

IN THE CIRCUIT COURT OF RITCHIE COUNTY, WEST VIRGINIA

ANTERO RESOURCES CORPORATION,

Petitioner,

v.

Civil Action No. ¹⁷16-AA-¹
The Honorable Sweeney

**THE HONORABLE MARK MATKOVICH,
West Virginia State Tax Commissioner,**

**THE HONORABLE ARLENE MOSSOR,
Assessor of Ritchie County, and**

**THE COUNTY COMMISSION OF RITCHIE COUNTY,
Sitting as a Board of Assessment Appeals,**

Respondents.

FILED
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ROSE ELLEN COX
CLERK CIRCUIT COURT
RITCHIE COUNTY, WV

COMPLAINT OF PETITIONER ANTERO RESOURCES CORPORATION

I. INTRODUCTION

Antero Resources Corporation ("Antero") is a producer of natural gas throughout the state of West Virginia, with several Marcellus wells located in Ritchie County.

Those wells are appraised by the West Virginia Department of Revenue, State Tax Department, Property Tax Division (the "Tax Department" or "State") based on a mass appraisal system, state-wide. Certain variables are used by the State to value producing oil and natural gas wells, including, notably for this Brief, operating expenses. Specifically, the Tax Department periodically circulates a survey by which it solicits data from oil and natural gas producing taxpayers regarding operating expenses for their wells, and based on that, the Tax Department determines the operating expense variables used in its mass appraisal system. The amount of operating expenses applied to a well using the mass appraisal system is based on a percentage of

the well's gross receipts not to exceed a maximum amount, and the percentage and maximum vary by the type of well (typical or conventional, Marcellus, etc.). The operating expense calculations are included in a natural resources "valuation variables" document that the Tax Department releases annually.

In addition to the valuation variables document, the Tax Department releases an annual administrative notice that lists the percentages and caps for operating expense calculations. In prior years, the Tax Department invited taxpayers to submit actual operating expenses that exceed the percentages and maximum amounts listed in the valuation variables document. The 2016 administrative notice, unlike administrative notices from 2000 through 2015, however, does not include language that invites taxpayers to submit actual expenses, despite no changes to the West Virginia Code or the Tax Department's Legislative Rule that governs the valuation of producing natural gas wells. For tax year 2016, Antero had submitted its actual operating expense information to the Tax Department prior to the Tax Department releasing the administrative notice in which it omitted the language inviting taxpayers to submit actual operating expense information.

In this matter, Antero evaluated its actual operating expenses for calendar year 2014, and determined that for Marcellus wells in the county, the amount of operating expenses that it was incurring for these wells exceeded the maximums set by the State. For property tax purposes, the operating expense data from calendar year 2014 is used to value the wells for tax year 2016.

When the Tax Department valued Antero's gas well values for tax year 2016, it failed to adhere to its own regulations that direct how it is to consider actual operating expenses. Antero, like many mineral producers, generally reports its operating expenses to the Tax Department on

a state-wide basis. Antero's average operating expense per well was \$648,000, which includes all lease operating expenses, gathering and compression expenses, processing expenses, and transportation expenses that are necessary to get the gas to the point of sale. Antero reports its gross revenues based on the amount it receives at the point of sale, and the allowed operating expenses should reflect the expenses incurred to get the gas to the point of sale.

For tax year 2016, the Tax Department capped operating expenses for Marcellus wells at the lesser of 20% of revenue or \$150,000. This cap unduly restricts the amount of operating expenses that should be allowed for each of well, and the imposition of a "cap" is not supported by the Tax Department's legislative rule regarding the valuation of producing oil and natural gas properties. In sum, the Tax Department incorrectly and unfairly ignored the actual operating expenses and instead relied on the maximum calculations found in its valuation variables document and administrative notice. By failing to consider Antero's actual operating expenses, the Tax Department significantly overvalued Antero's wells.

On October 20, 2016, Antero protested the Tax Department's valuation (as adopted by the Ritchie County Assessor) to the Ritchie County Commission sitting as the Ritchie County Board of Assessment Appeals (the "Board"). Antero presented clear and convincing evidence that the Tax Department failed to consider Antero's actual operating expenses in determining the valuation for the wells assessed for Ritchie County, which caused those wells to be overvalued. Antero also presented a complete analysis of its actual operating expenses from the state and local tax firm Altus Group US, Inc. ("Altus"), supported by testimony from Kirsten Evans, that correctly applies the approach to arrive at allowable operating expenses. The Board, however, made no adjustment to the Tax Department's valuation.

Antero timely petitioned the Court for appeal of the Board's decision. As explained below, the Tax Department has abused its discretion by failing to consider Antero's actual and allowable operating expenses in a manner contrary to the statutes, regulations and official releases from the Tax Department governing valuation of personal property. Moreover, the Tax Department has failed to support its valuation with substantial evidence. Antero, on the other hand, presented clear and convincing evidence for its allowable operating expenses to be used in valuing its wells for tax year 2016.

II. FACTUAL BACKGROUND

A. Antero's Property.

Antero owns several Marcellus wells in Ritchie County. (Certified Transcript of October 20, 2016 Hearing before the Ritchie County Board of Assessment Appeals, See Exhibit A [hereinafter "Hr'g Tr."], p. 5:4-5:8). Antero pays significant taxes to Ritchie County for its oil and gas wells.

B. Antero's 2014 Operating Expenses.

Antero completed the Tax Department's survey related to operating expenses. Phil Yoo, an officer of Antero who filled out the survey on Antero's behalf, testified that the survey only sought information regarding lease operating expenses (expenses related to lifting the gas out of the ground), not gathering and compression, processing, or transportation costs, which are necessary to get the gas to the market. (Hr'g Tr., p. 99:14-100:14). The Tax Department's survey information for horizontal Marcellus wells pertained almost solely to typical lease operating expenses and was based on prior surveys used for conventional wells. No line items were included for gathering and compression, processing or transportation. If such expense

categories had been included on the survey, Antero would have calculated and listed those substantial expenses, and the Tax Department's calculations would have been substantially different, given that Antero is the largest producer for Marcellus wells in West Virginia and represents approximately 40% of the Marcellus well production statewide. (Hr'g Tr., pp. 102:22-103:4, 41:1- 42:4, 54:3-55:6; *see also* Hr'g Exhibit 16). As required by the State Tax Department, Antero reports its gross revenues based on the point of sale, and the allowed operating expenses should reflect the expenses incurred to get the gas to the point of sale. Requiring gross receipts to be reported based on the point of sale, while not recognizing the substantial expenses incurred to get the gas to the point of sale, results in overvaluation of the produced natural gas. (Hr'g Tr., pp. 21:18-23:2, 57:4-57:10.)

Antero submitted proof of its actual operating expenses from 2014 to the Tax Department for consideration for tax year 2016. (*See* Hr'g Tr., 25:15-31:16, *See also* Hr'g Exhibits 4, 5, 6, 7, 8, 9, 10.) Antero's average operating costs for Marcellus wells is approximately 23% of gross revenue, or \$648,000. (Hr'g Tr. at pp. 11:22-11:24; 32:24-33:1.) Ultimately, the Tax Department did not adjust the operating expenses it used to value Antero's wells in Ritchie County for tax year 2016.

C. The Tax Department's Calculation of Antero's Operating Expenses.

The Tax Department prepares annual natural resource property valuation variables for appraising oil and gas. Further, the Tax Department makes determination of those valuation variables pursuant to Series 1J of Title 110, a legislative rule of the Tax Department, promulgated pursuant to W. Va. Code §§ 11-1C-5(b), 11-1C-5a, and 11-1C-10(d). In order to

determine the amount of Antero's operating expenses, and, in turn, the value of Antero's oil and gas wells, the Tax Department further is governed by Administrative Notices.

In the past, the Tax Department included a statement in its Administrative Notices indicating that it was willing to consider actual operating expenses if a taxpayer thought that the value of their wells was overstated. In 2016, the Tax Department decided that it would no longer consider actual operating expenses. (Hr'g Tr., pp. 96:15-96:23; 18:17-19:19). For tax year 2016, Antero had submitted its actual operating expense information to the Tax Department prior to the Tax Department releasing the administrative notice in which it omitted the language inviting taxpayers to submit actual operating expense information.

The State caps the allowed operating expenses for Marcellus Wells at the lesser of 20% of revenue, or \$150,000. Antero's operating expenses are on average \$648,000. (Hr'g Tr. at pp. 11:22-11:24). Due to the State's failure to take into account Antero's actual operating expenses, the value of Antero's wells is significantly overstated. The State valued Antero's wells in Ritchie County at over \$194 million, whereas Antero appraised them at \$84 million. (Hr'g Tr. p. 42:10-42:17.) Antero's expert, Hein & Associates, appraised the wells at \$59 million. (Hr'g Tr., p. 70:7-70:10).

Antero timely noticed the Ritchie County Commission with its Notice of Protest on February 10, 2016. The Ritchie County Commission, sitting as the Ritchie County Board of Assessment Appeals, held a hearing on October 20, 2016.

At the hearing, the Tax Department offered no credible evidence as the basis for its refusal to accept Antero's calculation of its operating expenses, except to argue that it would be impractical and expensive for the Tax Department to look at the actual expenses for individual

wells (Hr'g Tr., at p. 97:10-97:22), and that the State's current procedures are in accordance with the legislative rules and the law. (Hr'g Tr. at p. 8:21-9:1).

D. Antero's Expert Analysis and Testimony.

Antero's expert, Altus, a leading independent state and local tax firm, by Director Kirsten Evans, testified before the Board on October 20, 2016, and showed that a correct application of the allowable operating expenses demonstrated that the Tax Department had erred by failing to allow the operating expenses documented by Antero. (*See* Hr'g Tr., pp. 11-58). Detailed charts and documentation of actual operating expenses, with numbers specific to Ritchie County, were also submitted to the Board. (*see* Certified Record, Petitioner's Exhibits, 3, 4, 5, 6, 7, 8, 9, and 10).

Altus explained that by artificially capping operating expenses at \$150,000, which is not required by the legislative rule, the State is grossly overvaluing the fair market value of Antero's wells. (Hr'g Tr., at pp. 11:18-13:6; 96:9-96:14). The State also does not take into account Antero's point-of-sale, and the operating expenses incurred to get the gas downstream to market. (Hr'g Tr. at p. 22:3-23:2). Altus testified that Antero volumetrically represented 40% of horizontal production in West Virginia in 2014, and that its average operating expense was \$648,000 per well. (Hr'g Tr., pp. 41:15-42:17). Altus demonstrated that it would be mathematically impossible to get a weighted average of \$150,000 in operating expenses for the industry. (Hr'g Tr., pp. 41:10-42:4; *see also* Hr'g Exhibit 15.)

An expert appraiser from Hein & Associates, Alan Schoephoerster, also testified at the hearing. Hein & Associates testified that it appraised Antero's wells in Ritchie County. (*See*

Hr'g Tr., p. 61:10-61:16). Mr. Schoephoerster explained that the Tax Department's valuation did not properly account for the decline rate or actual operating costs of the wells at issue, and used a different discount rate than Hein & Associate's methodology. (Hr'g Tr. at pp. 61:21-71:5.) Hein & Associates valued Antero's Ritchie County wells at \$59 million, while the State valued them at over \$194 million. (Hr'g Tr. p. 70:7-70:10).

Finally, Altus testified that, while Hein & Associates' valuation is the fair market value of the wells, an alternative approach would be to calculate operating costs as 20% of gross production, without any cap. Altus stressed that this method would still overstate the fair market value of the wells, but that 20%, without a cap, is a reasonable resolution. (Hr'g Tr., pp. 82:11-83:10.) This approach would value Antero's wells at approximately \$126 million.

E. Antero's Protest to the Ritchie County Board of Assessment Appeals.

On February 10, 2016, Antero submitted to the Ritchie County Assessor and the Ritchie County Commission sitting as the Board of Assessment Appeals an Application for Review of Property Assessment with regard to its gas wells, and Antero appeared on October 20, 2016, by counsel, before the Board. (See W. Va. Code § 11-3-24). Antero hired a third-party court reporter to produce a certified transcript of the hearing at which it presented the evidence discussed above. Exhibits introduced at the hearing and provided to the Board will be transmitted to the Court within thirty (30) days, as provided by West Virginia Code § 11-3-25. The original transcript of the proceeding was attached to Antero's Petition as Exhibit A. (See W. Va. Code § 58-3-4.)

By December 8, 2016 Order, the Board determined to make no adjustment to the State Tax Department's valuation of Antero's gas wells for the 2016 tax year. (See Ex. B to Antero's

Petition). Antero received notice of the Order on December 12, 2016, and Antero timely petitions this Court for relief from the Board's erroneous determination on January 10, 2016. (See W. Va. Code § 11-3-25).

III. ANALYSIS

A. Applicable Legal Standards.

All property in the State of West Virginia is required to “be assessed annually at its true and actual value” W. Va. Code § 11-3-1. The West Virginia State Tax Commissioner¹ is charged with determining “the fair market value of all natural resource property in the State” and then providing the values to county assessors to use in assessing the property. W. Va. Code § 11-1C-10(d).

Pursuant to this responsibility to value producing mineral property and reserves, the Tax Commissioner promulgated Title 110, Series 1J of the West Virginia Code of State Rules, which explains the mechanisms to be utilized in valuing taxable property.

To determine the fair market value of producing oil and natural gas property, the Tax Department applies “a yield capitalization model to the net receipts (gross receipts less royalties paid less operating expenses) for the working interest. . . .” W. Va. Code R. § 110-1J-4.1. The methodology set forth in § 110-1J-4.1 is reflected in Tax Department Administrative Notice 2016-02, in which the Tax Commissioner states that the Tax Department primarily relies upon the income approach in valuing producing oil and gas property.

¹ Elsewhere in Brief, the Tax Commissioner is variously referred to as the Tax Department or simply the State. All terms refer to the same entity.

The Tax Department should consider actual operating expenses to offset the presumed valuation of expenses for each well. According to the Tax Department's legislative rule, the Tax Commissioner considers "operating expenses" to be "the "ordinary expenses which are directly related to the maintenance of production of natural gas and/or oil. These expenses do not include extraordinary expenses, depreciation, ad valorem taxes, capital expenditures, or expenditures relating to vehicles or other tangible personal property not permanently used in the production of natural gas or oil." Section 3.16 of Series 1J, Title 110 State Tax Department Legislative Rule for Valuation of Producing and Reserve Oil & Natural Gas for Ad Valorem Property Tax Purposes. Based on the testimony of Antero's experts, Altus and Hein & Associates, and the documents submitted to the Tax Department and the Board, the operating expenses submitted by Antero are those contemplated in Section 3.14.

Antero's burden before the Board was to show by clear and convincing evidence that the Tax Department's valuation (and, hence, the County's assessment) of its gas well operating expenses was erroneous. Syl. pts. 5-6, *Stone Brooke*, 224 W. Va. 691, 688 S.E.2d 300. On appeal to this Court, the Court relies on the record developed before the Board and determines whether the challenged property valuation is supported by substantial evidence.² See W. Va. Code § 58-3-4; syl. pts. 1-2, *Stone Brooke*, 224 W. Va. 691, 688 S.E.2d 300.

² Furthermore, "[p]ursuant to *In Re Pocahontas Land Co.*, 172 W. Va. 53, 61, 303 S.E.2d 691, 699 (1983), once a taxpayer makes a showing that tax appraisals are erroneous, the Assessor is then bound by law to rebut the taxpayer's evidence." *Mountain Am., LLC v. Huffman*, 224 W. Va. 669, 786 n.23, 687 S.E.2d 768, 785 n.23 (2009). While the Court in *In Re Pocahontas Land Co.* suggested that a county assessor could meet that burden by introducing the State Tax Department's valuation, in this case, Antero showed that the State Tax Department's valuation itself is incorrect, so it was incumbent on the State Tax Department to rebut Antero's evidence.

In this case, the Tax Department failed to apply the demonstrated actual operating expenses supplied by Antero in both informal and formal testimony. Accordingly, Antero now petitions this Court to find (1) that the Board incorrectly made no changes to the Tax Department's valuation and (2) that Antero's calculation of its allowed actual operating expenses to be used to value its producing natural gas wells is correct.

B. The Tax Department Failed to Consider the Actual Operating Expenses of Antero's Gas Wells and, Thus, Failed to Correctly Value that Property; Antero, on the Other Hand, Introduced Clear Evidence of the Allowable Operating Expenses.

While the State Tax Department has discretion to select the appraisal method that it determines should provide the most accurate valuation of personal property, once it chooses a method, it must correctly apply the method.

For Antero's Marcellus wells in Ritchie County, the Tax Department has not followed its own rules regarding average industry operating expenses, as set forth in Antero's Exhibits and expert testimony at the hearing before the Board on October 20, 2016, and the Tax Department has, therefore, failed to properly calculate the fair market value of Antero's Marcellus wells. It is also improper for the Tax Department to place a cap on operating expenses, another factor resulting in an inflated value for Antero's Marcellus wells. As demonstrated at the hearing, the survey used by the Tax Department to calculate average industry operating expenses for Marcellus wells was poorly drafted and misleading and resulted in the Tax Department calculating an operating expenses "cap" well below the amount of operating expenses actually required to operate a Marcellus well and to get gas to the point of sale. Antero avers that not only is a "cap" not supported by law, but that the Tax Department also calculated a wildly inaccurate "cap."

Finally, the Tax Department's valuation of Antero's wells did not properly account for the decline rate or discount rate. As a result, Antero's wells were overvalued.

IV. CONCLUSION

WHEREFORE, Antero Resources Corporation respectfully requests that the Court:

- (i) Find that the Ritchie County Board of Assessment Appeals incorrectly upheld the valuation of Antero's Ritchie County gas wells by the West Virginia Department of Revenue, State Tax Department, Property Tax Division for the 2016 tax year;
- (ii) Fix the value of Antero's Ritchie County gas wells for the 2016 tax year at its true and actual value of \$126,739,524, based on 20% of the actual direct operating expenses incurred by Antero; and
- (iii) Order such other relief as the Court deems appropriate.

ANTERO RESOURCES CORPORATION,

By Counsel



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EXHIBIT

A

In the case of:

RE: ANTERO NOTICE OF PROTEST, RITCHIE COUNTY v

HEARING

October 20, 2016



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TAX REASSESSMENT HEARING

RE: ANTERO NOTICE OF PROTEST

RITCHIE COUNTY

Hearing before the Ritchie County Commission,
before Karon L. Vorholt, a Certified Court Reporter and
Notary Public within and for the State of West Virginia,
commencing at 11:04 a.m., on the 20th day of October 2016,
at the Ritchie County Courthouse, 413 East Main Street,
Room 401, Harrisville, West Virginia.

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A P P E A R A N C E S

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1 MR. GRIFFITH: My name's Craig Griffith. I am with

2 Steptoe & Johnson. I work out of our Charleston office.

3 I'm here today on behalf of Antero Resources.

4 What we're here for today is to address the Tax

5 Department's methodology that they use and the set values

6 that they use for Antero values here in producing natural

7 gas wells in Ritchie County. They have about 24 active

8 Marcellus wells here in the county.

9 Antero believes that the Tax Department's

10 operating expense allowance failed to consider all the

11 expenses that are necessary to get its natural gas to the

12 point of sale and that Antero should have been allowed to

13 claim a higher amount of operating expenses for each well

14 than what was ultimately permitted by the Tax Department.

15 And by limiting that amount of operating

16 expenses that – the expenses that are applied to those

17 wells are overvalued.

18 Just a brief thumbnail sketch of my background,

19 I'm a former tax commissioner. I've worked closely with

20 the folks in the Tax Department in the past.

21 I've worked close with Jan when I was with the

22 Department. I've got to know Cindi better over the last

23 couple years as we've gone through this process.

24 But Cindi's been – and she'll go through this

Page 6 1 later, but she's been with the Department for 24 years and 2 both a valued employee with the Tax Department. 3 And I know they have a tough hat in appraising 4 these wells throughout the state. 5 So what they use is they mass appraisal system. 6 As part of that system, annually they will circulate what 7 are called valuation variables, various components that go 8 into the – to value the wells in the state. 9 Among those valuation variables that the Tax 10 Department releases are their operating expenses that are 11 applied to various well types. 12 The Tax Department uses survey information to 13 develop both the percentages and – and caps that they use, 14 that they include in these valuation variables that – that 15 are released annually. 16 For Marcellus wells, really the first year for 17 horizontal Marcellus wells included in those valuation 18 variables for Tax Year 2014. As the industry ramped up in 19 the state obviously it will be necessary to update those 20 valuation variables to include Marcellus wells. 21 So from 2014 through 2016, the Tax Department 22 used a – an operating expense percentage of – percentage 23 of 20 percent of the gross revenue per well. 24 And in conjunction with that, they also imposed	Page 8 1 default percentages. They used the 20 percent with those 2 – that \$150,000 cap. 3 Antero actually tracked their expenses by wells. 4 So that's been a point of contention with the Tax 5 Department in the past of how they apply these operating 6 expenses back to an individual well. Antero tracks that 7 internally by well. 8 We feel like using these – all percentages at 9 20 percent and that cap really disproportionately affect 10 Antero compared to a lot of other producers because Antero 11 sees a tremendous amount of revenue from wet gas. They 12 have NGLs that are included in – in their stream. 13 We don't feel like the \$150,000 operating 14 expense comes close to approaching what Antero incurs per 15 – on a per-well basis for operating expenses. 16 And that's really why we're here today, is to 17 discuss the valuation that the Tax Department came up with 18 on some of the valuation variables, that we feel are off. 19 MR. WORDEN: Does the State Tax Department want to 20 reply? 21 MR. MUDRINICH: Just briefly. As Craig said, is 22 correct, this is the mass appraisal process. 23 And everything is controlled by the legislative 24 rule in the production of oil and gas. That will be
Page 7 1 a cap per well of \$150,000 per well. 2 And, really, I think it's fair to say that the 3 cap is what we think throws these values – their really 4 primary driver runs value out of WACC. 5 We don't think that cap really represents what 6 the industry has seen – has seen. I don't think it 7 represents what – what Antero has seen certainly. 8 On actual operating expenses from – for a 9 15-year period, I – I looked at the Tax Department – going 10 back to 2000, they have invited producers to approach them 11 if they feel like their actual – their actual operating 12 expenses exceed the values that are included in those 13 valuation variables. 14 The Tax Department had changed in their admin 15 notice that they circulated their tax in 2016, to remove 16 that language that – that discuss actual operating 17 expenses. 18 I think it's likely that that was the reaction 19 to us going through this process last year for another 20 taxpayer. 21 So Antero for actually 2016 approached the 22 Tax Department with their actual operating expenses in 23 late 2015. 24 The Tax Department nonetheless used their	Page 9 1 110-CSR-1J. 2 And what that provides for is you are to – we're 3 talking about expense here. So I'll limit it to that. 4 That's basically what we will talk about today. 5 But every five years the Tax Department is to 6 conduct a survey of oil and gas operators to determine the 7 average industry operating expenses per well. 8 And the operating expenses for wells for those 9 day-to-day cost to get the gas out of the ground to a 10 field line point of sale. 11 It does not include extraordinary costs with the 12 initial drilling of the well, those type things. 13 But these are costs once the well is up and 14 running that will show what the average industry expense 15 is. 16 And the average industry expenses is what you 17 use for every well of a particular type, all shallow 18 wells, dispensing wells get the average industry operating 19 expense format as well. All Marcellus get the average 20 industry operating expense for the Marcellus well. 21 There's also a cap. That cap came upon as a 22 result of the expense survey. 23 When you have some people reporting expenses in 24 Marcellus, for instance, of \$40,000 per well of operating

Page 10 1 expenses, other people reporting a couple hundred thousand 2 of operating expenses, you then figure out what that 3 average expense was. Then you have a cap so that you 4 don't have the situation where people are – can come in 5 and basically say that they have a – such a high 6 percentage of cost that are out of line with what the 7 survey determined. 8 And in this case we will be presenting evidence 9 later on that Antero Corporation where we did this – the 10 last time we did the expense survey was 2015? 11 MS. HOOVER: Uh-huh. 12 MR. MUDRINICH: Was 2015. And they reported for the 13 horizontal Marcellus average expenses of \$32,994 and for 14 vertical Marcellus average expenses of \$6,273. 15 Now, today we're going to be talking about 16 expenses per well of millions of dollars. Some -- 17 something has changed. 18 Well, we are bound to use the survey results 19 that all these operators were free to submit, and they -- 20 they're in effect for the next five years. 21 With that, I'll turn it over to Craig. It's 22 their case. 23 MR. GRIFFITH: Okay. We'll start with our first 24 witness, Kirsten Evans.	Page 12 1 Using that reduced operating expense in the 2 State's methodology creates a net income calculation 3 that's well overstated for what the well will actually do. 4 And net income over time is the basis for valuation in the 5 State of West Virginia. 6 Furthermore, we're dealing with a somewhat 7 antiquated system that was developed pre-horizontal, 8 pre-Marcellus wells. 9 So it's a model that was designed to work well 10 for conventional wells, and has been over time to try to 11 account for the changes in drilling the horizontal wells 12 and the volume of gas that comes out of the Marcellus 13 wells, but it hasn't been adjusted enough to get to the 14 correct value. 15 It doesn't contemplate gathering compression and 16 open contemplate processing and it doesn't contemplate wet 17 gas coming out of the ground. 18 It seems to contemplate the LOE expenses. And 19 we'll -- we'll get into that and, you know, the survey Jan 20 mentioned, that \$32,000 per well is likely just the LOE 21 cost for those wells. 22 Because of these things, almost every single 23 well in Ritchie County is overvalued, based on the future 24 average along Ritchie County or Antero is overvalued.
Page 11 1 (WHEREUPON, the presenting witnesses were 2 sworn.) 3 KIRSTEN EVANS, 4 having been first duly sworn to tell the truth, testified 5 as follows: 6 EXAMINATION 7 BY MR. GRIFFITH: 8 Q Kirsten, if you could discuss your background, 9 including your experience with natural resource property 10 tax issues. 11 A Sure. My educational background is in economics 12 and accounting. I spent the last 15 years working in the 13 property tax arena. 14 The past 10 of that specifically working in oil 15 and gas valuation in the Appalachian region. 16 Q And why did Antero appeal its 2016 values in 17 Ritchie County? 18 A I think Craig alluded to the -- you know, the 19 main reason we're here is because of the tax that -- that 20 Jan talked about both in the valuation models there's an 21 operating expense capped at \$150,000. 22 Antero actually incurs operating expenses that 23 are well in excess of that. And we'll talk about the 24 details of that, but around \$648,000 per well.	Page 13 1 The future income is based off of actual revenue 2 streams. So what did it make today, decline it, what will 3 it make into the future. 4 But the operating expenses are based on 5 artificially limited amounts that is issue to net income, 6 that is a realistic number. 7 Q And this -- and I think this is probably best 8 under examples. So if we could move -- look at Exhibit 3. 9 Walk us through the State valuation process for 10 producing oil and natural gas properties as you understand 11 it at this stage. 12 (WHEREUPON, a recess was taken.) 13 A So it's a complex calculation -- the valuation of 14 these wells. So I'm going to try to, you know, relatively 15 quickly walk through just the input and how it works, so 16 that when we're talking later about, you know, how we 17 suggest changing with them, and how the actual population 18 works, we can all be on the same page. 19 So in Exhibit 3, the first page should look like 20 this. It's a -- it's a template. Is that maybe the second 21 page? 22 MR. WORDEN: Okay. 23 A Okay. Sorry. So we'll talk through this. So 24 this is -- this is the template that's used to calculate

Page 14 1 the value for all wells: You put in the income for the 2 wells, the interest for the – the gas and oil. 3 And then based on the decline rates that are 4 over to the left, the State protects that forward. 5 So it's a net present value calculation of the 6 future income stream. 7 So what we report to the State is gross revenue. 8 So what did the well make, how much did it produce, and 9 how much was sold times the price it sold at. 10 So that's what goes into the calculation, and 11 that's what goes in the left-hand column, all the way down 12 Year 1 through Year 40. 13 So in this case, a well that makes roughly \$5 14 million today, 18 months from now, or Year 1, it's going 15 to make \$2.7 million, the year after that \$2 million, and 16 the year after that, \$1.6 million, so on and so forth. 17 It's declining the way the particular formation 18 code formation and the State's decline. And this one is a 19 Marcellus well in Ritchie County. 20 Then what happens is the State determines what 21 operating expenses should be applied to that net income – 22 or to that working income for revenue. 23 So in this case, the State says that working 24 interest is going to be 20 percent of that Year 1 revenue.	Page 16 1 15 years down the road. 2 So by getting the net income stream wrong in the 3 first few years of the calculation, you're significantly 4 overstating the actual value of the well. 5 Antero's expense, if we go to the examples that 6 were on page 1 – what we did was, we pulled four Marcellus 7 wells. 8 They all started producing in 2013, they all 9 have roughly the same amount of gas receipts. They're all 10 producing about \$3.1 million in revenue related to gas. 11 So what's different about these wells? Well, 12 the difference is, are they producing oil with the gas, 13 and are they producing wet gas. 14 And the wet gas is what can be produced – can be 15 further processed into natural gas liquid, so NGL. 16 And these four scenarios, over to the left, we 17 have the State allowed operating expenses. 18 So for the first well, the State's going to say 19 it takes Antero \$150,000 to generate \$3.1 million in 20 revenue. 21 The actual expenses it takes to generate that 22 revenue, \$650,000. 23 Go down to the last long example. So this one 24 has gas receipts, it has NGL receipts, and has oil
Page 15 1 half the \$150,000. 2 This one's at \$141,767, because it happened to 3 have oil income. So that's the first well with the 4 State's – with the State's calculation, is that it's 5 saying that a well that produces 2.7 million, just gas, 6 would get \$150,000. But if oil happens to come out, it 7 only cost \$141,000 to produce that – that same revenue 8 stream. 9 From there you get to net income. What's the 10 net income of the well, revenue less what it cost to 11 operate it. And then that factor is in that present value 12 factor. It's a discount rate. 13 It's saying that the money I make next year is 14 worth more to me than the money that I'll make four years 15 from now or ten years from now. 16 So it discounts it forward to give you a value 17 today of that future income stream. 18 Once you got that, all of that is added together 19 to get to the 6.7 million in value that that entire year 20 was taxed on. 21 So what I'd like to point out is that the first 22 years of this value calculation, they're weighted heavier 23 than the later years, because the revenue I get in the 24 next five years is worth more to me than the revenue 10,	Page 17 1 receipts. So that well actually generated \$5.5 million in 2 revenue. 3 The State calculation's going to say even though 4 it generated \$2.1 million more in revenue, it took 5 \$141,000 to get that revenue. 6 It intuitively doesn't make sense, that they're 7 saying it takes less money to generate that much revenue 8 than it does \$2 million less. Actuality is, it took \$1 9 million to generate that revenue. 10 So I'm in an investor, I'm looking at this well. 11 What is this well worth? And I'm putting in \$150,000 of 12 the operating expense. The value of that well is a lot 13 more, but it's unrealistic. It's not what it actually 14 takes to generate that revenue. 15 So that's why the values are completely 16 overstated. 17 Q And under the State's mass appraisal system, do 18 they treat all taxpayers in this Marcellus category the 19 same as all, regardless of their corporate structure, they 20 -- whether or not they own their gathering systems or if 21 they use third parties to gather that gas? 22 A So when you – when you report to the State, 23 there's no ability to say my well is different because it 24 produces wet gas, because I'm incurring more expense from

Page 18 1 NGLs, because I use a third-party gatherer. 2 There's -- there's no ability to segregate a 3 producer into groups. 4 Q Okay. 5 A So they're treated -- 6 Q Okay. And -- 7 A -- the same. 8 Q And when these returns are filed with the State, 9 and I think we've referenced this earlier, this gross 10 amount, the revenue are included on that. There's not 11 netting. The taxpayer's not able to submit their -- their 12 actual operating expenses as part of that return; is that 13 correct? 14 A The return is just the revenue. 15 Q Okay. And the gross amount? 16 A And the gross amount. 17 Q Okay. And in the past -- you know, we've -- 18 we've dealt in the past on this. Has the Tax Department 19 been willing through its own admin notices to assess 20 actual operating expense data for that? 21 A Yes. And it's part of the administrative 22 notices that welcome actual operating expenses, and it's 23 actually part of return instructions that you're -- that 24 you can submit operating expenses if yours do not need the	Page 20 1 value in the State of West Virginia for the regulation 2 that would change that. 3 Q Okay. I think I referenced this earlier, the 4 Tax Department's often focused on tracking operating 5 expenses per well. Is that what Antero does for their 6 recordkeeping and accounting? 7 A Yes. They can pull data related to actual 8 wells. 9 Q Okay. 10 A Not just at the State division level. 11 Q Let's move on to Exhibit 4, includes a diagram 12 and some other information, some supporting information. 13 Let's start with the diagram. It's a -- it's a 14 fold-out, included on the first page, with some nice 15 illustrations. But it has been very helpful. 16 If you could walk us through that, kind of step 17 by step, talk about the revenue and the expenses that are 18 included on that to show how that -- you know, expenses 19 that are incurred to realize that revenue. 20 A We thought this diagram would help on seeing 21 what revenue was reported to the State and how much 22 expenses it takes to actually generate that revenue. 23 So on the top side of this diagram, you'll see 24 the revenue points.
Page 19 1 valuation variables published by the State. 2 Q So Antero during this process in late 2015, did 3 they submit actual operating expenses to the State? 4 A Yes. 5 Q Okay. And that was pursuant to the instructions 6 included on the return -- 7 A Right. 8 Q -- and prior experience of what the 9 administration notices said? 10 A Correct. 11 Q Okay. And then have you had a chance to review 12 -- and I think this may be in Jan's focus, but review the 13 administrative in 2016 -- did it continue to include that 14 actual operating expense language or had that been 15 excised? 16 A So the return we're talking about right now is 17 filed in July of 2015. In January of 2016, the State 18 issued a letter that removed the language that allowed you 19 to -- or that welcomed you to provide operating expenses. 20 Q And I know you're not an attorney, but are you 21 aware of any change in the Tax Department's legislative 22 rule between 2015 and 2016 that would lead to that change? 23 A No, I'm not aware of any change in the tax code 24 that references fair market value as being the basis for	Page 21 1 And there's two sources of revenue when it comes 2 to what's reported on the West Virginia tax return. There 3 is the revenue from the sale of natural gas and then the 4 revenue from the sale of natural gas and liquid, the sum 5 of which gets to the \$1.59 billion that's on the top. 6 But what does it take to generate, you know, 7 \$1.6 billion in revenue: The State would tell you that it 8 takes \$52 million to do that. That's what's allowed in 9 their operating expense calculation when they determine 10 the value of Antero's wells. 11 The reality is, it takes \$385 million between 12 several types of expenses. The first one being the lease 13 operating expense. 14 And if you look overall, that's \$18.2 million, 15 on average \$31,000 per well. 16 Q Let me interrupt real quick. That's saying -- 17 and likely with the survey that Antero submitted? 18 A You read my mind. So that was the next comment 19 that was going to come out of my mouth, which is, I 20 believe, the survey was reported at \$32,000 a well. 21 And when we look at that survey, it specifically 22 asks for things that would fall into the LOE category, 23 well pumping cost and well tending cost, stuff like that. 24 So if I'm filling out that survey without

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1 knowledge of this tax calculation, I'd probably only fill
2 out the LOE as well.
3 The reality is – so once you get the gas out of
4 the ground, you have to gather or suppress it to get it to
5 processing. It needs to be processing.
6 Processing occurs when wet gas comes out of the
7 ground. Wet gas comes out of the ground, you cannot sell
8 under transmission line. You have to process the water
9 out of it and the natural gas liquids out of it.
10 So that cost money. You have to pay a third-
11 party processor to do that. Usually it's Mark West.
12 Then you have to take the gas somewhere to be
13 sold. So depending on who you're selling it to, whether
14 it's further down the line, out of the State of West
15 Virginia, you're going to incur a cost to get that gas to
16 the point of sale.
17 So your revenue is up to that point of sale.
18 But the expenses are not. And you'll notice that on
19 average per well LOE is \$31,000; gathering/compression,
20 \$280,000 a well; processing, \$189,000 a well;
21 transportation, \$149,000 a well.
22 Again, it takes Antero on average \$648,000 per
23 well to get their gas out of the ground to the point of
24 sale.

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1 And that's where the revenue is captured from
2 and you need to calculate expenses at the same point.
3 **Q Let's move onto the spreadsheet. This is –**
4 **includes the categories of the different expense types, if**
5 **you want to just briefly walk us through.**
6 MR. MUDRINICH: What exhibit?
7 THE DEPONENT: The same one.
8 MR. GRIFFITH: It's the same exhibit behind – it's
9 still Exhibit 4. Yeah, it should be it.
10 A So – and this was provided –
11 MR. WORDEN: If I could interrupt.
12 (WHEREUPON, a recess was taken.)
13 A So the other pages in this exhibit are breaking
14 down the \$385 million into the different categories. And
15 this was provided to the State so they can look at the
16 types and – you know, ask any questions about the what's
17 being included, about whether they were direct and
18 ordinary expenses, and had the opportunity to comment on
19 that.
20 So LOE being the most detailed and the rest just
21 having just single – single account for – for capturing
22 the expenses.
23 **Q Okay. Let's take a peak at the last page on**
24 **that exhibit. It's a graph that was provided to the Tax**

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1 **Department, if you want to discuss what that graph shows.**
2 A So this graph was provided to show us how the
3 expenses relate to volumes produced.
4 So right now the State basis operating expense
5 allowance on revenue. So it's 20 percent of the revenue
6 you report.
7 The reality is that operating expenses are tied
8 to volume, not revenue. Now, revenue fluctuates with the
9 price of gas. So if gas price is \$8 for MCF, you know, 20
10 percent allowance might be – but not be the right percent.
11 At \$2 for MCF, it – it might be a better percent.
12 But this is showing how each of the types of
13 expenses are tied to volume.
14 So the green line and the, you know, magenta
15 line, I guess, which are LOE and transportation, it
16 fluctuates less on volume. There's a little bit of uptick
17 at the bottom, but they're relatively flat.
18 Well, you'll notice that gathering and
19 processing, they're at the same curve as volume. So, you
20 know, after volume goes up, the expenses goes up.
21 That becomes important when we're talking about
22 Marcellus wells, where if the volume is significant coming
23 out as well.
24 **Q And discuss the methodology that Antero uses to**

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1 **track their expenses at a sum per well level.**
2 A So, I guess, the point we want to make here is
3 that as a company Antero can track expenses either – you
4 know, we have other producers that we've seen that track
5 expenses by a well type or by a state, or a well type
6 within a state, and don't go as far as to actually track
7 specific operating expenses to a well or a well pad.
8 But where Antero has the ability to – if you
9 want to talk about one well, they can pull the operating
10 expenses for that one well specifically.
11 **Q Okay.**
12 A So it's not an allocation that, you know, all
13 that it's doing in order to get to how those expenses are
14 tracked in the county.
15 **Q Okay. Let's look at Exhibit 6.**
16 A Okay.
17 **Q I don't think we need to go into any great**
18 **detail in the exhibit.**
19 But our primary purposes of producing that which
20 is to show that there were good faith negotiations between
21 Antero and the Tax Department throughout 2015 and 2016.
22 A Exactly. So I mentioned we started these
23 discussions in November – or probably before November '15.
24 But pretty early in the season. It's been going on for

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1 about a year now.
 2 And this was just presented to the State as an
 3 alternative to the currently operating expense system,
 4 that recognizes that operating expenses need to track to
 5 what the well is doing and not be artificially capped at
 6 \$150,000.
 7 This is one of the many, you know, discussions
 8 we had with the State.
 9 **Q Okay. And if you take a look at Exhibit 8. And**
 10 **to the extent – I mean, as we go along here, you know,**
 11 **then we'll kind of do a blanket and have these admitted**
 12 **into evidence.**
 13 So we're discussing them now, but we'll just
 14 have them all admitted at the end of the presentation.
 15 Discuss the material provided in that e-mail to
 16 the Tax Department, the operating expense reporting. Was
 17 that in response to a request from the Tax Department?
 18 **A Yes.** But because Antero's expenses were so much
 19 larger than the \$150,000 allowance that the State had
 20 calculated during its survey period, there was a lot of
 21 time that the State discussing what the expenses were and
 22 proving out that those actually were the expenses incurred
 23 by Antero for these wells.
 24 So Exhibit 8 provided a sampling of invoices

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1 paid to the third-party gatherers. So it was a sampling
 2 of invoices showing that Antero actually paid those
 3 amounts to the third-party gatherers, to the third-party
 4 profits, to the transportation lines.
 5 It also proved the point of sale. So how do we
 6 know where Antero sold their gas, that it wasn't pulled
 7 right outside of the wellhead, and then all these other
 8 expenses were after the fact.
 9 So it also provided documentation of where
 10 Antero was selling their gas.
 11 **Q Okay. And the same with Exhibit 9, I don't**
 12 **think we need to go into great detail, but this discusses**
 13 **some of the processing expenses incurred by Antero, if you**
 14 **want to just briefly touch on --**
 15 **A Right.**
 16 **Q -- what the intent was behind that -- that**
 17 **particular e-mail.**
 18 **A Right.** So when it came to processing expenses,
 19 it's a little more convoluted. It required a little more
 20 digging into the numbers.
 21 And that's because NGLs are sold to Mark West at
 22 the processing facility. And there's a – a net amount
 23 that exchanged hands.
 24 So Mark West buys the NGLs for what they're

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1 going to sell for, but they also – they have an expense
 2 for processing them.
 3 So the money that changes hand is a net, but the
 4 revenue that's reported to the State of West Virginia is
 5 the gross revenue that they receive.
 6 So this was a series of spreadsheets and actual
 7 Mark West invoices that help back that revenue stream, to
 8 separate the revenue stream from the expenses.
 9 **Q We just – so everyone will know, we just**
 10 **included the summary information here that there was some**
 11 **proprietary information in the actual invoice. And we**
 12 **didn't think it really furthered anything, so we just – we**
 13 **did the summary sheet of what had been provided to the**
 14 **Tax Department.**
 15 **Kirsten, what are your thoughts on the**
 16 **application of the Tax Department's valuation variables to**
 17 **the NGLs? You know, I know the prices in that market**
 18 **fluctuate pretty wildly.**
 19 **Do you feel that the operating expenses and the**
 20 **variables that are applied to those NGL revenues really**
 21 **reflect – can reflect the amount of expense incurred to**
 22 **get those NGL separated from natural gas? And just give**
 23 **your overall thought on how this model applies to NGLs.**
 24 **A The way – my thoughts on that are twofold. The**

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1 first being that if you're going to include the revenue
 2 stream, then you absolutely have to include the expenses
 3 to generate that operating – that revenue.
 4 The interesting thing about NGLs is that, you
 5 know, we talked about processing natural gas, and that,
 6 you know, the State allowed 20 percent.
 7 Okay. 20 percent, that's a reasonable estimate
 8 to get to the production and the processing of natural gas
 9 point of sale.
 10 If you talk about just NGL – if you look at the
 11 NGL revenue compared to the processing expense of that,
 12 it's higher. It's 40, sometimes 50 percent. It can go
 13 negative. Sometimes – because it's a different commodity
 14 pricing. But, you know, the NYMEX of – they're talking
 15 about what natural gas is going to sell for doesn't –
 16 doesn't interrupt the NGLs. It's on a completely
 17 different pricing scheme.
 18 So while it's lumped in the State's calculation
 19 together, it doesn't necessarily trend the same way that
 20 natural gas does.
 21 But if you're going to put it in there, and have
 22 it trend the same way, you absolutely have to put
 23 operating expenses in there.
 24 **Q Okay. We can move on to Exhibit 10 now. And I**

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1 think there's some exhibit material in here that shows the
2 effect of looking at NGL on the last page.

