POPULAR INC
Form 8-K
October 23, 2015
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 8-K

CURRENT REPORT
Pursuant to Section 13 OR 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): October 23, 2015

POPULAR, INC.

(Exact name of registrant as specified in its charter)

COMMONWEALTH OF PUERTO RICO	**001-34084**	**66-0667416**
(State or other jurisdiction of incorporation or organization)	*(Commission File Number)*	*(IRS Employer Identification Number)*

209 MUNOZ RIVERA AVENUE

HATO REY, PUERTO RICO	**00918**
(Address of principal executive offices)	*(Zip code)*

(787) 765-9800

(Registrant's telephone number, including area code)

NOT APPLICABLE

(Former name, former address and former fiscal year, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 2.02. Results of Operations and Financial Condition.

On October 23, 2015 Popular, Inc. issued a news release announcing its unaudited financial results for the quarter ended September 30, 2015, a copy of which is attached as Exhibit 99.1 to this Current Report on Form 8-K. The information furnished pursuant to this Item 2.02 of this Current Report on Form 8-K, including Exhibit 99.1, shall not be deemed "filed" for purposes of the Securities Exchange Act of 1934, as amended, nor shall it be incorporated by reference into any of the Corporation’s filings under the Securities Act of 1933, as amended, unless otherwise expressly stated in such filing.

Item 9.01. Financial Statements and Exhibits

99.1 Press release dated October 23, 2015

SIGNATURE

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

		POPULAR, INC.
		(Registrant)
Date:	October 23, 2015	By: /s/ Jorge J. García
		Jorge J. García
		Senior Vice President and Corporate Comptroller

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC 410. The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligations liability is deemed to use Level 3 inputs. Asset retirement obligations incurred for the year ended December 31, 2016 were approximately $0.6 million.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. There were no transfers of financial assets or liabilities between Level 1, Level 2 or Level 3 inputs for the years ended December 31, 2016 and 2015.

NOTE 13 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

The Company utilizes commodity swap contracts, swaptions and collars (purchased put options and written call options) to (i) reduce the effects of volatility in price changes on the crude oil commodities it produces and sells, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending.

All derivative instruments are recorded on the Company's balance sheet as either assets or liabilities measured at their fair value (see Note 12). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in the fair value are recognized in the revenues section of the Company's statements of operations as a gain or loss on derivative instruments. Mark-to-market gains and losses represent changes in fair values of derivatives that have not been settled. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on the Company's derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

The following table presents cash settlements on matured or liquidated derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented. Cash receipts and payments below reflect proceeds received upon early liquidation of derivative positions and gains or losses on derivative contracts which matured during the period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of derivative instruments which continue to be held at period-end and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured or were liquidated during the period.

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	Years Ended December 31, 2016	2015	2014
Cash Received (Paid) on Derivatives[1]	$61,528,201	$161,098,510	$(7,863,104)
Non-Cash Gain (Loss) on Derivatives	(76,346,935)	(88,715,603)	171,275,719
Gain (Loss) on Derivative Instruments, Net	$(14,818,734)	$72,382,907	$163,412,615

(1) Net cash receipts for crude oil collars for the year ended December 31, 2015 include approximately $202,000 of proceeds received from crude oil derivative contracts that were settled in the second quarter of 2015 prior to their contractual maturities.

The Company has master netting agreements on individual crude oil contracts with certain counterparties and therefore the current asset and liability are netted on the balance sheet and the non-current asset and liability are netted on the balance sheet for contracts with these counterparties.

The following table reflects open commodity swap contracts as of December 31, 2016, the associated volumes and the corresponding fixed price.

