt under the Chambers Credit Agreement, as well as to fund certain fees and expenses incurred in connection with the Morgan Stanley Credit Agreement.

The Loans will initially bear interest at a per annum rate equal to 9% plus the greater of 1% or LIBOR, for a three month interest period. The interest rate will be automatically lowered if American Shale improves the ratio of the value of its proved developed producing (PDP PV9) properties to its funded debt, less cash and other liquid assets, as further defined under the Morgan Stanley Credit Agreement (the Net Debt Ratio). Upon the occurrence of certain events of default, the loans will bear interest at an additional 2% per annum above the initial rate, and with respect to other events of default, may bear interest at the higher default rate. Interest is due and payable monthly in arrears. During the three and six months ended June 30, 2015, the Company recorded interest expense of $2,905,634 and $5,873,603, respectively, related to the Morgan Stanley Credit Agreement.

The initial loan was advanced as a single funding of $102.5 million plus a PIK fee of $593,750 on the Funding Date. Additional amounts up to $47.5 million may be drawn within the two year period after the Funding Date provided that the Net Debt Ratio, pro forma for such subsequent drawdowns, based on the level of PDP PV9 that is projected six months from the date of each drawdown, meets certain pre-defined targets. All principal will be due on December 31, 2018 (the Maturity Date), if not accelerated before that date (See Note 15 Subsequent Events related to the First Amendment and Waiver). Scheduled amortization of the principal amount of the loans may begin on May 1, 2015, unless the Net Debt Ratio exceeds certain defined parameters, in which case scheduled amortization may begin as late as May 1, 2016. No amortization is required if American Shale s Net Debt Ratio meets certain criteria. The minimum amortization required each month will be the greater of (i) 0.75% of the then outstanding balance (after May 1, 2016) or (ii) the amortization amount that would be required for American Shale to achieve a predetermined Net Debt Ratio within six months. Such ratios increase over time.

The principal amount of the Loans may be prepaid, but not reborrowed. If the Loans are prepaid on or prior to the first anniversary of the Funding Date, a make-whole amount will be charged equal to 4.0% of the principal balance of the Loans, plus the sum of the remaining scheduled payments of interest prior to the first anniversary of the Funding Date. Up to $25 million of prepayments from specified sources will be exempt from this provision if payments are made prior to the first anniversary of the Funding Date. If the Loans are prepaid on or after the first anniversary of the Funding Date but prior to the second anniversary of the Funding Date, a make-whole amount equal to 4.0% of the principal balance of the Loans will be charged. Prepayments between the second and third anniversary of the Funding Date will be charged 3.0% of the principal balance of the Loans.

The Morgan Stanley Credit Agreement includes certain customary affirmative covenants such as minimum hedging requirements, delivery of financial information, operation and maintenance of properties, and maintenance of books and records. Financial covenants include a maximum leverage ratio (latest twelve months EBITDA to net debt) and minimum current ratio (consolidated current assets to consolidated current liabilities). The definition of net debt includes funded debt plus accounts payable, offset by cash as well as accounts receivable. American Shale is also required to apply toward approved capital expenditures a minimum of 50% of the proceeds of any equity issuance that occurs subsequent to the first anniversary of the Funding Date.

Negative covenants include limitations on indebtedness, liens, fundamental changes, dispositions of property, payment of dividends or distributions, capital expenditures, investments and transactions with affiliates. There are also limitations on hedging transactions, creation or acquisition of subsidiaries, use of proceeds, drilling without providing title opinions, amending certain documents and appointing non-approved officers or directors.

Upon the occurrence of a change of control (as defined in the Morgan Stanley Credit Agreement), the Lenders may require American Shale to pay all of the outstanding interest, make-wholes and fees in addition to 101% of the principal amounts of the Loans under the Morgan Stanley Credit Agreement.

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On the Funding Date, American Shale also entered into a Net Profits Interest Agreement (the NPI Agreement) with the Agent. The NPI Agreement provides that subsequent to the repayment of the Loans, American Shale will pay a net profits interest to the Agent (the NPI). The NPI is to be calculated based on production revenues less certain expenditures, including operating costs, general and administrative expenses, interest and capital expenditures. The amount of interest expense and general and administrative expenses that can be charged are limited based on the amounts that were previously expensed prior to repayment of the Loans. The NPI is earned based on amounts borrowed under the Morgan Stanley Credit Agreement. As of the Funding Date, a NPI of 6.5% of the net profits, as defined under the NPI Agreement, has been earned. The Agent will earn up to an additional 2.5% of the net profits pro rata for any subsequent borrowing by American Shale under the $47.5 million contingent commitment. At June 30, 2014, the Company recorded a discount related to the NPI of $3,339,376 on proved property and $733,034 on unproved property. The total value recorded as a discount on loan payable related to the NPI is $4,072,410. For the three and six months ended June 30, 2015, the Company recorded accretion of the discount related to the NPI in the amount of $222,131 and $444,262, respectively, which is computed using the straight line method over the life of the loan.

The NPI Agreement provides the Agent with the option to sell its NPI for fair value, as defined in the NPI Agreement, alongside American Shale or Trans Energy in the event that either American Shale or Trans Energy sells interests, including partial interests, in the subject properties at a fair value for the NPI that meets or exceeds $1.5 million for each 1.0% of NPI earned by the Agent prior to such date. In such event, American Shale can also require the Agent to sell all of its NPI to American Shale (or, alternatively, to the buyer of any subject interests) for fair value. In the event of a sale of all or substantially all of the assets of American Shale, fair value is defined as the net cash received that is attributable to the equity interests of either American Shale or Trans Energy in such transaction.

On August 20 and October 3, 2014, American Shale made $5 million draws in accordance with the Morgan Stanley Credit Agreement.

On April 27, 2015, American Shale entered into a consent and agreement (the Consent and Agreement) that amended the Morgan Stanley Credit Agreement and the associated NPI agreement. The Consent and Agreement reduced the contingent borrowing availability under the Tranche B facility from $47.5 million to $10.0 million, and eliminated the Tranche C facility. Potential borrowings under the Tranche B facility had been contingent on American Shale s ability to meet certain levels of PV-9 value for its producing properties, and as such there was no additional availability under Tranche B as of the signing of the Consent and Agreement. There were no other changes to the terms of the Tranche A facility loans under the Morgan Stanley Credit Agreement. The NPI agreement was amended to set the contingent NPI percentage at approximately 2.53%.