3 So let's start with the first spreadsheet that's
4 included there, which discussees calendar year 2014
5 operating expenses – expense data.

6 Walk me through that. That was in response to
7 the Tax Department's request for additional information;
8 is that right?

9 A Right. The Tax Department had asked for
10 additional information regarding the operating expenses,
11 specifically the NGL revenue in the processing.

12 I think – but in my opinion I'm just trying to
13 get around the fact that, you know, they aren't at 20
14 percent. Sometimes they're as high as, you know, 50
15 percent operating expenses on the revenue.

16 So we were breaking down – in the spreadsheet
17 what we were doing was breaking down gas receipts, oil
18 receipts, NGL receipts, and then also breaking down the
19 expenses for the same well, so that you could see that,
20 you know, profits and cost related to the well that have
21 an NGL. That there weren't processing costs for wells
22 that weren't producing wet gas.

23 So this was just helping the State kind of see
24 it on an individual well basis.

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1 There's also a column in there that talks about
2 the first 12 months of operating expense. So, you know,
3 there's some wells in there that look like they're
4 producing a pretty small amount of gas, because they're in
5 their first year of production and maybe that number is
6 only two months of revenue. So the actually operating
7 expenses will only be two months of operating expenses.

8 And what the State does in that scenario to
9 value the wells, is they annualize it, and they say, okay,
10 well, in two months they did this amount. In 12 months
11 what would it do? You have to do the same thing for the
12 operating expenses.

13 So the columns all the way to the right in this
14 spreadsheet are also annualized in the expenses, but they
15 would be equivalent to the revenue stream that the State
16 is taxing.

17 Q And, again, when the State ran its calculations
18 for this \$1.6 billion in revenue, they – the operating
19 expenses were 52 million; is that right?

20 A Yes. Most of the wells were capped at \$150,000
21 or less, less being if they had an oil stream – or oil
22 revenue coming out of the well.

23 That – that \$150,000 – that \$150,000 is 20
24 percent of \$750,000. So for any well producing over

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1 \$750,000 in revenue, it's capping the actual operating
2 expense less than they should be.

3 So anyone producing up to \$750,000 gets the
4 benefit of 20 percent of their revenue. It's not capped,
5 it's not artificially lowered. The minute a well goes
6 above \$750,000, they put a stop on operating expenses,
7 which is – unjust – unfairly limits the operating expenses
8 of all your larger wells.

9 Q So is it fair to say that 20 percent operating
10 expense percentage is – represents averaged wells, only if
11 you get up to \$750,000. For anyone else that average is
12 below.

13 A We're allowed 3 percent of our revenue stream.
14 So in the State calculation, \$52 million or \$1.6 billion
15 in revenue is about 3 percent.

16 So the State has valued us saying that our
17 operating expenses, 3 percent of revenue.

18 Q Okay. Let's jump to the last sheet of that
19 exhibit, which is a summary and maybe a little even easier
20 to follow than the spreadsheet.

21 Talk about that particular summary, and probably
22 the best box on that sheet is the lower left box that's –
23 that shows the percent that is calculated by Antero.

24 A So what does the State – you know, we're at

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1 23 percent operating expenses, is a percentage of revenue.

2 The State's at 20 percent. So those two
3 numbers, they're not that far off.

4 So, you know, but the State's saying that we're
5 going to take a revenue and multiply it by 20 percent to
6 get to what operating expenses are estimated at. That's
7 pretty close to what we are in actuality.

8 So it's just proven the point that it's the cap
9 that creates such a big issue with the tax calculation.

10 Q Okay. And let's talk about those caps. Look at
11 Exhibit 12, the first sheet there are the final valuation
12 variables for tax year 2016?

13 A Correct.

14 Q Okay. Well, page 16, have you look through –
15 they're not – it's not numbered. But I think it's the
16 16th page, at the top says "Industry Operating Expense
17 Survey and Results."

18 And those include the percentages and caps. I
19 want to briefly discuss those.

20 And I think we've kind of hammered the point
21 home, that we're at 20 percent, \$150,000 cap. But just
22 briefly discuss that – that page.

23 Q So this page – the one we're talking about in
24 Ritchie County is, you know, about halfway down the page,

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1 where it talks about Marcellus.

2 We have horizontal wells in Ritchie County, so
3 it's – the allowances are 20 percent, the maximum
4 operating expense of \$150,000.

5 So, again, I'm going to take that revenue input,
6 multiply it by 20 percent and cap it at \$150,000.

7 I think it's interesting to point out here,
8 though, that the State refers to this as a maximum
9 operating expense, yet calculated it based on an average.

10 And then average would tell you that 50 percent
11 are below and 50 percent are above.

12 So they're maxing – the maximum they're
13 allowing, is actually the midpoint of the entire
14 population. Which is kind of counterintuitive to calling
15 it a maximum operating expense.

16 Q Okay. And for 2017, which is – it's not an
17 issue here. Are you aware of an increase in that cap
18 rate? Is there a cap amount that is used for the maximum
19 operating expenses for Marcellus's horizontal wells?

20 A All right. We're talking about the 2016 tax
21 year. But the 2017 tax year, which is still being
22 assessed, which was just filed in July, they did increase
23 the maximum. It's still 20 percent. I believe it went to
24 \$175,000, the maximum operating expense.

1 that are being claimed?

2 A We had tons of discussions with the State around
3 the operating expenses and validating the operating
4 expenses.

5 They did have questions early on surrounding LOE
6 Expenses, which we provided answers to. And to be honest,
7 you can take out all of the LOE expenses and it doesn't
8 make an impact to that \$648,000 per well.

9 I mean, you'd still be at minus \$31,000. You'd
10 still be over \$600,000 per well in operating expenses.

11 They did have some concern that maybe unutilized
12 transportation costs were included, but we provided
13 documentation that it's only utilized transportation
14 costs.

15 Q Okay. Let's look at Exhibit 13. These are some
16 materials that were submitted to the Tax Department as
17 part of the valuation variable process.

18 Every year they elicit – or solicit public
19 comments prior to releasing the final variables.

20 These are responses received from the two
21 largest trade groups in the State, IOGA West Virginia and
22 then WVONGA.

23 If you could – let's start with the IOGA letter.

24 Are the – let's look at page 2 of that letter.

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1 Q And just referring back to Exhibit 4, I think
2 you already testified to this. And Exhibit 4 shows that
3 this – the lease operating expense alone almost cover that
4 entire \$150,000; is that correct?

5 A The lease operating expenses were \$31,000, but
6 it certainly – once you add gathering in there, it doesn't
7 cover even all of gathering.

8 So the \$150,000 will get the gas out of the
9 ground and partially to processing.

10 Q Got you. Discussing the prior exhibit, you
11 noted Antero's operating expenses percentages within a
12 reasonable range. So we're talking, well, 22 percent
13 versus 20 percent of that, right?

14 A Yes. About 23 percent versus 20, yes.

15 Q So is it fair – and I know you've said this, but
16 it's fair to say that the issue here is that cap, the
17 maximum amount that's being proposed by the Tax
18 Department.

19 A The biggest issue is related to the cap of the
20 operating expenses.

21 Q And have you had any feedback from the Tax
22 Department on the categories of expenses that were
23 submitted by Antero, or do you think it's this – we're
24 here today on – based entirely on the amount – amounts

1 The price per Mcf amounts that are included on
2 that first little kind of graph on there consistent with
3 what your experience is for the price of natural gas over
4 the last ten years?

5 A Yes.

6 Q Okay. And looking at the expenses for Mcf,
7 which are also included there, are those numbers remotely
8 close to the expense numbers that you've calculated for
9 Antero?

10 A Well, they're not. And if you read through the
11 letter what – what this whole exhibit is calculating – and
12 it's largely – page 2 is largely geared towards
13 conventional wells, which don't apply to Antero and
14 Ritchie County.

15 But it's basically calculating at the State's 30
16 percent what the minimum – what the operating expense
17 allowance from the State would be.

18 And in this case for a conventional well, you're
19 saying, you know, the State's allowing this operating
20 expense to be \$968.

21 And further goes on to say that it's simply
22 impossible to operate a well at \$968 per year

23 Just proving out that the State cap and
24 percentages just aren't quite right.

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Page 40

1 Q Look at the third full paragraph on the next
2 page, on page 3.
3 IOGA in that paragraph makes a comment that the
4 Tax Department requires these actual operating expenses if
5 accurate verifiable data is provided by the producer. Do
6 you agree with that? Is that consistent with the fair
7 market value goal of the legislative rules of the Tax
8 Department release?

9 A So under IOGA rules, if I believe that my
10 assessment out of mass appraisal is not in line with what
11 the actual value of my assets are, then the taxpayer has
12 the burden of proof of presenting information to prove
13 otherwise. And that's why we're here today.

14 It just so happens that our information to prove
15 otherwise is around operating expense, and largely based
16 on operating expense.

17 So, I believe, the State has the obligation to
18 hear us, to -- to hear us out, to analyze the data and use
19 actual operating expenses if it provided the correct
20 market value of the assets.

21 Q And I think we've kind of glossed over it, kind
22 of a decline methodology that you would have used for
23 operating expenses -- or actual operating expenses to get
24 to that true fair market value?

1 letter. We can refer to Exhibit 6 through 14, is -- is a
2 printout from the U.S. Energy Information Administration,
3 It shows on the second page there, the price for Mcf --
4 well, we can start from 2006, and then come forward to
5 2012.

6 A Yes.

7 Q Would you agree with WVONGA's contention that
8 while revenues have declined, operating expenses have not?

9 A Yes.

10 Q And are those charts that are on page 2 of that
11 exhibit consistent with what you've seen for Antero?

12 A So you have to remember that this letter was
13 written related to the 2017 tax year. So, and we're
14 talking about 2016.

15 Between '16 and '17 tax year, the price of gas
16 went down 55 percent. So if you're looking at the average
17 WVONGA participant operating expense as a percent of
18 revenue, you'll notice that they're a lot higher than the
19 20 percent we just talked about. They're up in the 38 to
20 41 percent.

21 So, yes, it is -- It is typical. But I would
22 argue that had this letter been written, you know, a year
23 ago, those numbers -- those percentages or the percent of
24 revenue would be lower.

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1 A -- Yes. And it's part of the testimony later of,
2 you know, why the wells were appraised. So, well, how do
3 you get the fair market value, what our actual operating
4 expenses at this point, or the declining point of revenue
5 of, you know, ten years from now and what are they tied to
6 and what is Antero actually going to incur and what would
7 an investor pay for that asset? So, yes, the original
8 example we provided to the State was one that went outside
9 their State method of mass appraisal and said, well, these
10 operating expenses would decline as volumes decline. And
11 you have to start higher, and you might spend lower, but
12 overall you have to take actual operating expenses --

13 Q Okay.

14 A -- and which is the point that Antero makes in
15 their letter.

16 Q And let's look at the -- WVONGA's letter. The
17 bottom of page 1, you would agree with the point made by
18 WVONGA that the Tax Department's operating expenses
19 variables remain unchanged since before tax year 2010,
20 except for the introduction in 2013 and '14 of
21 Marcellus/Utica categories?

22 A Yes.

23 Q And you can confirm the natural gas prices have
24 decreased significantly since 2008 as reflected in that

1 Q Let's look back at Exhibit 16, which is a
2 summary of data -- the DEP Production Report data that's
3 provided by various Marcellus producers throughout the
4 state.

5 Let's talk about Antero's information on there,
6 where they are at the percentage of Marcellus production
7 state wide and what their operating expenses look like.

8 A All right. If you look at --

9 Q Let me hand it to you.

10 A And this is just an excerpt from the DEP. It's
11 filtered on tax year and then horizontal is the well
12 indicated. So they don't have indicated as far as
13 Marcellus, but they do have one that's indicated for
14 horizontal.

15 Antero Resources is 40 percent of the -- the
16 total production at \$648,000 per well to operate those
17 wells.

18 It is -- we also have another -- yeah, the
19 taxpayer highlighted on this, that submitted information
20 to the State that, you know, they only represent 3 percent
21 of the market. But, again, their average operating
22 expenses, \$537,000 per well.

23 It is mathematically impossible to get to a
24 weighted average operating expense of \$150,000 for the

Page 42 1 industry if we've covered 43 percent of the population and 2 the average of \$600,000. 3 Other producers would have to be negative to get 4 to an average of \$150,000. 5 Q And would you say comments submitted by IOGA and 6 WVONGA are consistent with Antero's claims that the 7 operating expenses used by the Tax Department are 8 exceedingly low? 9 A Yes. 10 Q Let's look at -- we'll be brief on this -- Exhibit 11 1, the actual appeal material that we filed here in 12 Ritchie County, the original trade value was \$194 million; 13 is that correct? 14 A Yes. 15 Q Okay. And then the value determined by Antero 16 in the original appeal was \$84 million; is that right? 17 A Correct. 18 Q And I think we've hit on this, but you would 19 agree that the primary driver on that reduction is the 20 operating expense cap? 21 A That's correct. 22 Q I think we've discussed this a little bit, but 23 the -- actually, we'll go back -- we'll go back to that. 24 I think we're finished with Kirsten. We may	Page 44 1 expenses or says that the State can look at them, it's -- 2 the taxpayer's going to present information as to why the 3 mass appraisal is incorrect for their particular 4 circumstance. 5 Q But as far as you know the rule only provides 6 from the Tax Department to use the industry average from 7 the survey of the producers? 8 A The industry average, which I would argue, is 9 the 20 percent, it does not allow if they cap -- 10 Q I understand you don't like the cap -- 11 A Yes. 12 Q -- and we'll get into that. And you also 13 brought up, and you have agreed that you had submitted 14 over the course of last year or two what you claim were 15 the actual operating expenses for Antero? 16 A Yes. 17 Q And you say that the return still invites people 18 to submit with their return their actual operating 19 expenses that you've -- 20 A Yes. 21 Q -- described. Is there anything in that return 22 that says that the State has to blindly accept any number 23 that somebody submits? 24 A No, I didn't say the State should blindly accept
Page 43 1 want to recall her. We've got another witness, an 2 appraiser, that's going to testify. 3 And, I think, Kirsten is going to come back 4 after his testimony and offer some additional comments. 5 EXAMINATION 6 BY MR. MUDRINICH: 7 Q I'm going to ask some questions. 8 A Sure. 9 Q Just a couple brief ones. Are you familiar with 10 our legislative rule? 11 A I am. 12 Q I don't know if you need me to show them to you. 13 Can you tell me wherein that legislative rule it says that 14 the taxpayer -- I mean, the Tax Department shall consider 15 actual operating expenses that's submitted by the 16 producer? 17 A Well, it doesn't specifically say that the Tax 18 Department has to look at operating expenses. 19 However, as I stated before the mass appraisal 20 system is similar to if you were to get your real estate 21 valued by this county or the State, if that value comes 22 out wrong, then it's on the taxpayer -- the burden of proof 23 is on the taxpayer to prove why that value is wrong. 24 So whether it explicitly asks for operating	Page 45 1 whatever's on the exhibit. 2 Q Now, which is the exhibit that has the nice 3 diagram, the one with the plant -- 4 A Right. 4. 5 Q Yes, 4. 6 A Exhibit 4. 7 Q Can I turn your attention to that? 8 A Sure. 9 Q You stated that -- let's -- let's talk about the -- 10 is where the rule allows for the value in the expenses to 11 come up to the field line point of sale. 12 A Yes. 13 Q Where is the field line point of sale in this 14 diagram? 15 A The field line point of sale is after the 16 natural gas transmission line. So it is before the end 17 user or the arrow pointing down at the \$1.3 billion -- \$1.3 18 billion line. 19 Q Okay. Who owns this -- that line? 20 A Well, it depends where the -- Dominion or -- I 21 don't know who the other operators are. 22 Q Dominion -- what was this on the start of your 23 point of sale going backwards? 24 A Other than -- someone other than Antero.

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1 **Q Okay. What about the gathering line here, who**
 2 **owns that?**
 3 A So a variety of owners. So it's not just one
 4 particular gathering line. It depends on where the wells
 5 are who -- so it's a combination of third parties and some
 6 that are owned by Antero.
 7 **Q How did you determine and what evidence do you**
 8 **have where this field line point of sale is?**
 9 A That goes back to Exhibit 8. The last page in
 10 Exhibit 8 are point of sale contracts, samples from West
 11 Virginia.
 12 MR. GRIFFITH: And, again, that was something that
 13 had been provided to the Tax Department. They had
 14 available for review. There was some proprietary
 15 information in there that would include the actual
 16 transaction confirmations as part of the -- that the Tax
 17 Department had -- has had that available for review.
 18 MR. MUDRINICH: I really -- it may be proprietary, but
 19 I would think you'd need to put that in.
 20 A Well, if -- so the information is in there, but
 21 the contracts that are proprietary in nature with regard
 22 to their pricing --
 23 **Q But that's the conclusion of what the**
 24 **information would show?**

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1 A -- Right. And the State has those. The state has
 2 those...
 3 **Q You're the one with the burden of proof here**
 4 **today. I believe it to be the burden to be on you to**
 5 **submit that. But I'll keep moving on.**
 6 A Okay.
 7 **Q In the -- in the reg -- the regulation -- I want**
 8 **now to go back to the exhibit here. You have the working**
 9 **interest --**
 10 A Which exhibit, I'm sorry?
 11 **Q We're back at 4.**
 12 A Okay.
 13 **Q Regulation 3.30 says: "Working interest" means**
 14 **"the fractional interest in oil and/or natural gas**
 15 **production subject to development and operating expenses**
 16 **and owned by the leaseholder and/or operator."**
 17 A Okay.
 18 **Q They also have the definition of taking**
 19 **royalties from the landowners?**
 20 A Correct.
 21 **Q It's on that exhibit if I move down a little.**
 22 A Uh-huh.
 23 **Q "Royalty interest" means "the fractional**
 24 **interest in oil and/or natural gas production that is not**

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1 **subject to development costs or operating expenses and**
 2 **extends undiminished over the life of the property.**
 3 **Typically, it is retained by the oil and/or natural gas**
 4 **rights owner or lessor." That's the definition of**
 5 **"Royalty Interest" for purposes of valuing this.**
 6 A Okay.
 7 **Q Can you tell me since your biggest cost here or**
 8 **gathering, compression, processing, transportation costs**
 9 **you claim are to come under the "working interest" -- have**
 10 **you done a study of the royalty agreements for lease to**
 11 **see if the royalty owner also bears some of this**
 12 **post-production cost, that is the cost of the gathering**
 13 **line, pipeline, all the way down to the NGL separation?**
 14 A Whether a royalty owner shares in that expense
 15 is determined on a lease by lease basis. I did not look
 16 at every exact lease.
 17 But I will point out that on an average royalty
 18 percentage are 12.75 percent. So at most, even if every
 19 single lease shared in 100 percent of the expenses and the
 20 royalty owners got their share, we're talking about 12
 21 percent. So roughly \$60,000 -- \$64,000 I'm going to say,
 22 based on 10 percent in my head, you still have an issue
 23 where the average operating expense would be \$590,000 per
 24 well.

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1 So, no, I did not know the study on all the
 2 leases. But there is still an issue even if that were the
 3 case.
 4 **Q And you recognize that the field line point of**
 5 **sale is not defined anywhere in this regulation?**
 6 A And there's only one point where the gas is
 7 sold.
 8 **Q I understand what you claim.**
 9 A Okay.
 10 **Q I also read these definitions of royalty**
 11 **interest and working interest.**
 12 **So if the royalty owner shares in some of these**
 13 **post-production expenses, he wouldn't fit within the**
 14 **definition, because he'd be the one sharing -- he'd have an**
 15 **interest that is subject to operate -- what you claim will**
 16 **allow the operating expenses, correct?**
 17 A I believe that proves the point that these
 18 regulations were -- were written, and that the system that
 19 is somewhat antiquated with the reality of what the oil
 20 and gas industry is at this point in time.
 21 **Q But right now it's the law?**
 22 A Fair market value, it's the law.
 23 **Q So arguably to that royalty owner that has to**
 24 **share any post-production expenses, his point of sale for**

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1 purposes of computing his royalty will be right back at
2 the wellhead, because all the other expenses deduct that?
3 A And that revenue would be significantly lower,
4 because it wasn't gathered or processed. It was still
5 wet. It --
6 Q But he's paying for that?
7 A So is Antero.
8 Q So, but you're -- you're claiming that under your
9 theory of the field line point of sale includes all these
10 additional activities, all this additional heavy equipment
11 based on your -- and you believe those are allowable
12 expenses.
13 A If you're capturing the revenue after those
14 expenses, then they should be allowed.
15 Q But for the royalty owned by capturing the
16 revenue, the stop point here?
17 A If that is how it's stated, then
18 But they're not having -- they're getting the benefit of
19 the sales price after all of those and you are to report
20 gross.
21 Q But you are to report gross.
22 A Right.
23 Q In --
24 A And net would be against the rule.

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1 Q But we'll continue to disagree that they're
2 getting the benefit of the deduction out of their check.
3 A Okay.
4 Q And I'm just trying to expedite something. We
5 did reference the new administrative notice and the fact
6 that there's no invitation in the administrative notices
7 to submit actual operating expenses.
8 A Correct. And that was issued six months after
9 we would have had to give operating expenses in support of
10 the return.
11 Q And you do understand this is a mass appraisal
12 system?
13 A I do.
14 Q And what -- you would think that in a mass
15 appraisal system, if the cap -- would you say it's a fair
16 statement that the mass appraisal system, if the -- if the
17 Tax Department had to sit down with every operator, take
18 all these large expenses, sort through column after column
19 after column to verify the amounts, and whether they're
20 correct, and all that, that would be kind of out of a mass
21 appraisal system and into a high cost to administer tax
22 system?
23 A I'm unaware of a mass appraisal jurisdiction
24 that doesn't allow taxpayers to send information to prove

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1 that their mass appraisal system is wrong.
2 Q But we do allow taxpayers to submit information
3 when the surveys go around?
4 A That survey, there has been significant changes
5 in the economy since that survey was last --
6 Q Did the survey --
7 A -- taken.
8 Q But the survey, just about -- shouldn't be
9 significant changes in the expenses necessary to get gas
10 out of the ground, the types of them?
11 A I believe that survey is misleading.
12 Q Can I hand you this document? Are you familiar
13 with that?
14 A This survey?
15 Q Yes. The survey filled out by Antero Resource
16 Corporation for the year 2015?
17 A Is this the first page? Yes, yes.
18 Q And that comes out to \$32,994.
19 A Exactly.
20 Q May I turn your attention to the second page?
21 A Yes.
22 MR. MUDRINICH: Do you need one, Craig?
23 MR. GRIFFITH: Yes.
24 MR. MUDRINICH: Okay.

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1 Q Can you take one look at the second page, and I
2 believe that's your signature?
3 A It is.
4 Q And this is 2015.
5 A It is. With the return, I believe, that was
6 filed.
7 Q So this would be a few months probably after
8 that other page 1 was filed?
9 A I don't know when page 1 was filed. I didn't --
10 I believe it was in '14. It says for the calendar year
11 '13, so I imagine --
12 Q Oh, it was '14. Oh, I'm sorry. Sometime in
13 '14?
14 A Right.
15 Q And so it would be --
16 MS. HOOVER: May '15.
17 MR. MUDRINICH: Huh?
18 MS. HOOVER: May '15.
19 MR. MUDRINICH: May '15 is when that was filed?
20 MS. HOOVER: Yes.
21 Q We've got extra copies of that, so we'll give
22 one to Craig.
23 A May of 2014. May 15th of 2014.
24 Q Okay. You did it when you did it. And when you

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1 – and by a year or few months later, you calculated the
2 average actual expenses of \$1.06 million?

3 A Yes, the final survey, I believe it's simply the
4 LOE, because it was with the direct expenses that are
5 required. There's nothing to fit in "Other."

6 There's nothing that mentions gathering,
7 transmission, processing. And the \$32,000 is very similar
8 to what's on our diagram of \$31,000.

9 Now, to reconcile the \$1 million on page 2 which
10 the \$648,000 that we've been talking about here, that has
11 to do with the annualization of expenses.

12 So the \$648,000 average averages in the expenses
13 of wells that have not been producing a full year.

14 So as we talked about earlier, that this
15 calculation is going to annualize that revenue and tax
16 them on a full year of revenue, even though it hasn't been
17 operating a full year. You have to do that for the
18 expenses.

19 If you annualize first year wells, that \$648,000
20 becomes \$1 million on average.

21 Q And turn back to page 1, you say there's nothing
22 in here about gathering, compression and things that, I
23 think, you are claiming as part of this direct expense.
24 Is that what you're saying?

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1 A --I didn't fill this out, but it is \$32,000 on
2 average. There's no expenses large enough to cover a
3 profit in transmission and gathering. We've already
4 proved that those expenses are what they are through the
5 submission of actual invoices that Antero has paid. So,
6 yes, I believe this is just LOE.

7 Q And it indicated the opportunity, since the
8 company did – are you saying the company didn't believe
9 that you're allowed to take those expenses, you didn't
10 know?

11 A I mean, I was not involved in filling out the
12 survey, so – but I – not – if I didn't understand the
13 State's calculations the way I understand it, I would look
14 at the survey and think you were only interested in LOEs
15 based on the type of expenses that it specifically asked
16 for.

17 Q Even though we do – we do give the spot for
18 LOEs?

19 A Yes.

20 Q And, of course, if – if the gathering,
21 compression, et cetera, was past the field line point of
22 sale, you wouldn't list it anyhow? And the operator had a
23 field line point of sale --

24 A If --

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1 Q Well, and they wouldn't report those type of
2 expensee?

3 A If you sold your gas at the wellhead, then, no,
4 you would not have those expenses. But that's not the
5 case with Antero.

6 Q And you didn't calculate any of – when you did
7 the calculation, you didn't calculate the amount to take
8 out of those expenses what the royalty owner would have
9 been charged with?

10 A I did not. But as we discussed --

11 Q You're just stating minimal amount?

12 A It would be a minimal amount, and not change the
13 document. And --

14 Q Go ahead. And that's why I'm saying it --

15 A Well, I would just say if the structure was such
16 that you only incurred LOE and sold it at the wellhead,
17 the price per Mcf, the revenue reported to the State would
18 be significantly lower than the \$1.6 billion that Antero
19 was reporting.

20 First of all, there'd be no NGL. So that's \$263
21 million. Second of all, you wouldn't be transporting it
22 to a point of sale that is in a market that's willing to
23 pay more for the – it would be not – it would have to
24 account for the gathering, processing, and transmission of

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1 the gas.

2 The revenue that would come at the wellhead
3 would be significantly lower.

4 You can't apply apples to oranges. You either
5 have to take the revenue where it is sold, and that
6 includes a processed commodity for sale and every single
7 expense it takes to get there, or you take an unprocessed
8 wet gas that is not worth as much, and you take the
9 expenses to get that out of the ground. You can't take
10 one and – and mix it with the other.

11 MR. MUDRINICH: Okay. Let's see if I can wrap this
12 up. Just give me one minute to go through my head to see
13 if there's anything else. I don't think I have any
14 further questions.

15 REEXAMINATION

16 BY MR. GRIFFITH:

17 Q Just a couple questions. On the issue of
18 submitting actual operating expenses, the State code
19 requires a fair market value to help value these wells;
20 is that right?

21 A Correct.

22 Q The legislative rule is in support of the code
23 and is really the blueprint used to arrive at that fair
24 market value; is that accurate?

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1 A Yes.

2 Q So submission of those actual expenses to the

3 Department would reflect the polls to arrive at a fair

4 market value for these wells?

5 A That's correct.

6 Q And then on the issue of field line point of

7 sale, I think it referenced the ones on the left of the

8 rule undefined. So legislative rule promulgated and

9 drafted by the Tax Department, approved by the

10 Legislature. Is it a reasonable interpretation for Antero

11 to take to determine where the field point of sale is

12 based on their experience and their operations?

13 A Like I said before, it's the only time the gas

14 changes hands. So it is the place where gas is sold.

15 Q And I think you've already referenced this, that

16 other category in the survey --

17 A Uh-huh.

18 Q -- if you had been filling this out back in --

19 what was the date in 2013, the operating expense data,

20 would that have stood out to you as an area that lost

21 hundreds of millions of dollars of gathering and

22 compression expenses and transportation expenses?

23 A No.

24 MR. GRIFFITH: Okay. That's all I have.

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1 MR. MUDRINICH: Nothing further.

2 MR. GRIFFITH: We've got a second witness. And I

3 think I mentioned this earlier, we will recall Kirsten for

4 just a few questions following testimony from Alan.

5 ALAN SCHOEPHOERSTER,

6 having been first duly sworn to tell the truth, testified

7 as follows:

8 EXAMINATION

9 BY MR. GRIFFITH:

10 Q We're going to flip to Exhibit 11, which is a --

11 an appraisal we had performed -- Antero had performed for

12 their Ritchie County wells by Hein & Associates. And I'll

13 let you introduce yourself for the record and talk about

14 your background in the industry.

15 A Thanks for having me. My name is Alan

16 Schoephoerster. I'm a managing consulting with Hein &

17 Associates.

18 We are an audit, tax and consulting firm based

19 out of Houston, Texas.

20 I graduated high school in 1997. After that I

21 joined the military, where I served four years as a United

22 States Army paratrooper.

23 Upon leaving the military, I moved back to

24 Houston, Texas where I pursued an undergrad degree in

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1 finance.

2 After receiving my BBA in finance from the

3 University of Houston, I did a -- I took a role in the

4 energy industry, where I brokered energy options, futures,

5 and other commodities for approximately eight years.

6 About the time of the financial crisis, I

7 decided to go back to school to receive my MBA in energy

8 investment analysis and energy finance.

9 Shortly after graduating with my MBA, I was

10 recruited by an upstream consulting firm located in

11 Houston by the name of Opportune.

12 At Opportune, I was placed in a valuation group

13 where I specialized in upstream oil and gas valuations,

14 valuation of complex equity instruments, and valuation of

15 embedded derivatives with income securities.

16 In addition to valuations of those natures, I

17 participated in over \$3 million worth of MMA -- upstream

18 MMA transactions, where I conducted financial due

19 diligence.

20 In addition to that, I participated in several

21 Chapter 11 reorganizations for the upstream oil and gas

22 industry, including the third largest U.S. bankruptcy in

23 2011, involving an offshore Gulf of Mexico oil and gas

24 producer.

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1 And approximately two years ago, I left

2 Opportune to join Hein & Associates where I'm currently

3 one of the leading experts in upstream oil and gas

4 valuations.

5 I'm currently working on several engagements

6 located here in West Virginia, which involved valuation of

7 tens of thousands of oil and gas mineral interests

8 throughout West Virginia, as well as active oil and gas

9 wells.

10 Q Okay. And we'll start walking through the

11 appraisal now. And I'll leave a lot of this open-ended to

12 let you discuss the scope of your appraisal, exactly what

13 you're engaged to appraise here in Ritchie County. We'll

14 talk about your methodology and the assumptions as you --

15 as you kind of walk through the appraisal for us here.

16 A Sure. Ritchie County --

17 Q Sorry, some of the -- despite the font is small

18 here, we -- we tried doing this on a legal letter, more or

19 less it remains small. But I think Alan will do a good

20 job of explaining what's -- the various exhibits.

21 A Sure. Okay. We were kind of engaged to conduct

22 a fair market value analysis of producing oil and gas

23 wells, broken into various counties of West Virginia.

24 As has been discussed already, fair market value

Page 62 1 is defined as price that would be paid between a willing 2 buyer and willing seller, neither of which being under 3 compulsion to sell, and both being aware of all relevant 4 facts related to the subject assets under valuation. 5 And armed with that as the standard of value, we 6 began to – we sent out an information request list to all 7 groups where we requested certain data related to the 8 subject assets. 9 We were provided actual operating expenses by 10 well for Antero, along with actual revenues for 2014 and 11 2015 reporting periods. 12 Using that information we began to take a deeper 13 look at each well. So we – we utilized the service called 14 Drillinginfo where we could pull historic production data 15 by county, by well for any – any amount of states. 16 So using that service we pulled a – we developed 17 a type curve for Antero specific wells in Ritchie County. 18 Using this type curve, we're able to extrapolate 19 decline rates in which that we use to apply towards 2014 20 and 2015 revenue and declined revenues until we reach 21 essentially what would be an economic limit for the well. 22 So after applying the correct – so the first 23 step is obviously in declining revenue, but we wanted to 24 take a look at what the State of West Virginia uses, their	Page 64 1 But all the revenue's coming down because of the decline. 2 To kind of get a feel for the operating expenses 3 and if they were reasonable, we surveyed market 4 participants for traditional oil and gas operators in West 5 Virginia and calculated their operating expenses to the 6 percent of revenue, then compared it to what Antero 7 provided for us. 8 Using Antero's data, we came up with 9 approximately 20 percent of revenue for operating expense. 10 That includes gathering, compression, transportation, and 11 LOE. 12 Looking at the market participants, which 13 included Chesapeake, Consol, Carrizo, et cetera, market 14 participant ranged operating expenses percent of revenue 15 was between 16 and 73 percent. 16 So armed with that information we deemed the 17 expenses provided by Antero to be reasonable. 18 Furthermore, we took a look at what the EIA had 19 recently published in an upstream oil and gas top study 20 for the Marcellus. On a dollar per Mcf basis, EIA is 21 showing approximately \$2.08 for operating expense on a Mcf 22 basis, whereas Antero is showing their implied for Mcf, 23 including gas and compression, processing, and 24 transportation, it's \$1.61.
Page 63 1 variables. 2 Comparing our variables with the State of West 3 Virginia, I had surveyed marked participants with, the 4 State of West Virginia for Ritchie County, for Marcellus 5 wells, they're using the first three years – the first 6 three year decline rates of 46 percent, 29 percent and 7 23 percent. 8 Upon our analysis, we actually had more 9 aggressive decline rates based on the information we – 10 that was provided in Drillinginfo based on historical 11 data. 12 We used the 63 percent decline in the first 13 year, a 39 percent decline in the second year, and 14 terminal decline rate of 15 percent. 15 So our original basis steps down the value of 16 these – of the revenue initially, but it's based on the 17 actual production that's – that has actually occurred from 18 Antero-type wells. 19 Moving on into the expense side, because we had 20 per well data, we used that data and also applied these 21 decline rates to have revenues and operating expenses 22 being declined on the same basis. 23 As well as increase in age, operators become 24 more efficient, drilling expenses will tend to come down.	Page 65 1 So in view of that we're – we're see Antero 2 actually has a more conservative cost structure. And to 3 further add to that point, looking at a pair of recent 4 results, Antero was kind of leading the way as far as 5 increasing efficiency on their wells, setting new records 6 as far as lateral lengths in Marcellus. 7 So every step that they're taking is not only 8 going to improve efficiency of wells and set new standards 9 for industry, but also improve in their cost – or cost 10 structure, which can be evidenced by – by the variables 11 here. 12 And as Nancy said, the percent of revenue versus 13 what the State is showing is not extremely out of line. 14 They're kind of right on top of each other, so as an 15 independent valuator, we didn't see any major issues with 16 it. 17 But where we started to come into some issues 18 with looking at how the State calculated the discount rate 19 is how the expected cash flow is from each well. 20 Now, the State uses what is known as a build-up 21 method for calculating a discount rate, the discount oil 22 and gas cash flows. 23 The build-up method essentially takes an 24 inflation premium, a premium for – properties are –

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1 inflation premiums. They take a risk for – a premium for
2 a credit risk.

3 Right. On equity rate premium, inflation
4 premium, and a State rated premium, this – the State's
5 method for calculating a discount rate is essentially a
6 generic discount rate that doesn't include the inherent
7 risk that's in – involved in operating oil and gas wells.

8 So after reviewing their methodology, we took
9 the market participate approach to calculate weighted
10 average cost of capital, using publicly available market
11 data as published by F&D calculate for each of the
12 publicly traded guideline companies in our analysis.

13 And, again, those were Antero's and market
14 participant. Consol, Chesapeake, EQT, Noble, Range
15 Resources, all the traditional operators in West Virginia.

16 We looked at five-year operating data and
17 financial data for each of these companies to come up with
18 what would be a normalized capital structure, a normalized
19 level of cost structure.

20 Using this information we developed the debts of
21 total capital and equity, the total capital weights, which
22 came out to be approximately 30 percent debt to capital
23 and 70 percent equity to capital.

24 In addition we polled the five-year weekly

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1 historic beta for each of the companies. And the beta for
2 each stock is essentially how the stock price reacts in
3 relation to changes in the underlying index of stock
4 prices, like the S&P or Dow Jones.

5 Using this – this equity beta that we polled, we
6 unlevered each beta when we remove the effects of each
7 company's capital structure, to come down to what is known
8 as an active beta.

9 And then you re-lever that based on an average
10 market participant capital structure, we come up with a
11 new re-levered equity beta.

12 We take the equity beta, multiply it times the
13 market risk premium, which traditionally has been between
14 6 and 8 percent, we use a study that's published by Duff &
15 Phelps, that shows the equity risk premium to be 7
16 percent.

17 Multiplying your beta by your equity risk
18 premium, and then adding back your risk free rate gives
19 you your cost of equity.

20 In addition, we looked at their – each market
21 participant's, their borrowing rate or their cost of debt.

22 To do this, we pull in the – each party's credit
23 rating and using the yield curve published by S&P
24 capital IQ for each specific credit rating and assign a

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1 yield maturity or – or a required return for cost to
2 debtor or debt – to debt risk characteristic.

3 And then going back to the debt and equity rates
4 that we developed early on, we blend those two cost of
5 equity and cost of debt with those two rates to develop a
6 weighted average cost to capital for the – for Antero to
7 discount their specific cash flow as particular to the
8 well.

9 The difference here – our concluded discount
10 rate prior to any other adjustment was approximately 16.3
11 percent, which when compared to the State's 15.3 percent
12 seemed in line.

13 However, taking another look back at what the
14 State was using, the State did not incorporate any
15 additional risk premium for the inherent riskiness of
16 operating oil and gas assets.

17 So adding additional risk premium can be
18 subjective. However, we looked to some of the industry
19 leading states in oil and gas, Texas being one, and Texas
20 State comptroller puts – put that study every year that
21 calculates the discount rate to be used for oil and gas
22 valuation, similar to what West Virginia does.

23 They survey market participants similar to how
24 we – we developed our WACC, because of a baseline, we did

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1 average cost of capital.

2 But to each market participant, they immediately
3 add 2 percent risk for being in oil and gas and for
4 operating individual owned gas wells.

5 Well, we ended up using a 3 percent risk
6 premium. That includes the 2 percent used by the State,
7 plus another 100 basis points – plus another 100 basis
8 points to account for additional risks related to steeper
9 decline rates, limited production history. I think on
10 average the Ritchie wells are about 1.29 years. So that's
11 not a tremendous amount of production data.

12 So looking forward there could be a lot of work
13 overexpenses, so we want to try to incorporate that
14 additional risk in our WACC.

15 Blending it altogether, we get a pre-tax
16 discount rate at 20 percent, which when compared to the
17 15.3 percent that's calculated by the State of West
18 Virginia, there's a significant difference.

19 And generally oil and gas reserve, cash flows
20 are sensitive to changes in the discount rate, even more
21 so than changes in pricing, especially in the later years.