Settlement Period	Oil (Barrels)	Fixed Price ($)
Swaps-Crude Oil		
01/01/17 – 06/30/17	360,000	50.00
01/01/17 – 06/30/17	180,000	50.01
01/01/17 – 06/30/17	180,000	49.99
01/01/17 – 06/30/17[1]	60,000	55.20
01/01/17 – 12/31/17	360,000	54.20
01/01/17 – 12/31/17	240,000	53.25
01/01/17 – 12/31/17	365,000	54.10
07/01/17 – 12/31/17	240,000	52.75
07/01/17 – 12/31/17	120,000	52.75
07/01/17 – 12/31/17	120,000	53.50
07/01/17 – 12/31/17	60,000	54.60
07/01/17 – 12/31/17	120,000	51.75
07/01/17 – 12/31/17	120,000	53.75
01/01/18 – 9/30/18	270,000	54.00
01/01/18 – 9/30/18	270,000	54.00
01/01/18 – 9/30/18	273,000	55.20

(1) The Company has entered into crude oil derivative contracts that give counterparties the option to extend certain current derivative contracts for an additional six-month period. Options covering a notional volume of 10,000 barrels per month are exercisable on or about June 30, 2017. If the counterparties exercise all such options, the notional volume of the Company's existing crude oil derivative contracts would increase by 10,000 barrels per month at an average price of $55.20 per barrel for each month during the period July 1, 2017 through December 31, 2017.

As of December 31, 2016, the Company had a total volume on open commodity swaps of 3.3 million barrels at a weighted average price of approximately $53.00 per barrel.

The following table reflects the weighted average price of open commodity swap derivative contracts as of December 31, 2016, by year with associated volumes.

Weighted Average Price
Of Open Commodity
Swap Contracts

Year	Volumes (Bbl)	Weighted Average Price ($)
2017	2,525,000	52.55
2018	813,000	54.40

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In addition to the open commodity swap contracts the Company has entered into costless collars. The costless collars are used to establish floor and ceiling prices on anticipated crude oil production. There were no premiums paid or received by the Company related to the costless collar agreements. The following table reflects open costless collar agreements as of December 31, 2016.

Settlement Period	Oil (Barrels)	Floor/Ceiling Price ($)	Basis
01/01/17 – 12/31/17	180,000	$50.00/$60.00	NYMEX
01/01/17 – 12/31/17	120,000	$50.00/$60.15	NYMEX

The Company determines the estimated fair value of derivative instruments using a market approach based on several factors, including quoted market prices in active markets and quotes from third parties, among other things. The Company also performs an internal valuation to ensure the reasonableness of third party quotes. In consideration of counterparty credit risk, the Company assessed the possibility of whether the counterparty to the derivative would default by ailing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. For further details regarding the Company's derivative contracts see Note 12, Fair Value in the Notes to the Financial Statements.

The following table sets forth the amounts, on a gross basis, and classification of the Company's outstanding derivative financial instruments at December 31, 2016 and 2015, respectively. Certain amounts may be presented on a net basis on the financial statements when such amounts are with the same counterparty and subject to a master netting arrangement:

		December 31, Estimated Fair Value	
Type of Crude Oil Contract	Balance Sheet Location	2016	2015
Derivative Assets:			
Swap Contracts	Current Assets	$4,517	$64,611,558
Total Derivative Assets		$4,517	$64,611,558
Derivative Liabilities:			
Swap Contracts	Current Assets/Liabilities	$(9,512,724)	$—
Swap Contracts	Non-Current Liabilities	(1,738,329)	—
Swaption Contracts	Current Liabilities	(333,046)	—
Costless Collars	Current Liabilities	(155,794)	—
Total Derivative Liabilities		$(11,739,893)	$—

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. When the Company has netting arrangements with its counterparties that provide for offsetting payables against receivables from separate derivative instruments these assets and liabilities are netted on the balance sheet. The tables presented below provide reconciliation between the gross assets and liabilities and the amounts reflected on the balance sheet. The amounts presented exclude derivative settlement receivables and payables as of the balance sheet dates.