Under the Consent and Agreement, the administrative agent also consented to the monetization of a portion of American Shale s natural gas hedges and the disposition of a portion of American Shale s working and net revenue interests in wells in Marion County, West Virginia (the Working Interests) that have been recently drilled but not completed.

On the same date, American Shale entered into an agreement with Republic Energy Operating, LLC. Under this agreement, American Shale agreed to use the proceeds from the aforementioned hedge monetization as well as the sale of the Working Interests to pay all amounts due under the March 2015 joint interest billing statement in the amount of approximately $13.8 million provided by Republic Energy Operating, LLC. American Shale reserved the option to reacquire the Working Interests pursuant to a notice of election at agreed upon prices set forth in the agreement.

In December 2014, M3 Appalachia Gathering, LLC (M3) completed a waterline to improve water supply and lower completion costs, as compared to trucking, with respect to the Company s wells on the Jones lease in Marion County, West Virginia (the Jones Pad). M3 currently gathers all production from the Jones Pad. The Company s cost of the waterline is approximately $3.1 million, which is being paid to M3 through 36 monthly payments, at an internal rate of return to M3 of 15%, of $105,730. As of the June 30, 2015, the Company had recorded a long-term asset of $3.1 million, net of depreciation of 83,498, and current and long-term note payable in the amounts of $960,256 and $1,524,649, respectively.

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The following table summarizes the components of total debt recorded on the Company s consolidated balance sheets as of June 30, 2015 and December 31, 2014:

	June 30, 2015 (unaudited)	December 31, 2014 (audited)
Morgan Stanley Credit Agreement - Morgan Stanley Tranche A and B	112,500,000	112,500,000
Morgan Stanley Credit Agreement - Morgan Stanley PIK Fee	593,750	593,750
Morgan Stanley Credit Agreement - Morgan Stanley NPI	(3,109,841)	(3,554,103)
M3 Appalachia Gathering LLC Note Payable	2,484,905	
Other loan vehicles		4,402
Total debt	$ 112,468,814	$ 109,544,049

The debt balances under the Credit Agreements are presented as a long-term liabilities on the Company s balance sheet as of June 30, 2015 and December 31, 2014. As of September 30, 2014, the Company previously presented the debt balance as current due to an uncertainty of whether the Agent of the Credit Agreement believed the Company was in technical default of the current ratio covenant (greater than 1:1) thereunder due to the deferred gain liability recorded as of such date. Although non-cash in nature, the deferred gain recorded as a current liability as of September 30, 2014 resulted in a less than 1:1 current ratio and was not explicitly excluded from the covenant calculation within the Credit Agreement. The Company has also confirmed that the Credit Agreement provides for the inclusion of the $47.5 million contingent committed tranche as a current asset when calculating the current ratio defined therein, provided that the Company is not in violation of any other covenants. As such the Company was not in default under the Credit Agreement as of September 30, 2014 or December 31, 2014. The deferred gain proceeds were reclassified to a gain on sale in December 2014 due to the expiration of the Company s repurchase option under the Republic PSA. As of June 30, 2015 the Company s current ratio was less than 1:1; however, the Company has been granted a waiver of default by the lender, and at December 31, 2014, the Company s current ratio exceeds 1:1 and, thus, is not in default under the Credit Agreement. See Note 15 Subsequent Events related to the First Amendment and Waiver.

NOTE 9 DERIVATIVE AND HEDGING FINANCIAL INSTRUMENTS

On May 9, 2013, American Shale entered into costless collars (BP Hedge) covering approximately 85% of its expected natural gas production from wells that were considered proved developed producing (PDP) as of that date. Neither oil nor natural gas liquids have been hedged, but the BTU associated with our ethane production was essentially hedged, since it is sold as part of the natural gas stream. The costless collars consist of long put options (floor) with a strike price of $4.00 per MMBtu and offsetting short calls (ceiling) with a strike price of $4.28 per MMBtu. The aforementioned volumes are hedged beginning with the June 2013 contract and ending with the April 2015 contract. A total of 3.4 MMBtu were hedged over this period, with monthly volumes declining from a high of approximately 207,000 MMBtu in June 2013 to 113,000 MMBtu in April 2015. The contract period of this BP Hedge was completed in April 2015. The fair value of these commodity contracts was $0 and $410,389 at June 30, 2015 and December 31, 2014, respectively.

On May 21, 2014 American Shale, entered into fixed price hedges (Morgan Stanley Fixed I), which, when combined with existing hedges covered approximately 90% of its expected natural gas production from PDP wells as of that date. Neither oil nor natural gas liquids have been hedged, but the BTU associated with our ethane production was essentially hedged, since it is sold as part of the natural gas stream. The hedges consist of swaps with strike prices ranging between $4.38 per MMBtu to $4.06 per MMBtu. The hedges begin with the June 2014 contract and end with the December 2018 contract. A total of 13,932,171 MMBtu are hedged over this period, with monthly volumes declining from a high of 444,534 MMBtu in July 2014 to 171,940 MMBtu in November 2018. Under the April 27, 2015 Consent and Agreement, related to the Morgan Stanley Credit Agreement, the administrative agent also consented to the monetization of a portion of American Shale s natural gas hedges. The hedge was monetized in April 2015 for the hedges volumes in years 2016 through 2018 by resetting the strike price from $4.11 to the current market price of $3.27. The fair value of these commodity contracts was $2,315,865 and $5,878,302 at June 30, 2015 and December 31, 2014, respectively.

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On August 20, 2014 American Shale, entered into fixed price hedges (Morgan Stanley Fixed II), which, when combined with existing hedges, covered approximately 90% of its expected natural gas production from PDP wells as of that date. Neither oil nor natural gas liquids have been hedged, but the BTU associated with our ethane production was essentially hedged, since it is sold as part of the natural gas stream. The hedges consist of swaps with a fixed strike price of $3.92 per MMBtu. The hedges begin with the September 2014 contract and end with the December 2018 contract. A total of 10,499,038 MMBtu are hedged over this period, with monthly volumes declining from a high of 326,700 MMBtu in January 2015 to 45,854 MMBtu in November 2018. Under the April 27, 2015 Consent and Agreement, related to the Morgan Stanley Credit Agreement, the administrative agent also consented to the monetization of a portion of American Shale s natural gas hedges. The hedge was monetized in April 2015 for the hedges volumes in years 2016 through 2018 by resetting the strike price from $3.92 to the current market price of $3.27. The fair value of these commodity contracts was $901,834 and $1,941,465 at June 30, 2015 and December 31, 2014, respectively.