22 Applying this discount rate to the expected cash
23 flows, which were a net of the royalty interest and net of
24 operating expenses, is how we arrived to our value of –

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1 Q How did that value vary from what the State's
2 value was using their -- their model?

3 A Significantly. It was greater than -- I think in
4 Ritchie's case it was greater than -- our value was 50
5 percent less than what the State of West Virginia had
6 calculated.

7 Q And I think West Virginia had -- I think their
8 value was for the State Tax Department, it's \$194 million.

9 A Yeah, and we had \$59 million was our fair market
10 -- included fair market value.

11 And -- and that had a lot to do with the discount
12 rate and -- we did -- and I'm obviously using actual
13 operating expenses.

14 We did do an iteration where we apply the State
15 variables and in almost every case it would cap out the
16 operating expense and -- when you're looking at somebody
17 like Antero, who is essentially leading the way in -- in
18 Marcellus well operations, they are pretty -- in my
19 opinion, I would say are -- are the foremost experts in
20 understanding what it costs to -- to operate these kind of
21 wells and to limit, I suppose, their operating expenses,
22 but then accepting 100 percent of the revenue, doesn't
23 seem reasonable in my opinion.

24 Q And so just to summarize, so there are really

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1 three components that we're looking at that factored into
2 your difference in value: discount rate, the actual
3 operating expense, and then the different decline curve
4 used in Ritchie County?

5 A Yes.

6 MR. GRIFFITH: All right. That's all I have.

7 EXAMINATION

8 BY MR. MUDRINICH:

9 Q Can I get your name, again?

10 A Sure. Alan Schoephoerster.

11 Q Spell that for us.

12 A It's S-c-h-o-e-p-h-o-e-r-s-t-e-r.

13 Q Can I call you Alan?

14 A Yes.

15 Q Okay. Alan, you are familiar with the
16 administrative -- you reviewed the -- the variable that
17 show the decline rates and stages?

18 A I did not myself.

19 Q And they're 46, 29, 23?

20 A Yes. Yes.

21 Q Now, you came in here, you testified -- what was
22 the number you used?

23 A We used a 63 percent decline in Year 1, 39
24 percent decline in Year 2, and 15 percent terminal year.

1 So for a 20-year period -- the terminal rate's used for
2 anything past two years. So our terminal rate was lower
3 than what the State had.

4 Q How did you come up with 63 percent decline rate
5 the first year?

6 A The -- again, we -- we took all wells, all active
7 wells producing in Ritchie County.

8 Q Oh, Antero's active wells?

9 A All Antero's active wells in Ritchie County. We
10 did do additional analysis. We're willing to take or --
11 by state, by Marcellus, by other, because this -- we wanted
12 to get an actual picture of these particular wells.

13 We did just look at Antero producing wells. And
14 the 63 percent is a hyperbolic decline rate.

15 Q What's a "hyperbolic decline rate"?

16 A Well, there's different ways to decline -- or
17 production of oil wells essentially behave in certain
18 ways, and there's exponential decline and hyperbolic
19 decline.

20 It -- it's just the speed or the rate at which
21 the production from an oil well will increase or decrease
22 -- or decline rather.

23 Q And that's 39 percent for the second year?

24 A Yes, sir.

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1 Q What information to come up with this new
2 decline rate, what information did you look at that was
3 given to you by Antero? What types of information are we
4 talking about?

5 A For this particular exercise, we didn't have to
6 rely on anything provided by Antero, because it's public
7 data.

8 And I began using Drillinginfo, which is the
9 third-party service provider that houses all this
10 production data throughout the U.S., we're able to draw on
11 that information, develop curves, and plot hyperbolic
12 decline.

13 Q So basically you're just looking at the decline
14 rate for Antero's wells. You're not looking at other
15 producers in Ritchie County or other producers in the
18 State of West Virginia, what the average decline rate is
17 for the Marcellus Shale?

18 A For Ritchie -- correct. We looked at it, but
19 we're -- these are relying on Antero's as an operator.

20 Q So you believe it's a more accurate way to do a
21 mass appraisal, to have someone look at each company's
22 decline rate and have that applied to come up with a
23 value, as a way to come up with a value?

24 A Yes, I think so, because the decline curve of a

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1 well can change from area to area obviously. So you want
2 to be as specific as possible when you're trying to
3 identify these wells -- or declines for a specific well.

4 In cases where there would be no data, then you
5 start broadening it up to the larger type curves, so you
6 want to bring in more surveys, I suppose, of other
7 participants.

8 Q So just to sum up, just talking here with the
9 decline rate, you simply believe you've got better decline
10 -- you believe you've got better decline rates than what
11 the State uses in the mass appraisal process for Marcellus
12 for Ritchie County?

13 A I can't say it's -- it's better or worse. I
14 don't know exactly where the State -- I was unable to tie
15 back to the State's decline.

16 It's just the -- the most accurate, given the
17 data that was available.

18 Q So I'm going to jump -- I don't really have any
19 questions about your expense -- expenses. Again, what
20 we've already about -- what are allowable expenses within
21 the regulation, through the survey, caps.

22 So I'm going to jump to the capitalization.
23 You've got your capitalization analysis?

24 A Sure.

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1 Q Did you take a look at the legislative rule that
2 the State uses to value oil and gas --

3 A Yes.

4 Q -- with regards to discount rates,
5 capitalization rates?

6 A I did, I did.

7 Q And if I hand you this document, which would be
8 the one that's filed at the Secretary of State's office,
9 the variable -- will you go through that and explain to me
10 what is wrong with that or what -- or what you did
11 differently with that one that required to apply to all of
12 them?

13 A Certainly. The major difference -- just step by
14 step.

15 They're trying to develop a safe rate or a risk
16 free rate, which is essentially U.S. Treasury rates that
17 are -- are generally assumed to be risk free.

18 The U.S. government has their taxing authority
19 and ability to tax individuals and use that to pay debt.
20 So it's generally considered risk free.

21 They're using a -- the State of West Virginia,
22 rather, is using a three-month constant interest rate.
23 We're dealing with long-life assets. Some of these 20,
24 30, 40 years. You generally want to match your risk free

1 rate or safe rate as West Virginia labeled it, with the
2 term of the life of the assets.

3 So immediately off the bat we're -- we're not
4 comparing in required returns with the -- over whatever
5 term of assets that has a similar life.

6 The second major problem we noticed was -- and it
7 is the biggest one, is there is no accounting for oil and
8 gas risks at all throughout here.

9 And if there is, it's not published by the State
10 of West Virginia or it's not clear.

11 They say in the third line down, the equity
12 section, the equity rate, using a value line investment
13 survey analysis, that is not -- in the 12-plus years I've
14 been doing valuations, I don't know -- and have been
15 audited both on the -- for financial report and tax
16 purposes, no one uses the value line investment survey
17 analysis to develop equity risk premiums if that's what
18 they're assuming here.

19 Non-equity rate, they're assuming a nine-month
20 period is sufficient enough in today's -- or in the
21 environment of 2014/2015 to -- may go into the oil and gas
22 asset liquid or to effectuate a sale within a nine-month
23 period.

24 In my experience, given the downturn of pricing

1 in 2014, transactions have gone stale. It is longer than
2 a nine-month holding period -- or nine-month period to sell
3 a -- any kind of oil and gas assets.

4 And that's effectively what the State is
5 assuming here for -- another big issue here is we're
6 valuing individual oil and gas wells.

7 When we look at the way we would conduct this
8 valuation, we calculate and weigh average cost of capital
9 assuming you're getting a diversified set of assets.
10 Because the subject valuation is an individual well, there
11 should actually be additional risk premium added to our
12 WACC over and above the 3 percent that we have in here to
13 account for the fact that we don't have the
14 diversification effect in here.

15 And it is unclear with the State's methodology
16 if they're incorporating any diversification benefits or
17 if they're looking at this at an individual asset level.

18 Yeah.

19 Q Did you find during your review of what the
20 State did anything that shows that the State violated the
21 legislative rule on computing its cap rate?

22 A You mean did I --

23 Q You have -- and that can be done different. Do
24 you have any evidence that we violated the legislative

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1 rule?

2 A Will you allow me a few minutes to just go

3 through the definitions?

4 MR. GRIFFITH: Sure. Let me first give you the list.

5 A By first read, I've -- I have read it. It's just

6 I know how definitional it can be. So I just want to make

7 sure.

8 Q I think you can speak generally about what

9 you've seen and rule out -- I'm not sure that you can give

10 a legal opinion about what they violated, anything in the

11 rule.

12 A Yeah, exact -- I live in contracts, but I am

13 definitely not an attorney. So --

14 Q Well, I'm just going to ask you one more thing

15 about violating a certain rule.

16 Do you see anything in there on the

17 administrative note that shows that there needs to be an

18 additional 3 or 4 percent added to it based on some kind

19 of industry risk rate above and beyond the various rates

20 that are already set forth in the legislation language?

21 A There was no language in there to suggest that

22 the State had considered that in their calculation at all.

23 Q And the one you did here, you -- if I could

24 follow what you did here, did you determine the additional

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1 risk rate that you want to give Antero based on

2 Antero's --

3 A Yes.

4 Q -- capital ratios and all of those things that

5 go into the cap rate? Or did you do just this blanket

6 that the industry is actually the 3 or 4 percent?

7 A No, it was not blanket. That -- that does

8 directly come from the Texas State comptrollers discount

9 rate study that have years and years of experience

10 surveying a lot of market participants, and we have a lot

11 of similar assets that West Virginia does when it comes to

12 shale gas and shale oil.

13 But in these studies that the State of Texas

14 puts out, they actually want to buy the most qualifying --

15 this additional risk premium.

16 And we were very conservative in applying this

17 premium. Limited production history, especially for

18 Ritchie, when the average life of a well is less than two

19 years, that would suggest an immediate 2 percent based on

20 the State of Texas study.

21 So we could see initially a total of five extra

22 basis points -- or 500 basis points added to this. But we

23 took a conservative approach on it.

24 Q Basically you jumped out, I'm going to call,

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1 roughly 15 percent cap or even up to 20 percent. Just

2 generally?

3 A That's -- yeah.

4 Q Generally.

5 A Yeah. The concluded discount rate prior to that

6 addition was approximately rounded at 16-1/2 percent.

7 Q And so if we value something at \$1 million based

8 on 15 percent --

9 A Uh-huh.

10 Q -- what would have your use of 20 percent, what

11 would that value be?

12 A It's approximately 14 percent decline, I think.

13 Difference in value -- or it affects the value 14 percent.

14 MR. MUDRINICH: No further questions.

15 REEXAMINATION

16 BY MR. GRIFFITH:

17 Q I just have a couple for you, Alan. Look at

18 4.3. Can you identify in there where it mentions average

19 industry operating expenses for a well? Where does it

20 talk about a maximum amount that should be allowed for a

21 well?

22 A It does not.

23 MR. GRIFFITH: All right. That's all I have. Thank

24 you. And we were going to recall Kirsten for just a few

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1 housekeeping issues and have her discuss one other issue.

2 KIRSTEN EVANS,

3 having been first duly sworn to tell the truth, testified

4 as follows:

5 REEXAMINATION

6 BY MR. GRIFFITH:

7 Q Alan did a good job of explaining the categories

8 where they used different variables than what the Tax

9 Department used.

10 Let's look at Exhibit 15. If you could discuss

11 this particular exhibit, what's -- what kind of proposal is

12 in that exhibit, how you see that fitting in with the Tax

13 Department's mass appraisal system.

14 A It's something that we haven't really talked

15 about, what this means to Ritchie County in terms of where

16 the wells are appraised versus these values that we're

17 talking about.

18 We've talked about the theory, we've talked a

19 lot of facts about operating expense.

20 So to just kind of summarize what we've been

21 talking about, the schedule each well that's under appeal

22 gives you the State appraised value, the appeals value,

23 which was on the documentation that led to this hearing,

24 the taxpayer appraised value that Alan just spoke on.

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1 But what it also does, it gives you a fourth
2 value. And, you know, in this hearing we've been talking
3 a lot about what the – the fair market value of these
4 assets are, and that's what Alan was charged with doing.

5 We do recognize the State's need to assess these
6 upon a mass appraisal methodology.

7 That I'm sure you don't want to see us in here
8 year after year presenting a fair market value appraisal.
9 Even though I – you know, I do stand by that those are the
10 fair market value of the assets.

11 So this fourth scenario is one that takes our
12 largest issue with what the State is doing in terms of
13 valuation of the assets, which is that \$150,000 maximum
14 that they have placed on the operating expenses of wells.
15 It sticks to every other piece of the State's
16 methodology. The primary, it sticks to their cap rate. It
17 sticks to their template for these wells. It just removes
18 the max.

19 And you'll notice that, you know, while it
20 doesn't reach what we believe that the fair market value
21 is, we have discussed this proposal as a compromise with
22 the representatives from Antero. We feel that it's a
23 reasonable solution for the 2016 taxes, even though it –
24 it does overstate the true fair market value of the

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1 assets.

2 But we recognize the State needing to work with
3 the mass appraisal system and see that there's a potential
4 solution for the mass appraisal, but to also get to what
5 the true value of what the assets should be, because
6 that's all that's scheduled.

7 **Q I have a question on that. So basically what
8 you're doing in that fourth column is you believe the cap
9 should be removed?**

10 A Yes.

11 **Q So what these numbers – by removing the max cap,
12 the State would then be in the position of having to
13 accept what the taxpayer claims is their actual expenses,
14 correct? Just to remove it?**

15 A So they'll – the State would be in a position to
16 continue using their 20 percent of revenue as the
17 allowance for operating expenses, but not adversely impact
18 wells that are making revenue over and above that \$750,000
19 by capping them at \$150,000.

20 **Q Okay. A well makes \$1 million, do you think we
21 should just remove the cap on that, instead of analyzing
22 what type of – what caps will amount of what you're
23 claimed in actual expense. Is that what you're saying?**

24 A I'm saying that this is a reasonable solution

1 within your mass appraisal system, to get to a value that
2 – that is higher than what we believe fair market value
3 is. But would work within the system that you do.

4 **Q And that's – and to do that we have to all come
5 into agreement as to where the point of sale is, what's an
6 allowable expense and what isn't an allowable expense, to
7 really get beyond having a cap?**

8 A Yes. I believe it still allows the State to
9 survey the market participants and to determine whether
10 20 percent is correct. but not limited by the cap.

11 **Q You just don't like the cap?**

12 A I don't like the cap.

13 MR. MUDRINICH: I'm not perfect.

14 MR. GRIFFITH: Nothing further.

15 MR. MUDRINICH: Well, we're going to need to have
16 Cindy testify, but I'm starved.

17 (WHEREUPON, a discussion had had.)

18 CYNTHIA HOOVER,

19 having been first duly sworn to tell the truth, testified
20 as follows:

21 EXAMINATION

22 BY MR. MUDRINICH:

23 **Q Cindi, could you state your name for the record.**

24 A Cynthia Hoover.

1 **Q And what is your position with the Tax
2 Department?**

3 A Tax manager, special property.

4 **Q And you have handed the County Commission and
5 the taxpayer's counsel a whole packet. And we'll give one
6 to the court reporter after they're admitted in the record
7 later on before we leave.**

8 MR. GRIFFITH: That's what I thought of your
9 materials, Cindi.

10 **Q Can you explain what's in that packet?**

11 A In that packet is the legislative rule that is
12 required to be used in the appraisal of oil and gas, the
13 valuation variables, the administrative notices, and the
14 appraisal for each well for Tax Year 2016.

15 **Q So that's each well under protest here today?**

16 A That is correct. There's actually a few extras,
17 because it was easier to just put it all. But ...

18 **Q But also in that packet – let's just do this bit
19 of housekeeping – is a – this sheet?**

20 A Right. The ones that are notated red are the
21 ones that were not protested. And the last two are ones
22 where there is a joint working interest. And so I've
23 highlighted or put the portion of the value that was
24 Antero's in the different working interest partner.

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1 **Q So in other words you believe Antero's included?**
 2 **A** Right. The value that they've included on their
 3 sheet is the one that comes from the tentative appraisal,
 4 which is the total range for value.
 5 **Q So in other words, to just -- is housekeeping,**
 6 **this \$38,000 and this \$30,000 value, is somebody else's**
 7 **tax.**
 8 **A** That is correct. And the name of that person is
 9 listed beside it.
 10 **Q Okay. You reviewed the appraisals here today?**
 11 **A** Yes.
 12 **Q And how generally did you come up with the value**
 13 **that you placed on Antero's working interest?**
 14 **A** We take the information as received from the
 15 return and using the legislative rule and model -- the old
 16 capitalization model that's developed using that
 17 information, we estimated future income streams down to
 18 the present worth.
 19 **Q What do we do with expenses?**
 20 **A** For the Marcellus, the valuation variables
 21 require that we use 20 percent, not to exceed \$150,000.
 22 For Marcellus, if there's oil involved, the oil is 35
 23 percent not to exceed \$5,750. And if there's both, it's a
 24 percentage based upon what percentage of the receipt is

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1 gas or, what percentage is oil.
 2 **Q Would that be the reason when the taxpayer had**
 3 **their testimony, that the wells that contained some oil**
 4 **and some gas, there's a -- a lower expense. Can you**
 5 **explain why that was the case?**
 6 **A** When there is both gas and oil, the max that's
 7 used -- it's in the administrative notice, it says that
 8 it's based upon what percentage of the well is gas and
 9 what percentage is oil.
 10 So if it's -- the \$150,000 cap is only 90 percent
 11 -- if 90 percent of the well is gas, then the cap would be
 12 90 percent of \$150,000 for the gas portion.
 13 **Q And that's in accordance with how we set**
 14 **variables in the administrative notes?**
 15 **A** That is correct.
 16 **Q Let's talk about expenses a little more. How**
 17 **did we come up with this for this year, \$150,000 cap and**
 18 **what's the percent again for Marcellus?**
 19 **A** 20 percent, \$150,000?
 20 **Q** Uh-huh.
 21 **Q We send out a survey every five years.**
 22 **Actually, we did one the year before 2015 also, because**
 23 **Marcellus was new. And up until that point, we didn't**
 24 **have an actual operating expense. So we actually did it**

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1 in '14 and '15. But '15 is the most current one that we
 2 did.
 3 **The expenses, once we get the survey, the**
 4 **information's entered, and the portion of where the**
 5 **numbers area actually calculated, that is something Jeff**
 6 **Amburgey handles. And he filed the valuation variables.**
 7 **Q Do you have any information as to why the --**
 8 **there is a cap -- I'll just say a cap for this survey.**
 9 **A** That is something that he would do looking at
 10 what -- between each person, if you have -- when you're
 11 doing the average, if you have -- you know, you've got
 12 someone with \$20,000 and someone with \$200,000, then you
 13 would look at the average of those, and that would be your
 14 cap.
 15 **Q And you understand that the taxpayer disagrees**
 16 **with that --**
 17 **A** That --
 18 **Q -- correct?**
 19 **A** -- is correct.
 20 **Q So when you're valuing working interest, you'd**
 21 **come up with these appraised values, and that's decline in**
 22 **income stream over time, et cetera?**
 23 **A** Yes.
 24 **Q Briefly explain that.**

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1 **A** Right. We look at, if it's a new well, it's
 2 annualized -- the production is annualized.
 3 Once the well has been in production for three
 4 or four years, we actually use a 3-year average of the
 5 income, with the most weight being on the most current
 6 year.
 7 **Q And you've been in the business -- the oil and**
 8 **gas appraisal business for how long?**
 9 **A** Almost 25 years.
 10 **Q And is there, like, general rules of thumb of**
 11 **what these things average out on royalty interest, working**
 12 **interest?**
 13 **A** Before the Marcellus, we would usually tell a
 14 producer that their value's going to be two to four times
 15 on your income based upon the decline rate of the; a
 16 royalty owner, three to five. With the Marcellus, we're
 17 seeing it on the lower end with -- at times -- especially
 18 during the first year, where it's not even a 1 multiplier.
 19 **Q So when -- have you looked at the reported -- any**
 20 **of these here and looked at the gross proceeds or the**
 21 **income?**
 22 **A** I have a calculator.
 23 **Q See what ballpark these are coming in at, just a**
 24 **few. A couple.**

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1 A If we look at the first one, where I had the
2 income listed for -- in District 10, 2015, 0023, we have a
3 appraisal of \$15,652,042, and there was \$8,271,008 in gas,
4 and \$1,601,394 in working interest oil.
5 MR. GRIFFITH: Is that an exhibit? I'm not sure that
6 I have it.
7 Q Are you looking at the --
8 A This one, yes.
9 Q So that's roughly -- the appraisal's coming in --
10 how's the appraisal coming in as far as the relationship
11 to their income?
12 A Just a second. I'm just going to round it a
13 little bit.
14 Q Yeah, you can round it.
15 A About 1.59.
16 Q So the appraisal's roughly --
17 A One and a half times one's income.
18 Q And that's going to --
19 A And then the County takes that by 60 percent for
20 the assessment.
21 Q So if they made \$10 million, you have a value --
22 A At 15.
23 Q 15, based on the presumption it's going to
24 produce over a period of time, and that's what somebody

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1 would sell it for today?
2 A That is correct.
3 Q If the taxpayer has submitted, which is
4 protested -- if I tell you they believe the value of it --
5 that this well is going to produce over an extended period
6 of time is 9.39 -- \$9,314,567, that's less than the income
7 it produced that year?
8 A Yes.
9 Q Do you think somebody would sell something less
10 than the income that it's producing in that particular
11 year --
12 A I --
13 Q -- sell it --
14 A -- wouldn't think.
15 Q -- for less? Is it your belief that the -- these
16 appraisals were performed in accordance with the laws and
17 regulations and the filed variables to come out -- arise
18 out of the regulations?
19 A That is correct.
20 Q And you detected no -- in reviewing these, you
21 didn't see any errors that you may have made?
22 A No.
23 MR. MUDRINICH: Nothing further.
24 EXAMINATION

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1 BY MR. GRIFFITH:
2 Q Okay. Just a couple questions about that sheet.
3 These are gross revenue numbers; is that correct?
4 A That is correct.
5 Q It doesn't reflect the significant operating
6 expenses necessary to get that out of the ground --
7 A That is correct. That's what --
8 Q -- to market. It doesn't account for decline on
9 that sheet, either, does it?
10 A No. That's just listing the -- the actual income
11 for each of the years.
12 Q Okay. Let's look at the survey a little bit.
13 And we actually Phil Yoo here from Antero that filled out
14 that -- the Calendar Year 2013 survey. I'll ask him one
15 question after Cindi's done about that survey.
16 Cindi, on the survey that's circulated annually
17 -- it was circulated in what, '14 and '15 -- or '13 and '14
18 by the Tax Department?
19 A It was for Calendar Year '13 and Calendar Year
20 '14.
21 Q Okay. For those two recent surveys that were
22 circulated, is it fair to say that the categories listed
23 on there slant more towards lease operating expenses?
24 A Yes.

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1 Q Any category on there for gathering,
2 compression, transportation of expenses incurred for
3 Marcellus wells?
4 A Not under those categories, no.
5 Q Okay. Discuss the timing of the tentative and
6 the final variables that are made public by the Tax
7 Department each year?
8 A The variables are -- the tentatives are filed
9 July 1 of each year. They're open for a 30-day public
10 comment. That's till August 1. And then Jeff reviews
11 those --
12 Q Jeff Amburgey, right?
13 A Jeff Amburgey, yes. He reviews those and makes
14 any comments or any changes. And then he files the finals
15 on September 1st.
16 Q Okay. Typically are the tentative values -- or
17 do those change when the final variables are submitted or
18 are they generally static?
19 A Generally they're static. The last couple years
20 there have been some changes.
21 Q Okay. Based on your experiences with taxpayers
22 recently, including Antero, have you seen a claim that the
23 operating expenses that are included in those valuation
24 variables are exponentially higher than -- than what the

Page 94 1 Tax Department's allowing? 2 A We have had a couple producers protest, yes. 3 Q Okay. And a new revenue stream, obviously 4 Marcellus wells, are the proceeds from natural gas 5 liquids, when you're a client, and obviously there are 6 revenue streams associated with the natural gas from a 7 well, the NGLs from a well, do you apply those operating 8 expenses to each of those revenue streams separately? 9 A No. They're reported in with the Mcf and the 10 gas. 11 Q Okay. Do you understand that's kind of a 12 weakness there, being that to produce those NGLs, it's 13 pretty significant, expenses are incurred on top of the -- 14 the traditional expenses that have been allowed by the Tax 15 Department? Can you see the pitfall on that? 16 A All we can do is follow the rules. 17 Q Well, you agree when that rule was drafted that 18 NGLs were not really a major point of -- or a major revenue 19 producer in the state? 20 A That is correct. 21 Q Okay. Has the Tax Department, based on the 22 operating expenses that Antero has submitted through 2015 23 and 2016 -- have there been any objections to the 24 categories of expenses that -- that Antero submitted to the	Page 96 1 Q -- by imposing that cap -- are you treating 2 similarly situated taxpayers different? And other wise, 3 where it's a Marcellus operator that has \$750,000 gross 4 receipts for a well, you're getting the full 20 percent. 5 Any other Marcellus operator that goes over that 6 \$750,000 gross revenue, you're going under the 20 percent; 7 is that right? 8 A That is correct. 9 Q Finally, let's look at the legislative rule. 10 Can you point under the definition or the discussion of 11 average annual operating expenses where it discussed a cap 12 rate or cap -- cap amount or maximum rate that should be 13 allowed as part of that average? 14 A It does not mention the word "cap." 15 Q Okay. On the issue of actual operating 16 expenses, I think Jan mentioned you -- he aged you a little 17 bit, but you've been with the Department for 24 years. 18 During that time, for instance, from 2000 to 19 2015, the admin notice that the Tax Department circulates 20 is part of the valuation of producing wells, has invited 21 producers to approach the Tax Department with actual 22 operating expense information; is that right? 23 A That is correct. 24 MR. GRIFFITH: I think that's all I have.
Page 95 1 Tax Department? Have you articulated that to Antero in 2 any way? 3 A Our main thing has been over the point of sale 4 and what is allowable expense due to the point of sale. 5 Q Has that been communicated to Antero before 6 today? 7 A I believe it has. 8 Q Back to the survey. Do you audit those results 9 in any way? Do you require financials or anything like 10 that to -- to tie the amounts that are being listed on that 11 survey to actual financial information? 12 A No. 13 Q Do you make any attempt to group companies based 14 on their point of sale or production of wet gas, NGLs, 15 their corporate structure, or do you just lump everyone 16 together and then come up with the average based on that? 17 A To my knowledge, no. 18 Q Okay. So by using that average, you're 19 essentially using the actual operating expenses for 20 everyone under the cap, which is the 20 percent, but 21 limiting the operating expenses for larger producing 22 wells; is that correct? I mean, it's percentage basically 23 if you -- 24 A Right.	Page 97 1 REEXAMINATION 2 BY MR. MUDRINICH: 3 Q Just a couple of on redirect. How many 4 taxpayers have submitted actual operating expense with 5 their return, on an average? 6 A On an average in past years, there may have been 7 three or four. 8 Q But Antero did? 9 A Yes. 10 Q And we've already gone over why we -- that we 11 didn't accept them -- let's say we had a system where 12 everybody submitted their actual expenses and that's how 13 we get -- value oil and gas. 14 Do you think you can handle that with the staff 15 you have available today -- 16 A Absolutely -- 17 Q -- to look in -- 18 A -- not. 19 Q -- and see the accuracy of this information? So 20 the cost of administering the property tax system would 21 shoot through the roof? 22 A That is correct. 23 Q And just one other thing regarding -- he asked 24 you about when -- about treating similarly situated

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1 taxpayers different.
 2 If a tax – if two Marcellus taxpayers are making
 3 \$1 million, each made \$1 million gross, the well started
 4 the same day, often being equal, similarly situated, their
 5 values would be the same, wouldn't they?
 6 A That is correct.
 7 Q Likewise, if somebody's making \$400,000 a year,
 8 there's another guy making \$400,000 a year, their values
 9 would be the same?
 10 A Correct. As long as it's the same formation.
 11 Q Yes, let's assume all that.
 12 A Right.
 13 Q But, of course, somebody that's making \$400,000
 14 is not similarly situated with somebody making \$1 million
 15 because the guy making millions is making more than double
 16 their income, correct?
 17 A Correct.
 18 MR. MUDRINICH: Nothing further.
 19 REEXAMINATION
 20 BY MR. GRIFFITH:
 21 Q Just one follow-up on that. Does it not make a
 22 lot more sense that additional operating expenses are
 23 incurred for the \$1 million well versus the \$500,000 well?
 24 A Not if on the survey the – the greatest number

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1 was \$150,000 – or the average, the greatest was --
 2 Q Yeah.
 3 A -- \$150,000.
 4 MR. GRIFFITH: Okay.
 5 MR. MUDRINICH: I have one question.
 6 MR. GRIFFITH: I think we can rest. Just one
 7 question for Phil Yoo. He has not been sworn in, so we
 8 can just swear him in.
 9 PHIL YOO,
 10 having been first duly sworn to tell the truth, testified
 11 as follows:
 12 EXAMINATION
 13 BY MR. GRIFFITH:
 14 Q Phil, just one question. I think your name
 15 shows up as the contact person on the survey information
 16 that was submitted for Calendar Year 2013.
 17 When that survey was submitted, did you have any
 18 inkling that the Tax Department was asking for information
 19 regarding gathering expenses, compression expenses, or
 20 transportation expenses?
 21 A No. Generally speaking industry wise, when we
 22 talk about operating expenses, you think about just the
 23 cost to – the cost of getting it developed and not the
 24 gathering, transportation, compression costs.

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1 Industry wise, we think of that as what we
 2 typically call GP&T -- G P & T -- gathering, processing,
 3 and transportation.
 4 When we talk about LOE, or lease operating
 5 expenses, we think specifically about cost such as tending
 6 to the well and not the cost related to transporting,
 7 gathering, and processing.
 8 Q And when you look at these categories, that
 9 would tend to point you towards the lease operating
 10 expense information?
 11 A Absolutely.
 12 Q Okay.
 13 A And not – not the gathering, processing, and
 14 transportation cost.
 15 MR. GRIFFITH: Okay. That's all I have.
 16 EXAMINATION
 17 BY MR. MUDRINICH:
 18 Q Just one. Phil, it's a fair statement to say
 19 that what you reported here, as you testified, that you --
 20 it didn't include any gathering and transportation.
 21 But you believe this is a fair representation of
 22 what it cost to get the gas out of the ground?
 23 A I would say it's – it's a representation of the
 24 cost to get the gas out of the ground, but not a

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1 representation of the cost to get the gas or other
 2 products to market or to the point of sale.
 3 Q And your point of sale would be similar to where
 4 the person who testified about the point of sale – you
 5 don't have any differences --
 6 A You know, so we sell our gas. We do not sell
 7 our gas anywhere near the wellhead, except in the case of
 8 vertical wells, where it is much closer to the wellhead.
 9 Recently we've actually been going so far as to
 10 transport it out of state and selling it out of the state.
 11 Q And have you done any analysis of royalty owners
 12 – the royalty owners you deal with, to see if they're
 13 incurring some of these post-production costs, can be
 14 deducted from their royalty check?
 15 A I have.
 16 Q You have?
 17 A Yes.
 18 Q And do they?
 19 A In some cases they do, in some cases they do
 20 not. As Kirsten testified it is very lease specific.
 21 But we do pay our royalty owners based on the
 22 ultimate point of sale, not the – not – or wherever we
 23 actually sell our gas. So in the case of vertical wells,
 24 it is much closer to the wellhead. And in the case of

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1 others wells, it could be – and the recently out of state
 2 - but we also do deduct some processing cost or look at
 3 the economic or processing to see whether the owner is
 4 better off or worse than the case of processing, because
 5 processing can actually result in a reduction in value or
 6 reduction to the royalty owner. So.
 7 **Q In other words, they can get so much cost taken**
 8 **out, they end up owing the company money?**
 9 A That would never happen, because we always
 10 calculate royalties by NGLs, the higher of, and always pay
 11 the royalties –
 12 **Q NGL. Let's talk about gas, the same thing?**
 13 A If you – even with gas, no, that would never be
 14 the case, because realistically it cost us more to ship it
 15 out of state and sell it out of state. We wouldn't do
 16 that ourselves, because then we'd be losing, too, by
 17 shipping it out of state. Why wouldn't we just sell it at
 18 the wellhead.
 19 MR. MUDRINICH: Okay. Nothing further.
 20 REEXAMINATION
 21 BY MR. GRIFFITH:
 22 **Q Okay. Just one follow-up on this survey. If it**
 23 **were resubmitted today and you know that – you have a**
 24 **full understanding of what this survey was being used for,**

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1 I would imagine you'd approach it differently today,
 2 correct?
 3 A Absolutely. We'd include all our gathering,
 4 processing, and transportation costs.
 5 MR. GRIFFITH: That's all I have.
 6 MR. MUDRINICH: Nothing. Done.
 7 MR. GRIFFITH: And I think I mentioned this earlier
 8 on, but to the extent that any of these exhibits weren't
 9 specially discussed in detail, we'd ask that they be
 10 submitted for the record.
 11 MR. MUDRINICH: No objection to any of the taxpayer's
 12 exhibits. We ask that that packet that we gave you,
 13 including the expense survey and those accompanying
 14 documents were made part of the record. And we're going
 15 to also give the copy of ours to the court reporter.
 16 MR. GRIFFITH: That's fine.
 17 MR. WORDEN: I do have several questions to either
 18 party. So the issues at stake here is the cap limit per
 19 well? Correct or incorrect?
 20 MS. EVANS: Yes.
 21 MR. WORDEN: The end point of sale is at issue?
 22 MR. MUDRINICH: Yes.
 23 MR. GRIFFITH: Yes.
 24 MR. WORDEN: And the decline rate is at issue, the

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1 calculation.
 2 MR. GRIFFITH: Yes.
 3 MR. MUDRINICH: (Nodded affirmatively.)
 4 MR. GRIFFITH: And further than the appraisal, the
 5 capitalization rate would be an issue as well.
 6 MR. WORDEN: Okay. A lot of these issues are due to
 7 legislation and rules?
 8 MR. MUDRINICH: Yes.
 9 MR. WORDEN: Okay. And one question – or two more
 10 questions. If there are any changes to the rules, will
 11 they be retroactive back to these previous years?
 12 MR. MUDRINICH: Well, you couldn't speak for the
 13 Legislature. But the idea in the property tax realm, that
 14 they would pass something and it would have an effect on
 15 previous years, with the way budget and levy provisions
 16 exist in the Constitution, I don't even know if they could
 17 do that?
 18 MR. GRIFFITH: No. I think it would be a tough task
 19 to go back.
 20 MR. WORDEN: So the answer will be no, right?
 21 MR. GRIFFITH: I think most likely. I can tell you
 22 the association of counties has a pretty strong body –
 23 arm. So.
 24 MR. WORDEN: I'm sure the County Commission

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1 association --
 2 MR. MUDRINICH: Sometimes things are - changes in
 3 rules are -- perspective incrementally imposes what
 4 we've done with coal. We went from one method to a new
 5 method, they for the first either three or five years, I
 6 can't remember, it's been so long ago, they took your --
 7 the first year that new rule came in, you were still 80
 8 percent value on your -- under the old method. And they
 9 just gradually came in until everybody was under a new
 10 method. That's happened before.
 11 MS. EVANS: Can you clarify real quick the -- the
 12 Legislature is -- the rule is -- the fact of fair market
 13 value.
 14 This administrative rule tells the State how to
 15 administer their appraisal system does not talk about the
 16 cap, does not talk about the cap rate, which we've
 17 discussed.
 18 It tells them how they should build it up, and
 19 that a survey should be done. But it doesn't -- without
 20 going against the Legislature to remove a cap or change a
 21 cap rate. It just talks about how to administer a mass
 22 appraisal to get to fair market value.
 23 MR. MUDRINICH: I differ with that conclusion. I
 24 believe the State Department followed this. There's

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1 nothing in here authorizing a cap. The cap - the survey 2 is part of the rule. 3 We explained how the cap was done. It's done 4 through the survey. We believe we were compliant with 5 this rule and cannot do anything else until the rule is 6 changed. 7 MR. GRIFFITH: And, you know, our position on the 8 caps is that it's not supported by the rule. 9 Yet, in fact, the Department can put that in 10 their tentative - you know their valuation variables and 11 in their admin notices, but we don't think that's 12 supported by the rule, and we don't think that's supported 13 by the legislative rule. 14 MR. WORDEN: And when one final question. What 15 budgetary impact does this have on Ritchie County? 16 MR. GRIFFITH: Well, it -- 17 MR. MUDRINICH: You've got all the -- 18 MR. GRIFFITH: There's several different options. As 19 appealed the property tax amount would have been about 20 \$1.4 million. 21 Pursuant to the appraisal that Alan discussed, 22 the impact would be about \$1.8 million. 23 And then pursuant to the curve - the last 24 appraisal that Kirsten discussed, where you would just	1 Antero, Ritchie County was marked for 2 identification as Exhibit No. 1.) 3 (WHEREUPON, the hearing was concluded at 4 1:30 p.m.) 5 1 6 1 7 1 8 1 9 1 10 1 11 1 12 1 13 1 14 1 15 1 16 1 17 1 18 1 19 1 20 1 21 1 22 1 23 1 24 1 REPORTER'S CERTIFICATE I certify that the foregoing is a correct transcript of the hearing of proceedings in the above-entitled matter. November 2, 2016 Signature _____ Date _____
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1 remove that cap and use the 20 percent, that would be 2 about \$900,000. 3 MR. WORDEN: The impact to Ritchie County -- 4 MR. GRIFFITH: Yes. 5 MR. WORDEN: -- specifically? 6 MR. GRIFFITH: Yes. 7 MR. WORDEN: That's significant. No further 8 questions? 9 MR. GRIFFITH: No. 10 MR. MUDRINICH: No. 11 MR. WORDEN: I think this concludes our discussion. 12 MR. GRIFFITH: Okay. 13 MR. WORDEN: I want to thank everybody for coming 14 down and being patient. 15 (WHEREUPON, the Exhibit Notebook headed "Antero Notice of 16 Protest, Ritchie County," was marked for identification as 17 Exhibit No. 1; and the packet headed "Antero/Craig 18 Griffith, Ritchie County Commission" was marked for 19 identification as State Tax Department's Exhibit No. 1.) 20 (WHEREUPON, the notebook entitled "Antero 21 Notice of Protest, Ritchie County" was 22 marked for identification as Exhibit No. 1; 23 and the folder was marked for 24 identification as State Tax Department,	

Exhibits Exhibit 1 4:0 42:10, 11 107:17,19,22 108:2 \$ \$1 17:8 54:9,20 80:7 83:20 98:3,14,23 \$1,601,394 90:4 \$1.06 54:2 \$1.3 45:17 \$1.59 21:5 \$1.6 14:16 21:7 31:18 32:14 56:18 \$1.61 64:24 \$10 90:21 \$141,000 15:7 17:5 \$141,767 15:2 \$149,000 22:21 \$15,652,042 90:3 \$150,000 7:1 8:2,13 11:21 15:1,6 16:19 17:11 26:6,19 31:20, 23 33:21 34:4,6 35:4, 8 41:24 42:4 82:13 93:19 86:21 87:10,12, 17,19 99:1,3 \$175,000 34:24 \$18.2 21:14 \$189,000 22:20 \$194 42:12 70:8 \$2 14:15 17:8 24:11 \$2.08 64:21 \$2.1 17:4 \$2.7 14:15 \$20,000 88:12 \$200,000 88:12 \$263 56:20 \$280,000 22:20 \$3 60:17	\$3.1 16:10,19 \$30,000 86:6 \$31,000 21:15 22:19 35:5 36:9 54:8 \$32,000 12:20 21:20 54:7 55:1 \$32,994 10:13 52:18 \$38,000 86:6 \$385 21:11 23:14 \$40,000 9:24 \$400,000 98:7,8,13 \$5 14:13 \$5,750 86:23 \$5.5 17:1 \$500,000 98:23 \$52 21:8 32:14 \$537,000 41:22 \$59 70:9 \$590,000 48:23 \$6,273 10:14 \$60,000 48:21 \$600,000 36:10 42:2 \$64,000 48:21 \$648,000 11:24 22:22 36:8 41:16 54:10,12, 19 \$650,000 16:22 \$750,000 31:24 32:1, 3,6,11 83:18 96:3,6 \$8 24:9 \$8,271,008 90:3 \$84 42:16 \$9,314,567 91:6 \$968 37:20,22 0 0023 90:2	1 1 14:12,14,24 16:6 39:17 42:11 53:8,9 54:21 71:23 89:18 93:9,10 1.29 69:10 1.59 90:15 10 11:14 15:24 29:24 48:22 90:2 100 48:19 69:7 70:22 11 59:10 60:21 110-CSR-1J 9:1 12 31:2,10 33:11 48:20 12-plus 76:13 12.75 48:18 13 36:15 53:11 92:17, 19 14 39:20 40:1 53:10, 12,13 80:12,13 88:1 92:17,20 15 11:12 16:1 25:23 53:16,18,19 63:14 71:24 80:1,8 81:10 88:1 90:22,23 92:17 15-year 7:9 15.3 68:11 69:17 15th 53:23 16 33:14 40:15 41:1 64:15 16-1/2 80:6 16.3 68:10 16th 33:16 17 40:15 18 14:14 1997 59:20 1st 93:15 2 2 36:24 37:12 40:10 54:9 69:3,6 71:24 79:19	2.7 15:5 20 6:23 8:1,9 14:24 24:5,9 29:6,7 30:13 31:23 32:4,9 33:2,5, 21 34:3,6,23 35:13,14 40:19 44:9 64:9 69:16 75:23 80:1,10 83:16 84:10 86:21 87:19 95:20 96:4,6 20-year 72:1 2000 7:10 96:18 2006 40:4 2008 39:24 2010 39:19 2011 60:23 2012 40:5 2013 16:8 39:20 58:19 92:14 99:16 2014 6:18,21 30:4 53:23 62:10,19 77:1 2014/2015 76:21 2015 7:23 10:10,12 19:2,17,22 25:21 52:16 53:4 62:11,20 87:22 90:2 94:22 96:19 2016 6:21 7:15,21 11:16 19:13,17,22 25:21 33:12 34:20 40:14 82:23 85:14 94:23 2017 34:16,21 40:13 22 35:12 23 33:1 35:14 63:7 71:19 24 5:7 6:1 96:17 25 89:9 29 63:6 71:19 3 3 13:8,19 32:13,15,17 38:2 41:20 69:5 77:12 78:18 79:6 3-year 89:4	3.30 47:13 30 37:15 66:22 75:24 30-day 93:9 35 86:22 38 40:19 39 63:13 71:23 72:23 4 4 20:11 23:9 35:1.2 45:4,5,6 47:11 78:18 79:6 4.3 80:18 40 14:12 29:12 41:15 75:24 41 40:20 43 42:1 46 63:6 71:19 5 50 29:12 30:14 34:10, 11 70:4 500 79:22 52 31:19 55 40:16 6 6 25:15 40:1 67:14 6.7 15:19 60 90:19 63 63:12 71:23 72:4, 14 7 7 67:15 70 66:23 73 64:15 8 8 26:9,24 46:9,10

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39:5 59:21 60:5 61:1
63:5 69:10,21 72:2
75:24 76:13 79:9,19
87:21 89:4,9 92:11
93:19 96:17 97:6
99:11,15 105:5

yield 67:23 68:1

Yoo 92:13 99:7

Per Dep.
Exhibit -
Antero Survey
Report

Confidential

Marcellus Vertical and Horizontal and Other Horizontal
for Calendar Year 2013

Please submit information to:

Special Properties Section
WV Dept. of Revenue
Property Tax Division
PO Box 1345
Charleston, WV 25325-1345

Company Name: Antero Resources Corporation Contact Person: Phil Yoo

Per Series 1J, Title 110, State Tax Commission Legislative Rule for Valuation of Producing & Reserve Oil & Natural Gas for Ad Valorem Property Tax Purposes:

3.14: "Operating Expenses" means only those ordinary expenses which are directly related to the maintenance and production of natural gas and/or oil. These expenses do not include extraordinary expenses, depreciation, ad valorem taxes, capital expenditures, or expenditures relating to vehicles or other tangible personal property not permanently used in the production of natural gas or oil."