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	Estimated Fair Value at December 31, 2016		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$20,962	$(16,445)	$4,517
Non-Current Assets	—	—	—
Total Derivative Assets	$20,962	$(16,445)	$4,517
Offsetting of Derivative Liabilities:			
Current Liabilities	$(10,018,009)	$16,445	$(10,001,564)
Non-Current Liabilities	(1,738,329)	—	(1,738,329)
Total Derivative Liabilities	$(11,756,338)	$16,445	$(11,739,893)

	Estimated Fair Value at December 31, 2015		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$64,611,558	$ —	$64,611,558
Non-Current Assets	—	—	—
Total Derivative Assets	$64,611,558	$ —	$64,611,558
Offsetting of Derivative Liabilities:			
Current Liabilities	$—	$ —	$—
Non-Current Liabilities	—	—	—
Total Derivative Liabilities	$—	$ —	$—

All of the Company’s outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements (“ISDAs”) entered into with counterparties that are also lenders under the Company’s Revolving Credit Facility. The Company’s obligations under the derivative instruments are secured pursuant to the Revolving Credit Facility, and no additional collateral had been posted by the Company as of December 31, 2016. The ISDAs may provide that as a result of certain circumstances, such as cross-defaults, a counterparty may require all outstanding derivative instruments under an ISDA to be settled immediately. See Note 12 for the aggregate fair value of all derivative instruments that were in a net liability position at December 31, 2016 and 2015.

NOTE 14 EARNINGS PER SHARE

The following is a reconciliation of the numerator and denominator used to calculate basic earnings per share and diluted earnings per share for the years ended December 31, 2016, 2015, and 2014:

	2016 Net Loss	Shares	Per Share	2015 Net Loss	Shares	Per Share	2014 Net Income	Shares	Per Share
Basic EPS	$(293,493,708)	61,173,547	$(4.80)	$(975,354,541)	60,652,447	$(16.08)	$163,745,945	60,691,701	$2.70
Dilutive Effect of Options	—	—	—	—	—	—	—	169,068	(0.01)
Diluted EPS	$(293,493,708)	61,173,547	$(4.80)	$(975,354,541)	60,652,447	$(16.08)	$163,745,945	60,860,769	$2.69

For the year ended December 31, 2016, 2015 and 2014 restricted stock of 829,313, 322,393, and 15,590 shares of common stock were excluded from EPS due to the anti-dilutive effect, respectively.

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NOTE 15 RESTRUCTURING COSTS

In September 2015, the Company restructured certain of its operations in response to the current oil and gas commodity environment. These changes, which included a reduction in workforce, are expected to result in better utilization of the Company's resources and improved cost efficiencies. As of December 31, 2016, there were no unpaid restructuring costs.

Type of Restructuring Cost	Location in the Statement of Operations	Year Ended December 31, 2015
Severance and Benefit Costs	Operating Expenses – General and Administrative	$523,487

The following table summarizes the Company's restructuring costs:

Restructuring Liability at January 1, 2016	$32,493
Additions	—
Settlements	(32,493)
Revisions	—
Restructuring Liability at December 31, 2016	$—

NOTE 16 EMPLOYEE BENEFIT PLANS

In 2009, the Company adopted a defined contribution 401(k) plan for substantially all of its employees. The plan provides for Company matching of employee contributions to the plan. During 2016, 2015 and 2014, the Company provided a match contribution equal to 100% of an eligible employee's deferral contribution, up to 8% of the employee's earnings up to the maximum allowable amount. The Company contributed approximately $238,000, $279,000 and $269,000 to the 401(k) plan for the years ended December 31, 2016, 2015 and 2014, respectively.

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SUPPLEMENTAL OIL AND GAS INFORMATION
(UNAUDITED)

Oil and Natural Gas Exploration and Production Activities

Oil and gas sales reflect the market prices of net production sold or transferred with appropriate adjustments for royalties, net profits interest, and other contractual provisions. Production expenses include lifting costs incurred to operate and maintain productive wells and related equipment including such costs as operating labor, repairs and maintenance, materials, supplies and fuel consumed. Production taxes include production and severance taxes. Depletion of crude oil and natural gas properties relates to capitalized costs incurred in acquisition, exploration, and development activities. Results of operations do not include interest expense and general corporate amounts. The results of operations for the Company's crude oil and natural gas production activities are provided in the Company's related statements of income.