The fair value of the Fixed I and Fixed II commodity contracts for the hedges volumes in years 2016 through 2018 in total was $(125,768) at June 30, 2015.

On December 23, 2014 American Shale, entered into Basis Swap fixed price hedges (Morgan Stanley Fixed III) covering approximately 50% of its expected natural gas production from PDP wells as of December 23, 2014. Neither oil nor natural gas liquids have been hedged, but the BTU associated with our ethane production was essentially hedged, since it is sold as part of the natural gas stream. The hedges consist of swaps with a fixed strike price of $(1.12) per MMBtu. The hedges begin with the December 2014 contract and end with the December 2018 contract. A total of 7,301,209 MMBtu are hedged over this period, with monthly volumes declining from a high of 266,891 MMBtu in December 2014 to 104,084 MMBtu in November 2018. The fair value of these commodity contracts was $(859,439) and $(716,488) at June 30, 2015 and December 31, 2014, respectively.

The Company has a master netting agreement on the gas hedge and therefore the current asset and liability are netted on the condensed consolidated balance sheet and the non-current asset and liability are netted on the condensed consolidated balance sheet.

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. The Company has netting arrangements with BP Energy Company that provide for offsetting payables against receivables from separate derivative instruments.

The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place as of June 30, 2015 following the monetization of hedges that took place in April 2015:

Contract Period Of Morgan Stanley Fixed I	Volumes (MMBtu)	Weighted-Average Fixed Price (per MMBtu)
2015	1,857,538	$ 4.11
2016	3,002,489	$ 3.27
2017	2,495,153	$ 3.27
2018	1,995,696	$ 3.27
All gas hedges*	9,350,876	

* Gas hedges are comprised of IF Henry Hub (100%).

Contract Period Of Morgan Stanley Fixed II	Volumes (MMBtu)	Weighted-Average Fixed Price (per MMBtu)
2015	844,368	$ 3.92
2016	992,431	$ 3.27
2017	771,407	$ 3.27
2018	603,458	$ 3.27
All gas hedges*	3,211,664	

* Gas hedges are comprised of IF Henry Hub (100%).

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Contract Period Of Morgan Stanley Fixed III	Volumes (MMBtu)	Basis Swap Fixed Price (per MMBtu)
2015	1,333,640	$ (1.12)
2016	1,842,098	$ (1.12)
2017	1,518,648	$ (1.12)
2018	1,209,491	$ (1.12)
All gas hedges*	5,903,877	

* Gas hedges are comprised of IF Henry Hub (100%).

The following tables detail the fair value of derivatives recorded in the accompanying balance sheets, by category:

	As of June 30, 2015			
	Derivative Assets		**Derivative Liabilities**	
	Balance Sheet Classification	**Fair Value**	**Balance Sheet Classification**	**Fair Value**
Commodity derivative	Current assets	$ 3,577,996	Current liabilities	$
Commodity derivative	Noncurrent assets		Noncurrent liabilities	1,345,504
		$ 3,577,996		$ 1,345,504

	As of December 31, 2014			
	Derivative Assets		**Derivative Liabilities**	
	Balance Sheet Classification	**Fair Value**	**Balance Sheet Classification**	**Fair Value**
Commodity derivative	Current assets	$ 5,420,309	Current liabilities	$
Commodity derivative	Noncurrent assets	2,809,847	Noncurrent liabilities	716,488
		$ 8,230,156		$ 716,488

The table below summarizes the realized and unrealized gains and losses related to our derivative instruments for the three and six months ended June 30, 2015 and 2014.

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2015	**2014**	**2015**	**2014**
	$ 10,099,261	$ (189,506)	$ 12,129,437	$ (450,047)

Realized gains (loss) on commodity derivative				
Change in fair value of commodity derivative	(10,626,181)	(2,269,930)	(5,281,176)	(2,575,581)
Total realized and unrealized gains recorded	$ (526,920)	$ (2,459,436)	$ 6,848,261	$ (3,025,628)

These realized and unrealized gains and losses are recorded in the accompanying unaudited condensed consolidated statements of operations as derivative gains (losses).

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NOTE 10 FAIR VALUE MEASUREMENTS

The authoritative guidance establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company s assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices are available in active markets for identical assets or liabilities;

Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability; or

Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flows models or valuations.

The financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The Company s policy is to recognize transfers in and/or out of fair value hierarchy as of the end of the reporting period for which the event or change in circumstances caused the transfer. The valuation policies are determined by the Treasurer and are approved by the President. Fair value measurements are discussed with the Company s audit committee, as deemed appropriate. Each quarter, the inputs used in the fair value calculations are updated and management reviews the changes from period to period for reasonableness. The Company has consistently applied the valuation techniques discussed below in all periods presented.

The following table presents the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2015 and December 31, 2014 by level within the fair value hierarchy

	Level 1	Level 2	Level 3	Total
June 30, 2015				
ASSETS:				
Commodity contracts		$ 3,577,996		$ 3,577,996
LIABILITIES:				
Commodity contracts		$ 1,345,504		$ 1,345,504
December 31, 2014				
ASSETS:				
Commodity contracts		$ 8,230,156		$ 8,230,156
LIABILITIES:				
Commodity contracts		$ 716,488		$ 716,488

We use Level 2 inputs to measure the fair value of gas commodity collar derivatives. Level 2 assets consist of commodity derivative assets and liabilities (See Note 9 - Derivative and Hedging Financial Instruments). The fair value of the commodity derivative assets and liabilities are estimated by the Company using income valuation techniques utilizing the income approach and an option pricing model, which take into account notional quantities, market volatility, market prices, contract parameters, counterparty credit risk and discount rates based on published LIBOR rates. The Company validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to the Company s commodity derivatives.

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NOTE 11 STOCKHOLDERS EQUITY

In April 2015, Trans Energy issued 150,000 shares of common stock to Gordian Group, LLC, for fees related to services rendered at a price of $1.80 per share.

In February 2015, Trans Energy issued 100,000 shares of common stock to John G. Corp, President, for the 2014 Performance Payment at a price of $2.10 per share.

In February 2015, Trans Energy issued 100,000 shares of common stock to Stephen P. Lucado, Chairman of the Board, for the 2014 Performance Payment at a price of $2.10 per share.