	Vertical Marcellus	Horizontal Marcellus	Horizontal Other-Please list same**
Annual Revenue Net of Royalties:	542,359.9	771,773.728	
Annual Expenses:			
Direct Expenses:			
Well Tending Costs:	779,246	2,150,545	
Additional Supplies:	160,075	669,194	
Charting:	96,274	709,627	
Compressor/Pumping Costs:	3,562		
Electrical Costs:	67,027		
Other Expenses:	23,644	152,541	
Other Operating (3rd Party?) Costs:	115,168	308,091.2	
Swabbing, Service Rig		6,283	
Waste Disposal (e.g. Prod. Fluid)	205,934	3,816,612	
Roadway-Maint. & ROW	316,134	552,588	
Pipeline-Maint. & ROW			
Indirect Operating Costs:	522,088	437,568.2	
Environmental/Safety Costs:	114,934	282,473	
Insurance:			
Bookkeeping/Revenue Distrib.			
Overhead:			
Other Expenses Not in the above:	163,725.6	735,659.0	
List:			
Total Annual Expenses for the Year:	1,752,096	7,729,063	
Plug & Abandonment Expenses/Well			
Number of Wells in above data:	261	226	

**Send if horizontal and different than Marcellus

Suggestion: Show totals for all wells. Direct Expenses above are based on a per well situation.

6273

32,994

nothing
given

RECEIVED

Street Smart. World Wise.

AUG 6 2015



July 31, 2015

State Tax Department
Property Tax Division

West Virginia State Tax Department
Property Tax Division
Attention: Jeff Amburgey
P.O. Box 2389
Charleston, West Virginia 25328-2389

RE: Public Comment Concerning Property Valuation Variables for the 2016 Tax Year

Dear Mr. Amburgey:

Pursuant to the letter from Mr. Matkovich to Secretary Tennant dated June 30, 2015, this letter serves to provide you with our comments on the tentative natural resource property valuation variables specifically related to gas wells, for the 2016 tax year.

Specifically, our concerns regarding these variables relate to the following:

Operating Expenses: Based on a detailed review of actual operating expenses incurred in West Virginia by Antero Resources during the 2012, 2013 and 2014 calendar years, we believe that the tentative maximum operating expenses per well as allowed by the State of West Virginia are understated. To support this claim, we have submitted operating expense data for three years, as required by West Virginia, with the TY16 return filing. Actual annualized operating expenses incurred compared to allowable expense caps are as follows:

Well Type	Allowed Expense	Average of Actual Expense
Marcellus, Horizontal Wells	\$150,000	\$1,060,000
Horizontal Wells (Other than Marcellus)	\$20,000	\$419,000

We respectfully request that the State modify these variables, based on the information provided above, for use in its appraisal of gas wells for property tax purposes for the 2016 tax year. We would be happy to discuss our comments with and/or provide additional information that the State may need. Please feel free to contact me at (410) 568-0733

Sincerely,
Very truly yours,
Altus Group US, Inc.

A handwritten signature in cursive script that reads "Kirsten Evans".

Kirsten Evans

Cc: Phil Yoo, Chief Accounting Officer, Antero Resources Corporation

RECEIVED

August 1, 2016

AUG 5 2016



West Virginia State Tax Department
Property Tax Division
Attention: Jeff Amburgey
P.O. Box 2389
Charleston, West Virginia 25328-2389

State Tax Department
Property Tax Division

Antero Resources
1615 Wynkoop Street
Denver, CO 80202
Office 303.357.7310
Fax 303.357.7315

RE: Public Comment Concerning Property Valuation Variables for the 2017 Tax Year

Dear Mr. Amburgey:

Pursuant to the letter from Mr. Matkovich to Secretary Tennant dated June 30, 2016, this letter serves to provide you with our comments on the tentative natural resource property valuation variables specifically related to gas wells, for the 2017 tax year.

Specifically, our concerns regarding these variables relate to the following:

Operating Expenses: Based on a detailed review of actual operating expenses incurred in West Virginia by Antero Resources during the 2015 calendar year, we believe that the tentative maximum operating expenses per well, as well as the percentage of revenue allowances as published by the State of West Virginia are understated. Actual annualized operating expenses incurred as a percentage of revenue, and as an average per well are as follows:

Well Type	Average Operating Expense as Percent of Revenue	Average Operating Expense per Well
Marcellus, Horizontal Wells	44%	\$1,153,000
Horizontal Wells (Other than Marcellus)	73%	\$25,000
Typical Producing Wells	Operating at a loss	\$6,100

Consistent with recent discussions regarding the 2016 tax year, we believe that the State's use of actual operating expenses is the most accurate method of valuing the tax wells. Absent the ability to use actual data, at minimum the State's allowance percentages should be increased to be more consistent with actual data provided, and the maximum operating expense should be removed entirely. Without adjustment of these variables, the State is drastically overstating the value of Antero's property in West Virginia.

We respectfully request that the State modify these variables, based on the information provided above, for use in its appraisal of gas wells for property tax purposes for the 2017 tax year. We would be happy to discuss our comments with and/or provide additional information that the State may need. Please feel free to contact our tax agent, Kirsten Evans at (410) 568-0733.

Sincerely,
Antero Resources Corporation


Alwyn A. Schopp, SVP, Treasurer and Chief Administrative Officer

Cc: Kirsten Evans, Altus Group US, Inc.

Hoover, Cindi R

From: Phil Yoo <pyoo@anteroresources.com>
Sent: Thursday, May 15, 2014 5:08 PM
To: Hoover, Cindi R
Subject: West Virginia Oil & Gas Operating Expenses Survey
Attachments: SAccounting14051515031.pdf; 5Accounting14051515030.pdf

Ms. Hoover,

Please find attached our response to your Oil & Gas Operating Expenses Survey.

Please contact me if you have any questions. Thank you.

K. Phil Yoo, CPA
Chief Accounting Officer & Corporate Controller
Antero Resources
1615 Wynkoop Street
Denver, CO 80202
Work: (303)357-7364
Mobile: (720) 239-3916
www.anteroresources.com

For Impl. Review -
 hp 5 production well

CY	NRA	API	TY2016 MCF	TY2016 W1 \$	TY2015 MCF	TY2015 W1 \$	TY2014 MCF	TY2014 W1 \$	TY2017 MCF	TY2017 W1 \$	Rev. Info
OIL	43 1020150023	10023	1325147	8271008	1163492	1937649			995455	2157259	153 DAYS
			23003	1601394	16721	1193402			12979	473705	
OIL	43 1020159970	9970	1251917	7292713	1078895	1762865			1005336	2170294	
			22492	1542504	22707	1664781			14340	420448	153 DAYS
OIL	43 0320150036	10036	1107840	6864513					680037	1626036	
			10639	729372	5991	416022			5493	165324	153 DAYS
OIL	43 0320160062	10062	871332	3452602					2325693	5097205	64 DAYS
			5538	243085					10006	287232	
OIL	43 0320160088	10088	872253	4573862					1718824	4255514	93 DAYS
			8731	447132					8037	237673	

1st April, Sunday -
 Street works, etc.

JUR	ACCOUNT	LC	PARID	OWN1	FINALVAL	
43	1020160005	FP	15010005	IRELAND BETTY S	38400	not on protest
43	1020160005	FP	16010005	ANTERO RESOURCES CORPORATION	9772851	not on protest
43	1020160005	FP	14010015	SWN PRODUCTION COMPANY LLC	30956	not on protest
43	1020160005	FP	16010015	ANTERO RESOURCES CORPORATION	7540723	

For Dept.
Exhibit

110CSR1J

**TITLE 110
LEGISLATIVE RULE
STATE TAX DEPARTMENT**

**SERIES 1J
VALUATION OF PRODUCING AND RESERVE OIL AND
NATURAL GAS FOR AD VALOREM PROPERTY TAX PURPOSES**

§110-1J-1. General.

1.1. Scope. -- This rule provides the methodology the State Tax Commissioner shall use to determine the appraised value of producing and reserve oil and natural gas properties for ad valorem tax purposes.

1.2. Authority. -- W. Va. Code §§11-1C-5(b), 11-1C-5a, and 11-1C-10(d).

1.3. Filing date. -- May 5, 2005.

1.4. Effective date. -- June 1, 2005
This rule applies to tax years beginning on or after January 1, 2006.

§110-1J-2. Introduction.

Oil or natural gas is one of the several estates in real property which may be owned either separately or in conjunction with other estates. If oil or natural gas is owned as a separate estate, either absolute, as a leasehold, or in conjunction with other estates, West Virginia property tax law requires that ownership be listed, valued and taxed in proportion to its value to be ascertained as directed by law. If oil or natural gas is owned in conjunction with other estates, the value of the oil or natural gas shall be included in the value of the other estate. Oil or natural gas may be owned without being produced. Oil or natural gas title may exist where no oil or natural gas is known to be present, or where the oil or natural gas is unproducible or depleted.

2.1. Categories for valuing oil and/or

natural gas properties. -- Parcels of property bearing or having the potential to bear oil and/or natural gas or having the oil and/or natural gas mineral interest separated from the fee of the property shall be categorized as:

2.1.1. producing property (to include home. use/industrial on-property consumption);

2.1.2. non-producing property;

2.1.3. barren property; or

2.1.4. plugged and/or abandoned property.

§110-1J-3. Definitions.

As used in this rule and unless the context clearly requires a different meaning, the following terms have the meaning ascribed in this section.

3.1. "Bands of investment discount component" means a discount rate derived by assigning rates to various debt and equity investment financing tiers and summing these rates, weighted by their respective percentages of total financing.

3.2. "Barren oil and natural gas property" means those fee and mineral parcels in West Virginia where data suggests that the presence of oil and natural gas is very unlikely.

3.3. "Capitalization rate" means a rate used to convert an estimate of income to an

estimate of market value. Subsection 4.5 of this rule further explains this term.

3.4. "Commissioner" or "Tax Commissioner" means the Tax Commissioner of the State of West Virginia, or his or her delegate.

3.5. "Discount component" means a rate reflecting a provision for returning to an investor a sum of money equal to the aggregate of the anticipated return-on-investment over the economic life of an investment.

3.6. "Flat Rate royalty" means a royalty rate in which the amount paid per year (e.g. \$100 per year) is set within a lease and is not dependant on the production or income derived from the well.

3.7. "Flush production" means the production of oil and/or natural gas from any well on an oil and/or natural gas property with an initial production date that is two (2) calendar years or less prior to the July 1st assessment date. Production beginning after December 31st and prior to the July 1st assessment date must be reported.

3.8. "Gross receipts" means total income received from production on any well, at the field line point of sale, during a calendar year before subtraction of any royalties and/or expenses.

3.9. "Management rate" means a rate reflecting a return to an investor for the management of similar investment portfolios.

3.10. "Natural gas producing property" means the property from which natural gas has been produced or extracted at any time during the calendar year preceding the July 1 assessment date. Natural gas producing property includes the interest or interests underlying an area of up to one hundred

twenty-five (125) acres of surface per well for property with active wells on the parcel. All acreage of a natural gas producing property in excess of one hundred twenty-five (125) acres per well, shall be valued at the non-producing rate per acre referenced in section 4. of this rule.

3.11. "Nonliquidity rate" means a rate reflecting a return to an investor representing the loss of interest on an investment arising from the time required to sell the investment.

3.12. "Non-Producing or Shut-in Well" means a well, which due to the producer's decisions, market reasons and/or product performance, was non-productive during the entire most recent calendar year preceding the July 1st assessment date.

3.13. "Oil and/or natural gas, non-producing property" means properties that were not engaged in production during the previous assessment year period of July 1st through June 30th. This category includes any acreage that has been shut-in for the entire year.

3.14. "Oil and/or natural gas plugged and abandoned property" means plugged and abandoned oil and/or natural gas wells.

3.15. "Oil producing property" means property from which oil has been produced or extracted at any time during the calendar year preceding the July 1 assessment date. Oil producing property includes the interest or interests underlying an area of up to forty (40) acres of surface per well with one (1) or more active well(s) on the parcel. All acreage of an oil producing property in excess of forty (40) acres per well, shall be valued at the non-producing rate per acre referenced in Section 4 of this rule.

3.16. "Operating expenses" means only those ordinary expenses which are directly related to the maintenance and production of

natural gas and/or oil. These expenses do not include extraordinary expenses, depreciation, ad valorem taxes, capital expenditures or expenditures relating to vehicles or other tangible personal property not permanently used in the production of natural gas or oil.

3.17. "Overriding royalty" means the fractional interest in the gross production payable to a person who is neither the producer nor the owner of the oil and natural gas estate and who is not required to bear a share of the development or operating costs of the well.

3.18. "Personal property" used in oil or natural gas production means machinery and equipment in and about the well and all other tangible personal property used in oil and/or natural gas production from the well to the fieldline point of sale. It shall not include vehicles or other tangible personal property not permanently used in production.

3.19. "Producer/operator" means any person or persons, corporation, partnership, joint venture or other enterprise which proposes to or does locate, drill, produce, manage, or abandon any well.

3.20. "Property tax component" means a rate reflecting a provision for returning to an investor a sum of money equal to property taxes paid over the economic life of an investment.

3.21. "Recapture component" means a rate reflecting a provision for returning to an investor a sum of money equal to his or her investment.

3.22. "Risk rate" means a rate reflecting a return to an investor necessary to attract capital to an investment containing a possible loss of principal and/or interest.

3.23. "Royalty interest" means the

fractional interest in oil and/or natural gas production that is not subject to development costs or operating expenses and extends undiminished over the life of the property. Typically, it is retained by the oil and/or natural gas rights owner or lessor.

3.24. "Safe rate" means a rate reflecting a return to an investor on an investment which has little, if any, likelihood of loss of principal or of loss in anticipated return on investment.

3.25. "Settled production" means the production of oil and/or natural gas from all wells on a property with an initial production date that is more than two (2) calendar years prior to the July 1st assessment date.

3.26. "Storage wells" means drilled and completed wells on any property used for the artificial injection or storage of natural gas into a natural reservoir strata.

3.27. "Sum of the Years digit" means the weighted average that will be used in the calculations. For a 3 year weighted average, the sum of the years digit method places the first year at 50%, the second year at 33.33% and the third year at 16.67%.

3.28. "Summation discount component" means a discount rate expressed as the aggregate of a safe rate, risk rate, nonliquidity rate, and management rate, adjusted for inflation.

3.29. "Well" means any shaft or hole sunk, drilled, bored or dug into the earth or into underground strata for the extraction of oil or gas.

3.30. "Working interest" means the fractional interest in oil and/or natural gas production subject to development and operating expenses and owned by the leaseholder and/or operator.

§110-1J-4. Methods of Valuation.

4.1. General. -- Oil and/or natural gas producing property value shall be determined through the process of applying a yield capitalization model to the net receipts (gross receipts less royalties paid less operating expenses) for the working interest and a yield capitalization model applied to the gross royalty payments for the royalty interest. Where ownership is split through a lease or royalty arrangement, different values shall be determined for the working interest and the royalty interest. If the well produced for less than twelve (12) months during the first calendar year of production, or during the first calendar year of production after being shut-in during the previous calendar year, the gross receipts and royalties paid shall be annualized prior to the process of applying a yield capitalization rate. Each term in this valuation is discussed below.

4.2. Percentage interest in oil and/or natural gas. -- Where the ownership of oil and/or natural gas in place is divided through a lease or other arrangement, the compensation to the owner of the property is derived by designating a percentage (generally one-eighth) of the production income to be the royalty payment to the owner. The remainder (generally seven-eighths) is the working interest. The Tax Commissioner shall annually determine working and royalty percentage interests on a per well or lease basis, through a review of oil and natural gas producer/operator annual property tax returns. These percentages shall be determined annually by dividing the total royalty paid by the reported gross income.

4.3. Average industry operating expenses. -- The Tax Commissioner shall every five (5) years, determine the average annual industry operating expenses per well. The average annual industry operating expenses shall be deducted from working

interest gross receipts to develop an income stream for application of a yield capitalization procedure.

4.4. Average industry production decline rates. -- The Tax Commissioner shall every five (5) years derive and report the average industry production decline rates by reviewing well production records of various State agencies along with data provided by companies and individuals.

4.5. Capitalization rate. -- A single statewide capitalization rate for oil and natural gas shall be determined annually by the Tax Commissioner through the use of generally accepted methods. The rate shall be based on the assumption of a declining-terminal, non-inflating income series. The capitalization rate used to value oil and natural gas shall be developed through consideration of: (1) a discount rate determined by the summation technique, and (2) a property tax component.

4.5.1. Discount component.

The summation technique shall be used in developing a discount component of the capitalization rate. The five subcomponents of the discount rate are:

4.5.1.a. Safe rate. -- The "safe rate" shall reflect a rate of return that an investor could expect on an investment of minimal risk. It shall be developed through review of interest rates offered on thirteen (13) week United States Constant Maturity Treasury Yields for a period of three (3) calendar years immediately prior to the July 1st assessment date. A weighted average (sum of years digits) will be used in order to arrive at a Safe Rate.

4.5.1.b. Risk rate -- The relative degree of risk of an investment in oil and natural gas property is difficult to determine from published interest rates. Interest rates required on loans for acquisition and/or

development of oil and natural gas properties shall be calculated by adding two percent (2%) to the Prime Interest Rate Charged By banks as published in the Economic Indicators Prepared By The Council Of Economic Advisors For The Joint Economic Committee for the three (3) calendar years immediately prior to the July 1 assessment date. The loan rate shall be compared to quarterly interest rates offered on thirteen (13) week United States Constant Maturity Treasury Yields for the same three (3) calendar years period. The weighted average (sum of years digits) difference between the two, combined with bands-of-investment analysis, shall be used as a basis to estimate the risk rate;

4.5.1.c. Nonliquidity rate. -- The "nonliquidity rate" shall be developed through an annual survey to determine a reasonable estimate of time that oil and natural gas properties, when exposed to the market for sale, remain on the market. The time determined in this manner shall be used to identify United States Constant Maturity Treasury Yields with similar time differentials in excess of thirteen (13) week United States Constant Maturity Treasury Yields. The interest differential between these securities shall be used to represent the nonliquidity rate. For example, if it is determined that oil and natural gas property remains on the market for an average of nine months (39 weeks) before being sold, the nonliquidity rate shall be derived by taking the rate on one (1) year United States Constant Maturity Treasury Yields minus the rate on 13-week United States Constant Maturity Treasury Yields; The rate used will be a weighted average (sum of years digits) of the data from the three (3) calendar year periods prior to the July 1 assessment date.

4.5.1.d. Management rate. -- The "management rate" represents the cost of managing the investment, not the cost of managing the oil and natural gas property. Because the management rate has

historically been one-half of one percent (0.5%) of the value of investment portfolios, for purposes of determining the discount component the management rate shall be one-half of one percent (0.5%); and

4.5.1.e. Inflation rate (negative). -- Nominal interest rates, including the "safe rate" mentioned in paragraph 4.5.1.a of this subdivision, are higher than real rates by an amount representing expectation of future inflation; however, net annual income from oil and natural gas property is to be estimated assuming level future royalties (no inflation). The capitalization rate shall be a real rate, net of expectation of inflation. The inflation rate shall be estimated through analysis of the most recent calendar year's urban consumer price index as determined by the U.S. Department of Labor, Bureau of Labor Statistics. The weighted average (sum of years digits) rate will be used from the data of the three (3) calendar year periods prior to the July 1 assessment date.

4.5.2. In determining the discount component of the capitalization rate; the Tax Commissioner shall deduct the inflation rate from the sum of the safe rate, the risk rate, the nonliquidity rate and the management rate.

4.5.3. Property tax component. -- This component shall be estimated by multiplying the assessment rate by the prior tax year's statewide average for Class III property. At the present time, research indicates that royalty rates on oil and natural gas include a component for property tax, with no additional compensation from the producer. As a result, the property tax component shall be used in the capitalization rate; however, if this described general practice changes and property taxes are paid as additional compensation, the use of this component shall be deleted. The rate used will be a weighted average (sum of years digits) of the data from the three (3) tax year periods prior to the July 1 assessment date.

4.5.4. Results of capitalization rate survey -- A review of economic data for development of components referenced in Subdivision 4.5.1 of this rule shall be conducted annually and results filed by the Tax Commissioner in the State Register on or before July 1st of each year. Public comment on the published results shall be accepted until August 1st of each year with final results filed in the State Register on or before September 1st of each year.

4.6. Yield capitalization model. -- A yield capitalization model shall be developed for each producing property. The model shall use as a beginning point and include for each producing well, the gross receipts (both working interest and royalty interest) and production amounts based on those gross receipts from the most recent consecutive three (3) full production calendar years preceding the July 1 assessment date. These amounts will be weighted average (sum of years digits) and then adjusted for production decline to reflect the income available to the property owner beginning with the July 1st assessment date to June 30 next succeeding the assessment date. Gross receipts and production amounts shall be proportionately reduced by application of the appropriate production decline rate, referenced in Subsection 4.4 of this rule, to yield a declining terminal income series typical of the producing area and strata. The income series shall be apportioned to the working interest and to the royalty interest based upon percentage interests referenced in Subsection 4.2 of this rule. Where the well did not produce during the entire calendar year, the gross receipts and royalties paid will be annualized prior to the process of applying a yield capitalization procedure.

4.6.1. Working interest model. -- The working interest weighted average (sum of years digits) gross receipts income series referenced in Subsection 4.6 of this rule

shall be reduced by the annual operating expenses referenced in Subsection 4.3 of this rule to yield a net working interest income series. The net working interest income series shall be discounted by applying, on an annual basis, a mid-year life Inwood factor reflecting the capitalization rate referenced in Subsection 4.5 of this rule. The summation of the annual discounted income streams shall be the market value estimate for the working interest of the producing oil and/or natural gas well including personal property as defined by Section 3 of this rule. The minimum appraised value for any producing well will not be less than the machinery and equipment value discussed in Section 4.16 of this rule. This minimum rate will not apply to home-use only wells.

4.6.2. Royalty interest model. -- The royalty interest weighted average (sum of years digits) gross receipts income series referenced in Subsection 4.6 of this rule shall be discounted by applying, on an annual basis, a mid-year life Inwood factor reflecting the capitalization rate referenced in Subsection 4.5 of this rule. This amount will then be proportionally distributed to each royalty owner based on the royalty percentage received during the most recent calendar year to the July 1 assessment date. The summation of the annual discounted income streams shall be the market value estimate for the royalty interest of the producing oil and/or natural gas well for an area of up to one hundred twenty-five (125) acres per producing natural gas wells and up to forty (40) acres per producing oil wells.

4.6.3. Valuation of home-use only wells. -- The appraised value of wells used for home-use only will be an annual appraised value of \$500.00 resulting in an assessed value of \$300.00. If the home-use well owner has ownership in the mineral rights, the assessed value will be added to the real property assessment. However, if the home-use well owner only has rights in

the surface, the assessed value will be added to the personal property assessment.

4.6.4. Valuation of industrial use wells. -- The appraised value of wells used for industrial purposes only will be based on the actual most recent calendar year preceding the July 1 appraisal date MCF usage times the average West Virginia spot price for that calendar year determined by the "Natural Gas Monthly," published by the U.S. Department of Energy, Energy Information Administration.

4.7. Valuation of non-producing acreage. -- The value per acre of non-producing acreage, which includes shut-in wells, shall equal the discounted annual lease payment per acre. A valuation schedule for non-producing properties shall be determined annually by the Tax Commissioner for each district within a county, where data is available. The Tax Commissioner shall annually conduct a review of oil and/or natural gas lease agreements transacted at arms-length in all fifty-five (55) counties to determine the average annual delay rental lease payment per acre, and lease term. The per-acre value for non-producing property shall be the sum of the projected annual income stream from delay rental during the lease term discounted in each year by a capitalization rate. A valuation of \$1.00 per acre shall be used where property is located in those areas of the State where drilling activity/production have not been established and the property is presumed to be barren.

4.8. Valuation of plugged and abandoned acreage. -- Plugged and abandoned acreage shall be valued to the oil or gas owner at the nominal rate of one dollar (\$1.00) per acre. This category includes any plugged and abandoned acreage of up to one hundred twenty-five (125) acres per natural gas well and up to forty (40) acres per oil well.

4.9. Valuation of barren oil and natural gas areas. -- These oil and natural gas areas (fee accounts) shall be valued at \$1.00 per deed acre.

4.10. Valuation of wells that produce both oil and natural gas. -- The valuation of wells that produce both oil and natural gas shall be determined by use of the methods described in this rule. These values shall then be summed to result in the overall value of the oil and/or natural gas producing acreage.

4.11. Valuation of storage well areas. -- The valuation of storage well areas shall equal the discounted annual lease payment per acre that is applied to the reserve oil and gas acreage within the county. The minimum value applied to the areas will not be less than \$5.00 per deed acre. The value shall not include inventories stored within. Natural gas storage inventories shall be assessed to the inventory owner.

4.12. Annual reports. -- The Tax Commissioner shall on or before July 1st of each year publish and file in the State Register an annual summary of the variables to be considered in arriving at the value of the specific oil and/or natural gas related property. Public comments shall be accepted until August 1st of each year with the final results filed in the State Register on or before September 1st of each year.

4.13. Farm properties. -- The oil and gas rights, that are part of a "fee" estate where the use of the surface has qualified for farm use appraisal, shall be valued as described in the Tax Commission's rule, Valuation of Farmland and Structures Situated Thereon For Ad Valorem Property Tax Purposes, 110 C.S.R. 1A.

4.14. Property reports. -- On or before August 1st of each year the producer shall file the West Virginia Oil and Gas Producer/Operator Return with the State Tax

Commission, with acknowledgement to the county assessors in the counties where the oil and natural gas property is located. This Return form shall be designed by the State Tax Commissioner so that information pertinent to the valuation of the producing property, and plugged and abandoned property shall be reported properly by the oil and gas producer.

4.15. Confidentiality -- All information provided by or on behalf of a natural resources property owner or by or on behalf of an owner or an interest in natural resources property to any state or county representative for use in the valuation or assessment of natural resources property or for use in the development or maintenance of a legislatively funded mineral mapping or geologic information system is confidential. The information is exempt from disclosure under the provisions of West Virginia Code § 29B-1-4, and shall be kept, held, and maintained confidential except to the extent the information is needed by the state tax commissioner to defend an appraisal challenged by the owner or lessee of the natural resources property subject to the appraisal: Provided, That this section may not be construed to prohibit publication or release of information generated as part of the minerals mapping or geologic information system, whether in the form of aggregated statistics, maps, articles, reports, professional talks, or otherwise presented in accordance with generally accepted practices and in a manner so as to preclude the identification or determination of information about particular property owners.

4.16. Valuation of the Producer's Personal Property at Non-Producing or Shut-In wells—The valuation of the producer's personal property that is part of a non-producing or shut-in well's appraisal will be assigned to the producer at the same value applied to home use only wells.

4.17. Valuation of Pre-Production/Permit Leaseholds---Chattel real accounts (personal property) for pre-production/permit leaseholds will be valued by the county assessor.

4.18. Valuation of Producing Flat-Rate Royalty accounts --- The appraised value of a producing flat-rate royalty will be valued using a level terminal income series rather than the declining terminal income series as discussed in Subsection 4.6 of this rule.



Earl Ray Tomblin
Governor

STATE OF WEST VIRGINIA
Department of Revenue
State Tax Department

Mark W. Matkovich
State Tax Commissioner

Ter Dept.
E.L.J.7

August 27, 2015

The Honorable Natalie Tennant
Secretary of State
Building 1, Suite 157-K
State Capitol
Charleston, West Virginia 25305

RECEIVED
AUG 28 2015
STATE TAX DEPARTMENT

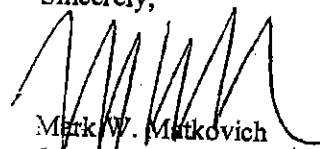
Dear Secretary Tennant:

Attached are final natural resource property valuation variables for the 2016 Tax Year that have been developed by the State Tax Department for use in appraising oil and gas, managed timberland, coal and other natural resource properties for ad valorem tax purposes.

In accordance with requirements of §§ 110 CSR 1-I, 1-J, and 1-K, tentative variables were made available for public comments on June 30, 2014. The Department received six comments on the tentative variables. Three comments related to the valuation of coal and three comments related to the valuation of producing oil and gas wells. The information supplied in the coal comments resulted in an increase in the capitalization rate for coal properties. One of the oil and gas commenters supplied data supporting an increase in the decline rate for Marcellus gas wells in the North West region.

The final valuation variables are being filed for inclusion in the State Register.

Sincerely,


Mark W. Matkovich
State Tax Commissioner

MWM/jaj

Attachment

cc: All County Assessors

OIL AND GAS PROPERTIES ANALYSIS

Tax Year 2016

FILED
AUG 27 AM 11:23
OFFICE OF THE ATTORNEY GENERAL
STATE OF CONNECTICUT

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

OIL AND GAS

TY 2016

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bonds-of-Investment and Summation Technique approaches are utilized in establishing discount rates for producing oil and gas properties. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 1J.

<u>Rate Rate</u>	(3-Month Constant Maturity Interest Rates)		
	January	December	2014
			1.033%

<u>Risk Rate</u>	(Interest differential between Loan Rate and 3-Month Constant Maturity Interest Rates)		
	<u>Loan Rate**</u>		<u>Risk Rate</u>
	2014	3.250%	5.217%
		*Prime plus 2%	

<u>Equity</u>	(Differential between Equity Rates and 3-Month Constant Maturity Interest Rates)		
	<u>Equity Rate**</u>		<u>Risk Rate</u>
	2014	[11.5%/(1-.37)]=0.033%	18.221%
	** Value Line Investment Survey Analysis		

<u>Composite Risk Rate</u>	Loan and Equity Rates weighted by industry estimated capital structure.				
	<u>Equity Rate</u>		<u>Debt Rate</u>		<u>Composite Risk</u>
	2014	11.8436%	1.826%		14.389%
	Note: Debt equity Ratio		Debt	35%	Equity
	*** Effective severance tax adjustment			0.95	65%

<u>Non Liquidity Rate</u>	Interest differential between 3-month Constant Maturity Interest Rates and a 1 year Constant Maturity Interest Rates which reflects a reasonable time necessary to sell active property.				
				<u>90 day T Bill</u>	<u>Non Liquidity Rate</u>
	January	December	2014	0.121%	0.033%
					0.088%

<u>Management Rate</u>	Charges for the management of investment portfolios.	
	Fixed Rate (by Rule)	0.500%

<u>Property Tax Rate</u>	Sixty percent (60%) of State average Class III property tax rate.		
	2014	80% of 2.18	1.314%

<u>Inflation Rate</u>	January	December	2014
			0.760%

Capitalization Rate

Since the valuation of oil and gas property is predicated on a three year production, the capitalization rate will be considered in a similar manner.

	2014	2013	2012
Inflation Rate	-0.780%	-1.500%	-1.700%
Safe Rate	0.033%	0.058%	0.068%
Composite Risk Rate	14.389%	14.834%	14.805%
Non Liquidity Rate	0.088%	0.074%	0.089%
Management Rate	0.500%	0.500%	0.500%
Property Tax Rate	1.314%	1.314%	1.328%
Total	15.564%	15.080%	14.906%
	10.000%	13.333%	18.667%
	7.722%	5.027%	1.484%
			15.293%

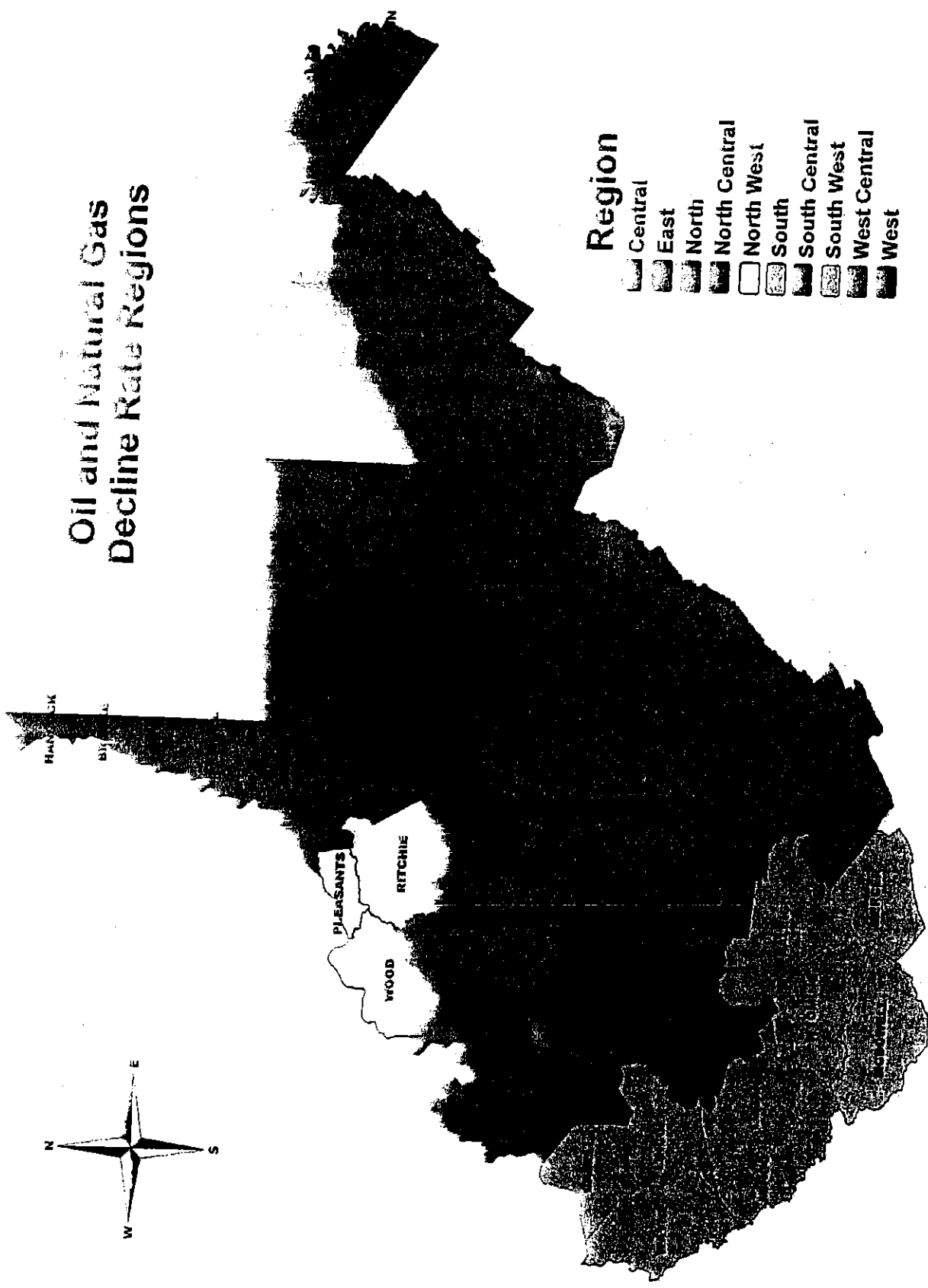
Capitalization Rate Rounded to:

15.30%

MULTIPLIERS FOR 15.3% MID-YEAR LIFE (ANNUALLY)

YEAR		YEAR	
1	0.931291	21	0.054013
2	0.807711	22	0.046846
3	0.700530	23	0.040829
4	0.607572	24	0.035238
5	0.526948	25	0.030582
6	0.457024	26	0.026507
7	0.396378	27	0.022988
8	0.343780	28	0.019938
9	0.298181	29	0.017293
10	0.258598	30	0.014888
11	0.224281	31	0.013008
12	0.194519	32	0.011282
13	0.168707	33	0.009785
14	0.146320	34	0.008488
15	0.126804	35	0.007380
16	0.110064	36	0.006384
17	0.095458	37	0.005538
18	0.082782	38	0.004802
19	0.071808	39	0.004185
20	0.062277	40	0.003612

Oil and Natural Gas Decline Rate Regions



Region

- Central
- East
- North
- North Central
- North West
- South
- South Central
- South West
- West Central
- West

Decline Rates for Natural Gas and Oil Formations: Central				
Central: Braxton, Clay, Fayette, Nicholas, Webster				
Code	Formation	Year 1	Year 2	Year 3 +
12	Alexander, Benson	-0.31	-0.20	-0.10
14	Benson	-0.48	-0.08	-0.08
16	Benson, Balltown+	-0.45	-0.16	-0.12
17	Gordon +	-0.30	-0.07	-0.07
13	Big Injun	-0.34	-0.13	-0.13
19	Big Injun, Big Lime	-0.36	-0.13	-0.13
22	Big Lime	-0.34	-0.34	-0.13
26	Ravenc Cliff	-0.40	-0.40	-0.25
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.41	-0.22	-0.09
110	Marcellus *	-0.41	-0.22	-0.09
9	Exception (Median)	-0.41	-0.22	-0.09
10	Non-Filer	-0.30	-0.07	-0.07

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations East				
East, Berkeley, Grant, Greenbrier, Hampshire, Hardy, Jefferson, Mineral, Monroe, Morgan, Pendleton, Pocahontas, Preston, Randolph, Summers, Tucker				
Code	Formation	Year 1	Year 2	Year 3
1	Oriskany	-0.30	-0.30	-0.19
14	Benson	-0.31	-0.17	-0.12
20	Benson +	-0.44	-0.20	-0.08
21	Benson, Fifth	-0.29	-0.28	-0.09
32	Brallier +	-0.48	-0.20	-0.05
33	Elk, Benson	-0.39	-0.21	-0.08
34	Elk, Benson, Riley	-0.53	-0.19	-0.05
35	Elk, Benson, Riley +	-0.36	-0.19	-0.11
36	Elk, Benson, Balltown	-0.34	-0.18	-0.11
37	Elk, Alexander, Benson	-0.50	-0.07	-0.07
38	Elk, Alexander, Benson +	-0.40	-0.16	-0.16
39	Huntermville	-0.31	-0.31	-0.14
40	Fox, Haverly	-0.36	-0.21	-0.15
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
110	Marcellus	-0.59	-0.22	-0.17
9	Exception (Median)	-0.41	-0.22	-0.10
10	Non-Filer	-0.29	-0.07	-0.05

Decline Rates for Natural Gas and Oil Formations: North

North: Brooke, Hancock, Marshall, Ohio, Tyler, Wetzel

Code	Formation	Year 1	Year 2	Year 3
11	Gordon	-0.47	-0.31	-0.09
13	Alexander, Benson, Riley	-0.26	-0.16	-0.15
15	Benson, Riley	-0.18	-0.16	-0.06
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
97	Coalbed Methane (Vertical)	-0.23	-0.08	-0.05
110	Marcellus	-0.52	-0.23	-0.18
9	Exception (Median)	-0.39	-0.23	-0.08
10	Non-Filer	-0.18	-0.16	-0.06