Costs Incurred and Capitalized Costs

The costs incurred in crude oil and natural gas acquisition, exploration and development activities are highlighted in the table below.

	Years Ended December 31,		
	2016	2015	2014
Costs Incurred for the Year:			
Proved Property Acquisition and Other	$18,531,518	$9,068,139	$29,838,482
Unproved Property Acquisition	2,301,285	3,346,214	27,561,901
Development	63,621,429	116,255,535	479,472,251
Total	$84,454,232	$128,669,888	$536,872,634

Excluded costs for unproved properties are accumulated by year. Costs are reflected in the full cost pool as the drilling costs are incurred or as costs are evaluated and deemed impaired. The Company anticipates these excluded costs will be included in the depletion computation over the next five years. The Company is unable to predict the future impact on depletion rates. The following is a summary of capitalized costs excluded from depletion at December 31, 2016 by year incurred.

	Years Ended December 31,			
	2016	2015	2014	Prior Years
Property Acquisition	$1,110,907	$736,514	$579,536	$196,845
Development	—	—	—	—
Total	$1,110,907	$736,514	$579,536	$196,845

Oil and Natural Gas Reserves and Related Financial Data

Information with respect to the Company's crude oil and natural gas producing activities is presented in the following tables. Reserve quantities, as well as certain information regarding future production and discounted cash flows, were determined by Ryder Scott Company, independent petroleum consultants based on information provided by the Company.

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Oil and Natural Gas Reserve Data

The following tables present the Company's independent petroleum consultants' estimates of its proved crude oil and natural gas reserves. The Company emphasizes that reserves are approximations and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

	Natural Gas (MCF)	Oil (BBLS)	BOE
Proved Developed and Undeveloped Reserves at December 31, 2013	50,168,133	75,799,125	84,160,481
Revisions of Previous Estimates	2,465,251	(11,397,088)	(10,986,213)
Extensions, Discoveries and Other Additions	21,984,514	29,662,181	33,326,267
Production	(3,682,781)	(5,150,913)	(5,764,710)
Proved Developed and Undeveloped Reserves at December 31, 2014	70,935,117	88,913,305	100,735,825
Revisions of Previous Estimates	(23,552,809)	(36,277,018)	(40,202,486)
Extensions, Discoveries and Other Additions	8,170,259	9,346,864	10,708,574
Production	(4,651,583)	(5,168,687)	(5,943,951)
Proved Developed and Undeveloped Reserves at December 31, 2015	50,900,984	56,814,464	65,297,962
Revisions of Previous Estimates	(8,697,825)	(13,995,801)	(15,445,439)
Extensions, Discoveries and Other Additions	7,695,309	7,142,439	8,424,991
Purchases of Minerals in Place	960,758	640,108	800,234
Production	(4,026,899)	(4,325,919)	(4,997,069)
Proved Developed and Undeveloped Reserves at December 31, 2016	46,832,327	46,275,291	54,080,679
Proved Developed Reserves:			
December 31, 2013	20,642,967	32,043,405	35,483,900
December 31, 2014	38,277,770	44,666,408	51,046,037
December 31, 2015	33,619,954	36,573,821	42,177,147
December 31, 2016	32,808,111	32,245,139	37,713,158
Proved Undeveloped Reserves:			
December 31, 2013	29,525,166	43,755,720	48,676,581
December 31, 2014	32,657,347	44,246,897	49,689,788
December 31, 2015	17,281,030	20,240,643	23,120,815
December 31, 2016	14,024,216	14,030,152	16,367,521

Proved reserves are estimated quantities of crude oil and natural gas, which geological and engineering data indicate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are included for reserves for which there is a high degree of confidence in their recoverability and they are scheduled to be drilled within the next five years.