In January, 2015, Trans Energy issued 109,005 shares of common stock to William F. Woodburn, a related party, for the exercise of options at a price of $1.50 per share.

In January, 2015, Trans Energy issued 109,005 shares of common stock to Loren E. Bagley, a related party, for the exercise of options at a price of $1.50 per share.

In December 2014, we issued 142,857 shares of common stock to Mark D. Woodburn, a related party, for the exercise of options at a price of $0.80 per share.

In August 2014, Trans Energy issued 400,000 shares of common stock to William F. Woodburn, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, Trans Energy issued 190,000 shares of common stock to Loren E. Bagley, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, Trans Energy issued 75,000 shares of common stock to Mark D. Woodburn, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, Trans Energy issued 10,000 shares of common stock to Brett Greene, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, Trans Energy issued 20,998 shares of common stock to Jordan Corp, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, Trans Energy issued 62,963 shares of common stock to John G. Corp, a related party, for the exercise of options at a price of $0.65 per share.

In July 2014, we granted 27,000 shares of stock to three employees under the long-term incentive bonus program. The 27,000 shares are not performance based and vest semi-annually over a three year period. The 27,000 shares were valued at $3.90 per share of common stock using the fair value of the common stock at the date of grant and the fair value will be amortized to compensation expense semi-annually over three years.

In April 2014, we granted 21,000 shares of stock to three employees under the long-term incentive bonus program. The 21,000 shares are not performance based and vest semi-annually over a three year period. The 21,000 shares were valued at $3.80 per share of common stock using the fair value of the common stock at the date of grant and the fair value will be amortized to compensation expense semi-annually over three years.

In April 2014, we also granted 252,000 common stock options to six employees and five outside board members. These options vest semi-annually over three years and have a five year term. These stock options were granted at an exercise price of $3.80 per common share and the fair value was determined using the Black Scholes option pricing model. The options are being amortized to share-based compensation expense semi-annually over the vesting period.

In January 2014, Trans Energy issued 25,000 shares of common stock to Jonathan J. Corp, a related party, for the exercise of options at a price of $0.65 per share.

In January 2014, Trans Energy issued 138,331 shares of common stock to Clarence E. Smith, a 5% beneficial owner, for the exercise of options at a price of $1.50 per share.

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The Company has computed the fair value of all options granted using the Black-Scholes option pricing model. In order to calculate the fair value of the options, certain assumptions are made regarding components of the model, including the estimated fair value of the underlying common stock, risk-free interest rate, volatility, expected dividend yield and expected option life. Changes to the assumptions could cause significant adjustments to valuation. The Company estimated a volatility factor utilizing a weighted average of comparable published volatilities of peer companies. The Company has estimated a forfeiture rate of zero as the effect of forfeitures has not been significant and the small number of option holders does not provide a reasonable basis for prediction. The Company estimates the expected term based on the average of the vesting term and the contractual term of the options. The risk-free interest rate is based on the U.S. Treasury yield in effect at the time of the grant for treasury securities of similar maturity. The fair value of all options granted during the three and six months ending June 30, 2015 was determined using the following assumptions:

Expected volatility	70% - 90%
Risk free interest rate	0.80% - 1.75%
Expected term (years)	3.0 - 5.0
Dividend yield	0%

As a result of the above stock and option transactions, we recorded total stock-based compensation of $136,225 and, $284,675 for the three months ended June 30, 2015 and 2014, respectively and, $692,003 and $483,216 for the six months ended June 30, 2015 and 2014, respectively.

Stock option activity is as follows:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Fair Value
Outstanding December 31, 2013	4,045,324	$ 1.85	2.05 Years	$ 7,483,849
Granted	252,000	$ 3.80		
Exercised	(1,138,331)	$ 0.78		
Forfeited	(14,000)	$ 2.43		
Expired				
Outstanding December 31, 2014	3,144,993	$ 2.39	1.48 Years	$ 7,516,533
Granted				
Exercised	(218,010)	$ 1.50		
Forfeited				
Expired				
Outstanding June 30, 2015	2,926,983	$ 2.45	.75 Years	$ 7,171,108
Exercisable at June 30, 2015	2,724,650	$ 2.39		$ 6,511,914
Unvested at June 30, 2015	202,333			

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NOTE 12 EARNINGS PER SHARE

Basic net income (loss) per share is computed by dividing net income (loss) by the weighted-average number of common shares outstanding during the reporting period. The shares of restricted common stock granted to certain officers and employees of the Company are included in the computation of basic net income (loss) per share only after the shares become fully vested. Diluted net income (loss) per share of common stock includes both vested and unvested shares of restricted stock. Diluted net income (loss) per common share of stock is computed by dividing net income by the diluted weighted-average common shares outstanding. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share. As the Company had losses for the three and six month periods ended June 30, 2015 and 2014, the potentially dilutive shares were anti-dilutive and were thus not included in the net loss per share calculation.

As of June 30 2015, potentially dilutive securities included (i) 34,000 unvested shares of restricted common stock and (ii) 446,983 in-the-money outstanding options.

NOTE 13 BUSINESS SEGMENTS

Our principal operations consist of exploration and production through Trans Energy, American Shale and Prima, and pipeline transmission with Ritchie County Gathering Systems and Tyler Construction Company.

Certain financial information concerning our operations in different segments is as follows:

	For the Three Months Ended June 30	Exploration and Production	Pipeline Transmission	Corporate	Total
Revenue	2015	$ 3,620,627	$ 41,173	$ 4,137	$ 3,665,937
	2014	8,432,592	22,830	1,303	8,456,725
(Loss) income from operations	2015	(3,110,429)	22,557	(1,820,220)	(4,908,092)
	2014	2,744,344	(27,472)	(1,533,174)	1,183,698
Interest expense	2015	3,046,382		1,361	3,047,743
	2014	9,673,862		896	9,674,758
Depreciation, depletion, amortization and accretion	2015	2,568,920	250	19,457	2,588,627
	2014	2,248,720	250		2,248,970
Property and equipment acquisitions, including oil and gas properties	2015	(6,914,445)		2,929	(6,911,516)
	2014	14,021,282		2,087	14,023,369

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	For the Six Months Ended June 30	Exploration and Production	Pipeline Transmission	Corporate	Total
Revenue	2015	$ 8,005,664	$ 83,889	$ 5,914	$ 8,095,467
	2014	18,149,015	77,619	6,433	18,233,067
Income (Loss) from operations	2015	(3,532,005)	52,137	(3,019,540)	(6,499,408)
	2014	7,298,948	28,855	(2,975,862)	4,351,941
Interest expense	2015	6,161,740		1,740	6,163,480
	2014	13,801,363		4,588	13,805,951
Depreciation, depletion, amortization and accretion	2015	4,351,233	500	39,724	4,391,457
	2014	4,360,089	606		4,360,695
Property and equipment acquisitions, including oil and gas properties	2015	193,597		5,168	198,765
	2014	16,008,089		2,087	16,010,176
Total assets, net of intercompany accounts:					
June 30, 2015		103,379,424	13,058		103,392,482
December 31, 2014		111,755,587	13,558		111,769,145

Property and equipment acquisitions include accrued amounts and reclassifications.