Decline Rates for Natural Gas and Oil Formations North Central				
North Central Barbour, Doddridge, Glimmer, Harrison, Lewis, Marion, Monongalia, Taylor, Upshur				
Code	Formation	Year 1*	Year 2*	Year 3*
11	Gordon	-0.41	-0.14	-0.12
12	Alexander, Benson	-0.37	-0.19	-0.11
13	Alexander, Benson, Riley	-0.40	-0.28	-0.05
14	Benson	-0.31	-0.17	-0.12
15	Benson, Riley	-0.34	-0.17	-0.14
18	Big Injun	-0.38	-0.18	-0.13
21	Benson, Fifth	-0.31	-0.20	-0.14
28	Weir	-0.34	-0.34	-0.07
29	Weir +	-0.28	-0.28	-0.23
33	Elk, Benson	-0.34	-0.16	-0.11
34	Elk, Benson, Riley	-0.42	-0.27	-0.08
37	Elk, Alexander, Benson	-0.19	-0.23	-0.08
38	Elk, Alexander, Benson +	-0.38	-0.20	-0.12
40	Fox, Haverly	-0.46	-0.16	-0.08
40	Rhinestreet	-0.28	-0.03	-0.03
47	Alexander, Benson, Balltown	-0.39	-0.26	-0.08
48	Alexander	-0.35	-0.20	-0.10
49	Alexander +	-0.39	-0.22	-0.10
60	Alexander, Benson, Riley +	-0.39	-0.35	-0.12
61	Balltown	-0.35	-0.20	-0.10
62	Balltown, Speechley	-0.28	-0.22	-0.10
63	Balltown, Speechley +	-0.30	-0.13	-0.10
64	Benson, Balltown, Speechley	-0.28	-0.22	-0.09
65	Benson, Bradford	-0.37	-0.20	-0.10
66	Benson, Balltown	-0.29	-0.23	-0.11
67	Benson, Riley +	-0.38	-0.14	-0.10
68	Benson, Speechley	-0.30	-0.22	-0.14
69	Brallier, Elk	-0.42	-0.20	-0.13
70	Brallier	-0.40	-0.22	-0.15
71	Deeper/Onondaga or Oriskany/Helderberg	-0.24	-0.24	-0.03
72	Elk, Alexander	-0.42	-0.22	-0.09
73	Elk, Benson +	-0.38	-0.20	-0.12
74	Elk	-0.43	-0.12	-0.10
75	Elk, Riley	-0.60	-0.35	-0.17
76	Fox +	-0.46	-0.18	-0.09
77	Haverly, Elk, Benson (No Alexander)	-0.35	-0.16	-0.16
78	Haverly	-0.45	-0.15	-0.15
79	Riley	-0.44	-0.22	-0.10
80	Speechley	-0.30	-0.18	-0.09
81	Alexander, Benson, Speechley	-0.39	-0.24	-0.10
82	Haverly, Elk, Alexander	-0.47	-0.14	-0.14
85	Fifth, Oil	-0.45	-0.25	-0.22
87	Bayard All	-0.30	-0.20	-0.05
88	Fifth	-0.29	-0.18	-0.12
89	Fifth +	-0.25	-0.15	-0.13
90	Gordon, Injun All	-0.41	-0.23	-0.23
91	Squaw	-0.37	-0.31	-0.08
92	Injun +	-0.34	-0.22	-0.22
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.28	-0.07
95	Injun/Weir	-0.51	-0.28	-0.09
96	Maxton	-0.70	-0.27	-0.08
97	Coalbed Methane (Vertical)	-0.23	-0.08	-0.05
98	Coalbed Methane (Horizontal)	-0.05	-0.05	-0.32
109	Trenton/Deeper *	-0.38	-0.21	-0.11
110	Marcellus	-0.59	-0.29	-0.23
9	Exception (Median)	-0.38	-0.21	-0.11
10	Non-Filer	-0.23	-0.03	-0.03

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: North West				
North West: Pleasants, Ritchie, Wood				
Code	Formation	Year 1	Year 2	Year 3
2	Huron, Rhinestreet	-0.41	-0.28	-0.07
4	Huron	-0.42	-0.24	-0.14
5	Huron, Sheles above Huron	-0.39	-0.25	-0.14
3	Berea	-0.31	-0.15	-0.15
11	Gordon	-0.38	-0.10	-0.10
12	Alexander, Benson (No Riley)	-0.34	-0.23	-0.10
13	Alexander, Benson, Riley	-0.32	-0.20	-0.10
14	Benson	-0.19	-0.19	-0.10
44	Rhinestreet, Huron, Shallow Shele	-0.43	-0.28	-0.11
47	Alexander, Riley, (No Benson)	-0.41	-0.05	-0.05
48	Rhinestreet, Alexander, Benson, Riley	-0.31	-0.24	-0.10
49	Weir, Squaw, Big Injun	-0.27	-0.17	-0.07
50	Rhinestreet	-0.40	-0.27	-0.27
51	Rhinestreet +	-0.38	-0.21	-0.10
52	All Upper Devonien (Undiv)	-0.48	-0.33	-0.19
53	Huron, Chemung	-0.35	-0.11	-0.09
54	Huron, Hampshire, Pocono	-0.12	-0.12	-0.11
55	Upper Devonian (Above Huron)	-0.46	-0.33	-0.23
56	Chemung Sands= Riley, Bradford, Balltown, Speechley, Warren (No Benson or Alexander)	-0.28	-0.18	-0.10
83	Huron Oil	-0.74	-0.44	-0.40
93	4th Sand	-0.42	-0.32	-0.08
34	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.39	-0.23	-0.13
110	Marcellus	-0.46	-0.29	-0.13
9	Exception (Median)	-0.39	-0.23	-0.13
10	Non-Filer	-0.12	-0.05	-0.05

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: South				
South: McDowell, Mercer, Raleigh, Wyoming				
Code	Formation	Year 1	Year 2	Year 3 +
3	Berea	-0.34	-0.15	-0.15
12	Big Lime	-0.31	-0.19	-0.07
23	Big Lime, Maxton	-0.31	-0.19	-0.07
24	Big Lime, Ravencloff	-0.29	-0.29	-0.17
25	Berea +	-0.37	-0.12	-0.08
26	Ravencloff	-0.40	-0.08	-0.07
28	Weir	-0.44	-0.20	-0.10
29	Weir +	-0.28	-0.21	-0.08
30	Weir, Big Lime	-0.37	-0.19	-0.13
42	Maxton, Ravencloff	-0.40	-0.08	-0.07
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.28	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.27	-0.13	-0.09
97	Coalbed Methane (Vertical)	0.03	0.10	-0.05
98	Coalbed Methane (Horizontal)	-0.05	-0.05	-0.32
110	Marcellus *	-0.36	-0.19	-0.09
9	Exception (Median)	-0.36	-0.19	-0.09
10	Non-Filer	-0.23	-0.08	-0.05

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: South Central				
South Central: Boone, Kanawha				
Code	Formation	Year 1	Year 2	Year 3 +
3	Devonian Shale	-0.23	-0.08	-0.05
4	Huron	-0.31	-0.15	-0.04
3	Berea	-0.23	-0.14	-0.09
18	Big Injun	-0.29	-0.25	-0.12
27	Huron, Shales above Huron	-0.21	-0.08	-0.05
28	Weir	-0.30	-0.21	-0.14
29	Weir +	-0.31	-0.25	-0.09
31	Devonian Shales +	-0.27	-0.07	-0.05
36	Big Injun-Oil	-0.19	-0.18	-0.10
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.33	-0.19	-0.08
110	Marcellus *	-0.33	-0.19	-0.08
9	Exception (Median)	-0.33	-0.19	-0.08
10	Non-Filer	-0.19	-0.07	-0.04

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: South West				
South West: Cabell, Lincoln, Logan, Mingo, Wayne				
Code	Formation	Year 1	Year 2	Year 3 +
3	Devonian Shale	-0.31	-0.15	-0.04
8	Berea	-0.38	-0.11	-0.11
18	Big Injun	-0.38	-0.22	-0.04
22	Big Lime	-0.19	-0.19	-0.19
43	Berea, Big Lime	-0.18	-0.18	-0.18
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.38	-0.22	-0.10
110	Marcellus *	-0.38	-0.22	-0.10
9	Exception (Median)	-0.38	-0.22	-0.10
10	Non-Filer	-0.18	-0.11	-0.04

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: West				
West: Jackson, Mason, Putnam				
Code	Formation	Year 1	Year 2	Year 3 +
1	Oriskany	-0.40	-0.40	-0.29
2	Huron, Rhinestreet	-0.13	-0.12	-0.03
3	Devonian Shale	-0.31	-0.15	-0.04
4	Huron	-0.29	-0.14	-0.05
5	Huron, Shales above Huron	-0.38	-0.15	-0.06
6	Huron, Berea	-0.29	-0.08	-0.08
7	Berea, Devonian Shale	-0.08	-0.08	-0.08
8	Berea	-0.36	-0.16	-0.16
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.35	-0.20	-0.09
110	Marcellus *	-0.35	-0.20	-0.09
9	Exception (Median)	-0.35	-0.20	-0.09
10	Non-Filer	-0.08	-0.08	-0.03

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: West Central				
West Central: Galhoun, Roane, Wirt				
Code	Formation	Year 1	Year 2	Year 3 +
2	Huron, Rhinestreet	-0.49	-0.11	-0.06
4	Huron	-0.33	-0.22	-0.14
27	Huron, Shales above Huron	-0.42	-0.23	-0.12
44	Rhinestreet, Huron, Shallow Shale	-0.51	-0.14	-0.11
45	Devonian Shale, Pocono	-0.25	-0.17	-0.12
46	Pocono	-0.29	-0.25	-0.12
84	Big Injun, Oil	-0.41	-0.41	-0.11
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.42	-0.24	-0.10
110	Marcellus *	-0.42	-0.24	-0.10
9	Exception (Median)	-0.42	-0.24	-0.10
10	Non-Filer	-0.25	-0.11	-0.06

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Industry Operating Expense Survey and Results

This component was determined through a review of responses to a survey distributed by the State Tax Department to producers of all oil and natural gas wells producing in West Virginia and through use of other market data.

GAS

- % Working Interest Expenses for Typical Producing Well	=	30%
- Maximum Operating Expenses	=	\$5,000
- Coal Bed Methane, Vertical Wells Expenses	=	\$2,000

OIL

- % Working Interest Expenses for Typical Producing Well	=	35%
- Maximum Operating Expenses	=	\$5,750
- Maximum Enhanced Operating Expenses	=	\$9,000

MARCELLUS

- % Working Interest Expenses for Vertical Producing Well	=	30%
- Maximum Operating Expenses	=	\$30,000
- % Working Interest Expenses for Horizontal Producing Well	=	20%
- Maximum Operating Expenses	=	\$150,000

HORIZONTAL WELLS (OTHER THAN MARCELLUS)

- % Working Interest Expenses for Horizontal Producing Well	=	30%
- Maximum Operating Expenses	=	\$20,000

Minimum Working Interest Appraisal = \$500 per well

Flat Rate Royalty Multiplier = 5.75

Home Use Only Wells:

Appraised at \$500 per well

Industrial Use Only Wells:*

MCF usage X \$ 4.39/MCF
BBL usage X \$93.26/BBL

*(Also includes Department of Environmental Protection reported wells.)

Non-Filer Valuations

Working Interest	=	150% of previous year's appraisal
Royalty Interest	=	90% of previous year's appraisal

Valuation

The previously discussed variables are used to establish a future income stream converted to present worth through application of a capitalization rate. The sum of the discounted future net income per year represents a reasonable estimate of market value.

Lease Rate/Term Survey and Results

The non-producing property value for each county is determined by multiplying the average delay rental by a factor, which represents the average lease term under present economic conditions.

As a result of higher lease terms being inversely proportional to the value of oil and gas (thus counties with little leasing or production activities reflect inflated values) and with the volatile nature of county activity, necessary adjustments in the review have been made.

A compilation of lease terms produced a statewide average of 5 years. This term (5 years) was applied to all county lease rates and compared to the appraisal rates derived from calculations using individual county data. The two resulting calculations were reviewed and considered in the assignment of an appraisal rate per acre.

The appraisal rate/acre amounts shown on the next page are preliminary figures, which may change if additional lease data is received. These rates have been applied to all county magisterial districts with either producing wells, lease activity within the past 5 years or both. Tax districts void of activity within the past 5 years have been assigned the minimum value per acre.

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
BARBOUR	1	1	\$50.00
		2	\$1.00
		3	\$50.00
		4	\$50.00
		5	\$50.00
		6	\$1.00
		7	\$50.00
		8	\$50.00
		9	\$50.00
		10	\$50.00
		11	\$50.00
BERKELEY	2	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
BOONE	3	1	\$20.00
		2	\$1.00
		3	\$1.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
		7	\$1.00
		8	\$20.00
		9	\$1.00
BRAXTON	4	1	\$20.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$20.00
		7	\$20.00
		8	\$1.00
BROOKE	5	1	\$1.00
		2	\$1.00
		3	\$25.00
		4	\$25.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CD #	DISTRICT #	TY2016 \$/AC
CABELL	6	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$1.00
		10	\$20.00
CALHOUN	7	1	\$30.00
		2	\$1.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		6	\$30.00
CLAY	8	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
JODDRIDGE	9	1	\$60.00
		2	\$60.00
		3	\$60.00
		4	\$60.00
		5	\$60.00
		6	\$60.00
		7	\$60.00
		8	\$60.00
		9	\$1.00
FAYETTE	10	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
GILMER	11	1	\$25.00
		2	\$25.00
		3	\$25.00
		4	\$1.00
		5	\$1.00
		6	\$25.00
GRANT	12	1	\$1.00
		2	\$1.00
		3	\$10.00
		4	\$1.00
		5	\$10.00
GREENBRIER	13	1	\$1.00
		2	\$1.00
		3	\$10.00
		4	\$10.00
		5	\$1.00
		6	\$10.00
		7	\$10.00
		8	\$10.00
		9	\$10.00
		10	\$1.00
		11	\$10.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$10.00
		17	\$1.00
		18	\$10.00
HAMPSHIRE	14	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$5.00
		6	\$1.00
		7	\$5.00
		8	\$1.00
		9	\$5.00
		10	\$1.00
HANCOCK	15	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$1.00
		6	\$1.00

OIL & GAS RESERVE RATES FOR TY 2018			
COUNTY	CO #	DISTRICT #	TY2018 \$/AC
HARDY	16	1	\$1.00
		2	\$10.00
		3	\$10.00
		4	\$10.00
		5	\$10.00
		6	\$1.00
HARRISON	17	1	\$60.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$60.00
		6	\$1.00
		7	\$60.00
		8	\$1.00
		9	\$60.00
		10	\$1.00
		11	\$60.00
		12	\$60.00
		13	\$1.00
		14	\$60.00
		15	\$60.00
		16	\$1.00
		17	\$1.00
		18	\$60.00
		19	\$1.00
		20	\$60.00
		21	\$1.00
JACKSON	18	1	\$35.00
		2	\$35.00
		3	\$1.00
		4	\$35.00
		5	\$1.00
		6	\$35.00
		7	\$35.00
JEFFERSON	19	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
KANAWHA	20	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$30.00
		16	\$30.00
		17	\$1.00
		18	\$1.00
		19	\$30.00
		20	\$1.00
		21	\$1.00
		22	\$1.00
		23	\$30.00
		24	\$30.00
		25	\$30.00
		26	\$1.00
		27	\$1.00
		28	\$30.00
		29	\$1.00
		30	\$1.00
		31	\$1.00
LEWIS	21	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$30.00
		5	\$1.00
		6	\$30.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
LINCOLN	22	1	\$15.00
		2	\$15.00
		3	\$1.00
		4	\$15.00
		5	\$15.00
		6	\$15.00
		7	\$15.00
		8	\$15.00
		9	\$15.00
		10	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
LOGAN	23	1	\$15.00
		2	\$15.00
		3	\$15.00
		4	\$15.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$15.00
		9	\$1.00
MARION	24	1	\$5.00
		2	\$5.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$55.00
		10	\$1.00
		11	\$55.00
		12	\$55.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$55.00
		17	\$1.00
		18	\$55.00
		19	\$55.00
		20	\$1.00
		21	\$1.00
		22	\$1.00
MARSHALL	25	1	\$50.00
		2	\$1.00
		3	\$50.00
		4	\$50.00
		5	\$50.00
		6	\$1.00
		7	\$50.00
		8	\$1.00
		9	\$50.00
		10	\$1.00
		11	\$1.00
		12	\$50.00
		13	\$50.00
		14	\$50.00
		15	\$50.00
		16	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
MASON	26	1	\$25.00
		2	\$25.00
		3	\$25.00
		4	\$25.00
		5	\$25.00
		6	\$25.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$25.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$25.00
		15	\$25.00
		16	\$25.00
MC DOWELL	27	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$1.00
		6	\$20.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$20.00
		12	\$1.00
		13	\$20.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
MERCER	28	1	\$1.00
		2	\$15.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$15.00
		7	\$1.00
		8	\$1.00
		9	\$15.00
		10	\$1.00
		11	\$15.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
MINERAL	29	1	\$10.00
		2	\$1.00
		3	\$1.00
		4	\$10.00
		5	\$1.00
		6	\$10.00
		7	\$1.00
		8	\$10.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
MINGO	30	1	\$1.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
		7	\$20.00
		8	\$1.00
		9	\$20.00
		10	\$20.00
		11	\$20.00
		12	\$1.00
MONONGALIA	31	1	\$25.00
		2	\$1.00
		3	\$25.00
		4	\$25.00
		5	\$25.00
		6	\$1.00
		7	\$25.00
		8	\$25.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$25.00
		19	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
MONROE	32	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$10.00
		5	\$10.00
		6	\$1.00
		7	\$10.00
		8	\$1.00
		9	\$10.00
MORGAN	33	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
NICHOLAS	34	1	\$15.00
		2	\$15.00
		3	\$15.00
		4	\$15.00
		5	\$15.00
		6	\$1.00
		7	\$15.00
		8	\$1.00
		9	\$15.00
OHIO	35	1	\$1.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$35.00
		6	\$35.00
		7	\$1.00
		8	\$35.00
		9	\$35.00
		10	\$35.00
PENDLETON	36	1	\$1.00
		2	\$10.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$10.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
PLEASANTS	37	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$35.00
		6	\$1.00
		7	\$35.00
		8	\$35.00
POCAHONTAS	38	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$10.00
		8	\$1.00
PRESTON	39	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$35.00
		6	\$35.00
		7	\$35.00
		8	\$35.00
		9	\$1.00
		10	\$35.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$1.00
		19	\$1.00
		20	\$1.00
PUTNAM	40	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$20.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$1.00
		10	\$20.00
		11	\$20.00
		12	\$20.00
		13	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
RALEIGH	41	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$1.00
		7	\$20.00
		8	\$20.00
		9	\$20.00
		10	\$1.00
		11	\$20.00
		12	\$20.00
RANDOLPH	42	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$20.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$20.00
		11	\$20.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$20.00
		17	\$1.00
		18	\$1.00
RITCHIE	43	1	\$40.00
		2	\$1.00
		3	\$40.00
		4	\$1.00
		5	\$40.00
		6	\$1.00
		7	\$40.00
		8	\$1.00
		9	\$1.00
		10	\$40.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CD #	DISTRICT #	TY2016 \$/AC
ROANE	44	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		6	\$30.00
		7	\$30.00
		8	\$1.00
		9	\$20.00
SUMMERS	45	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$10.00
		6	\$1.00
		7	\$1.00
TAYLOR	46	1	\$1.00
		2	\$1.00
		3	\$55.00
		4	\$55.00
		5	\$55.00
		6	\$55.00
		7	\$55.00
TUCKER	47	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$20.00
		10	\$1.00
		11	\$20.00
		12	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2015 \$/AC
TYLER	48	1	\$55.00
		2	\$55.00
		3	\$1.00
		4	\$55.00
		5	\$55.00
		6	\$55.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
JPSHUR	9	1	\$50.00
		2	\$50.00
		3	\$1.00
		4	\$50.00
		5	\$50.00
		6	\$50.00
		7	\$50.00
WAYNE	30	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$20.00
		10	\$20.00
		11	\$1.00
		12	\$20.00
WEBSTER	51	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$15.00
		5	\$15.00
		6	\$15.00
		7	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
TYLER	48	1	\$55.00
		2	\$55.00
		3	\$1.00
		4	\$55.00
		5	\$55.00
		6	\$55.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
JPSHUR	9	1	\$50.00
		2	\$50.00
		3	\$1.00
		4	\$50.00
		5	\$50.00
		6	\$50.00
		7	\$50.00
WAYNE	30	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$20.00
		10	\$20.00
		11	\$1.00
		12	\$20.00
WEBSTER	51	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$15.00
		5	\$15.00
		6	\$15.00
		7	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
WETZEL	62	1	\$59.00
		2	\$69.00
		3	\$55.00
		4	\$55.00
		5	\$69.00
		6	\$1.00
		7	\$1.00
		8	\$55.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$65.00
		13	\$1.00
WIRT	53	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$1.00
		5	\$30.00
		6	\$30.00
		7	\$30.00
		8	\$30.00
WOOD	54	1	\$38.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$1.00
		6	\$35.00
		7	\$35.00
		8	\$35.00
		9	\$35.00
		10	\$1.00
		11	\$38.00
		12	\$35.00
		13	\$1.00
		14	\$1.00
WYOMING	55	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$1.00
		7	\$20.00
		8	\$1.00
		9	\$1.00
		10	\$20.00

**MANAGED TIMBER
PROPERTY ANALYSIS**

Tax Year 2016

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

MANAGED TIMBERLAND APPRAISAL RATES **TAX YEAR 2016**

(based on market 2010-2014)

Rates Per Acre

Class II Parcels

	<u>Grade 1</u>	<u>Grade 2</u>	<u>Grade 3</u>
Region 1	\$200	\$140	\$50
Region 2	\$200	\$140	\$50
Region 3	\$230	\$185	\$50
Region 4	\$265	\$180	\$55
Region 5	\$210	\$140	\$50

Class III/IV Parcels

	<u>Grade 1</u>	<u>Grade 2</u>	<u>Grade 3</u>
Region 1	\$225	\$150	\$75
Region 2	\$225	\$150	\$75
Region 3	\$250	\$165	\$75
Region 4	\$235	\$160	\$75
Region 5	\$225	\$150	\$75

- Region 1 = Brooke, Cabell, Hancock, Jackson, Marshall, Mason, Ohio, Pleasants, Putnam, Tyler, Wetzel, and Wood Counties
- Region 2 = Braxton, Calhoun, Clay, Doddridge, Gilmer, Harrison, Lewis, Marion, Monongalia, Ritchie, Roans, Taylor, and Wirt Counties
- Region 3 = Barbour, Greenbrier, Monroe, Nicholas, Pendleton, Pocahontas, Preston, Randolph, Tucker, Upshur, and Webster Counties
- Region 4 = Berkeley, Grant, Hampshire, Hardy, Jefferson, Mineral and Morgan Counties
- Region 5 = Boone, Fayette, Kanawha, Lincoln, Logan, McDowell, Mercer, Mingo, Raleigh, Summers, Wayne, and Wyoming Counties

Harvest Volume per Acre

Harvest Interval

Grade

1 - Site Index 75 or more

<u>35 yrs.</u>	<u>45 yrs.</u>	<u>55 yrs.</u>	<u>80 yrs.</u>		<u>Total</u>
4.6 cords	--	2.6 cords	3.3 cords		10.5 cords
1.5 Mbf	--	4.4 Mbf	8.6 Mbf		14.5 Mbf

2 - Site Index 65 - 75

3.3 cords	--	7.0 cords	4.6 cords		14.9 cords
1.0 Mbf	--	3.2 Mbf	5.5 Mbf		9.7 Mbf

3 - Site Index less than 65

--	3.1 cords	--	15.4 cords		18.5 cords
--	0.8 Mbf	--	3.7 Mbf		4.5 Mbf

Managed Timberland Statistics

Estimation of Required Rate of Return: Class II Rates

A. Safe Rate of Return (5 Year T-Bill Rate)

Year	Rate	W/A %	W/A Rate
2014	1.6410	28.87%	0.4377
2013	1.1725	13.33%	0.1563
2012	0.7608	8.67%	0.0507
2011	1.5225	20.00%	0.3045
2010	1.9275	33.33%	0.6424

1.592 %

B. Nonliquidity Rate

(12 Month T-Bills vs. 3 Month T-Bills)

Year	Rate	W/A %	W/A Rate
2014	0.0883	33.33%	0.0294
2013	0.0733	28.67%	0.0195
2012	0.1292	20.00%	0.0258
2011	0.1617	13.33%	0.0242
2010	0.3200	6.67%	0.0213

0.120 %

C. Risk Rate (30 yr T-bills vs 5 yr T-bills)

Year	Rate	W/A %	W/A Rate
2014	1.8992	33.33%	0.5683
2013	2.2758	28.67%	0.6070
2012	2.1600	20.00%	0.4320
2011	2.3883	13.33%	0.3184
2010	2.3233	8.67%	0.1550

2.079 %

D. Management Factor of 0.5%

0.500 %

E. Property Tax Component

(50% of Class II Rate)

Year	Rate	W/A %	W/A Rate
2014	0.714	33.33%	0.2380
2013	0.708	28.87%	0.1888
2012	0.714	20.00%	0.1428
2011	0.708	13.33%	0.0944
2010	0.708	8.87%	0.0472

0.711 %

F. Inflation Rate:

(Bureau of Labor Statistics)

Year	Rate	W/A %	W/A Rate
2014	0.760	33.33%	0.2533
2013	1.500	28.67%	0.4001
2012	1.700	13.33%	0.2288
2011	3.000	8.87%	0.2001
2010	1.500	20.00%	0.3000

(1.380) %

TOTAL REQUIRED RATE OF RETURN (REAL)

3.822 %

LESS: PROPERTY TAX COMPONENT

(0.711)

TOTAL DISCOUNT COMPONENT

2.911 %

Stumpage Prices:

	<u>Sawtimber</u>	<u>Pulpwood</u>
Stumpage Price Adjustment Factor	0.00%	1.86%

SAWTIMBER	Current \$/MBF	1.0000 \$/MBF at age 35	1.0000 \$/MBF at age 46	1.0000 \$/MBF at age 55	1.0000 \$/MBF at age 60
		35	46	55	60
Region 1	174.30	174.30	174.30	174.30	174.30
Region 2	169.80	169.80	169.80	169.80	169.80
Region 3	248.26	248.26	248.26	248.26	248.26
Region 4	231.30	231.30	231.30	231.30	231.30
Region 5	195.10	195.10	195.10	195.10	195.10

PULPWOOD:	\$/Cord	1.0080 \$/cd at age 35	2.2917 \$/cd at age 45	2.7555 \$/cd at age 55	4.3681 \$/cd at age 60
		35	45	55	60
Region 1	5.62	10.72	12.89	15.49	24.56
Region 2	6.85	13.06	15.71	18.69	29.94
Region 3	6.14	11.71	14.08	16.93	26.84
Region 4	8.41	16.03	19.27	23.17	36.73
Region 5	6.46	12.31	14.80	17.79	28.20

Management Costs:

Region	\$/acre (1)
1	3.17
2	3.17
3	3.17
4	3.17
5	3.17
State	

Tax Rates:

Effective Federal Income Tax Rate	35.00%
Effective WV State Income Tax Rate (8.5% * (1-.35))	4.23%
Effective WV Severance Tax Rate (2.78% * (1-.35))	1.81%

Yield (Volumes) (80 year rotation)

Timberland		Yield - MBF	Yield - Cords
Productivity Grades	Site Index		
Grade I	75 or more	14.5	10.5
Grade II	65-74	9.7	14.8
Grade III	less than 65	4.5	18.5

Managed Timberland Statistics

Estimation of Required Rate of Return: Class III & IV Blended Rates

A. Safe Rate of Return (5 Year T-Bill Rate)

Year	Rate	W/A %	W/A Rate
2014	1.6410	28.67%	0.4377
2013	1.1725	13.33%	0.1563
2012	0.7608	6.67%	0.0507
2011	1.5225	20.00%	0.3045
2010	1.9275	33.33%	0.6424

1.592 %

3. Nonliquidity Rate

(12 Month T-Bills vs. 3 Month T-Bills)

Year	Rate	W/A %	W/A Rate
2014	0.0383	33.33%	0.0294
2013	0.0733	28.67%	0.0195
2012	0.1292	20.00%	0.0258
2011	0.1817	13.33%	0.0242
2010	0.3200	6.67%	0.0213

0.120 %

C. Risk Rate (30 yr T-bills vs 5 yr T-bills)

Year	Rate	W/A %	W/A Rate
2014	1.6992	33.33%	0.5663
2013	2.2758	26.67%	0.6070
2012	2.1600	20.00%	0.4320
2011	2.3883	13.33%	0.3184
2010	2.3233	6.67%	0.1550

2.079 %

D. Management Factor of 0.5%

0.500 %

E. Property Tax Component

(60% of Blended III&IV Rates)

Year	Rate	W/A %	W/A Rate
2014	1.314	33.33%	0.4380
2013	1.314	26.67%	0.3504
2012	1.326	20.00%	0.2652
2011	1.326	13.33%	0.1766
2010	1.314	6.67%	0.0676

1.318 %

F. Inflation Rate:

(Bureau of Labor Statistics)

Year	Rate	W/A %	W/A Rate
2014	0.760	33.33%	0.2533
2013	1.500	28.67%	0.4001
2012	1.700	13.33%	0.2266
2011	3.000	6.67%	0.2001
2010	1.500	20.00%	0.3000

(1.330) %

TOTAL REQUIRED RATE OF RETURN (REAL)

4.229 %

LESS: PROPERTY TAX COMPONENT

(1.316)

TOTAL DISCOUNT COMPONENT

2.911 %

Stumpage Prices:

	<u>Sawtimber</u>	<u>Pulpwood</u>
Stumpage Price Adjustment Factor	0.00%	1.86%

SAWTIMBER

		1.0000	1.0000	1.0000	1.0000
	Current	\$/MBF at age	\$/MBF at age	\$/MBF at age	\$/MBF at age
Region	\$/MBF	35	45	55	60
Region 1	174.30	174.30	174.30	174.30	174.30
Region 2	169.80	169.80	169.80	169.80	169.80
Region 3	248.28	248.28	248.28	248.28	248.28
Region 4	231.30	231.30	231.30	231.30	231.30
Region 5	195.10	195.10	195.10	195.10	195.10

PULPWOOD:

		1.9060	2.2917	2.7555	4.3881
		\$/cd at age	\$/cd at age	\$/cd at age	\$/cd at age
Region	\$/Cord	35	45	55	60
Region 1	5.62	10.72	12.89	15.49	24.56
Region 2	5.85	13.08	15.71	18.89	29.94
Region 3	6.14	11.71	14.08	16.93	28.84
Region 4	8.41	16.03	19.27	23.17	38.73
Region 5	5.46	12.31	14.80	17.79	28.20

Management Costs:

Region	\$/acre (1)
1	3.17
2	3.17
3	3.17
4	3.17
5	3.17
State	3.17

Tax Rates:

Effective Federal Income Tax Rate	15.00%
Effective WV State Income Tax Rate (6.5% * (1-.35))	4.23%
Effective WV Severance Tax Rate (2.78% * (1-.35))	1.81%

Yield (Volumes) (80 year rotation)

Timberland	Productivity Grades	Site Index	Yield - MBF	Yield - Cords
Grade I	75 or more		14.5	10.5
Grade II	55-74		3.7	14.9
Grade III	less than 55		4.5	13.5

West Virginia Wgt/Avg Managed Timberland Stumpage Prices

REGION 1 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	12,182.08	176.34	33.33%	58.76
2013	19,017.77	177.45	26.67%	47.32
2012	12,828.15	186.58	20.00%	37.31
2011	11,196.24	144.69	13.33%	19.32
2010	15,157.58	173.52	6.67%	11.57
	70,160.80			174.30

REGION 1 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	184.40	3.40	33.33%	1.80
2013	6,102.20	2.06	26.67%	0.79
2012	45,387.00	3.42	20.00%	1.28
2011	18.10	1.67	13.33%	1.29
2010	1,059.30	6.90	6.67%	0.46
	53,061.00			5.32

REGION 2 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	12,001.80	182.47	33.33%	60.82
2013	26,886.85	177.79	26.67%	47.41
2012	25,640.98	149.01	20.00%	29.60
2011	12,839.41	166.26	13.33%	20.83
2010	36,575.40	163.96	6.67%	10.93
	114,754.44			169.60

REGION 2 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	2,188.10	5.04	33.33%	1.66
2013	119,279.40	12.63	26.67%	3.42
2012	22,847.40	2.36	20.00%	0.57
2011	6,235.20	6.78	13.33%	0.90
2010	23,291.90	4.15	6.67%	0.26
	172,822.00			6.85

REGION 3 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	91,467.44	280.52	33.33%	93.51
2013	161,397.70	275.83	26.67%	73.50
2012	111,920.60	201.57	20.00%	40.31
2011	102,218.30	201.45	13.33%	26.66
2010	145,592.20	211.21	6.67%	14.06
	512,596.24			246.28

REGION 3 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	170,736.30	3.57	33.33%	1.19
2013	153,197.40	7.78	26.67%	2.07
2012	183,132.80	6.39	20.00%	1.28
2011	159,040.70	7.34	13.33%	0.96
2010	123,858.50	9.34	6.67%	0.62
	789,965.50			1.14

REGION 4 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	5,020.80	303.89	33.33%	101.30
2013	12,820.20	211.47	26.67%	56.39
2012	4,808.73	193.47	20.00%	36.89
2011	15,517.51	178.40	13.33%	23.79
2010	24,125.85	167.02	5.67%	11.13
	62,293.19			231.30

REGION 4 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	7,765.20	2.16	33.33%	2.72
2013	15,488.60	9.32	26.67%	2.22
2012	7,782.20	9.81	20.00%	1.92
2011	21,074.10	8.84	13.33%	1.15
2010	35,223.70	5.93	5.67%	0.10
	77,953.80			2.21

REGION 5 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	21,861.40	235.95	33.33%	88.65
2013	31,859.00	196.20	26.67%	52.85
2012	10,867.05	138.63	20.00%	27.73
2011	24,760.43	122.43	13.33%	16.32
2010	56,603.00	143.15	5.67%	9.54
	145,770.88			195.10

REGION 5 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	10,191.40	5.19	33.33%	2.06
2013	18,292.60	7.13	26.67%	1.90
2012	3,296.30	6.93	20.00%	1.39
2011	6,432.30	6.26	13.33%	0.83
2010	19,223.30	4.06	5.67%	0.27
	32,435.90			1.46

COAL PROPERTIES ANALYSIS

Tax Year 2016

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

COAL CAPITALIZATION RATE

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for active coal. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 11.

<u>Safe Rate</u>	90 day Treasury Bills			<u>Safe Rate</u>
	January	December	2014	0.033%
	January	December	2013	0.058%
	January	December	2012	0.086%

<u>Risk Rate</u>	Interest differential between Loan Rate and 90 day Treasury Bills			<u>Debt Risk Rate</u>
	2014	5.25%		5.217%
	2013	5.25%		5.192%
	2012	5.25%		5.164%
	Prime plus 2%			

<u>Equity</u>	Differential between Equity Rates and 90 day Treasury Bills			<u>Equity Risk Rate</u>
	2014	$(15.50\% / (1-.30)) - 0.033$		22.110%
	2013	$(13.25\% / (1-.30)) - 0.058$		18.871%
	2012	$(13.25\% / (1-.30)) - 0.088$		18.843%

** Value Line Investment Survey Analysis

<u>Composite Risk Rate</u>	Loan and Equity Rates weighted by industry estimated capital structure		
	Equity Rate	Debt Rate	Composite Risk
2014	15.477%	1.565%	17.042%
2013	11.322%	2.077%	13.399%
2012	11.308%	2.086%	13.372%
Note: Debt/Equity Ratio		Debt 30%	Equity 70%

Non Liquidity Rate Interest differential between a 90 day Treasury Bill and a 1 year Treasury Bill which reflects a reasonable time necessary to sell active property.

			<u>1yr T Bill</u>	<u>90 d T Bill</u>	<u>Non Liquidity Rate</u>
January	December	2014	0.121%	0.033%	0.088%
January	December	2013	0.132%	0.058%	0.074%
January	December	2012	0.175%	0.086%	0.089%

Management Rate Charges for the management of investment portfolios.
Fixed Rate (by Rule) 0.500%

<u>Inflation Rate</u>			
January	December	2014	0.760%
January	December	2013	1.500%
January	December	2012	1.700%

Capitalization Rate Since the valuation of active coal property is predicated on a three year production average, the capitalization rate is considered in a similar manner.

	2014	2013	2012
Inflation Rate	-0.760%	-1.500%	-1.700%
Safe Rate	0.033%	0.058%	0.086%
Composite Risk Rate	17.042%	13.399%	13.372%
Non Liquidity Rate	0.088%	0.074%	0.089%
Management Rate	0.500%	0.500%	0.500%
Total	16.903%	12.531%	12.347%

Three Yr Average: 13.927 Rounded to: **13.90%**

CAPITALIZATION RATE - 13.9%			
MULTIPLIERS:	%		%
1YR	0.937	9YR	5.298
2YR	1.760	10YR	5.589
3YR	2.482	11YR	5.844
4YR	3.116	12YR	6.067
5YR	3.673	13YR	6.264
6YR	4.162	14YR	6.437
7YR	4.591	15YR	6.588
8YR	4.967		

COAL

Price and Royalty Rate Analysis

The development of royalty rates for the various categories of mines and markets involves information collection and review from a variety of sources. Coal lease rates have been derived from transaction information provided by county assessors, tax auditors, producers, and by individual lessors/lessees involved in the specific transaction. The prices for mined coal, as per 110-CSR-11, have been calculated from information provided by the WV Public Service Commission and U.S. Energy Information Administration concerning power plant fuel purchases. Prices provided by producers as part of tax filing and from data obtained from market summaries are included for comparison. Because a large portion of the data used in this analysis is, by law, considered confidential, only a summary of the results are published.

COAL SALE PRICES CY2014 FOR TY2016 APPLICATION

GRAND SUMMARY ALL SOURCES 2014	STEAM SPOT	STEAM TERM	NET
PERC	\$53.58	\$6.85	
PERC	\$58.77	\$2.58	
Coal Market Publication		\$7.81 (Platts-CAPP-CSX)	
Active Return Summary		\$23.36 52.7 MM tons	\$103.35 7.8 MM Tons

STATE STEAM PRICE (SPOT Market)	\$20.35 PERC & PSC, 3 YR AVE
STATE NET PRICE	\$103.35 Active Return

2014 WVPSC Tons reported in millions	Spot Sales	Term Sales	Total
	2,170,351	15,503,854	17,674,205

COAL TY2016 ROYALTY RATES	2014 1YR		2013 2YR		2012 3YR		2011 4YR		2010 5YR	
	%S	%D	%S	%D	%S	%D	%S	%D	%S	%D
TOTAL RECORDS	1,447	305	1,354	589	1,908	2,756	1,877	2,241	2,446	3,197
SUM of PERCENT	3,869.07	4,695.25	8,087.34	3,313.83	11,881.68	14,883.03	8,924.28	11,181.05	14,406.71	16,405.76
STRAIGHT AVERAGE	2.13	5.19	5.97	5.53	6.23	5.32	5.32	4.99	5.89	5.13
MEDIAN	9.00	5.00	5.00	5.00	8.00	5.13	5.00	5.00	5.22	5.00
WEIGHTED AVERAGE (by Mines)	1.94	3.49	6.68	5.84	8.45	6.26	6.27	5.72	6.24	5.66
TENTATIVE RATE DEEP (%)	5.80									
TENTATIVE RATE SURFACE (%)	6.50									

ROYALTY RATE CALCULATIONS

Steam Coal/ Deep Mine	\$80.35	per ton X	5.80%	=	\$3.50	per ton
Metallurgical Coal/ Deep Mine	\$103.35	per ton X	5.80%	=	\$5.99	per ton
Steam Coal/ Surface Mine	\$80.35	per ton X	6.50%	=	\$3.92	per ton
Metallurgical Coal/ Surface Mine	\$103.35	per ton X	6.50%	=	\$6.71	per ton

Explanation of Reserve Coal Valuation

The RCVN consists of a computer model, which utilizes a database consisting of coal beds and characteristics, property locations, mine locations, sales, transportation, etc., for the entire state. An extensive algorithm calculates in-place tonnage, expected time of mining and present value for all the mineable coal on every property.

There are, therefore, no set "rates" available on reserve coal under the Rule. The RCVN values on each property will not be available until all data has been entered, after October 15 of each year. Please refer to the State Register, Legislative Rules, Title 110, Series 11 for details of the process.