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Notable changes in proved reserves for the year ended December 31, 2016 included the following:

- Extensions and discoveries. In 2016, total extensions and discoveries of 8.4 MMBOE were primarily attributable to successful drilling in the Williston Basin. Both the new wells drilled in these areas as well as the proved undeveloped locations added as a result of drilling increased the Company's proved reserves.

- Purchases of minerals in place. In 2016, total purchases of minerals in place of 0.8 MMBOE were primarily attributable to an acquisition with a third party (See Note 3).

- Revisions to previous estimates. In 2016, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 15.4 MMBOE. Included in these revisions were 15.7 MMBOE of downward adjustments caused by lower crude oil and natural gas prices and 3.4 MMBOE of downward adjustments related to the removal of undeveloped drilling locations related to the 5 year rule which was partially offset by a 3.6 MMBOE upward adjustment attributable to well performance when comparing the Company's reserve estimates at December 31, 2016 to December 31, 2015.

Notable changes in proved reserves for the year ended December 31, 2015 included the following:

- Extensions and discoveries. In 2015, total extensions and discoveries of 10.7 MMBOE were primarily attributable to successful drilling in the Williston Basin. Both the new wells drilled in these areas as well as the proved undeveloped locations added as a result of drilling increased the Company's proved reserves.

- Revisions to previous estimates. In 2015, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 40.2 MMBOE. Included in these revisions were 52.6 MMBOE of downward adjustments caused by lower crude oil and natural gas prices and 12.4 MMBOE of net upward adjustments attributable to reservoir analysis and well performance when comparing the Company's reserve estimates at December 31, 2015 to December 31, 2014.

Notable changes in proved reserves for the year ended December 31, 2014 included the following:

- Extensions and discoveries. In 2014, total extensions and discoveries of 33.3 MMBOE were primarily attributable to successful drilling in the Williston Basin. Both the new wells drilled in these areas as well as the proved undeveloped locations added as a result of drilling increased the Company's proved reserves.

- Revisions to previous estimates. In 2014, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 11.0 MMBOE. Included in these revisions were 0.9 MMBOE of net upward adjustments attributable to well performance and 2.1 MMBOE of downward adjustments caused by lower crude oil prices and 9.8 MMBOE downward adjustments attributable to reservoir analysis when comparing the Company's reserve estimates at December 31, 2014 to December 31, 2013.

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Standardized Measure of Discounted Future Net Cash Inflows and Changes Therein

The following table presents a standardized measure of discounted future net cash flows relating to proved crude oil and natural gas reserves and the changes in standardized measure of discounted future net cash flows relating proved crude oil and natural gas were prepared in accordance with the provisions of ASC 932 Extractive Activities - Oil and Gas. Future cash inflows were computed by applying average prices of crude oil and natural gas for the last 12 months to estimated future production. Future production and development costs were computed by estimating the expenditures to be incurred in developing and producing the proved crude oil and natural gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions. Future income tax expenses were calculated by applying appropriate year end tax rates to future pretax cash flows relating to proved crude oil and natural gas reserves, less the tax basis of properties involved and tax credits and loss carry forwards relating to crude oil and natural gas producing activities. Future net cash flows are discounted at the rate of 10% annually to derive the standardized measure of discounted future cash flows. Actual future cash inflows may vary considerably, and the standardized measure does not necessarily represent the fair value of the Company’s crude oil and natural gas reserves.