NOTE 14 RELATED PARTY TRANSACTIONS

In November 2013, Clarence E. Smith, a 5% Beneficial Owner, issued payment to the Company in the amount of $200,000. Mr. Smith was exercising 138,331 options at a price of $1.50 per share. On January 24, 2014, Mr. Smith s stock was issued. The Company recognized interest expense since the funds were held approximately three months before the stock was actually issued. At December 31, 2013, the $205,314 due to Mr. Smith is recorded as a note payable, related party in the current liability section of the balance sheet.

During 2015 and 2014, the Company has conducted business with two companies owned by Clarence E. Smith. Work was awarded the companies after bids were sought and reviewed. The amount of payments total $70,000 and $32,000 for 2015 and 2014, respectively.

In May 2015, the Company engaged Opportune LLP, a consulting firm specializing in assisting clients across the energy industry, to perform reporting functions for which the company did not have the staff to complete in the prescribed timeframes. Josh L. Sherman, a member of our board of directors and chairman of our Audit Committee, is a partner in Opportune, LLP. As a result of our engagement of Opportune, LLP, Mr. Sherman will no longer be considered an independent director. The amount of payments total $98,295 and $0 for 2015 and 2014 respectively.

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NOTE 15 SUBSEQUENT EVENTS

On July 31, 2015, American Shale entered into an amendment and waiver (the ***First Amendment and Waiver***) that amended the Morgan Stanley Credit Agreement and the associated NPI agreement. Under the terms of the First Amendment and Waiver, the parties agreed to:

Increase the Applicable Margin to 12% in the event that interest is paid in cash, and 14% if paid in kind (which represents a change in the 9% Applicable Margin currently payable in cash);

Change the Maturity Date to December 31, 2016;

Remove the Leverage Ratio covenant;

Add a covenant requiring the PV-9 of the Borrower s proved reserves to be greater than 1.5 times the net debt, with a minimum PDP component of proved reserves that increases over time;

Eliminate the make-whole premium and any other prepayment penalties related to debt paydowns;

Require the Borrower to limit its capital expenditures and other monthly expenditures to amounts agreed upon in the First Amendment and Waiver;

Require the Borrower to close the sale of assets in Wetzel County and pay down at least $30 million of debt by September 30, 2015;

Allow the Borrower to use the next $17 million of proceeds from the Wetzel County sale, plus 50% of any proceeds thereafter, primarily for expenditures in connection with an approved plan of development;

Begin a process to refinance the debt facility, or otherwise effect its paydown through a sale of assets, during the first quarter of 2016;

Defer any payment related to the NPI on the Wetzel County assets until the loans are repaid in full;

Increase the NPI on the assets remaining after the Wetzel County sale by 2%, to approximately 11%;

Pay total fees to the administrative agent of $4 million, of which $1 million was added to the loan balance upon execution of the First Amendment and Waiver. The remainder is to be added to the loan balance upon the closing of the sale of the Wetzel County assets.

On April 3, 2015, Trans Energy, Inc. (the Company), and its wholly owned subsidiaries American Shale Development, Inc. and Prima Oil Company, Inc., along with Republic Energy Ventures, LLC, Republic Partners VIII, LLC, Republic Partners VI, LP, Republic Partners VII, LLC, and Republic Energy Operating, LLC (collectively, the Sellers) entered into a Purchase and Sale Agreement (the PSA), pursuant to which the Sellers agreed to sell certain interests located in Wetzel County, West Virginia, including 5,159 net acres held by the Company and the Company s interest in twelve Marcellus producing wellbores, to TH Exploration, LLC (Buyer). On July 30, 2015, the Buyer elected to formally extend the expiration date of the PSA until August 14, 2015 (the Extension Period). During the Extension Period, the Buyer provided notice to the Company that the PSA would terminate on August 13, 2015. The Company believes that the PSA terminated as a result of such notice. No assets were sold under the PSA.

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

The following discussion will assist in the understanding of our financial position and results of operations. The information below should be read in conjunction with the consolidated financial statements, the related notes to consolidated financial statements and our 2014 Form 10-K. Our discussion contains both historical and forward-looking information. We assess the risks and uncertainties about our business, long-term strategy and financial condition before we make any forward-looking statements but we cannot guarantee that our assessment is accurate or that our goals and projections can or will be met. Statements concerning results of future exploration, development and acquisition expenditures as well as revenue, expense and reserve levels are forward-looking statements. We make assumptions about commodity prices, drilling results, production costs, administrative expenses and interest costs that we believe are reasonable based on currently available information. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control.

We intend to focus our development and exploration efforts in our Marcellus properties and utilize our acreage position to expand our reserve base through continued exploratory and development drilling in the Marcellus Shale for 2015 and beyond. We will evaluate our properties on a continuous basis in order to optimize our existing asset base. We plan to employ the latest drilling, completion, and fracturing technology in all of our wells to enhance recoverability and accelerate cash flows associated with these wells. We believe that our extensive acreage position will allow us to grow through high risk drilling in the near term.

In summary, our strategy is to increase our oil and gas reserves and production while keeping our development costs and operating costs as low as possible. We will implement this strategy through drilling exploratory and development wells from our inventory of available prospects that we have evaluated for geologic and mechanical risk and future reserve or resource potential. The success of this strategy is contingent on various risk factors, as discussed in our 2014 Form 10-K.

Results of Operations

Three months ended June 30, 2015 compared to June 30, 2014

The following table sets forth the relationship of total revenues of principal items contained in our Unaudited Condensed Consolidated Statements of Operations for the three months ended June 30, 2015 and 2014.