Title 110, Series 11
Valuation of Active and Reserve Coal Property for Ad Valorem Property Tax Purposes

The above Legislative Rule was modified during the 2006 Legislative Session requiring biennial (every other year) updating of the geostatistical basis for several valuation factors used in the Reserve Coal Valuation Model. To satisfy that requirement, maps and data files concerning the Market Interest Factor, the Market Mineability Factor, the Use Conflict Factor and the Environmental Factor have been revised for Tax Year 2016. Preliminary research has been conducted to determine the effects of the factors on coal valuation. The results are as follows:

Market Interest Factor

This is the relationship between transactions (sales, leases, prospects, permit applications, etc.) and mining as it relates to properties and locations. Trans_Ct is the number of transactions counted within the radius.
Radius = 5 miles

```
If Trans_Ct >= 20 Then TransFactor = 20  
  
If Trans_Ct < 20 And Trans_Ct >= 10 Then TransFactor = 40  
  
Else TransFactor = 80
```

Market Mineability Factor

This is the relationship between property location and mining, through time. Determining feature is count of mines within the radius.
Radius = 2.5 miles

```
Surface Mines: Smine  
  
Deep Mines: Dmine  
  
Boom Mines: Bmine  
  
Historic Mines: Omine  
  
Current Mines: Cmine  
  
To assign MineFactor:  
  
If Cmine > 0 Then MineFactor = 20  
  
If Cmine = 0 And (Omine > 0 Or Bmine > 0) Then MineFactor = 40  
  
Else MineFactor = 80
```

Use Conflict Factor

This is the relationship between oil & gas well drilling and mining as it relates to property location. Well density is in wells per square mile.

```
WellDensity < 5 Then WellFactor = 0  
  
WellDensity >= 5 And WellDensity < 10 Then WellFactor = 20  
  
WellDensity >= 10 And WellDensity < 20 Then WellFactor = 40  
  
WellDensity > 20 Then WellFactor = 80
```

Environmental Factor

This is the relationship of known environmental hazards and impediments to the likelihood of mining occurring at this location. The rates are compiled from maps and represent densities of problems mapped.

```
Envrate <= 10 and Null Then EnvFactor = 0  
  
Envrate > 10 and Envrate <= 30 Then EnvFactor = 20  
  
Envrate > 30 and Envrate < 60 Then EnvFactor = 40  
  
Envrate >= 60 Then EnvFactor = 80
```

**OTHER MINED MINERAL
PROPERTY ANALYSIS**

Tax Year 2016

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

OTHER MINED MINERALS CAPITALIZATION RATE

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for active coal. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 1k.

Safe Rate	90 day Treasury Bills	Safe Rate
January	December 2014	0.033%
January	December 2013	0.058%
January	December 2012	0.086%

Risk Rate Interest differential between Loan Rate and 90 day Treasury Bills

Loan Rate	Debt Risk Rate
2014 5.25%	5.17%
2013 5.25%	5.192%
2012 5.25%	5.164%
Prime plus 2%	

Equity Differential between Equity Rates and 90 day Treasury Bills

Equity Rate**	Equity Risk Rate
2014 $(11.75\% / (1-.30)) - 0.033$	16.753%
2013 $(11.75\% / (1-.30)) - 0.058$	18.728%
2012 $(11.75\% / (1-.30)) - 0.086$	18.700%

** Value Line Investment Survey Analysis

Composite Risk Rate Loan and Equity Rates weighted by industry estimated capital structure.

	Equity Rate	Debt Rate	Composite Risk
2014	10.052%	2.087%	12.109%
2013	10.037%	2.077%	12.114%
2012	10.020%	2.068%	12.088%
Note: Debt Equity Ratio		Debt 40%	Equity 60%

Non Liquidity Rate

Interest differential between 90 day Treasury Bills and a 1 year Treasury Bill which reflects a reasonable time necessary to sell active property.

			1 Yr T Bill	90 d T Bill	Non Liquidity Rate
January	December	2014	0.121%	0.033%	0.088%
January	December	2013	0.132%	0.058%	0.074%
January	December	2012	0.175%	0.088%	0.089%

Management Rate Charges for the management of investment portfolios.

Fixed Rate (by Rule)	0.500%

Inflation Rate

January	December 2014	0.780%
January	December 2013	1.500%
January	December 2012	1.700%

Property Tax Rate Sixty percent (60%) of State average Class III property tax rate.

January	December 2014	60% of 2.190 =	1.314%
January	December 2013	60% of 2.190 =	1.314%
January	December 2012	60% of 2.210 =	1.326%

Capitalization Rate

Since the valuation of other mined mineral property is predicated on a three year production average, the capitalization rate is considered in a similar manner.

	2014	2013	2012
Inflation Rate	-0.780%	-1.500%	-1.700%
Safe Rate	0.033%	0.058%	0.086%
Composite Risk Rate	12.109%	12.114%	12.088%
Non Liquidity Rate	0.088%	0.074%	0.089%
Management Rate	0.500%	0.500%	0.500%
Property Tax Rate	1.314%	1.314%	1.326%
Total	13.314%	12.560%	12.387%

Three Yr Average: 12.754% Rounded to: 12.80%

CAPITALIZATION RATE - 12.80%

MULTIPLIERS:	%	%
1YR	0.942	9YR 5.481
2YR	1.776	10YR 5.809
3YR	2.518	11YR 5.892
4YR	3.172	12YR 6.342
5YR	3.754	13YR 5.564
6YR	4.289	14YR 4.791
7YR	4.727	15YR 6.936
8YR	5.132	



Earl Ray Tomblin
Governor

STATE OF WEST VIRGINIA
Department of Revenue
State Tax Department

Mark W. Matkovich
State Tax Commissioner

7-11-16, 6:15, 21

ADMINISTRATIVE NOTICE 2016-06

PROPERTY TAX
STATE TAX COMMISSIONER'S STATEMENT
FOR THE DETERMINATION OF THE CAPITALIZATION RATES FOR
PRODUCING AND RESERVE COAL, OIL AND GAS AND OTHER MINED
MINERALS FOR PROPERTY TAX PURPOSES FOR TAX YEAR 2016,
PURSUANT TO §§ 110 CSR 11-4.1.7, 1J-4.5 AND 1K-4.1.7

OFFICE OF THE
STATE TAX COMMISSIONER
STATE OF WEST VIRGINIA

2016 JAN 21 P 2:28

FILED

On August 27, 2015, the State Tax Department filed valuation variables to be used in conjunction with legislative rules for the appraisal of producing natural resource properties. (See: §§ 110 CSR 1-I, 1-J and 1-K) This notice will address one of the variables, the capitalization rate, setting forth the generally accepted appraisal procedures used in developing the respective rates and in applying the rates to income streams generated by natural resource properties. To this end, this notice will discuss development of industry capitalization rates for properties containing coal, and/or oil and gas, and/or other mined minerals.

DISCUSSION

The International Association of Assessing Officers text *Property Appraisal and Assessment Administration*, 1990, defines a capitalization rate as: "Any rate used to convert an estimate of income to an estimate of market value; the ratio of net operating income to market value." In other words a rate used to convert an estimate of future income into an estimate of present value.

Generally, there are three (3) components that must be considered and if appropriate developed and included in an overall capitalization rate. These components are: the discount component, the recapture component, and the property tax component. The development of each of these three (3) components will be discussed in the remainder of this Notice.

DISCOUNT COMPONENT

Of the three (3) generally accepted methods of estimating a discount component, the bands-of-investment method and the summation method have received primary consideration. Consideration was given to use of the comparison method; however, the Tax Department is of the opinion that the bands-of-investment and summation methods are the more appropriate methods to employ for properties containing coal, and/or oil and gas, and/or other mined minerals as there are a limited number of sales of these types of properties and these methods lend themselves more readily to the conversion of the equity rate portion of the discount component to a pre-tax rate.

The first step in the process is to construct a capital structure. The capital structure of an industry depicts typically the sources of capital financing (i.e.: what portion of the total capital financing is raised through debt and through equity financing). The Tax Department developed an average industry capital structure based on mining and oil and gas industries as grouped in the Value Line Investment Survey. The capital structure was segregated into percentages of capital financing generated through debt and through equity financing in order to develop a profile for typical leveraging characteristics by type industry. (Equity financing represents capital acquired through sale of stock and earnings retention and debt financing represents capital acquired through issuance of instruments of debt.)

Once the capital structure had been established a return on investment is developed for each financing band. The Tax Department analyzed the financial information of companies grouped by industry in the Value Line Investment Survey in order to develop a return by type industry for common stocks. This "after-tax" return was then adjusted to a "pre-tax" return where applicable and used in developing the equity portion of the discount component.

The debt return for the debt finance band was established, by adding two percent (2%) to the Prime Rate Charged by Banks as published in the Economic Indicators Prepared by the Council of Economic Advisors for the Joint Economic Committee. Once a safe rate and a risk rate are developed from the previously mentioned analysis, a management rate (for management of investment portfolios), a non-liquidity rate (time required to sell the investment), and an inflation rate (rate used to adjust the discount component to a real rate net of inflationary expectations) are estimated.

RECAPTURE COMPONENT

The discount component previously discussed provides an investor with a rate of return-on-investment (interest). The second capitalization rate component, recapture, provides the investor with a return-of-investment principal (i.e.: provides an estimate of return necessary for the investor to recover the principal invested). Once a capitalization rate has been developed for coal, oil and gas, and other mined mineral properties, the income series is discounted to present worth through selection of a multiplier(s) extracted from a standard mid-year life Inwood table. The Inwood table has a factor for recapture built into the table coefficients thus removing the need to separately accommodate for recapture in the capitalization rate.

PROPERTY TAX COMPONENT

The third component, property taxes, was derived by multiplying the assessment rate by the statewide average of tax rates on Class III property. Tax Department research indicates that in addition to royalty rates negotiated in producing coal property leases, property taxes are customarily paid by the coal producer. Thus the capitalization rate for producing coal properties does not contain a property tax component as the income stream does not contain income to be used to pay property taxes.

APPLICATION

The summation of the previously discussed components (i.e.: discount, recapture, and property tax components) yields a reasonable estimate for the overall capitalization rate. The overall capitalization rate is used to select the factor(s) from a standard mid-year life Inwood table (i.e.: present worth of one (1) per period) that converts the income stream(s) into an estimate of present worth.

For more information concerning the development of capitalization rates for producing natural resource properties see §§ 110 CSR 1-I, 1-J and 1-K, or contact the State Tax Department at (304) 558-3940.

Notice of this determination will be filed in the West Virginia Register.

Issued: January 27, 2016


Mark W. Matkovich
State Tax Commissioner

State Tax Department
Property Tax Division
P. O. Box 2389
Charleston, WV 25328-2389

Operator on Duty 8:30 am - 5:00 pm
Monday through Friday
Phone: (304) 558-3940
FAX: (304) 558-1843



Earl Ray Tomblin
Governor

STATE OF WEST VIRGINIA
Department of Revenue
State Tax Department

Mark W. Matkovich
State Tax Commissioner

Ter. Dept. B.L.U.7

ADMINISTRATIVE NOTICE 2016-07

PROPERTY TAX
STATE TAX COMMISSIONER'S STATEMENT
FOR THE DETERMINATION OF PRODUCTION DECLINE RATES FOR
PRODUCING OIL AND GAS PROPERTIES FOR PROPERTY TAX PURPOSES
FOR TAX YEAR 2016, PURSUANT TO § 110 CSR 1J-4.4

OFFICE OF THE STATE
TAX COMMISSIONER

2015 JAN 27 P 2 33

FILED

On August 27, 2015, the State Tax Department filed valuation variables to be used in conjunction with the legislative rule for the appraisal of oil and gas properties. (See: §§ 110 CSR 1J-1, *et seq.*) This notice will address one of the variables, the production decline rate(s), setting forth the procedures used in developing the rate(s) for Tax Year 2016.

DISCUSSION

The income stream generated from a producing oil or gas well is directly dependent upon the quantity of the natural resource produced from the well. Once drilled an oil or gas well will experience a sharper production decline, typically for the first two (2) years of production. This is known as flush production. Thereafter production decline levels off into what is known as settled production. The rate of production decline is dependent upon the physical location of the well and the stratigraphic formation(s) from which the well is producing.

The West Virginia Geological and Economic Survey ("Survey") has in past years created a database that contains well-by-well production data by producing formation(s). The Tax Department contracted with the Survey to develop an analytical model to plot production declines by location/formation throughout the State using data available at the time of the contract.

The Survey has divided the State into ten (10) regions that contain similar oil and gas geological characteristics. A map of the State depicting each of the ten (10) regions and a complete list of the oil and gas decline rates can be found in the above referenced variables filed on August 27, 2015.

For Tax Year 2014, in addition to the data from the Survey, the Tax Department also did a survey for Marcellus wells. The results from this data were used in the above-referenced variables as well.

For Tax Year 2016, further data was also utilized to update the Marcellus decline for the North West Region.

The appropriate production decline rate(s) are applied to individual well gross receipts to develop a probable future income series for the respective wells. The income streams from these wells are then discounted to present value.

For more information concerning the development of oil and gas well production decline rates contact the State Tax Department at (304) 558-3940.

Notice of this determination will be filed in the West Virginia Register.

Issued: January 27, 2016



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STATE OF WEST VIRGINIA

Department of Revenue
State Tax Department

Earl Ray Tomblin
Governor

Mark W. Matkovich
State Tax Commissioner

ADMINISTRATIVE NOTICE 2016-08

PROPERTY TAX STATE TAX COMMISSIONER'S STATEMENT FOR THE DETERMINATION OF OIL AND GAS OPERATING EXPENSES FOR PROPERTY TAX PURPOSES FOR TAX YEAR 2016, PURSUANT TO § 110 CSR 1J-43

FILED
JAN 21 P 2:33
OFFICE OF THE STATE TAX COMMISSIONER
STATE OF WEST VIRGINIA

The Legislative Rule for the appraisal of oil and gas properties (See §§ 110 CSR 1J-1, *et seq.*) became effective June 1, 2005. This notice will address one of the valuation variables referenced in the Rule, oil and gas operating expenses, setting forth procedures used in developing these expenses and their application against receipts for the working interest of oil and gas producing properties.

DISCUSSION

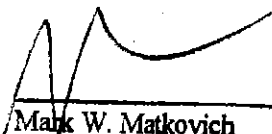
In 2014, the Tax Department received responses from over 16,000 producing wells. This information involved the average annual operating expenses for a "typical" West Virginia well under present economic conditions. The Tax Department has developed the following criteria for the direct ordinary operating expenses as a result of this research activity. Direct ordinary operating expenses will be estimated to be 30% of the gross receipts derived from gas production, not to exceed \$5,000, 35% of gross receipts derived from oil production, not to exceed \$5,750, and 35% of the gross receipts derived from enhanced recovery oil wells, not to exceed \$9,000. In 2014, the Tax Department also received responses from a survey specifically for Marcellus and horizontal wells other than Marcellus. Utilizing that information, the Tax Department developed the following criteria for Marcellus wells and horizontal other than Marcellus wells. For Marcellus vertical wells, the maximum operating expenses allowed is 30% of the gross receipts derived from gas production, not to exceed \$30,000. For Marcellus horizontal wells the maximum operating expense allowed is 20% of the gross receipts derived from gas production, not to exceed \$150,000. For horizontal, other than Marcellus, the maximum operating expenses allowed is 30% not to exceed \$20,000. As required in the amended Rule, the Tax Department will review such rates every five years.

In instances where the well is producing both oil and gas, the allotted maximum ordinary operating expense will vary between \$5,000 and \$5,750 depending on the percentage of gas versus oil receipts involved. For Marcellus vertical wells the allotted maximum operating expense will vary between \$5,750 and \$30,000 depending upon the percentage of gas versus oil receipts involved. For Marcellus horizontal wells the allotted maximum operating expense will vary between \$5,750 and \$150,000 depending upon the percentage of gas versus oil receipts involved. For horizontal, other than Marcellus, the allotted maximum operating expense will vary between \$5,750 and \$20,000 depending upon the percentage of gas versus oil receipts involved.

For additional information concerning oil and gas annual operating expenses see § 110 CSR JJ-1 et seq. or call the State Tax Department at (304) 558-3940.

Notice of this determination will be filed in the West Virginia Register.

Issued: January 27, 2016



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Earl Ray Tomblin
Governor

STATE OF WEST VIRGINIA
Department of Revenue
State Tax Department

Mark W. Matkovich
State Tax Commissioner

ADMINISTRATIVE NOTICE 2016-10

PROPERTY TAX
STATE TAX COMMISSIONER'S STATEMENT
CONCERNING PRIMARY RELIANCE ON THE INCOME APPROACH FOR
APPRAISING RESERVE OIL AND GAS PROPERTY PURSUANT TO § 110 CSR 1J-4

FILED
2016 JAN 27 P
OFFICE OF THE STATE TAX COMMISSIONER
SECRETARY OF STATE

On June 1, 2005, the State Legislature amended Legislative Rule §§ 110 CSR 1J-1, *et seq.* (for the appraisal of producing and reserve oil and gas properties) became effective. This notice will address this rule's primary reliance on the income approach to value when appraising reserve oil and gas properties for property tax purposes.

DISCUSSION

There are three (3) generally accepted approaches to value that must be considered when estimating market value of properties for ad valorem tax purposes. These are the cost, market and income approaches to value. These approaches to value must be considered and should be developed, if appropriate, to properly estimate market value in compliance with generally accepted appraisal principals. The following is a brief discussion of these three (3) approaches to value and their potential use when estimating the market value of reserve oil and gas natural resource properties for ad valorem tax purposes.

COST APPROACH

The cost approach to value is based upon the assumption that the cost of a property, less depreciation (loss in value), yields a reasonable estimate of market value. There are three (3) generally accepted types of cost approach appraisal methods; these are: original cost less depreciation, reproduction cost less depreciation, and replacement cost less depreciation. Depreciation is a loss in value due to physical deterioration through use, functional obsolescence through design or utility and economic obsolescence due to outside market forces.

Original cost less depreciation is the cost of acquisition of a property less a loss in value due to physical deterioration, functional obsolescence and economic obsolescence. This approach is widely employed in the appraisal of "cost-based" regulated utilities, however it has a limited

application when appraising reserve oil and gas properties, as many of these types of properties were acquired years ago at substantially less than current market value.

Reproduction cost less depreciation is the cost of reproducing an exact replica of a property less physical deterioration, functional obsolescence, and economic obsolescence. This approach is employed in appraising one-of-a-kind properties such as works of art or special purpose properties, an example of which may be the State's Capitol Building. Oil and gas properties are a nonrenewable natural resource and can therefore not be reproduced. Because of their nonrenewable nature, reserve oil and gas properties do not lend themselves to development of a reproduction cost less depreciation appraisal.

Replacement cost less depreciation is the cost of replacing a property with one of like utility less physical deterioration and economic obsolescence. This approach is the most widely used of the three (3) cost approaches to value and is widely employed in the appraisal of commercial and industrial personal property. Replacement cost has limited application, however, in the appraisal of nonrenewable natural resource properties, as the resource cannot by its nature be replaced. Because of their nonrenewable nature, reserve oil and gas properties do not lend themselves to the development of replacement cost new less depreciation appraisals.

MARKET APPROACH

The market approach to value is based upon the assumption that the recent selling price of comparable properties, if properly analyzed and adjusted, will yield a reasonable estimate of current market value. While sales of reserve oil and gas properties do occur within the State, the sales are infrequent and quite often oil and gas interests represent only a portion of the property acquisition thus diluting the purity of the market transaction. Because of these drawbacks the Legislative Rule does not contemplate the development of a market comparable approach to value for reserve oil and gas properties.

INCOME APPROACH

The income approach to value is based upon the assumption that a property is worth the future income, discounted to present worth, that it will generate for the prospective buyer. In the oil and gas industry, a common business practice of negotiating advance payments ("delay rentals") for the right to, at some future date, produce oil and gas has developed. By analyzing the amount and duration, typically, of delay rentals and by discounting the resulting income series to present worth an estimate of the probable selling price of reserve oil and gas properties can be developed. This procedure contained in § 110 CSR 1J-4.7 is the method used by the Department to develop, on a county and district basis, the per acre market value of reserve (non-producing acreage) oil and gas properties. The resultant per acre values were developed and published, in finalized form, in the State Register on August 27, 2015.

For more information concerning the appraisal of reserve oil and gas properties consult § 110 CSR 1J-1 et seq. or contact the State Tax Department at telephone number (304) 558-3940.

Notice of this determination will be filed in the West Virginia Register.

Issued: January 27, 2016



Mark W. Matkovich
State Tax Commissioner

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7/14/15 5:43.7



STATE OF WEST VIRGINIA

Department of Revenue
State Tax Department

Earl Ray Tomblin
Governor

Mark W. Matkovich
State Tax Commissioner

August 27, 2015

The Honorable Natalie Tennant
Secretary of State
Building 1, Suite 157-K
State Capitol
Charleston, West Virginia 25305

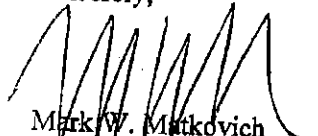
Dear Secretary Tennant:

Attached are final natural resource property valuation variables for the 2016 Tax Year that have been developed by the State Tax Department for use in appraising oil and gas, managed timberland, coal and other natural resource properties for ad valorem tax purposes.

In accordance with requirements of §§ 110 CSR 1-I, 1-J, and 1-K, tentative variables were made available for public comments on June 30, 2014. The Department received six comments on the tentative variables. Three comments related to the valuation of coal and three comments related to the valuation of producing oil and gas wells. The information supplied in the coal comments resulted in an increase in the capitalization rate for coal properties. One of the oil and gas commenters supplied data supporting an increase in the decline rate for Marcellus gas wells in the North West region.

The final valuation variables are being filed for inclusion in the State Register.

Sincerely,


Mark W. Matkovich
State Tax Commissioner

MWM/jaj

Attachment

cc: All County Assessors

OIL AND GAS PROPERTIES ANALYSIS

Tax Year 2016

FILED
AUG 27 2015
STATE TAX COMMISSIONER
DEPARTMENT OF REVENUE

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

OIL AND GAS

TY 2016

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for producing oil and gas properties. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 1J.

<u>Rate</u>	(3-Month Constant Maturity Interest Rates)		
	January	December	2014
			0.033%

<u>Risk Rate</u>	(Interest differential between Loan Rate and 3-Month Constant Maturity Interest Rates)		
	<u>Loan Rate*</u>		<u>Risk Rate</u>
	2014	5.250%	5.217%
		*Prime plus 2%	

<u>Equity</u>	(Differential between Equity Rates and 3-Month Constant Maturity Interest Rates)		
	<u>Equity Rate**</u>		<u>Risk Rate</u>
	2014	$[11.5\% / (1 - .37)] - 0.033\%$	18.221%
	** Value Line Investment Survey Analysis		

<u>Composite Risk Rate</u>	Loan and Equity Rates weighted by industry estimated capital structure.		
	<u>Equity Rate</u>	<u>Debt Rate</u>	<u>Composite Risk</u>
	2014	11.8436%	1.828%
			14.389%
	Note: Debt equity Ratio		35%
	*** Effective severance tax adjustment		0.95
			Equity 65%

<u>Non Liquidity Rate</u>	Interest differential between 3-month Constant Maturity Interest Rates and a 1 year Constant Maturity Interest Rates which reflects a reasonable time necessary to sell active property.		
	January	December	2014
			1yr T Bill
			0.121%
			90 day T Bill
			0.033%
			Non Liquidity Rate
			0.088%

<u>Management Rate</u>	Charges for the management of investment portfolios.	
	Fixed Rate (by Rule)	0.500%

<u>Property Tax Rate</u>	Sixty percent (60%) of State average Class III property tax rate.	
	2014	90% of 2.19
		1.314%

<u>Inflation Rate</u>	January	December	2014
			0.750%

Capitalization Rate

Since the valuation of oil and gas property is predicated on a three year production, the capitalization rate will be considered in a similar manner.

	2014	2013	2012
Inflation Rate	-0.780%	-1.500%	-1.700%
Safe Rate	0.033%	0.056%	0.066%
Composite Risk Rate	14.389%	14.634%	14.605%
Non Liquidity Rate	0.038%	0.074%	0.069%
Management Rate	0.500%	0.500%	0.500%
Property Tax Rate	1.314%	1.314%	1.326%
Total	15.584%	15.080%	14.966%
	50.000%	33.333%	16.667%
	7.782%	5.027%	2.484%
			15.293%

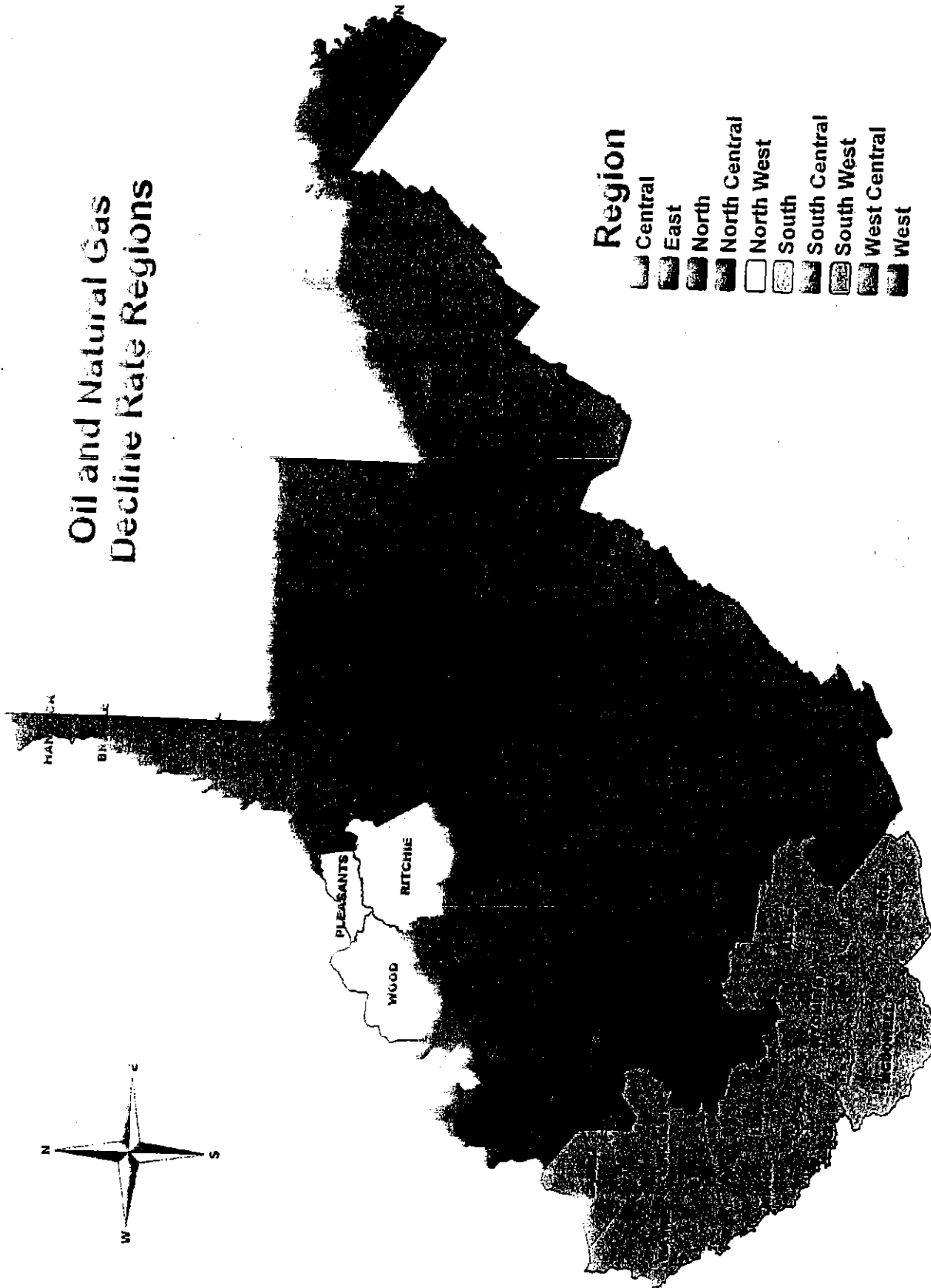
Capitalization Rate Rounded to:

15.30%

MULTIPLIERS FOR 15.3% MID-YEAR LIFE (ANNUALLY)

YEAR		YEAR	
1	0.931291	21	0.054013
2	0.807711	22	0.046648
3	0.700530	23	0.040626
4	0.607572	24	0.035238
5	0.526646	25	0.030562
6	0.457024	26	0.026507
7	0.396378	27	0.022888
8	0.343780	28	0.019838
9	0.298181	29	0.017293
10	0.258596	30	0.014898
11	0.224281	31	0.013008
12	0.194519	32	0.011282
13	0.168707	33	0.009785
14	0.146320	34	0.008466
15	0.126904	35	0.007360
16	0.110064	36	0.006384
17	0.095459	37	0.005538
18	0.082792	38	0.004802
19	0.071808	39	0.004155
20	0.062277	40	0.003612

Oil and Natural Gas Decline Rate Regions



Decline Rates for Natural Gas and Oil Formations: Central				
Central: Braxton, Clay, Fayette, Nicholas, Webster				
Code	Formation	Year 1	Year 2	Year 3 +
12	Alexander, Benson	-0.31	-0.20	-0.10
14	Benson	-0.48	-0.08	-0.08
16	Benson, Balltown+	-0.45	-0.16	-0.12
17	Gordon +	-0.30	-0.07	-0.07
18	Big Injun	-0.34	-0.13	-0.13
19	Big Injun, Big Lime	-0.36	-0.13	-0.13
22	Big Lime	-0.34	-0.34	-0.13
23	Ravenciff	-0.40	-0.40	-0.25
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.41	-0.22	-0.09
110	Marcellus *	-0.41	-0.22	-0.09
9	Exception (Median)	-0.41	-0.22	-0.09
10	Non-Filer	-0.30	-0.07	-0.07

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: East

East, Berkeley, Grant, Greenbrier, Hampshire, Hardy, Jefferson, Mineral,
Monroe, Morgan, Pendleton, Pocahontas, Preston, Randolph, Summers,
Tucker

Code	Formation	Year 1	Year 2	Year 3 +
1	Oriskany	-0.30	-0.30	-0.19
14	Benson	-0.31	-0.17	-0.12
20	Benson +	-0.44	-0.20	-0.08
21	Benson, Fifth	-0.29	-0.28	-0.09
32	Brallier +	-0.48	-0.20	-0.05
33	Elk, Benson	-0.39	-0.21	-0.08
34	Elk, Benson, Riley	-0.53	-0.19	-0.05
35	Elk, Benson, Riley +	-0.36	-0.19	-0.11
36	Elk, Benson, Balltown	-0.34	-0.18	-0.11
37	Elk, Alexander, Benson	-0.50	-0.07	-0.07
38	Elk, Alexander, Benson +	-0.40	-0.16	-0.16
39	Huntermville	-0.31	-0.31	-0.14
40	Fox, Haverty	-0.36	-0.21	-0.15
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
110	Marcellus	-0.59	-0.22	-0.17
9	Exception (Median)	-0.41	-0.22	-0.10
10	Non-Filer	-0.29	-0.07	-0.05

Decline Rates for Natural Gas and Oil Formations: North				
North: Brooke, Hancock, Marshall, Ohio, Tyler, Wetzel				
Code	Formation	Year 1	Year 2	Year 3 +
11	Gordon	-0.47	-0.31	-0.09
13	Alexander, Benson, Riley	-0.26	-0.16	-0.15
15	Benson, Riley	-0.18	-0.16	-0.06
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
97	Coalbed Methane (Vertical)	-0.23	-0.08	-0.05
110	Marcellus	-0.52	-0.23	-0.18
9	Exception (Median)	-0.39	-0.23	-0.08
10	Non-Filer	-0.18	-0.16	-0.06

Decline Rates for Natural Gas and Oil Formations North Central				
North Central, Barbour, Doddridge, Gilmer, Harrison, Lewis, Marion, Monongalia, Taylor, Upshur				
Code	Formation	Year 1	Year 2	Year 3
11	Gordon	-0.41	-0.14	-0.12
12	Alexander, Benson	-0.37	-0.19	-0.11
13	Alexander, Benson, Riley	-0.40	-0.28	-0.05
14	Benson	-0.31	-0.17	-0.12
15	Benson, Riley	-0.34	-0.17	-0.14
18	Big Injun	-0.36	-0.16	-0.13
21	Benson, Fifth	-0.31	-0.20	-0.14
28	Weir	-0.34	-0.34	-0.07
29	Weir +	-0.28	-0.28	-0.23
33	Elk, Benson	-0.34	-0.16	-0.11
34	Elk, Benson, Riley	-0.42	-0.27	-0.08
37	Elk, Alexander, Benson	-0.49	-0.23	-0.08
38	Elk, Alexander, Benson +	-0.38	-0.20	-0.12
40	Fox, Haverty	-0.48	-0.16	-0.08
50	Rhinestreet	-0.28	-0.03	-0.03
57	Alexander, Benson, Balltown	-0.39	-0.26	-0.08
58	Alexander	-0.35	-0.20	-0.10
59	Alexander +	-0.39	-0.22	-0.10
60	Alexander, Benson, Riley +	-0.39	-0.35	-0.12
61	Balltown	-0.35	-0.20	-0.10
62	Balltown, Speechley	-0.28	-0.22	-0.10
63	Balltown, Speechley +	-0.30	-0.13	-0.10
64	Benson, Balltown, Speechley	-0.28	-0.22	-0.09
65	Benson, Bradford	-0.37	-0.20	-0.10
66	Benson, Balltown	-0.29	-0.23	-0.11
67	Benson, Riley +	-0.38	-0.14	-0.10
68	Benson, Speechley	-0.30	-0.22	-0.14
69	Brallier, Elk	-0.42	-0.20	-0.13
70	Brallier	-0.40	-0.22	-0.15
71	Deeper/Onondaga or Oriskany/Heiderberg	-0.24	-0.24	-0.03
72	Elk, Alexander	-0.42	-0.22	-0.09
73	Elk, Benson +	-0.38	-0.20	-0.12
74	Elk	-0.43	-0.12	-0.10
75	Elk, Riley	-0.60	-0.35	-0.17
76	Fox +	-0.48	-0.18	-0.09
77	Haverty, Elk, Benson (No Alexander)	-0.35	-0.18	-0.18
78	Haverty	-0.45	-0.15	-0.15
79	Riley	-0.44	-0.22	-0.10
80	Speechley	-0.30	-0.18	-0.09
81	Alexander, Benson, Speechley	-0.39	-0.24	-0.10
82	Haverty, Elk, Alexander	-0.47	-0.14	-0.14
85	Fifth, Oil	-0.45	-0.25	-0.22
87	Bayard All	-0.30	-0.20	-0.05
88	Fifth	-0.29	-0.18	-0.12
89	Fifth +	-0.25	-0.15	-0.13
90	Gordon, Injun All	-0.41	-0.23	-0.23
91	Squaw	-0.37	-0.31	-0.06
92	Injun +	-0.34	-0.22	-0.22
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.28	-0.09
96	Maxton	-0.70	-0.27	-0.08
97	Coalbed Methane (Vertical)	-0.23	-0.08	-0.05
98	Coalbed Methane (Horizontal)	-0.05	-0.05	-0.32
109	Trenton/Deeper *	-0.38	-0.21	-0.11
110	Marcellus	-0.59	-0.29	-0.23
9	Exception (Median)	-0.38	-0.21	-0.11
10	Non-Filer	-0.23	-0.03	-0.03

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: North West				
North West: Pleasants, Ritchie, Wood				
Code	Formation	Year 1	Year 2	Year 3
2	Huron, Rhinestreet	-0.41	-0.26	-0.07
4	Huron	-0.42	-0.24	-0.14
5	Huron, Shales above Huron	-0.39	-0.25	-0.14
3	Berea	-0.31	-0.15	-0.15
11	Gordon	-0.38	-0.10	-0.10
12	Alexander, Benson (No Riley)	-0.34	-0.23	-0.10
13	Alexander, Benson, Riley	-0.32	-0.20	-0.10
14	Benson	-0.19	-0.19	-0.10
44	Rhinestreet, Huron, Shallow Shale	-0.43	-0.28	-0.11
47	Alexander, Riley, (No Benson)	-0.41	-0.05	-0.05
48	Rhinestreet, Alexander, Benson, Riley	-0.31	-0.24	-0.10
49	Weir, Squaw, Big Injun	-0.27	-0.17	-0.07
50	Rhinestreet	-0.40	-0.27	-0.27
51	Rhinestreet +	-0.36	-0.21	-0.10
52	All Upper Devonian (Undiv)	-0.48	-0.33	-0.19
53	Huron, Chemung	-0.35	-0.11	-0.09
54	Huron, Hampshire, Pocono	-0.12	-0.12	-0.11
55	Upper Devonian (Above Huron)	-0.46	-0.33	-0.23
56	Chemung Sands= Riley, Bradford, Balltown, Speechley, Warren (No Benson or Alexander)	-0.28	-0.18	-0.10
83	Huron Oil	-0.74	-0.44	-0.40
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.39	-0.23	-0.13
110	Marcellus	-0.46	-0.29	-0.13
9	Exception (Median)	-0.39	-0.23	-0.13
10	Non-Filer	-0.12	-0.05	-0.05

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: South				
South: McDowell, Mercer, Raleigh, Wyoming				
Code	Formation	Year 1	Year 2	Year 3 +
3	Berea	-0.34	-0.15	-0.15
22	Big Lime	-0.31	-0.19	-0.07
23	Big Lime, Maxton	-0.31	-0.19	-0.07
24	Big Lime, Ravencloff	-0.29	-0.29	-0.17
25	Berea +	-0.37	-0.12	-0.08
26	Ravencloff	-0.40	-0.08	-0.07
28	Weir	-0.44	-0.20	-0.10
29	Weir +	-0.28	-0.21	-0.08
30	Weir, Big Lime	-0.37	-0.19	-0.13
42	Maxton, Ravencloff	-0.40	-0.08	-0.07
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.28	-0.09
96	Maxton	-0.27	-0.13	-0.09
97	Coalbed Methane (Vertical)	0.03	0.10	-0.05
98	Coalbed Methane (Horizontal)	-0.05	-0.05	-0.32
110	Marcellus *	-0.36	-0.19	-0.09
9	Exception (Median)	-0.36	-0.19	-0.09
10	Non-Filer	-0.23	-0.08	-0.05

* New Formation(s) involved in recent production. These will be valued with the Exception Ratea until decline information is available.

Decline Rates for Natural Gas and Oil Formations: South Central				
South Central: Boone, Kanawha				
Code	Formation	Year 1	Year 2	Year 3 +
3	Devonian Shale	-0.23	-0.08	-0.05
4	Huron	-0.21	-0.15	-0.04
8	Berea	-0.23	-0.14	-0.09
18	Big Injun	-0.29	-0.25	-0.12
27	Huron, Shales above Huron	-0.21	-0.08	-0.05
28	Weir	-0.30	-0.21	-0.14
29	Weir +	-0.31	-0.25	-0.09
31	Devonian Shales +	-0.27	-0.07	-0.05
86	Big Injun-Oil	-0.19	-0.18	-0.10
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.33	-0.19	-0.08
110	Marcellus *	-0.33	-0.19	-0.08
9	Exception (Median)	-0.33	-0.19	-0.08
10	Non-Filer	-0.19	-0.07	-0.04

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: South West				
South West: Cabell, Lincoln, Logan, Mingo, Wayne				
Code	Formation	Year 1	Year 2	Year 3
3	Devonian Shale	-0.31	-0.15	-0.04
8	Berea	-0.36	-0.11	-0.11
18	Big Injun	-0.38	-0.22	-0.04
22	Big Lime	-0.19	-0.19	-0.19
43	Berea, Big Lime	-0.18	-0.18	-0.18
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.38	-0.22	-0.10
110	Marcellus *	-0.38	-0.22	-0.10
9	Exception (Median)	-0.38	-0.22	-0.10
10	Non-Filer	-0.18	-0.11	-0.04

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations - West				
West: Jackson, Mason, Putnam				
Code	Formation	Year 1	Year 2	Year 3 *
1	Oriskany	-0.40	-0.40	-0.29
2	Huron, Rhinestreet	-0.13	-0.12	-0.03
3	Devonian Shale	-0.31	-0.15	-0.04
4	Huron	-0.29	-0.14	-0.05
5	Huron, Shales above Huron	-0.38	-0.15	-0.06
6	Huron, Berea	-0.29	-0.08	-0.08
7	Berea, Devonian Shale	-0.08	-0.08	-0.08
8	Berea	-0.36	-0.16	-0.16
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.35	-0.20	-0.09
110	Marcellus *	-0.35	-0.20	-0.09
9	Exception (Median)	-0.35	-0.20	-0.09
10	Non-Filer	-0.08	-0.08	-0.03

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: West Central				
West Central: Calhoun, Roane, Wirt				
Code	Formation	Year 1	Year 2	Year 3 +
2	Huron, Rhinestreet	-0.49	-0.11	-0.06
4	Huron	-0.33	-0.22	-0.14
27	Huron, Shales above Huron	-0.42	-0.23	-0.12
44	Rhinestreet, Huron, Shallow Shale	-0.51	-0.14	-0.11
45	Devonian Shale, Pocono	-0.25	-0.17	-0.12
46	Pocono	-0.29	-0.25	-0.12
64	Big Injun, Oil	-0.41	-0.41	-0.11
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.42	-0.24	-0.10
110	Marcellus *	-0.42	-0.24	-0.10
3	Exception (Median)	-0.42	-0.24	-0.10
10	Non-Filer	-0.25	-0.11	-0.06

* New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Industry Operating Expense Survey and Results

This component was determined through a review of responses to a survey distributed by the State Tax Department to producers of all oil and natural gas wells producing in West Virginia and through use of other market data.