	Years Ended December 31,		
	2016	2015	2014
Future Cash Inflows	$1,708,870,912	$2,470,707,712	$7,912,622,500
Future Production Costs	(775,534,832)	(981,256,096)	(2,281,320,000)
Future Development Costs	(220,869,664)	(356,401,888)	(1,453,562,125)
Future Income Tax Expense	(2,477,353)	(5,740,623)	(1,058,511,086)
Future Net Cash Inflows	$709,989,063	$1,127,309,105	$3,119,229,289
10% Annual Discount for Estimated Timing of Cash Flows	(330,963,050)	(552,510,342)	(1,713,849,746)
Standardized Measure of Discounted Future Net Cash Flows	$379,026,013	$574,798,763	$1,405,379,543

The twelve month average prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate the Company’s reserves. The price of other liquids is included in natural gas. The prices for the Company’s reserve estimates were as follows:

	Natural Gas MCF	Oil Bbl
December 31, 2016	$ 1.67	$35.24
December 31, 2015	$ 1.63	$42.03
December 31, 2014	$ 7.37	$83.11

The expected tax benefits to be realized from utilization of the net operating loss and tax credit carryforwards are used in the computation of future income tax cash flows. As a result of available net operating loss carryforwards and the remaining tax basis of its assets at December 31, 2016, the Company’s future income taxes were significantly reduced.

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Changes in the Standardized Measure of Discounted Future Net Cash Flows at 10% per annum follow:

	Years Ended December 31,		
	2016	2015	2014
Beginning of Period	$574,798,763	$1,405,379,543	$1,224,366,826
Sales of Oil and Natural Gas Produced, Net of Production Costs	(98,497,165)	(128,964,023)	(330,395,323)
Extensions and Discoveries	59,542,911	96,770,078	567,026,734
Previously Estimated Development Cost Incurred During the Period	23,271,960	114,208,095	205,125,299
Net Change of Prices and Production Costs	(174,656,448)	(1,384,474,928)	(52,577,882)
Change in Future Development Costs	57,481,060	235,578,690	(64,185,447)
Revisions of Quantity and Timing Estimates	(130,664,183)	(363,975,445)	(326,674,460)
Accretion of Discount	57,569,313	170,222,344	152,128,992
Change in Income Taxes	497,950	295,949,531	(79,196)
Purchases of Minerals in Place	9,576,760	—	—
Other	105,092	134,104,878	30,644,000
End of Period	$379,026,013	$574,798,763	$1,405,379,543

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QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

Quarterly data for the years end December 31, 2016 and 2015 is as follows:

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2016				
Total Revenues	$31,836,236	$32,014,226	$45,109,408	$35,943,626
Gains (Losses) on Derivative Instruments, Net	3,463,883	(10,522,948)	3,381,564	(11,141,233)
Total Operating Expenses	141,220,772	124,946,744	74,583,046	33,457,789
Impairment	104,311,122	88,880,921	43,820,791	—
Income (Loss) from Operations	(109,384,536)	(92,932,518)	(29,473,638)	2,485,837
Other Income (Expense)	(17,181,218)	(16,046,144)	(16,145,257)	(16,218,413)
Income Tax Benefit	—	—	—	(1,402,179)
Net Loss	(126,565,754)	(108,978,662)	(45,618,895)	(12,330,397)
Net Loss Per Common Share – Basic	(2.08)	(1.78)	(0.74)	(0.20)
Net Loss Per Common Share – Diluted	(2.08)	(1.78)	(0.74)	(0.20)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2015				
Total Revenues	$76,124,638	$40,863,194	$101,156,552	$56,913,029
Gains (Losses) on Derivative Instruments, Net	25,663,283	(22,211,048)	51,366,762	17,563,910
Total Operating Expenses	429,607,005	343,402,927	408,323,554	213,112,194
Impairment	360,428,962	281,964,097	354,422,654	167,143,533
Loss from Operations	(353,482,367)	(302,539,733)	(307,167,002)	(156,199,165)
Other Income (Expense)	(11,736,205)	(14,387,494)	(16,152,574)	(16,114,205)
Income Tax Benefit	(135,480,000)	(66,866,610)	(77,544)	(50)
Net Loss	(229,738,572)	(250,060,617)	(323,242,032)	(172,313,320)
Net Loss Per Common Share – Basic	(3.79)	(4.12)	(5.33)	(2.84)
Net Loss Per Common Share – Diluted	(3.79)	(4.12)	(5.33)	(2.84)