	Three months ended June 30,	
	2015	**2014**
Total revenues	$ 3,665,937	$ 8,456,725
Total costs and expenses	(8,574,029)	(7,272,729)
Loss on sale of assets		(298)
(Loss) income from operations	(4,908,092)	1,183,698
Other expenses, net	(3,574,123)	(12,133,609)
Income tax		

Net loss	$ (8,482,215)	$ (10,949,911)

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The following table is a summary of revenues, volumes, and pricing for the three months ended June 30, 2015 and 2014.

Three Months Ended June 30, 2015 compared to the Three Months Ended June 30, 2014

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Increase/ (Decrease)	
Natural gas sales	$ 3,389,404	$ 7,826,661	$ (4,437,257)	-56.7%
Oil sales	$ 23,276	$ 66,789	$ (43,513)	-65.1%
Natural gas liquid sales	$ 207,947	$ 539,142	$ (331,195)	-61.4%
Total Oil & Gas Sales	$ 3,620,627	$ 8,432,592	$ (4,811,965)	-57.1%
Transportation and other revenue	$ 45,310	$ 24,133	$ 21,177	87.8%
Total revenue	$ 3,665,937	$ 8,456,725	$ (4,790,788)	-56.7%
Net Production				
Natural gas sales (MCF)	2,157,218	1,644,606	512,612	31.2%
Oil sales (Bbls)	473	827	(354)	-42.8%
Natural gas liquids (gallons)	1,442,261	621,205	821,056	132.2%
Natural Gas Equivalent (MCFe)	2,366,091	1,738,315	627,776	36.1%
Average Sales Price per Unit				
Natural Gas (MCF)	$ 1.57	$ 4.76	$ (3.19)	-67.0%
Oil (Bbl)	$ 49.25	$ 80.71	$ (31.46)	-39.0%
Natural gas liquids (gallons)	$ .14	$ .87	$ (0.73)	-83.9%
Natural Gas Equivalent (MCFe)	$ 1.53	$ 4.85	$ (3.32)	-68.5%

Expenses

All data presented below is derived from costs and production volumes for the relevant period indicated.

	Three Months Ended June 30, 2015	**Three Months Ended June 30, 2014**
Costs and expenses of production:		
Production expenses	$ 3,800,257	$ 2,799,303
Production taxes	340,521	689,979
G&A expenses (excluding share-based compensation)	1,708,398	1,302,612
Non-cash shared-based compensation	136,226	231,865
Depletion of oil and natural gas properties	2,535,317	2,222,498
Depreciation and amortization	51,188	25,571
Accretion of discount on asset retirement obligation	2,122	901
Costs and expenses per MCFE of production:		
Production expenses	1.61	1.64
Production taxes	0.14	0.40

G&A expenses (excluding share-based compensation)	0.72	2.51
Non-cash shared-based compensation	0.06	0.13
Depletion of oil and natural gas properties	1.07	1.24
Depreciation and amortization	0.02	0.01
Accretion of discount on asset retirement obligation		

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Total revenues decreased primarily due to a decrease in natural gas, natural gas liquid (NGL), and oil prices. The increase in natural gas, natural gas liquid (NGL) and oil volumes was the result of recently drilled wells put into production. For the three months ended June 30, 2015 and 2014, respectively, we had 38 gross wells and 15.84 net wells compared to 28 gross wells and 11.46 net wells.

Production costs increased $651,496 or 18.7% for the three months ended June 30, 2015 as compared to the same period for 2014, primarily due to an increase in natural gas liquid transportation and processing fees associated with the increased production in 2015.

Depreciation, depletion, amortization and accretion expense increased by $339,657 or 15.1% for the three months ended June 30, 2015 compared to the same period for 2014, primarily due to the increased production volumes and depreciation of additional assets.

Selling, general and administrative expense increased $310,147 or 20.2% for the three months ended June 30, 2015 as compared to the same period for 2014, primarily due to an increase in legal and professional fees.

Interest expense decreased $6,627,015 or 68.5% for the three months ended June 30, 2015 as compared to the same period for 2014 primarily due to an additional $4,074,788 amortization of debt discount and additional interest and termination fees of $2,977,519 included in the June 30, 2014 interest expense balance, which was eliminated with the Morgan Stanley refinancing. Stated interest rate was 10% for both periods. For the three months ended June 30, 2015 the average loan balance was $113,093,750 compared to $93,113,567 for the same period in 2014.

Loss on commodity derivative for the three months ended June 30, 2015 was $526,920 as compared to a loss of $2,459,436 for the same period of 2014. This represents the increase in the fair value of the gas hedges.

Net loss for the three months ended June 30, 2015 was $8,482,215 compared to a net loss of $10,949,911 for the same period of 2014. This decrease in net loss is due primarily to a decrease in both interest expense and loss on commodity derivatives.

Six months ended June 30, 2015 compared to June 30, 2014

The following table sets forth the relationship of total revenues of principal items contained in our Unaudited Condensed Consolidated Statements of Operations for the six months ended June 30, 2015 and 2014.

	Six months ended June 30,	
	2015	**2014**
Total revenues	$ 8,095,467	$ 18,233,067
Total costs and expenses	(14,594,875)	(14,088,223)
Gain on sale of assets		207,097
(Loss) income from operations	(6,499,408)	4,351,941
Other expenses, net	685,862	(16,830,085)
Income tax		

Net loss	$ (5,813,546)	$ (12,478,144)

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The following table is a summary of revenues, volumes, and pricing for the six months ended June 30, 2015 and 2014.

Six Months Ended June 30, 2015 compared to the Six Months Ended June 30, 2014

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	Increase/ (Decrease)	
Natural gas sales	$ 6,848,628	$ 15,764,426	$ (8,915,798)	-56.6%
Oil sales	$ 27,261	$ 128,091	$ (100,830)	-78.7%
Natural gas liquid sales	$ 1,129,775	$ 2,256,498	$ (1,126,723)	-49.9%
Total Oil & Gas Sales	$ 8,005,664	$ 18,149,015	$ (10,143,351)	-55.9%
Transportation and other revenue	$ 89,803	$ 84,052	$ 5,751	6.8%
Total revenue	$ 8,095,467	$ 18,233,067	$ (10,137,600)	-55.6%
Net Production				
Natural gas sales (MCF)	3,837,738	3,088,910	748,828	24.2%
Oil sales (Bbls)	602	1615	(1,013)	-62.7%
Natural gas liquids (gallons)	3,191,358	2,088,396	1,102,962	52.8%
Natural Gas Equivalent (MCFe)	4,297,261	3,396,944	900,317	26.5%
Average Sales Price per Unit				
Natural Gas (MCF)	$ 1.78	$ 5.10	$ (3.32)	-65.1%
Oil (Bbl)	$ 45.25	$ 79.30	$ (34.05)	-42.9%
Natural gas liquids (gallons)	$ 0.35	$ 1.08	$ (0.73)	-67.6%
Natural Gas Equivalent (MCFe)	$ 1.86	$ 5.34	$ (3.48)	-65.2%

Expenses

All data presented below is derived from costs and production volumes for the relevant period indicated.