GAS

- % Working Interest Expenses for Typical Producing Well	=	30%
- Maximum Operating Expenses	=	\$5,000
- Coal Bed Methane, Vertical Wells Expenses	=	\$9,000

OIL

- % Working Interest Expenses for Typical Producing Well	=	35%
- Maximum Operating Expenses	=	\$5,750
- Maximum Enhanced Operating Expenses	=	\$9,000

MARCELLUS

- % Working Interest Expenses for Vertical Producing Well	=	30%
- Maximum Operating Expenses	=	\$30,000
- % Working Interest Expenses for Horizontal Producing Well	=	20%
- Maximum Operating Expenses	=	\$150,000

HORIZONTAL WELLS (OTHER THAN MARCELLUS)

- % Working Interest Expenses for Horizontal Producing Well	=	30%
- Maximum Operating Expenses	=	\$20,000

Minimum Working Interest Appraisal = \$500 per well

Flat Rate Royalty Multiplier = 5.75

Home Use Only Wells:

Appraised at \$500 per well

Industrial Use Only Wells:*

MCF usage X \$ 4.39/MCF
BBL usage X \$93.26/BBL

*(Also includes Department of Environmental Protection reported wells.)

Non-Filer Valuations

Working Interest	=	150% of previous year's appraisal
Royalty Interest	=	90% of previous year's appraisal

Valuation

The previously discussed variables are used to establish a future income stream converted to present worth through application of a capitalization rate. The sum of the discounted future net income per year represents a reasonable estimate of market value.

Lease Rate/Term Survey and Results

The non-producing property value for each county is determined by multiplying the average delay rental by a factor, which represents the average lease term under present economic conditions.

As a result of higher lease terms being inversely proportional to the value of oil and gas (thus counties with little leasing or production activities reflect inflated values) and with the volatile nature of county activity, necessary adjustments in the review have been made.

A compilation of lease terms produced a statewide average of 5 years. This term (5 years) was applied to all county lease rates and compared to the appraisal rates derived from calculations using individual county data. The two resulting calculations were reviewed and considered in the assignment of an appraisal rate per acre.

The appraisal rate/acre amounts shown on the next page are preliminary figures, which may change if additional lease data is received. These rates have been applied to all county magisterial districts with either producing wells, lease activity within the past 5 years or both. Tax districts void of activity within the past 5 years have been assigned the minimum value per acre.

OIL & GAS RESERVE RATES FOR TY 2018			
COUNTY	CO #	DISTRICT #	TY2018 \$/AC
BARBOUR	1	1	\$80.00
		2	\$1.00
		3	\$50.00
		4	\$50.00
		5	\$50.00
		6	\$1.00
		7	\$50.00
		8	\$50.00
		9	\$50.00
		10	\$50.00
		11	\$50.00
BERKELEY	2	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
BOONE	3	1	\$20.00
		2	\$1.00
		3	\$1.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
		7	\$1.00
		8	\$20.00
		9	\$1.00
BRAXTON	4	1	\$20.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$20.00
		7	\$20.00
		8	\$1.00
BROOKE	5	1	\$1.00
		2	\$1.00
		3	\$25.00
		4	\$25.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
CDUNTY	CD #	DISTRICT #	TY2016 \$/AC
CABELL	6	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$1.00
		10	\$20.00
DALHOUS	7	1	\$30.00
		2	\$1.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		6	\$30.00
CLAY	8	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
DODDRIDGE	9	1	\$60.00
		2	\$60.00
		3	\$60.00
		4	\$60.00
		5	\$60.00
		6	\$60.00
		7	\$60.00
		8	\$60.00
		9	\$1.00
FAYETTE	10	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CD #	DISTRICT #	TY2016 \$/AC
GILMER	11	1	\$25.00
		2	\$25.00
		3	\$25.00
		4	\$1.00
		5	\$1.00
		6	\$25.00
GRANT	12	1	\$1.00
		2	\$1.00
		3	\$10.00
		4	\$1.00
		5	\$10.00
GREENBRIER	13	1	\$1.00
		2	\$1.00
		3	\$10.00
		4	\$10.00
		5	\$1.00
		6	\$10.00
		7	\$10.00
		8	\$10.00
		9	\$10.00
		10	\$1.00
		11	\$10.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$10.00
		17	\$1.00
		18	\$10.00
HAMPSHIRE	14	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$5.00
		6	\$1.00
		7	\$5.00
		8	\$1.00
		9	\$5.00
		10	\$1.00
HANCOCK	15	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$1.00
		6	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
HARDY	16	1	\$1.00
		2	\$10.00
		3	\$10.00
		4	\$10.00
		5	\$10.00
		6	\$1.00
HARRISON	17	1	\$60.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$60.00
		6	\$1.00
		7	\$60.00
		8	\$1.00
		9	\$60.00
		10	\$1.00
		11	\$60.00
		12	\$60.00
		13	\$1.00
		14	\$60.00
		15	\$60.00
		16	\$1.00
		17	\$1.00
		18	\$60.00
		19	\$1.00
		20	\$60.00
		21	\$1.00
JACKSON	18	1	\$35.00
		2	\$35.00
		3	\$1.00
		4	\$35.00
		5	\$1.00
		6	\$35.00
		7	\$35.00
JEFFERSON	19	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CD #	DISTRICT #	TY2016 \$/AC
KANAWHA	20	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$30.00
		16	\$30.00
		17	\$1.00
		18	\$1.00
		19	\$30.00
		20	\$1.00
		21	\$1.00
		22	\$1.00
		23	\$30.00
		24	\$30.00
		25	\$30.00
		26	\$1.00
		27	\$1.00
		28	\$30.00
		29	\$1.00
		30	\$1.00
		31	\$1.00
LEWIS	21	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$30.00
		5	\$1.00
		6	\$30.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
LINCOLN	22	1	\$15.00
		2	\$15.00
		3	\$1.00
		4	\$15.00
		5	\$15.00
		6	\$15.00
		7	\$15.00
		8	\$15.00
		9	\$15.00
		10	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
LOGAN	23	1	\$15.00
		2	\$15.00
		3	\$15.00
		4	\$15.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$15.00
MARION	24	3	\$1.00
		1	\$55.00
		2	\$55.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$55.00
		10	\$1.00
		11	\$55.00
		12	\$55.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$55.00
		17	\$1.00
		18	\$55.00
		19	\$55.00
		20	\$1.00
		21	\$1.00
		22	\$1.00
MARSHALL	25	1	\$50.00
		2	\$1.00
		3	\$50.00
		4	\$50.00
		5	\$50.00
		6	\$1.00
		7	\$50.00
		8	\$1.00
		9	\$50.00
		10	\$1.00
		11	\$1.00
		12	\$50.00
		13	\$50.00
		14	\$50.00
		15	\$50.00
		16	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
MASON	26	1	\$25.00
		2	\$25.00
		3	\$25.00
		4	\$25.00
		5	\$25.00
		6	\$25.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$25.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$25.00
		15	\$25.00
		16	\$25.00
		17	\$25.00
MC DOWELL	27	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$1.00
		6	\$20.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$20.00
		12	\$1.00
		13	\$20.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
MERCER	28	1	\$1.00
		2	\$15.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$15.00
		7	\$1.00
		8	\$1.00
		9	\$15.00
		10	\$1.00
		11	\$15.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
MINERAL	29	1	\$10.00
		2	\$1.00
		3	\$1.00
		4	\$10.00
		5	\$1.00
		6	\$10.00
		7	\$1.00
		8	\$10.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
MINGO	30	1	\$1.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
		7	\$20.00
		8	\$1.00
		9	\$20.00
		10	\$20.00
		11	\$20.00
		12	\$1.00
MONONGALIA	31	1	\$25.00
		2	\$1.00
		3	\$25.00
		4	\$25.00
		5	\$25.00
		6	\$1.00
		7	\$25.00
		8	\$25.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$25.00
		19	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
MONROE	32	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$10.00
		5	\$10.00
		6	\$1.00
		7	\$10.00
		8	\$1.00
		9	\$10.00
MORGAN	33	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
NICHOLAS	34	1	\$15.00
		2	\$15.00
		3	\$15.00
		4	\$15.00
		5	\$15.00
		6	\$1.00
		7	\$15.00
		8	\$1.00
		9	\$15.00
OHIO	35	1	\$1.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$35.00
		6	\$35.00
		7	\$1.00
		8	\$35.00
		9	\$35.00
		10	\$35.00
PENOLETON	36	1	\$1.00
		2	\$10.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$10.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
PLEASANTS	37	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$35.00
		6	\$1.00
		7	\$35.00
		8	\$35.00
POCAHONTAS	38	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$10.00
		8	\$1.00
PRESTON	39	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$35.00
		6	\$35.00
		7	\$35.00
		8	\$35.00
		9	\$1.00
		10	\$35.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$1.00
		19	\$1.00
		20	\$1.00
PUTNAM	40	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$20.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$1.00
		10	\$20.00
		11	\$20.00
		12	\$20.00
		13	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
RALEIGH	41	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$1.00
		7	\$20.00
		8	\$20.00
		9	\$20.00
		10	\$1.00
		11	\$20.00
		12	\$20.00
RANDOLPH	42	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$20.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$20.00
		11	\$20.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$20.00
		17	\$1.00
		18	\$1.00
RITCHIE	43	1	\$40.00
		2	\$1.00
		3	\$40.00
		4	\$1.00
		5	\$40.00
		6	\$1.00
		7	\$40.00
		8	\$1.00
		9	\$1.00
		10	\$40.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
ROANE	44	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		6	\$30.00
		7	\$30.00
		8	\$1.00
		9	\$30.00
SUMMERS	45	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$10.00
		6	\$1.00
		7	\$1.00
TAYLOR	46	1	\$1.00
		2	\$1.00
		3	\$55.00
		4	\$55.00
		5	\$55.00
		6	\$55.00
		7	\$55.00
TUCKER	47	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$20.00
		10	\$1.00
		11	\$20.00
		12	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
TYLER	48	1	\$55.00
		2	\$55.00
		3	\$1.00
		4	\$55.00
		5	\$55.00
		6	\$55.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$55.00
UPSHUR	49	1	\$50.00
		2	\$50.00
		3	\$1.00
		4	\$50.00
		5	\$50.00
		6	\$50.00
		7	\$50.00
WAYNE	50	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$20.00
		10	\$20.00
		11	\$1.00
		12	\$20.00
WEBSTER	51	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$15.00
		5	\$15.00
		6	\$15.00
		7	\$1.00

OIL & GAS RESERVE RATES FOR TY. 2016			
COUNTY	CD #	DISTRICT #	TY2016 \$/AC
WETZEL	52	1	\$55.00
		2	\$55.00
		3	\$55.00
		4	\$55.00
		5	\$55.00
		6	\$1.00
		7	\$1.00
		8	\$55.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$5.00
		13	\$1.00
VIRT	53	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$1.00
		5	\$30.00
		6	\$30.00
		7	\$30.00
		8	\$30.00
WOOD	54	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$1.00
		6	\$35.00
		7	\$35.00
		8	\$35.00
		9	\$35.00
		10	\$1.00
		11	\$35.00
		12	\$35.00
		13	\$1.00
		14	\$1.00
WYOMING	55	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$1.00
		7	\$20.00
		8	\$1.00
		9	\$1.00
		10	\$20.00

**MANAGED TIMBER
PROPERTY ANALYSIS**

Tax Year 2016

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

MANAGED TIMBERLAND APPRAISAL RATES

TAX YEAR 2016

(based on market 2010-2014)

Rates Per Acre

Class II Parcels

	<u>Grade 1</u>	<u>Grade 2</u>	<u>Grade 3</u>
Region 1	\$200	\$140	\$50
Region 2	\$200	\$140	\$50
Region 3	\$280	\$185	\$50
Region 4	\$265	\$180	\$55
Region 5	\$210	\$140	\$50

Class III/IV Parcels

	<u>Grade 1</u>	<u>Grade 2</u>	<u>Grade 3</u>
Region 1	\$225	\$150	\$75
Region 2	\$225	\$150	\$75
Region 3	\$250	\$165	\$75
Region 4	\$235	\$160	\$75
Region 5	\$225	\$150	\$75

- Region 1 = Brooke, Cabell, Hancock, Jackson, Marshall, Mason, Ohio, Pleasants, Putnam, Tyler, Wetzel, and Wood Counties
- Region 2 = Braxton, Calhoun, Clay, Doddridge, Gilmer, Harrison, Lewis, Marion, Monongalia, Ritchie, Roane, Taylor, and Wirt Counties
- Region 3 = Barbour, Greenbrier, Monroe, Nicholas, Pendleton, Pocahontas, Preston, Randolph, Tucker, Upshur, and Webster Counties
- Region 4 = Berkeley, Grant, Hampshire, Hardy, Jefferson, Mineral and Morgan Counties
- Region 5 = Boone, Fayette, Kanawha, Lincoln, Logan, McDowell, Mercer, Mingo, Raleigh, Summers, Wayne, and Wyoming Counties

Harvest Volumes per Acre

Harvest Interval

Grade

	<u>35 yrs.</u>	<u>45 yrs.</u>	<u>55 yrs.</u>	<u>80 yrs.</u>		<u>Total</u>
1 - Site Index 75 or more	4.6 cords	--	2.8 cords	3.3 cords		10.5 cords
	1.5 Mbf	--	4.4 Mbf	8.6 Mbf		14.5 Mbf
2 - Site Index 65 - 75	3.3 cords	--	7.0 cords	4.6 cords		14.9 cords
	1.0 Mbf	--	3.2 Mbf	5.5 Mbf		9.7 Mbf
3 - Site Index less than 65	--	3.1 cords	--	15.4 cords		18.5 cords
	--	0.8 Mbf	--	3.7 Mbf		4.5 Mbf

Managed Timberland Statistics

Estimation of Required Rate of Return: Class II Rates

A. Safe Rate of Return (5 Year T-Bill Rate)

Year	Rate	WIA %	WIA Rate
2014	1.6410	26.87%	0.4377
2013	1.1725	13.33%	0.1563
2012	0.7608	6.67%	0.0507
2011	1.5225	20.00%	0.3045
2010	1.9275	33.33%	0.6424

1.592 %

B. Nonliquidity Rate

(12 Month T-Bills vs. 3 Month T-Bills)

Year	Rate	WIA %	WIA Rate
2014	0.0883	33.33%	0.0294
2013	0.0733	26.67%	0.0195
2012	0.1292	20.00%	0.0258
2011	0.1817	13.33%	0.0242
2010	0.3200	6.67%	0.0213

0.120 %

C. Risk Rate (30 yr T-bills vs 5 yr T-bills)

Year	Rate	WIA %	WIA Rate
2014	1.6992	33.33%	0.5683
2013	2.2758	26.67%	0.6070
2012	2.1600	20.00%	0.4320
2011	2.3883	13.33%	0.3184
2010	2.3233	6.67%	0.1550

2.079 %

D. Management Factor of 0.5%

0.600 %

E. Property Tax Component

(50% of Class II Rate)

Year	Rate	WIA %	WIA Rate
2014	0.714	33.33%	0.2380
2013	0.708	26.87%	0.1888
2012	0.714	20.00%	0.1428
2011	0.708	13.33%	0.0944
2010	0.708	6.67%	0.0472

0.711 %

F. Inflation Rate:

(Bureau of Labor Statistics)

Year	Rate	WIA %	WIA Rate
2014	0.760	33.33%	0.2533
2013	1.500	26.87%	0.4001
2012	1.700	13.33%	0.2268
2011	3.000	6.67%	0.2001
2010	1.500	20.00%	0.3000

(1.380) %

TOTAL REQUIRED RATE OF RETURN (REAL)

3.622 %

LESS: PROPERTY TAX COMPONENT

(0.711)

TOTAL DISCOUNT COMPONENT

2.911 %

Stumpage Prices:

	<u>Sawtimber</u>	<u>Pulpwood</u>
Stumpage Price Adjustment Factor	0.00%	1.86%

<u>SAWTIMBER</u>	Current \$/MBF	1.0000 \$/MBF at age 35	1.0000 \$/MBF at age 46	1.0000 \$/MBF at age 55	1.0000 \$/MBF at age 60
		35	46	55	60
Region 1	174.30	174.30	174.30	174.30	174.30
Region 2	159.80	159.80	159.80	159.80	159.80
Region 3	248.26	248.26	248.26	248.26	248.26
Region 4	231.30	231.30	231.30	231.30	231.30
Region 5	195.10	195.10	195.10	195.10	195.10

<u>PULPWOOD:</u>	\$/Cord	2.060 \$/cd at age 35	2.2917 \$/cd at age 46	2.7065 \$/cd at age 55	4.3881 \$/cd at age 60
		35	46	55	60
Region 1	5.62	10.72	12.89	15.49	24.56
Region 2	6.85	13.06	15.71	18.89	29.94
Region 3	6.14	11.71	14.08	16.93	26.84
Region 4	8.41	18.03	19.27	23.17	36.73
Region 5	8.46	12.31	14.80	17.79	28.20

Management Costs:

Region	\$/acre (1)
1	3.17
2	3.17
3	3.17
4	3.17
5	3.17
State	

Tax Rates:

Effective Federal Income Tax Rate	35.00%
Effective WV State Income Tax Rate (6.5% * (1-.35))	4.23%
Effective WV Severance Tax Rate (2.76% * (1-.35))	1.81%

Yield (Volumes) (80 year rotation)

Timberland		Yield - MBF	Yield - Cords
Productivity Grades	Site Index		
Grade I	75 or more	14.5	10.5
Grade II	55-74	9.7	14.9
Grade III	less than 55	4.5	18.5

Managed Timberland Statistics

Estimation of Required Rate of Return: Class III & IV Blended Rates

A. Safe Rate of Return (5 Year T-Bill Rate)

Year	Rate	W/A %	W/A Rate
2014	1.6410	26.67%	0.4377
2013	1.1725	13.33%	0.1583
2012	0.7608	6.67%	0.0507
2011	1.5225	20.00%	0.3045
2010	1.5275	33.33%	0.6424

1.592 %

B. Nonliquidity Rate

(12 Month T-Bills vs. 3 Month T-Bills)

Year	Rate	W/A %	W/A Rate
2014	0.0383	13.33%	0.0294
2013	0.0733	26.67%	0.0195
2012	0.1292	20.00%	0.0258
2011	0.1817	13.33%	0.0242
2010	0.3200	6.67%	0.0213

0.120 %

C. Risk Rate (30 yr T-bills vs 5 yr T-bills)

Year	Rate	W/A %	W/A Rate
2014	1.6992	33.33%	0.5663
2013	2.2756	26.67%	0.8070
2012	2.1600	20.00%	0.4320
2011	2.3883	13.33%	0.3184
2010	2.3233	6.67%	0.1550

2.079 %

D. Management Factor of 0.5%

0.500 %

E. Property Tax Component

(60% of Blended III&IV Rates)

Year	Rate	W/A %	W/A Rate
2014	1.314	33.33%	0.4360
2013	1.314	26.67%	0.3504
2012	1.328	20.00%	0.2652
2011	1.326	13.33%	0.1766
2010	1.314	6.67%	0.0876

1.318 %

F. Inflation Rate:

(Bureau of Labor Statistics)

Year	Rate	W/A %	W/A Rate
2014	0.760	33.33%	0.2533
2013	1.500	26.67%	0.4001
2012	1.700	13.33%	0.2266
2011	3.000	6.67%	0.2001
2010	1.500	20.00%	0.3000

(1.380) %

TOTAL REQUIRED RATE OF RETURN (REAL)

4.229 %

LESS: PROPERTY TAX COMPONENT

(1.316)

TOTAL DISCOUNT COMPONENT

2.911 %

Stumpage Prices:

	<u>Sawtimber</u>	<u>Pulpwood</u>
Stumpage Price Adjustment Factor	0.00%	1.86%

		1.0000	1.0000	1.0000	1.0000
SAWTIMBER	Current	\$/MBF at age	\$/MBF at age	\$/MBF at age	\$/MBF at age
Region	\$/MBF	35	45	55	60
Region 1	174.30	174.30	174.30	174.30	174.30
Region 2	169.80	169.80	169.80	169.80	169.80
Region 3	248.28	248.28	248.28	248.28	248.28
Region 4	231.30	231.30	231.30	231.30	231.30
Region 5	195.10	195.10	195.10	195.10	195.10

		1.0000	1.0000	1.0000	1.0000
PULPWOOD:		\$/cd at age	\$/cd at age	\$/cd at age	\$/cd at age
Region	\$/Cord	35	45	55	60
Region 1	5.62	10.72	12.39	15.49	24.58
Region 2	6.85	13.08	15.71	18.89	29.94
Region 3	6.14	11.71	14.08	18.93	28.84
Region 4	8.41	16.03	19.27	23.17	36.73
Region 5	6.48	12.31	14.80	17.79	28.20

Management Costs:

Region	\$/acra (1)
1	3.17
2	3.17
3	3.17
4	3.17
5	3.17
State	

Tax Rates:

Effective Federal Income Tax Rate	35.00%
Effective WV State Income Tax Rate (6.5% * (1-.35))	4.23%
Effective WV Severance Tax Rate (2.78% * (1-.35))	1.81%

Yield (Volumes) (80 year rotation)

Productivity Grades	Site Index	Yield - MBF	Yield - Cords
Grade I	75 or more	14.6	10.5
Grade II	65-74	9.7	14.9
Grade III	less than 65	4.5	18.5

West Virginia Wgt/Avg Managed Timberland Stumpage Prices

REGION 1 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	12,182.08	176.34	33.33%	58.78
2013	19,017.77	177.48	28.67%	47.32
2012	12,828.15	188.58	20.00%	37.31
2011	11,195.24	144.89	13.33%	19.32
2010	15,157.58	173.52	5.67%	11.57
	70,160.80			174.30

REGION 1 - Pulpwood *

Year	Volume	\$/CORG	W/A%	\$/CORG
2014	4,400	5.40	33.33%	1.30
2013	3,192.20	2.06	28.67%	0.79
2012	45,387.00	6.42	20.00%	1.28
2011	8,100	7.67	13.33%	1.29
2010	1,359.30	9.90	5.67%	0.46
	53,061.00			5.62

REGION 2 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	22,001.80	102.47	33.33%	60.82
2013	35,396.85	177.79	28.67%	47.41
2012	25,640.98	149.01	20.00%	29.60
2011	12,839.41	156.28	13.33%	20.83
2010	56,575.40	163.98	5.67%	10.93
	142,754.44			169.60

REGION 2 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	2,168.10	5.04	33.33%	1.68
2013	119,279.40	12.83	28.67%	3.42
2012	22,647.40	2.88	20.00%	0.57
2011	5,235.20	8.78	13.33%	0.90
2010	23,291.90	4.15	5.67%	0.26
	172,822.00			3.85

REGION 3 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	91,467.44	280.52	33.33%	93.51
2013	181,397.70	275.83	28.67%	73.50
2012	111,920.80	201.57	20.00%	40.31
2011	102,218.30	201.45	13.33%	28.88
2010	145,592.20	211.21	5.67%	14.08
	512,596.24			248.28

REGION 3 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	170,736.30	3.57	33.33%	1.19
2013	153,197.40	7.78	28.67%	2.07
2012	183,132.80	6.39	20.00%	1.28
2011	159,040.70	7.34	13.33%	0.98
2010	123,858.50	9.34	5.67%	0.62
	789,965.50			5.14

REGION 4 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	5,020.80	303.89	33.33%	101.30
2013	12,620.20	211.47	26.67%	56.39
2012	4,808.73	193.47	20.00%	36.69
2011	15,517.51	176.40	13.33%	23.79
2010	24,125.65	167.02	6.67%	11.13
	<u>62,293.19</u>			<u>31.30</u>

REGION 4 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	7,735.20	3.16	33.33%	2.72
2013	15,488.60	4.32	26.67%	2.22
2012	7,332.20	3.61	20.00%	1.92
2011	21,974.10	3.64	13.33%	1.15
2010	36,223.70	5.93	6.67%	1.40
	<u>72,933.80</u>			<u>1.41</u>

REGION 5 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	21,661.40	155.95	33.33%	88.65
2013	31,859.00	196.20	26.67%	52.65
2012	10,887.05	136.63	20.00%	27.73
2011	24,760.43	122.43	13.33%	16.32
2010	56,603.00	143.15	6.67%	9.54
	<u>145,770.88</u>			<u>195.10</u>

REGION 5 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	10,191.40	6.19	33.33%	2.06
2013	16,292.60	7.13	26.67%	1.90
2012	8,296.30	6.93	20.00%	1.39
2011	6,432.30	6.26	13.33%	0.83
2010	19,223.30	4.06	6.67%	0.27
	<u>62,435.90</u>			<u>6.46</u>

COAL PROPERTIES ANALYSIS

Tax Year 2016

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

COAL CAPITALIZATION RATE

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for active coal. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 11.

<u>Safe Rate</u>	90 day Treasury Bills	<u>Safe Rate</u>
January	December 2014	0.033%
January	December 2013	0.058%
January	December 2012	0.088%

Risk Rate Interest differential between Loan Rate and 90 day Treasury Bills

<u>Loan Rate*</u>	<u>Debt Risk Rate</u>
2014 5.25%	5.217%
2013 5.25%	5.192%
2012 5.25%	5.164%
*Prime plus 2%	

Equity Differential between Equity Rates and 90 day Treasury Bills

<u>Equity Rate**</u>	<u>Equity Risk Rate</u>
2014 $[15.50\%/(1-.30)]-0.033$	22.110%
2013 $[13.25\%/(1-.30)]-0.058$	18.871%
2012 $[13.25\%/(1-.30)]-0.088$	16.643%

** Value Line Investment Survey Analysis

Composite Risk Rate Loan and Equity Rates weighted by industry estimated capital structure

	<u>Equity Rate</u>	<u>Debt Rate</u>	<u>Composite Risk</u>
2014	15.477%	1.585%	17.042%
2013	11.322%	2.077%	13.399%
2012	11.308%	2.068%	13.372%
Note: Debt/Equity Ratio		Debt. 30%	Equity 70%

Non Liquidity Rate Interest differential between a 90 day Treasury Bill and a 1 year Treasury Bill which reflects a reasonable time necessary to sell active property.

			<u>1yr T Bill</u>	<u>90 d T Bill</u>	<u>Non Liquidity Rate</u>
January	December	2014	0.121%	0.033%	0.088%
January	December	2013	0.132%	0.058%	0.074%
January	December	2012	0.175%	0.086%	0.089%

Management Rate Charges for the management of investment portfolios.

Fixed Rate (by Rule)	0.500%

Inflation Rate

January	December	2014	0.760%
January	December	2013	1.500%
January	December	2012	1.700%

Capitalization Rate Since the valuation of active coal property is predicated on a three year production average, the capitalization rate is considered in a similar manner.

	2014	2013	2012
Inflation Rate	-0.760%	-1.500%	-1.700%
Safe Rate	0.033%	0.058%	0.088%
Composite Risk Rate	17.042%	13.398%	13.372%
Non Liquidity Rate	0.088%	0.074%	0.089%
Management Rate	0.500%	0.500%	0.500%
Total	16.903%	12.531%	12.347%

Three Yr Averages: 13.927 Rounded to: **13.90%**

CAPITALIZATION RATE - 13.9%

MULTIPLIERS:	%	%
1YR	0.937	3.298
2YR	1.760	5.589
3YR	2.482	5.844
4YR	3.116	6.087
5YR	3.673	6.264
6YR	4.182	6.437
7YR	4.591	6.588
8YR	4.967	

COAL

Price and Royalty Rate Analysis

The development of royalty rates for the various categories of mines and markets involves information collection and review from a variety of sources. Coal lease rates have been derived from transaction information provided by county assessors, tax auditors, producers, and by individual lessors/lessees involved in the specific transaction. The prices for mined coal, as per 110-CSR-11, have been calculated from information provided by the WV Public Service Commission and U.S. Energy Information Administration concerning power plant fuel purchases. Prices provided by producers as part of tax filing and from data obtained from market summaries are included for comparison. Because a large portion of the data used in this analysis is, by law, considered confidential, only a summary of the results are published.

COAL SALE PRICES CY2014 FOR TY2016 APPLICATION

GRAND SUMMARY ALL SOURCES 2014	STEAM SPOT	STEAM TERM	MET
PSC	\$3.58	\$3.35	
FERC	\$3.77	\$2.58	
Coal Market Publication		\$7.91 (Platts-CAPP-CSX)	
Active Return Summary		\$3.36 52.7 MM tons	\$103.35 7.6 MM Tons

STATE STEAM PRICE (SPOT Market)
STATE MET PRICE

\$60.35 FERC & PSC, 3 YR AVE
\$103.35 Active Return

2014 WVPSC Tons reported in millions	Spot Sales	Term Sales	Total
	2,170,351	15,503,854	17,674,205

COAL TY2016 ROYALTY RATES

	2014 1YR		2013 2YR		2012 3YR		2011 4YR		2010 5YR	
	%S	%D	%S	%D	%S	%D	%S	%D	%S	%D
TOTAL RECORDS	1,447	905	1,354	598	1,908	2,768	1,677	2,241	2,148	3,197
SUM of PERCENT	3,889.07	4,695.25	3,087.34	3,313.83	11,881.88	14,863.03	8,924.28	11,181.05	14,408.71	16,405.76
STRAIGHT AVERAGE	3.13	5.19	5.97	5.53	6.23	5.32	5.32	4.98	5.89	5.13
MEDIAN	3.00	5.00	5.00	5.00	6.00	5.13	5.00	5.00	5.22	5.00
WEIGHTED AVERAGE (by Mineac)	3.94	5.48	5.58	5.84	6.46	6.28	6.27	5.72	6.24	5.68
TENTATIVE RATE DEEP (%)	5.00									
TENTATIVE RATE SURFACE (%)	6.50									

ROYALTY RATE CALCULATIONS

Steam Coal/ Deep Mine	\$60.35	per ton X	5.80%	=	\$3.50	per ton
Metallurgical Coal/ Deep Mine	\$103.35	per ton X	5.80%	=	\$5.99	per ton
Steam Coal/ Surface Mine	\$60.35	per ton X	5.50%	=	\$3.32	per ton
Metallurgical Coal/ Surface Mine	\$103.35	per ton X	5.50%	=	\$5.71	per ton

Explanation of Reserve Coal Valuation

The RCVM consists of a computer model, which utilizes a database consisting of coal beds and characteristics, property locations, mine locations, sales, transportation, etc., for the entire state. An extensive algorithm calculates in-place tonnage, expected time of mining and present value for all the mineable coal on every property.

There are, therefore, no set "rates" available on reserve coal under the Rule. The RCVM values on each property will not be available until all data has been entered, after October 15 of each year. Please refer to the State Register, Legislative Rules, Title 110, Series 11 for details of the process.

Title 110, Series 11
Valuation of Active and Reserve Coal Property for Ad Valorem Property Tax Purposes

The above Legislative Rule was modified during the 2005 Legislative Session requiring biennial (every other year) updating of the geostatistical base for several valuation factors used in the Reserve Coal Valuation Model. To satisfy that requirement, maps and data files concerning the Market Interest Factor, the Market Mineability Factor, the Use Conflict Factor and the Environmental Factor have been revised for Tax Year 2015. Preliminary research has been conducted to determine the effects of the factors on coal valuation. The results are as follows:

Market Interest Factor

This is the relationship between transactions (sales, leases, prospects, permit applications, etc.) and mining as it relates to properties and locations. Trans_Ct is the number of transactions counted within the radius.
Radius = 5 miles

```
If Trans_Ct >= 20 Then TransFactor = 20  
If Trans_Ct < 20 And Trans_Ct >= 10 Then TransFactor = 40  
Else TransFactor = 80
```

Market Mineability Factor

This is the relationship between property location and mining, through time. Determining feature is count of mines within the radius.
Radius = 2.5 miles

```
Surface Mines: Smine  
Deep Mines: Dmine  
Boom Mines: Bmine  
Historic Mines: Omine  
Current Mines: Cmine  
To assign MineFactor:  
If Cmine > 0 Then MineFactor = 20  
If Cmine = 0 And (Omine > 0 Or Bmine > 0) Then MineFactor = 40  
Else MineFactor = 80
```

Use Conflict Factor

This is the relationship between oil & gas well drilling and mining as it relates to property location. Well density is in wells per square mile.

```
WellDensity < 5 Then WellFactor = 0  
WellDensity >= 5 And WellDensity < 10 Then WellFactor = 20  
WellDensity >= 10 And WellDensity < 20 Then WellFactor = 40  
WellDensity > 20 Then WellFactor = 80
```

Environmental Factor

This is the relationship of known environmental hazards and impediments to the likelihood of mining occurring at this location. The rates are compiled from maps and represent densities of problems mapped.

```
Envrate <= 10 and Null Then EnvFactor = 0  
Envrate > 10 and Envrate <= 30 Then EnvFactor = 20  
Envrate > 30 and Envrate < 60 Then EnvFactor = 40  
Envrate >= 60 Then EnvFactor = 80
```

**OTHER MINED MINERAL
PROPERTY ANALYSIS**

Tax Year 2016

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

OTHER MINED MINERALS CAPITALIZATION RATE

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for active coal. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 1k.

<u>Safe Rate</u>	90 day Treasury Bills			<u>Safe Rate</u>
	January	December	2014	0.033%
	January	December	2013	0.058%
	January	December	2012	0.086%

<u>Risk Rate</u>	<u>Interest differential between Loan Rate and 90 day Treasury Bills</u>	<u>Debt Risk Rate</u>
<u>Loan Rate*</u>		
2014	5.25%	5.217%
2013	5.25%	5.192%
2012	5.25%	5.164%
*Prime plus 2%		

Year	Differential between Equity Rates and 90 day Treasury Bills	Equity Risk Rate
Equity Rate**		
2014	$[(11.75\% / (1-.30)) - 0.033]$	16.753%
2013	$[(11.75\% / (1-.30)) - 0.058]$	16.728%
2012	$[(11.75\% / (1-.30)) - 0.086]$	15.700%
** Value Line Investment Survey Analysis		

<u>Composite Risk Rate</u>		Loan and Equity Rates weighted by Industry estimated capital structure.			
	Equity Rate	Debt Rate		Composite Risk	
2014	10.052%	2.087%		12.138%	
2013	10.037%	2.077%		12.114%	
2012	10.020%	2.066%		12.086%	
Note: Debt Equity Ratio		Debt	40%	Equity	60%

Non Liquidity Rate Interest differential between 90 day Treasury Bills and a 1 year Treasury Bill which reflects a reasonable time necessary to sell active property.

			1 yr. T. Bill	90 d. T. Bill	Non Liquidity Rate
January	December	2014	0.121%	0.033%	0.086%
January	December	2013	0.132%	0.058%	0.074%
January	December	2012	0.175%	0.086%	0.089%

Management Rate Charges for the management of investment portfolios.
Fixed Rate (by Rule) 0.500%

<u>Inflation Rate</u>			
January	December	2014	0.760%
January	December	2013	1.500%
January	December	2012	1.700%

<u>Property Tax Rate</u>	Sixty percent (60%) of State average Class (II) property tax rate.			
January	December	2014	60% of 2.190 =	1.314%
January	December	2013	60% of 2.190 =	1.314%
January	December	2012	60% of 2.210 =	1.326%

Capitalization Rate Since the valuation of other mined mineral property is predicated on a three year production average, the capitalization rate is considered in a similar manner.

	2014	2013	2012
Inflation Rate	-0.760%	-1.500%	-1.700%
Safe Rate	0.033%	0.058%	0.086%
Composite Risk Rate	12.138%	12.114%	12.086%
Non Liquidity Rate	0.086%	0.074%	0.089%
Management Rate	0.500%	0.500%	0.500%
Property Tax Rate	1.314%	1.314%	1.326%
Total	13.314%	12.560%	12.387%

Three Yr Average: 12.754% Rounded to: 12.80%

CAPITALIZATION RATE - 12.80%

MULTIPLIERS:	%	%
1YR	0.942	5.491
2YR	1.778	5.809
3YR	2.518	6.092
4YR	3.172	6.342
5YR	3.754	6.564
6YR	4.269	6.761
7YR	4.727	6.935
8YR	5.132	

OTHER MINED MINERALS

ROYALTY RATE SURVEY

The determination of royalty rates for other mined minerals within the state of West Virginia is dependent upon the availability of leasehold information. Since this information is limited, the Department has chosen to review data for the most recent thirty year period. A summary only of this review is shown below in order to protect the confidentiality of parties involved.

RESOURCE	DATA SOURCES	AVERAGE ROYALTY	MEDIAN ROYALTY	T/2016 RATE
LIMESTONE	15	\$0.22	\$0.20	\$0.22
SANDSTONE	8	\$0.31	\$0.25	\$0.30
CLAY/SHALE	34	\$0.12	\$0.10	\$0.11
SAND/GRAVEL	10	\$0.35	\$0.40	\$0.40
SALT BRINE	1	N/A	N/A	\$0.10

RESERVE VALUES

	number of sales	\$/AC
LIMESTONE	5	\$3,000.00
SANDSTONE	3	\$2,300.00
CLAY/SHALE	16	\$850.00
SAND/GRAVEL	5	\$4,000.00
SALT	2	\$1,140.00

Tex Dep. B. 1/1/02



STATE OF WEST VIRGINIA

Department of Revenue

State Tax Department

Earl Ray Tomblin
Governor

Mark W. Matkovich
State Tax Commissioner

ADMINISTRATIVE NOTICE 2016-02

PROPERTY TAX
STATE TAX COMMISSIONER'S STATEMENT
CONCERNING PRIMARY RELIANCE ON THE INCOME
APPROACH TO VALUE FOR APPRAISALS OF PRODUCING AND
RESERVE COAL, PRODUCING OIL AND GAS, AND PRODUCING
OTHER MINED MINERALS PURSUANT TO §§ 110 CSR 11-4, 1J-4 AND 1K-4

OFFICE OF THE
SECRETARY OF STATE

2016 JAN 27 P 2:33

FILED

The Legislative Rule §§ 110 CSR 1J-1, *et seq.* concerning the appraisal of producing and reserve oil and gas properties became effective June 1, 2005, §§ 110 CSR 11-1, *et seq.* for the appraisal of producing and reserve coal properties became effective May 1, 2006 and §§ 110 CSR 1K-1, *et seq.* for the appraisal of producing other mined mineral properties became effective May 1999. This notice will address these rules' primary reliance on the income approach to value when appraising active and reserve coal, producing oil and gas, and other mined mineral properties for property tax purposes.

DISCUSSION

There are three (3) generally accepted approaches to value that must be considered when estimating market value of property for ad valorem tax purposes. These are the cost, market, and income approaches. These approaches to value must be considered and should be developed, if appropriate, to properly estimate market value in compliance with generally accepted appraisal principles. The following is a brief discussion of these three (3) approaches to value and their potential use when estimating the market value of producing natural resource properties for ad valorem tax purposes.

COST APPROACH

The cost approach to value is based upon the assumption that the cost of a property, less depreciation (loss in value), yields a reasonable estimate of market value. There are three (3) generally accepted types of cost approach appraisal methods; these are: original cost less depreciation, reproduction cost less depreciation, and replacement cost less depreciation. Depreciation is a loss in value due to physical deterioration through use, functional obsolescence through design or utility and economic obsolescence due to outside market forces.

Original cost less depreciation is the cost of acquisition of a property less a loss in value due to physical deterioration, functional obsolescence and economic obsolescence. This approach is widely employed in the appraisal of "cost-based" regulated utilities, however it has a limited application when appraising producing natural resource properties, as many of these types of properties were acquired years ago at substantially less than current market value.

Reproduction cost less depreciation is the cost of reproducing an exact replica of a property less physical deterioration, functional obsolescence, and economic obsolescence. This approach is employed in appraising one-of-a-kind properties such as works of art or special purpose properties, an example of which is the State's Capitol Building. Coal, oil and gas, and other mined minerals are a nonrenewable natural resource and therefore cannot be reproduced. Because of their nonrenewable nature, producing natural resource properties do not lend themselves to development of a reproduction cost less depreciation appraisal.

Replacement cost less depreciation is the cost of replacing a property with one of like utility less physical deterioration and economic obsolescence. This approach is the most widely used of the three (3) cost approaches to value and is widely employed in the appraising of commercial and industrial personal property. Replacement cost has limited application, however, in the appraisal of nonrenewable natural resource properties, as the resource cannot, by its nature, be replaced.

MARKET APPROACH

The market approach to value is based upon the assumption that the recent selling price of comparable properties if properly analyzed and adjusted, if appropriate, will yield a reasonable estimate of current market value. This valuation approach is widely employed in the valuation of residential real estate where a considerable number of properties transfer on a reasonably frequent basis. Natural resource properties sell infrequently and when they do sell they are quite often only a portion of the property acquisition thus diluting the purity of the market transaction. Therefore, the market approach to value has limited application because of the lack of a sufficient number of sales of natural resource properties to statistically support development of the approach for natural resource properties.

INCOME APPROACH

The income approach to value is based upon the assumption that a property is worth the future income, discounted to present worth, that it will generate for a perspective buyer. The income approach is widely used in the appraisal of various types of income producing properties and is appropriately used in several taxing jurisdictions to value producing natural resource properties, i.e. natural resource properties that produce an income stream. In addition, the income approach can be developed for non-producing properties through use of estimating the unit income value and apportioning the value to non-producing properties based upon their probable time of mining.