	Six Months Ended June 30, 2015	**Six Months Ended June 30, 2014**
Costs and expenses of production:		
Production expenses	$ 6,466,966	$ 5,695,737
Production taxes	710,998	1,049,495
G&A expenses (excluding share-based compensation)	2,753,450	2,551,890
Non-cash shared-based compensation	272,004	430,406
Depletion of oil and natural gas properties	4,264,189	4,314,865
Depreciation and amortization	124,173	44,084
Accretion of discount on asset retirement obligation	3,095	1,746
Costs and expenses per MCFE of production:		
Production expenses	1.50	1.68
Production taxes	0.17	0.31
G&A expenses (excluding share-based compensation)	0.64	1.65

Non-cash shared-based compensation	0.99	0.13
Depletion of oil and natural gas properties	1.07	1.25
Depreciation and amortization	0.03	0.01
Accretion of discount on asset retirement obligation		

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Total revenues decreased primarily due to a decrease in natural gas, natural gas liquid (NGL), and oil prices. The increase in natural gas, natural gas liquid (NGL) and oil volumes was the result of recently drilled wells put into production. For the six months ended June 30, 2015 and 2014, respectively, we had 38 gross wells and 15.84 net wells compared to 28 gross wells and 11.46 net wells.

Production costs increased $432,732 or 6.4% for the six months ended June 30, 2015 as compared to the same period for 2014, primarily due to an increase in natural gas liquid transportation and processing fees associated with the increased production in 2015.

Depreciation, depletion, amortization and accretion expense increase by $30,672 or 0.7% for the six months ended June 30, 2015 compared to the same period for 2014, primarily due to the increased production volumes and depreciation of additional assets.

Selling, general and administrative expense increased $43,158 or 1.4% for the six months ended June 30, 2015 as compared to the same period for 2013, primarily due to an increase in legal and professional fees.

Interest expense decreased $7,642,471 or 55.4% for the six months ended June 30, 2015 as compared to the same period for 2014 primarily due to an additional $4,074,788 amortization of debt discount and additional interest and termination fees of $2,977,519 included in the June 30, 2014 interest expense balance, which was eliminated with the Morgan Stanley refinancing. Stated interest rate was 10% for both periods. For the six months ended June 30, 2015 the average loan balance was $113,093,750 compared to $90,352,327 for the same period in 2014.

Gain on commodity derivative for the six months ended June 30, 2015 was $6,848,261 as compared to a loss of $3,025,628 for the same period of 2014. This represents the increase in the fair value of our gas hedges.

Net loss for the six months ended June 30, 2015 was $5,813,546 compared to a net loss of $12,478,144 for the same period of 2014. This decrease in net loss is due primarily to net of a decrease in operating revenue and the combined decrease in interest expense and gain on commodity derivatives.

Liquidity and Capital Resources

Historically, we have satisfied our working capital needs with borrowed funds and the proceeds of acreage sales. At June 30, 2015, we had positive working capital of $419,660 compared to negative working capital of $4,211,011 at December 31, 2014. The increase in working capital is primarily due to an increase in accounts receivable trade and a decrease in accounts payable to drilling operator.

During the first six months of 2015, net cash used by operating activities was $3,195,454 compared to $1,309,255 of net cash used for the same period of 2014. This decrease in cash flow from operations was primarily due to an increase in accounts receivable trade and gains on commodity derivatives which were offset by a decrease in prepaid expenses and a decrease in accounts payable to drilling operator.

Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices, or changes in working capital accounts and actual well performance. In addition, our oil and gas production may be curtailed due to factors beyond our control, such as downstream activities on major pipelines causing us to shut-in production for various lengths of time.

During the first six months of 2015, net cash used by investing activities was $198,765 compared to net cash used of $750,633 in the same period in 2014. The change was due to higher capital expenditures in 2014 that were offset by greater proceeds from the sale of assets in 2014.

During the first six months of 2015, net cash provided by financing activities was $2,807,519 compared to net cash provided of $319,126 for the same period in 2014. This change was primarily due to an increase in debt to M3 Appalachia Gathering LLC and an increase in stock issuances in 2015.

We anticipate meeting our working capital needs with revenues from our ongoing operations, particularly from our wells in Marshall, Marion, and Wetzel counties in West Virginia, and additional borrowings. There can be no assurance, however, that these sources of financing will be sufficient to provide our continuing working capital needs.

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Critical accounting policies

We consider accounting policies related to our estimates of proved reserves, accounting for derivatives, share-based payments, accounting for oil and natural gas properties, asset retirement obligations and accounting for income taxes as critical accounting policies. The policies include significant estimates made by management using information available at the time the estimates are made. However, these estimates could change materially if different information or assumptions were used. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2014.

Forward-looking and Cautionary Statements

This report includes forward-looking statements. These forward-looking statements may relate to such matters as anticipated financial performance, future revenues or earnings, business prospects, projected ventures, new products and services, anticipated market performance and similar matters. When used in this report, the words may, will, expect, anticipate, continue, estimate, project, intend, and similar expressions are intended to identify forward statements regarding events, conditions, and financial trends that may affect our future plans of operations, business strategy, operating results, and our future plans of operations, business strategy, operating results, and financial position. We caution readers that a variety of factors could cause our actual results to differ materially from the anticipated results or other matters expressed in forward-looking statements. These risks and uncertainties, many of which are beyond our control, include:

- the sufficiency of existing capital resources and our ability to raise additional capital to fund cash requirements for future operations;
- uncertainties involved in the rate of growth of our business and acceptance of any products or services;
- success of our drilling activities;
- volatility of the stock market, particularly within the energy sector;
- the risk factors described elsewhere herein; and
- general economic conditions.

Although we believe the expectations reflected in these forward-looking statements are reasonable, such expectations cannot guarantee future results, levels of activity, performance or achievements.

Item 4. Controls and Procedures

We maintain disclosure controls and procedures that are designed to be effective in providing reasonable assurance that information required to be disclosed in our reports under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the U.S. Securities and

Exchange Commission (SEC), and that such information is accumulated and communicated to our management to allow timely decisions regarding required disclosure.

In designing and evaluating disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute assurance of achieving the desired objectives. Also, the design of a control system must reflect the fact that there are resource constraints and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. The design of any system of controls is based, in part, upon certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of 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) of the Exchange Act. Based on the assessment, our management has concluded that our internal control over financial reporting was ineffective as of June 30, 2015 due to insufficient financial reporting resources. The results of management s assessment were reviewed with our Board of Directors. To remediate these issues, our management has retained the services of additional third party consulting personnel and will modify existing internal controls in a manner designed to ensure compliance.

In order to support our disclosure controls and procedures, we have engaged Opportune, LLP to provide certain services to the Company. Josh L. Sherman, a member of our board of directors and chairman of our Audit Committee, is a partner in Opportune, LLP. As a result of our engagement of Opportune, LLP, Mr. Sherman will no longer be considered an independent director.

During the period ended, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II

Item 1. Legal Proceedings

We may be engaged in various lawsuits and claims, either as plaintiff or defendant, in the normal course of business. In the opinion of management, based upon advice of counsel, the ultimate outcome of these lawsuits will not have a material impact on our financial position or results of operations.

Certain material pending legal proceedings to which we are a party or to which any of our property is subject, is set forth below:

EQT Corporation

On May 11, 2011, we filed an action in the U.S. District Court for the Northern District of West Virginia against EQT Corporation, a Pennsylvania corporation (Trans Energy, Inc., et al. v. EQT Corporation). The action relates to our attempt to quiet title to certain oil and gas properties referred to as the Blackshere Lease, consisting of approximately 22 oil and/or gas wells on the Blackshere Lease. On November 26, 2012, the Court granted our motion for summary judgment and on February 25, 2014, the United States Court of Appeals for the Fourth Circuit in Richmond Virginia affirmed the summary judgment. The defendant s time to appeal this judgment has passed, so this judgment in our favor is final.

On June 12, 2013, EQT Production Company filed a quiet title action in the Circuit Court of Wetzel County, West Virginia. The action relates to a quiet title action relating to a 1,314 acre lease in Wetzel County, West Virginia known as the Robinson lease. On February 28, 2014, the presiding Judge issued an order granting a motion to stay this case pending appeal of the Blackshere case and the same styled case pending in the U.S. District Court of the Northern District of West Virginia.

On July 18, 2013, we filed an action in the U.S. District Court for the Northern District of West Virginia against EQT Production Company. The action relates to a quiet title action relating to a 1,314 acre lease known as the Robinson lease.

Abcouwer

On March 6, 2012, James K. Abcouwer (Abcouwer), former Chief Executive Officer of the Company, filed an action in the Circuit Court of Kanawha County, West Virginia against the Company (James K. Abcouwer vs. Trans Energy, Inc.). The action relates to the Stock Option Agreement (the Agreement) entered into between the Company and Abcouwer on February 7, 2008. By his complaint, Abcouwer alleges that the Company has breached the Agreement by not permitting Abcouwer to exercise options that are the subject of the Agreement. The Company believes that according to the terms of the Agreement all options and other rights described in the Agreement terminated ninety (90) days after the termination of Abcouwer s employment with the Company. Mr. Abcouwer is requesting an amount for his loss of the value of the stock options that are subject to the Agreement. Said amount has not been determined. Abcouwer and the Company filed cross motions for summary judgment, which were heard by the Court in June 2014. All deadlines in the litigation have been suspended pending rulings on the motions for summary judgment.

On January 14, 2013, Abcouwer filed an action in the Circuit Court of Kanawha County, West Virginia against the Company, and two individual defendants currently on the Board of Directors of the Company William F. Woodburn and Loren E. Bagley. In his complaint, Abcouwer alleges that Plaintiff and Defendants entered into a verbal agreement that required the Company to enter into a third party sales transaction which would have allegedly caused

Abcouwer to make significant profit as the result of his ownership of Company stock. Abcouwer alleges that he lost approximately $30 million as a result of the fact that no sale of the Company ever took place. The Company believes that no such agreement existed and that Abcouwer s claims are wholly without merit. On March 25, 2013, the Company filed an answer denying the existence of any liability and asserting, in the alternative, counterclaims for fraud and breach of fiduciary duty. The Company s counterclaims allege that, to the extent a binding agreement between Abcouwer and the Company existed, Abcouwer failed to disclose such agreement to the Company and the SEC despite a duty to do so. The Company has filed a motion for summary judgment which was currently set to be heard on June 18, 2015, but still remains outstanding.

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

In April 2015, Trans Energy issued 150,000 shares of common stock to Gordian Group, LLC, for fees related to services rendered at a price of $1.80 per share.

In February 2015, Trans Energy issued 100,000 shares of common stock to John G. Corp, President, for the 2014 Performance Payment at a price of $2.10 per share.

In February 2015, Trans Energy issued 100,000 shares of common stock to Stephen P. Lucado, Chairman of the Board, for the 2014 Performance Payment at a price of $2.10 per share.

In January, 2015, Trans Energy issued 109,005 shares of common stock to William F. Woodburn, a related party, for the exercise of options at a price of $1.50 per share.

In January, 2015, Trans Energy issued 109,005 shares of common stock to Loren E. Bagley, a related party, for the exercise of options at a price of $1.50 per share.

All of the foregoing shares were issued in transactions not constituting a public offering as provided in Section 4(2 of the Securities Act of 1933.

Item 3. Defaults Upon Senior Securities

Not Applicable

Item 4. Mine Safety Disclosures

Not Applicable.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit 31.1	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit 31.2	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit 32.1	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit 32.2	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit 99.1	Purchase and Sale Agreement dated April 3, 2015

**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase
**101.DEF	XBRL Taxonomy Extension Definition Linkbase
**101.LAB	XBRL Taxonomy Extension Label Linkbase
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase

** Filed herewith.

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SIGNATURES

In accordance with the requirements of the Securities Exchange Act of 1934, the Registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	TRANS ENERGY, INC.
Date: August 24, 2015	By /s/ JOHN G. CORP JOHN G. CORP Principal Executive Officer
Date: August 24, 2015	By /s/ MICHAEL R. GUZZETTA MICHAEL R. GUZZETTA Treasurer