Earl Ray Tomblin
Governor

STATE OF WEST VIRGINIA
Department of Revenue
State Tax Department

Mark W. Matkovich
State Tax Commissioner

For App. Exhibit

ADMINISTRATIVE NOTICE 2016-06

PROPERTY TAX
STATE TAX COMMISSIONER'S STATEMENT
FOR THE DETERMINATION OF THE CAPITALIZATION RATES FOR
PRODUCING AND RESERVE COAL, OIL AND GAS AND OTHER MINED
MINERALS FOR PROPERTY TAX PURPOSES FOR TAX YEAR 2016,
PURSUANT TO §§ 110 CSR 11-4.1.7, 1J-4.5 AND 1K-4.1.7

OFFICE OF THE
SECRETARY OF STATE

2016 JAN 21 P 2 38

FILED

On August 27, 2015, the State Tax Department filed valuation variables to be used in conjunction with legislative rules for the appraisal of producing natural resource properties. (See: §§ 110 CSR 1-I, 1-J and 1-K) This notice will address one of the variables, the capitalization rate, setting forth the generally accepted appraisal procedures used in developing the respective rates and in applying the rates to income streams generated by natural resource properties. To this end, this notice will discuss development of industry capitalization rates for properties containing coal, and/or oil and gas, and/or other mined minerals.

DISCUSSION

The International Association of Assessing Officers text *Property Appraisal and Assessment Administration*, 1990, defines a capitalization rate as: "Any rate used to convert an estimate of income to an estimate of market value; the ratio of net operating income to market value." In other words a rate used to convert an estimate of future income into an estimate of present value.

Generally, there are three (3) components that must be considered and if appropriate developed and included in an overall capitalization rate. These components are: the discount component, the recapture component, and the property tax component. The development of each of these three (3) components will be discussed in the remainder of this Notice.

DISCOUNT COMPONENT

Of the three (3) generally accepted methods of estimating a discount component, the bands-of-investment method and the summation method have received primary consideration. Consideration was given to use of the comparison method; however, the Tax Department is of the opinion that the bands-of-investment and summation methods are the more appropriate methods to employ for properties containing coal, and/or oil and gas, and/or other mined minerals as there are a limited number of sales of these types of properties and these methods lend themselves more readily to the conversion of the equity rate portion of the discount component to a pre-tax rate.

The first step in the process is to construct a capital structure. The capital structure of an industry depicts typically the sources of capital financing (i.e.: what portion of the total capital financing is raised through debt and through equity financing). The Tax Department developed an average industry capital structure based on mining and oil and gas industries as grouped in the Value Line Investment Survey. The capital structure was segregated into percentages of capital financing generated through debt and through equity financing in order to develop a profile for typical leveraging characteristics by type industry. (Equity financing represents capital acquired through sale of stock and earnings retention and debt financing represents capital acquired through issuance of instruments of debt.)

Once the capital structure had been established a return on investment is developed for each financing band. The Tax Department analyzed the financial information of companies grouped by industry in the Value Line Investment Survey in order to develop a return by type industry for common stocks. This "after-tax" return was then adjusted to a "pre-tax" return where applicable and used in developing the equity portion of the discount component.

The debt return for the debt finance band was established, by adding two percent (2%) to the Prime Rate Charged by Banks as published in the Economic Indicators Prepared by the Council of Economic Advisors for the Joint Economic Committee. Once a safe rate and a risk rate are developed from the previously mentioned analysis, a management rate (for management of investment portfolios), a non-liquidity rate (time required to sell the investment), and an inflation rate (rate used to adjust the discount component to a real rate net of inflationary expectations) are estimated.

RECAPTURE COMPONENT

The discount component previously discussed provides an investor with a rate of return-on-investment (interest). The second capitalization rate component, recapture, provides the investor with a return-of-investment principal (i.e.: provides an estimate of return necessary for the investor to recover the principal invested). Once a capitalization rate has been developed for coal, oil and gas, and other mined mineral properties, the income series is discounted to present worth through selection of a multiplier(s) extracted from a standard mid-year life Inwood table. The Inwood table has a factor for recapture built into the table coefficients thus removing the need to separately accommodate for recapture in the capitalization rate.

PROPERTY TAX COMPONENT

The third component, property taxes, was derived by multiplying the assessment rate by the statewide average of tax rates on Class III property. Tax Department research indicates that in addition to royalty rates negotiated in producing coal property leases, property taxes are customarily paid by the coal producer. Thus the capitalization rate for producing coal properties does not contain a property tax component as the income stream does not contain income to be used to pay property taxes.

APPLICATION

The summation of the previously discussed components (i.e.: discount, recapture, and property tax components) yields a reasonable estimate for the overall capitalization rate. The overall capitalization rate is used to select the factor(s) from a standard mid-year life Inwood table (i.e.: present worth of one (1) per period) that converts the income stream(s) into an estimate of present worth.

For more information concerning the development of capitalization rates for producing natural resource properties see §§ 110 CSR 1-I, 1-J and 1-K, or contact the State Tax Department at (304) 558-3940.

Notice of this determination will be filed in the West Virginia Register.

Issued: January 27, 2016



Mark W. Matkovich
State Tax Commissioner

State Tax Department
Property Tax Division
P. O. Box 2389
Charleston, WV 25328-2389

Operator on Duty 8:30 am - 5:00 pm
Monday through Friday
Phone: (304) 558-3940
FAX: (304) 558-1843

STATE OF WEST VIRGINIA
TAX AND REVENUE - PROPERTY TAX DIVISION
UNIFORM STATE OF WEST VIRGINIA AS/OIL VALUE ABSTRACT FOR EXCEL
FOR YEAR: 2016

NR120FTD

PRODUCER	CY	ACCOUNT	PTN	TL	WFLS	API	GWIFTD	GWIFTD	TOTAL OPERATOR
ANTERO RESOURCES CORPORATION									
43 0318189636 Y						1 09636	23159	0	23159 A HALL 2
43 0318189639 Y						1 09639	12861	0	12861 B HALL 1
43 0320109672 Y						1 09672	32010	0	32010 A HALL 1
43 0320150036 Y						1 10036	10588851	0	
43 0320159963 Y						1 09963	6332527	0	11801733 BLANCHE UNIT 1H 40993
43 0320150027 Y						1 10027	8857185	0	6766223 ANNA UNIT 2H 40324
43 0320150028 Y						1 10028	5953786	0	8857185 BELLE UNIT 1H (40459)
43 0320150029 Y						1 10029	8427646	0	8857185 BELLE UNIT 2H (40644)
43 0320150060 Y						1 10060	8731251	0	8427646 BELLE UNIT 3H (40554)
43 0320150063 Y						1 10063	10589234	0	8731251 HENDERSHOT UNIT 1H (40642)
43 0320150088 Y						1 10088	8263514	0	10589234 HORNET UNIT 1H (45573)
43 1020148960 Y						1 09960	9880555	0	8263514 HORNET UNIT 2H (45568)
43 1020150002 Y						1 10002	5305498	0	9880555 HENDERSHOT UNIT 2H (40643)
43 1020150023 Y						1 10023	3691420	0	6813391 NICHOLSON UNIT 2H
43 1020159961 Y						1 09961	12987145	0	4594617 KUHN UNIT 1H 40958
43 1020159964 Y						1 09964	3385880	0	15652042 CONSTABLE UNIT 1H 40431
43 1020159966 Y						1 09966	5272113	0	4433217 NICHOLSON UNIT 1H 40371
43 1020159970 Y						1 09970	4486456	0	6688592 O'NEIL UNIT 1H 40379
43 1020159978 Y						1 09978	11372055	0	5772728 O'NEIL UNIT 2H 40380
43 1020160005 Y						1 10005	2683629	0	13938228 PRUNTY UNIT 1H 40393
43 1020160017 Y						1 10017	9811251	0	3263358 PULLMAN UNIT 2H 40363
43 1020160019 Y						1 10019	6577125	0	9811251 IRELAND UNIT 1H (40972)
43 1020160045 Y						1 10045	8709950	0	6577125 ALSTARE UNIT 2H (40538)
43 1020160046 Y						1 10046	7715025	0	8709950 MCCABE UNIT 3H (40537)
43 1020169996 Y						1 09996	8093655	0	7715025 LANGFORD UNIT 2H (40687)
43 1020169999 Y						1 09999	4503041	0	8093655 RUFUS UNIT 1H (40510)
							8563011	0	4503041 SMOOTHERS UNIT 2H (40554)
								0	8563011 DERRBY UNIT 1H (40401)

For Dep. Exh. 1A -
will Apprais.

OCT 12, 2016
01:52 PM

'RITCHIE' COUNTY, WV
YIELD CAP MODEL REPORT FOR - 2016

NR105: 1

ACCOUNT: 0318189636

STATUS: M API#: 09636

DATE: 10/10/2016 DAYS: 365 BBLs:

RESOURCE: GS OWNER: ANTERO RESOURCES CORPORATION LOCATION: A HALL 2

NCFS: 1808 RCPTS: 30694 GWT: 26018 OMI:

SYSTEM RATES:

CAP RATE: 15.300 DECLINE RATE:

0.460

0.290

0.230 WELL LIFE: 29

EXPENSE:

0.3

30000

30000

300

RATES USED:

CAP RATE: 15.300 DECLINE RATE:

0.460

0.290

0.230 WELL LIFE: 29

EXPENSE:

0.3

30000

30000

300

SETTLED YEARS: 8

	GAS WORKING INTEREST			GAS ROYALTY INTEREST			OIL WORKING INTEREST			OIL ROYALTY INTEREST		
	GROSS INCOME	NET INCOME	DISCOUNT INCOME	GROSS INCOME	DISCOUNT INCOME	FACTOR	GROSS INCOME	NET INCOME	DISCOUNT INCOME	GROSS INCOME	DISCOUNT INCOME	FACT
1	17,042	11,929	11,110	3,053	2,852	0.931						
2	13,122	8,010	6,469	2,358	1,905	0.808						
3	10,104	4,992	3,497	1,816	1,272	0.701						
4	7,780	2,668	1,621	1,398	850	0.608						
5	5,991	878	463	1,077	567	0.527						
6	4,613	0	0	829	0	0.457						

TOTAL: 23,150

7,446

EXPENSE: 5113

5113

5113

OCT 12, 2016
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'RITCHIE' COUNTY, WV
YIELD CAP MODEL REPORT FOR - 2016

NR105: 2

ACCOUNT: 0318189639

STATUS: A API#: 09639

RESOURCE: GS

OWNER: ANTEPO RESOURCES CORPORATION LOCATION: B HALL 1

SYSTEM RATES:

DATE: 10/12/2007 DAYS: 365

BBLs:

MOES:

616 RCPTS:

9555 GWT:

8099 OWT:

RATES USED:

CAP RATE: 15.300

DECLINE RATE:

0.390

0.230

0.130

WELL LIFE: 99

EXPENSE:

0.3

5000

50

SETTLED YEARS: 8

	GAS WORKING INTEREST				GAS ROYALTY INTEREST				OIL WORKING INTEREST				OIL ROYALTY INTEREST			
	GROSS INCOME	NET INCOME	DISCOUNT INCOME		GROSS INCOME	DISCOUNT INCOME	FACTOR		GROSS INCOME	NET INCOME	DISCOUNT INCOME		GROSS INCOME	DISCOUNT INCOME	FACTOR	
1	6,520	4,564	4,250		1,172	1,092	0.931									
2	5,672	3,716	3,002		1,020	824	0.808									
3	4,935	2,979	2,087		887	621	0.701									
4	4,293	2,337	1,420		772	469	0.608									
5	3,735	1,779	938		671	354	0.527									
6	3,250	1,294	591		584	267	0.457									
7	2,827	871	345		508	201	0.396									
8	2,460	504	173		442	152	0.344									
9	2,140	184	55		385	115	0.298									
10	1,862	0	0		335	0	0.259									

TOTAL:

13,661

4,095

EXPENSE:

1956

1956

1956

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'RITCHIE' COUNTY, WV
YIELD CAP MODEL REPORT FOR - 2015

NR105: 3

ACCOUNT: 0320109672 RESOURCE: GS OWNER: ANTERO RESOURCES CORPORATION LOCATION: A HALL 1
STATUS: M API#: 09672 DATE: 02/01/2008 DAYS: 365 BPTS: NCPS: 2038 RCPTS: 42423 GWI: 35961 OWI:
SYSTEM RATES: CAP RATE: 15.300 DECLINE RATE: 0.450 0.290 0.230 WELL LIFE: 99 EXPENSE: 0.3 30000 30000 300
RATES USED: CAP RATE: 15.300 DECLINE RATE: WELL LIFE: 99 EXPENSE: 0.3 30000 30000 300
SETTLED YEARS: 7

	GAS WORKING INTEREST			GAS ROYALTY INTEREST			OIL WORKING INTEREST			OIL ROYALTY INTEREST		
	GROSS INCOME	NET INCOME	DISCOUNT INCOME	GROSS INCOME	DISCOUNT INCOME	FACTOR	GROSS INCOME	NET INCOME	DISCOUNT INCOME	GROSS INCOME	DISCOUNT INCOME	FACTOR
1	23,554	16,488	15,355	4,233	3,942	0.931						
2	18,137	11,071	8,942	3,259	2,632	0.808						
3	13,965	6,899	4,833	2,510	1,758	0.701						
4	10,753	3,687	2,240	1,932	1,174	0.608						
5	8,280	1,214	710	1,488	784	0.527						
6	6,376	0	0	1,146	0	0.457						
TOTAL:			32,010						10,290			

EXPENSE: 7066

7066

7066

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'RITCHIE' COUNTY, NV
YIELD CAP MODEL REPORT FOR - 2016

ACCOUNT: 0320150036

NR105: 4

STATUS: 2 API#: 10036

RESOURCE: OG OWNER: ANTERO RESOURCES CORPORATION LOCATION: BLANCHE UNIT 1R 40993

SYSTEM RATES:

CAP RATE: 15.300

DECLINE RATE:

0.460

0.290

0.230

WELL LIFE: 99

EXPENSE:

0.2

150000

150000

1500

RATES USED:

CAP RATE: 15.300

DECLINE RATE:

0.460

0.230

WELL LIFE: 99

EXPENSE:

0.2

150000

150000

1500

SETTLED YEARS: 2

OL EXPENSE:

0.2

5750

5750

5750

5750

	GAS WORKING INTEREST			GAS ROYALTY INTEREST			OIL WORKING INTEREST			OIL ROYALTY INTEREST		
	GROSS INCOME	NET INCOME	DISCOUNT INCOME	GROSS INCOME	DISCOUNT INCOME	FACTOR	GROSS INCOME	NET INCOME	DISCOUNT INCOME	GROSS INCOME	DISCOUNT INCOME	FACTOR
1	4,084,385	3,948,792	3,677,475	830,278	773,231	0.931	433,576	433,424	403,644	88,219	82,157	0.91
2	3,144,977	3,009,384	2,430,712	639,314	516,381	0.808	334,162	333,610	269,460	67,929	54,867	0.81
3	2,421,632	2,286,039	1,601,439	492,272	344,851	0.701	257,305	256,752	179,863	52,305	36,641	0.70
4	1,864,657	1,729,064	1,050,531	379,050	230,300	0.608	198,125	197,572	120,039	40,275	24,470	0.60
5	1,435,786	1,300,193	685,134	291,868	153,799	0.527	152,556	152,004	80,098	31,012	16,342	0.51
6	1,105,555	969,962	443,296	224,738	102,711	0.457	117,468	116,916	53,433	23,879	10,913	0.45
7	851,277	715,684	283,682	173,049	68,593	0.396	90,450	89,898	35,634	18,387	7,288	0.39
8	555,484	519,891	178,728	133,247	45,808	0.344	69,647	69,095	23,753	14,158	4,867	0.34
9	404,722	369,129	110,060	102,601	30,591	0.298	53,628	53,076	15,825	10,902	3,250	0.29
10	388,636	253,043	65,436	79,002	20,430	0.259	41,294	40,741	10,536	8,394	2,171	0.25
11	299,250	163,657	36,705	60,832	13,643	0.224	31,796	31,244	7,007	4,977	1,450	0.22
12	230,422	94,829	18,446	46,841	9,111	0.195	24,483	23,931	4,655	3,832	968	0.19
13	177,425	41,832	7,057	36,067	6,085	0.169	18,852	18,300	4,655	3,832	968	0.16
14	136,617	1,025	150	27,772	4,064	0.146	14,516	13,964	2,043	2,951	432	0.14
15	105,195	0	0	21,384	0	0.127	11,177	10,625	1,348	2,272	288	0.12
16							8,607	8,054	886	1,750	193	0.11
17							6,627	6,075	580	1,347	129	0.11
18							5,103	4,551	377	1,037	86	0.10
19							3,929	3,377	242	799	57	0.09
20							3,025	2,473	154	615	38	0.08
21							2,330	1,777	96	474	26	0.07
22							1,794	1,242	58	365	17	0.06
23							1,381	829	34	281	11	0.05
24							1,064	511	18	216	8	0.04
25							819	267	8	166	5	0.03
26							631	78	2	128	3	0.02
27							486	0	0	99	0	0.02

TOTAL:

10,598,851

2,319,598

1,212,882

247,324

GS EXPENSE: 135593

135593

135593

OL EXPENSE: 552

552

552

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'RITCHIE' COUNTY, WV
YIELD CAP MODEL REPORT FOR - 2016

NR105: 5

ACCOUNT:0320159963

RESOURCE:OG

OWNER:ANTERO RESOURCES CORPORATE LOCATION:ANNA UNIT 2H 40324

STATUS:2 API#:09963

DATE:10/01/2013

DAYS:365

BRLS: 3807.000 MCFS:

673656 RCPTS:

5494252 CWT:

4317391 OMI:

2613

SYSTEM RATES:

CAP RATE:

15.300 DECLINE RATE:

0.460

0.290

0.230 WELLLIFE:99

EXPENSE:

0.2

150000

150000

RATES USED:

CAP RATE:

15.300 DECLINE RATE:

0.460

0.290

0.230 WELLLIFE:99

GS EXPENSE:

0.2

150000

150000

SETTLED YEARS: 2

OL EXPENSE:

0.2

5750

5750

57

GAS WORKING INTEREST
GROSS INCOME NET DISCOUNT
INCOME INCOME INCOME

GAS ROYALTY INTEREST
GROSS INCOME DISCOUNT
INCOME INCOME FACTOR

OIL WORKING INTEREST
GROSS INCOME NET DISCOUNT
INCOME INCOME INCOME

OIL ROYALTY INTEREST
GROSS INCOME DISCOUNT
INCOME INCOME FACTOR

1	2,568,848	2,427,409	2,260,624	513,644	478,352	0.931	155,497	155,169	144,507	31,092	28,955	0.9
2	1,978,013	1,836,574	1,483,421	395,506	319,454	0.808	119,732	119,404	96,444	23,941	19,337	0.8
3	1,523,070	1,381,631	967,874	304,539	213,339	0.701	92,194	91,866	64,355	18,434	12,914	0.7
4	1,172,764	1,031,325	626,604	234,495	142,473	0.608	70,989	70,661	42,932	14,194	8,624	0.6
5	903,028	761,590	401,318	180,561	95,146	0.527	54,662	54,334	28,631	10,930	5,759	0.5
6	695,332	553,893	253,142	139,032	63,541	0.457	42,090	41,761	19,086	8,416	3,846	0.4
7	535,405	393,967	156,160	107,055	42,434	0.396	32,409	32,081	12,716	6,480	2,569	0.3
8	412,262	270,824	93,104	82,432	28,339	0.344	24,955	24,627	8,466	3,990	1,715	0.3
9	317,442	176,003	52,477	63,473	18,925	0.298	19,215	18,887	5,631	2,958	1,146	0.2
10	244,430	102,992	26,633	48,874	12,639	0.259	14,796	14,468	3,741	2,482	765	0.2
11	188,211	46,773	10,490	37,633	8,440	0.224	11,393	11,065	2,482	2,278	511	0.2
12	144,923	3,484	678	28,977	5,637	0.195	8,772	8,444	1,643	1,754	341	0.2
13	111,590	0	0	22,313	0	0.159	6,755	6,427	1,084	1,351	228	0.1
14							5,201	4,873	713	1,040	132	0.1
15							4,005	3,677	467	801	68	0.1
16							3,084	2,756	303	617	30	0.1
17							2,375	2,046	195	475	45	0.1
18							1,828	1,500	124	366	35	0.1
19							1,408	1,080	78	282	20	0.1
20							1,084	756	47	217	13	0.1
21							835	507	27	167	9	0.1
22							643	315	15	129	6	0.1
23							495	167	7	99	4	0.1
24							381	53	2	76	3	0.1
25							293	0	0	59	0	0.1

TOTAL:

6,332,527

1,438,719

433,696

87,163

GS EXPENSE: 141438

141438

141438

OL EXPENSE: 328

328

328

NATURAL GAS APPRAISAL - PLUSH WELLS TYPE											
		2014		GAS INCOME		OIL INCOME		GAS CAP INCOME		OIL CAP INCOME	
DECLINE RATES		WYR INT	\$	5,178,241	\$	852,881	YR1	\$	3,229,220	\$	328,908
YR 1	48%	ROY INT	\$	1,814,318	\$	164,428		\$	637,068	\$	64,848
YR 2	20%						YR2	\$	2,389,823	\$	243,393
YR3+	13%							\$	471,868	\$	48,061
\$ 9,867,185											
TY2016 WORKING INTEREST											
YEAR	WYR INT INCOME	WORKING COST	NET INC	PRCT FCTR(18.0%)	DIS INC	YEAR	ROY INT INCOME	PRCT FCTR(18.0%)	DIS INC		
1	\$ 3,558,129	\$ 136,668	\$ 3,421,461	0.931291	\$ 3,188,378	1	\$ 702,603	0.931291	\$ 654,328		
2	\$ 2,633,016	\$ 136,668	\$ 2,496,350	0.807711	\$ 2,019,329	2	\$ 519,827	0.807711	\$ 419,950		
3	\$ 2,027,422	\$ 136,668	\$ 1,890,756	0.700530	\$ 1,324,532	3	\$ 400,343	0.700530	\$ 280,463		
4	\$ 1,581,115	\$ 136,668	\$ 1,444,449	0.607572	\$ 965,465	4	\$ 308,264	0.607572	\$ 187,293		
5	\$ 1,202,059	\$ 136,668	\$ 1,065,393	0.526948	\$ 681,407	5	\$ 237,364	0.526948	\$ 125,078		
6	\$ 925,585	\$ 136,668	\$ 788,919	0.457024	\$ 460,555	6	\$ 182,770	0.457024	\$ 83,530		
7	\$ 712,700	\$ 136,668	\$ 576,035	0.396378	\$ 288,328	7	\$ 140,733	0.396378	\$ 55,783		
8	\$ 548,779	\$ 136,668	\$ 412,114	0.343780	\$ 141,878	8	\$ 108,364	0.343780	\$ 37,253		
9	\$ 422,580	\$ 136,668	\$ 285,914	0.298181	\$ 85,243	9	\$ 83,441	0.298181	\$ 24,879		
10	\$ 325,371	\$ 136,668	\$ 188,708	0.258568	\$ 48,799	10	\$ 64,249	0.258568	\$ 18,815		
11	\$ 250,538	\$ 136,668	\$ 113,870	0.224281	\$ 25,539	11	\$ 49,472	0.224281	\$ 11,096		
12	\$ 192,913	\$ 136,668	\$ 56,247	0.194519	\$ 10,841	12	\$ 38,093	0.194519	\$ 7,410		
13	\$ 148,543	\$ 136,668	\$ 11,877	0.168707	\$ 2,004	13	\$ 29,332	0.168707	\$ 4,948		
14	\$ 114,379	\$ 136,668	\$ -	0.148320	\$ -	14	\$ 22,586	0.148320	\$ -		
15	\$ 87,071	\$ 136,668	\$ -	0.126904	\$ -	15	\$ 17,391	0.126904	\$ -		
16	\$ 67,816	\$ 136,668	\$ -	0.110084	\$ -	16	\$ 13,391	0.110084	\$ -		
17	\$ 52,217	\$ 136,668	\$ -	0.095459	\$ -	17	\$ 10,311	0.095459	\$ -		
18	\$ 40,207	\$ 136,668	\$ -	0.082792	\$ -	18	\$ 7,940	0.082792	\$ -		
19	\$ 30,980	\$ 136,668	\$ -	0.071686	\$ -	19	\$ 6,113	0.071686	\$ -		
20	\$ 23,839	\$ 136,668	\$ -	0.062277	\$ -	20	\$ 4,707	0.062277	\$ -		
21	\$ 18,356	\$ 136,668	\$ -	0.054013	\$ -	21	\$ 3,828	0.054013	\$ -		
22	\$ 14,134	\$ 136,668	\$ -	0.046846	\$ -	22	\$ 2,791	0.046846	\$ -		
23	\$ 10,883	\$ 136,668	\$ -	0.040829	\$ -	23	\$ 2,149	0.040829	\$ -		
24	\$ 8,380	\$ 136,668	\$ -	0.036238	\$ -	24	\$ 1,655	0.036238	\$ -		
25	\$ 6,463	\$ 136,668	\$ -	0.030582	\$ -	25	\$ 1,274	0.030582	\$ -		
26	\$ 4,969	\$ 136,668	\$ -	0.026507	\$ -	26	\$ 981	0.026507	\$ -		
27	\$ 3,826	\$ 136,668	\$ -	0.022989	\$ -	27	\$ 755	0.022989	\$ -		
28	\$ 2,946	\$ 136,668	\$ -	0.019939	\$ -	28	\$ 582	0.019939	\$ -		
29	\$ 2,268	\$ 136,668	\$ -	0.017283	\$ -	29	\$ 449	0.017283	\$ -		
30	\$ 1,747	\$ 136,668	\$ -	0.014998	\$ -	30	\$ 345	0.014998	\$ -		
31	\$ 1,345	\$ 136,668	\$ -	0.013008	\$ -	31	\$ 268	0.013008	\$ -		
32	\$ 1,038	\$ 136,668	\$ -	0.011282	\$ -	32	\$ 204	0.011282	\$ -		
33	\$ 797	\$ 136,668	\$ -	0.009785	\$ -	33	\$ 157	0.009785	\$ -		
34	\$ 614	\$ 136,668	\$ -	0.008486	\$ -	34	\$ 121	0.008486	\$ -		
35	\$ 473	\$ 136,668	\$ -	0.007360	\$ -	35	\$ 93	0.007360	\$ -		
36	\$ 364	\$ 136,668	\$ -	0.006384	\$ -	36	\$ 72	0.006384	\$ -		
37	\$ 280	\$ 136,668	\$ -	0.005538	\$ -	37	\$ 55	0.005538	\$ -		
38	\$ 216	\$ 136,668	\$ -	0.004802	\$ -	38	\$ 43	0.004802	\$ -		
39	\$ 168	\$ 136,668	\$ -	0.004165	\$ -	39	\$ 33	0.004165	\$ -		
40	\$ 128	\$ 136,668	\$ -	0.003612	\$ -	40	\$ 25	0.003612	\$ -		
WORKING INTEREST APPRAISAL											
ROYALTY INTEREST APPRAISAL											

43 03 2016 0027

2014									
WRK INT					ROY INT				
YR 1	48%			\$ 5,938,880	\$ 381,811	YR1	\$ 2,345,848	\$ 180,818	
YR 2	29%			\$ 1,169,118	\$ 75,384	YR2	\$ 481,802	\$ 29,781	
YR3+	23%						\$ 1,738,828	\$ 111,803	
							\$ 341,738	\$ 22,038	
\$ 5,963,788					2016 WORKING INTEREST				
YEAR	WRK INT INCOME	WORKING COST	NET INC	PRCT FCTR(18.0%)	DIS INC	YEAR	ROY INT INCOME	PRCT FCTR(18.0%)	DIS INC
1	\$ 2,468,681	\$ 141,288	\$ 2,355,376	0.931291	\$ 2,193,539	1	\$ 481,582	0.931291	\$ 457,806
2	\$ 1,847,629	\$ 141,288	\$ 1,706,243	0.807711	\$ 1,378,151	2	\$ 363,771	0.807711	\$ 293,822
3	\$ 1,422,587	\$ 141,288	\$ 1,281,311	0.700530	\$ 97,597	3	\$ 280,104	0.700530	\$ 136,221
4	\$ 1,085,400	\$ 141,288	\$ 954,114	0.507572	\$ 578,693	4	\$ 215,680	0.607872	\$ 131,041
5	\$ 843,458	\$ 141,288	\$ 702,172	0.526948	\$ 370,008	5	\$ 168,073	0.526948	\$ 37,512
6	\$ 648,483	\$ 141,288	\$ 508,178	0.457024	\$ 232,249	6	\$ 127,377	0.457024	\$ 58,443
7	\$ 500,636	\$ 141,288	\$ 358,300	0.396378	\$ 142,220	7	\$ 86,465	0.396378	\$ 39,029
8	\$ 335,066	\$ 141,288	\$ 243,780	0.343780	\$ 33,807	8	\$ 75,818	0.343780	\$ 26,066
9	\$ 226,501	\$ 141,288	\$ 155,215	0.298181	\$ 48,279	9	\$ 58,380	0.298181	\$ 17,407
10	\$ 228,308	\$ 141,288	\$ 37,020	0.258596	\$ 22,503	10	\$ 44,952	0.258596	\$ 11,626
11	\$ 175,798	\$ 141,288	\$ 34,509	0.224281	\$ 7,740	11	\$ 34,613	0.224281	\$ 7,769
12	\$ 135,393	\$ 141,288	\$ -	0.194619	\$ -	12	\$ 28,852	0.194619	\$ -
13	\$ 104,228	\$ 141,288	\$ -	0.168707	\$ -	13	\$ 20,522	0.168707	\$ -
14	\$ 80,256	\$ 141,288	\$ -	0.146320	\$ -	14	\$ 15,802	0.146320	\$ -
15	\$ 61,787	\$ 141,288	\$ -	0.128904	\$ -	15	\$ 12,186	0.128904	\$ -
16	\$ 47,584	\$ 141,288	\$ -	0.110084	\$ -	16	\$ 9,369	0.110084	\$ -
17	\$ 36,840	\$ 141,288	\$ -	0.095459	\$ -	17	\$ 7,214	0.095459	\$ -
18	\$ 28,213	\$ 141,288	\$ -	0.082792	\$ -	18	\$ 5,558	0.082792	\$ -
19	\$ 21,724	\$ 141,288	\$ -	0.071806	\$ -	19	\$ 4,277	0.071806	\$ -
20	\$ 16,727	\$ 141,288	\$ -	0.062277	\$ -	20	\$ 3,294	0.062277	\$ -
21	\$ 12,880	\$ 141,288	\$ -	0.054013	\$ -	21	\$ 2,538	0.054013	\$ -
22	\$ 9,918	\$ 141,288	\$ -	0.046848	\$ -	22	\$ 1,953	0.046848	\$ -
23	\$ 7,937	\$ 141,288	\$ -	0.040829	\$ -	23	\$ 1,504	0.040829	\$ -
24	\$ 6,880	\$ 141,288	\$ -	0.035238	\$ -	24	\$ 1,158	0.035238	\$ -
25	\$ 4,628	\$ 141,288	\$ -	0.030562	\$ -	25	\$ 891	0.030562	\$ -
26	\$ 3,488	\$ 141,288	\$ -	0.026507	\$ -	26	\$ 588	0.026507	\$ -
27	\$ 2,884	\$ 141,288	\$ -	0.022989	\$ -	27	\$ 529	0.022989	\$ -
28	\$ 2,087	\$ 141,288	\$ -	0.019939	\$ -	28	\$ 407	0.019939	\$ -
29	\$ 1,592	\$ 141,288	\$ -	0.017283	\$ -	29	\$ 313	0.017283	\$ -
30	\$ 1,228	\$ 141,288	\$ -	0.014998	\$ -	30	\$ 241	0.014998	\$ -
31	\$ 944	\$ 141,288	\$ -	0.013008	\$ -	31	\$ 188	0.013008	\$ -
32	\$ 727	\$ 141,288	\$ -	0.011282	\$ -	32	\$ 143	0.011282	\$ -
33	\$ 580	\$ 141,288	\$ -	0.009786	\$ -	33	\$ 110	0.009786	\$ -
34	\$ 431	\$ 141,288	\$ -	0.008488	\$ -	34	\$ 85	0.008488	\$ -
35	\$ 332	\$ 141,288	\$ -	0.007360	\$ -	35	\$ 65	0.007360	\$ -
36	\$ 255	\$ 141,288	\$ -	0.006384	\$ -	36	\$ 50	0.006384	\$ -
37	\$ 197	\$ 141,288	\$ -	0.005538	\$ -	37	\$ 39	0.005538	\$ -
38	\$ 151	\$ 141,288	\$ -	0.004802	\$ -	38	\$ 30	0.004802	\$ -
39	\$ 117	\$ 141,288	\$ -	0.004165	\$ -	39	\$ 23	0.004165	\$ -
40	\$ 90	\$ 141,288	\$ -	0.003612	\$ -	40	\$ 18	0.003612	\$ -
WORKING INTEREST APPRAISAL					ROYALTY INTEREST APPRAISAL				

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2014									
WRK INT					ROY INT				
YR 1	46%			\$ 7,832,437	\$ 788,828	YR1	\$ 3,101,713	\$ 299,687	
YR 2	29%			\$ 1,580,878	\$ 148,802	YR2	\$ 612,478	\$ 58,172	
YR3+	23%					YR3	\$ 2,296,267	\$ 221,746	
							\$ 463,233	\$ 43,787	
\$ 8,427,648									
FY2016 WORKING INTEREST									
YEAR	WRK INT INCOME	WORKING COST	NET INC	PRCT FCTR(16.0%)	DIS INC	YEAR	ROY INT INCOME	PRCT FCTR(16.0%)	DIS INC
1	\$ 3,401,370	\$ 137,292	\$ 3,264,078	0.931291	\$ 3,039,807	1	\$ 371,849	0.931291	\$ 325,501
2	\$ 2,517,814	\$ 137,292	\$ 2,379,722	0.807711	\$ 1,822,128	2	\$ 497,020	0.807711	\$ 401,449
3	\$ 1,938,101	\$ 137,292	\$ 1,800,809	0.700530	\$ 1,261,521	3	\$ 382,708	0.700530	\$ 268,097
4	\$ 1,482,337	\$ 137,292	\$ 1,355,045	0.607572	\$ 823,288	4	\$ 294,883	0.607572	\$ 179,041
5	\$ 1,149,100	\$ 137,292	\$ 1,011,808	0.528848	\$ 533,170	5	\$ 226,906	0.528848	\$ 119,588
6	\$ 884,807	\$ 137,292	\$ 747,515	0.457024	\$ 341,632	6	\$ 174,718	0.457024	\$ 79,850
7	\$ 681,301	\$ 137,292	\$ 544,010	0.396378	\$ 215,633	7	\$ 134,633	0.396378	\$ 53,326
8	\$ 524,602	\$ 137,292	\$ 387,310	0.343780	\$ 133,160	8	\$ 103,560	0.343780	\$ 35,812
9	\$ 403,944	\$ 137,292	\$ 266,652	0.298161	\$ 79,505	9	\$ 79,784	0.298161	\$ 23,783
10	\$ 311,037	\$ 137,292	\$ 173,745	0.258598	\$ 44,830	10	\$ 61,419	0.258598	\$ 15,883
11	\$ 239,498	\$ 137,292	\$ 102,206	0.224261	\$ 22,923	11	\$ 47,292	0.224261	\$ 10,607
12	\$ 184,414	\$ 137,292	\$ 47,122	0.194519	\$ 9,168	12	\$ 36,416	0.194519	\$ 7,083
13	\$ 141,098	\$ 137,292	\$ 4,707	0.168707	\$ 784	13	\$ 28,040	0.168707	\$ 4,730
14	\$ 109,339	\$ 137,292	\$ -	0.146320	\$ -	14	\$ 21,591	0.146320	\$ -
15	\$ 84,927	\$ 137,292	\$ -	0.128904	\$ -	15	\$ 18,626	0.128904	\$ -
16	\$ 69,817	\$ 137,292	\$ -	0.110084	\$ -	16	\$ 12,801	0.110084	\$ -
17	\$ 58,436	\$ 137,292	\$ -	0.095459	\$ -	17	\$ 9,687	0.095459	\$ -
18	\$ 49,598	\$ 137,292	\$ -	0.082792	\$ -	18	\$ 7,590	0.082792	\$ -
19	\$ 42,769	\$ 137,292	\$ -	0.071808	\$ -	19	\$ 5,844	0.071808	\$ -
20	\$ 37,547	\$ 137,292	\$ -	0.062277	\$ -	20	\$ 4,500	0.062277	\$ -
21	\$ 33,511	\$ 137,292	\$ -	0.054013	\$ -	21	\$ 3,485	0.054013	\$ -
22	\$ 30,404	\$ 137,292	\$ -	0.046846	\$ -	22	\$ 2,688	0.046846	\$ -
23	\$ 28,011	\$ 137,292	\$ -	0.040629	\$ -	23	\$ 2,054	0.040629	\$ -
24	\$ 26,168	\$ 137,292	\$ -	0.035238	\$ -	24	\$ 1,592	0.035238	\$ -
25	\$ 24,750	\$ 137,292	\$ -	0.030582	\$ -	25	\$ 1,218	0.030582	\$ -
26	\$ 23,657	\$ 137,292	\$ -	0.026507	\$ -	26	\$ 938	0.026507	\$ -
27	\$ 22,816	\$ 137,292	\$ -	0.022969	\$ -	27	\$ 722	0.022969	\$ -
28	\$ 22,168	\$ 137,292	\$ -	0.019939	\$ -	28	\$ 556	0.019939	\$ -
29	\$ 21,670	\$ 137,292	\$ -	0.017293	\$ -	29	\$ 428	0.017293	\$ -
30	\$ 21,288	\$ 137,292	\$ -	0.014998	\$ -	30	\$ 330	0.014998	\$ -
31	\$ 21,000	\$ 137,292	\$ -	0.013008	\$ -	31	\$ 254	0.013008	\$ -
32	\$ 20,802	\$ 137,292	\$ -	0.011282	\$ -	32	\$ 195	0.011282	\$ -
33	\$ 20,685	\$ 137,292	\$ -	0.009785	\$ -	33	\$ 151	0.009785	\$ -
34	\$ 20,648	\$ 137,292	\$ -	0.008486	\$ -	34	\$ 118	0.008486	\$ -
35	\$ 20,688	\$ 137,292	\$ -	0.007360	\$ -	35	\$ 89	0.007360	\$ -
36	\$ 20,798	\$ 137,292	\$ -	0.006384	\$ -	36	\$ 69	0.006384	\$ -
37	\$ 20,968	\$ 137,292	\$ -	0.005536	\$ -	37	\$ 53	0.005536	\$ -
38	\$ 21,198	\$ 137,292	\$ -	0.004802	\$ -	38	\$ 41	0.004802	\$ -
39	\$ 21,485	\$ 137,292	\$ -	0.004165	\$ -	39	\$ 31	0.004165	\$ -
40	\$ 21,822	\$ 137,292	\$ -	0.003612	\$ -	40	\$ 24	0.003612	\$ -
WORKING INTEREST APPRAISAL					ROYALTY INTEREST APPRAISAL				

43 0320160029

NATURAL GAS PRODUCTION AND REVENUE									
2014									
DEVELOPMENT		WORKING INTEREST		ROYALTY INTEREST		TOTAL		TOTAL	
YR 1	16%	WRK INT	\$ 8,179,800	\$ 718,848	YR1	\$ 3,231,081	\$ 284,339		
YR 2	28%	ROY INT	\$ 1,342,831	\$ 118,173		\$ 630,428	\$ 48,678		
YR3+	13%				YR2	\$ 2,360,988	\$ 210,411		
						\$ 392,518	\$ 34,642		
3,731,251									
2015 WORKING INTEREST									
YEAR	WRK INT INCOME	WORKING COST	NET INC	PRCT FCTR(16.0%)	OS INC	YEAR	ROY INT INCOME	PRCT FCTR(16.0%)	OS INC
1	\$ 3,515,400	\$ 138,333	\$ 3,377,067	0.931291	\$ 3,145,032	1	\$ 577,104	0.931291	\$ 537,462
2	\$ 3,501,398	\$ 138,333	\$ 2,463,065	0.807711	\$ 1,989,443	2	\$ 427,057	0.807711	\$ 344,509
3	\$ 2,003,075	\$ 138,333	\$ 1,864,742	0.700530	\$ 1,306,308	3	\$ 328,834	0.700530	\$ 230,152
4	\$ 1,542,368	\$ 138,333	\$ 1,404,035	0.607572	\$ 853,052	4	\$ 253,202	0.607572	\$ 151,839
5	\$ 1,187,623	\$ 138,333	\$ 1,049,291	0.526948	\$ 552,922	5	\$ 194,968	0.526948	\$ 102,737
6	\$ 914,470	\$ 138,333	\$ 776,137	0.457024	\$ 354,713	6	\$ 150,124	0.457024	\$ 68,610
7	\$ 704,142	\$ 138,333	\$ 565,809	0.396378	\$ 224,274	7	\$ 115,595	0.396378	\$ 45,819
8	\$ 542,189	\$ 138,333	\$ 403,857	0.343780	\$ 138,838	8	\$ 89,008	0.343780	\$ 30,589
9	\$ 417,486	\$ 138,333	\$ 279,153	0.298181	\$ 83,233	9	\$ 68,538	0.298181	\$ 20,436
10	\$ 321,484	\$ 138,333	\$ 183,151	0.258506	\$ 47,357	10	\$ 52,773	0.258506	\$ 13,647
11	\$ 247,527	\$ 138,333	\$ 109,195	0.224281	\$ 24,490	11	\$ 40,835	0.224281	\$ 9,114
12	\$ 190,598	\$ 138,333	\$ 52,265	0.194518	\$ 10,186	12	\$ 31,289	0.194518	\$ 6,086
13	\$ 146,759	\$ 138,333	\$ 8,426	0.168707	\$ 1,422	13	\$ 24,093	0.168707	\$ 4,068
14	\$ 113,004	\$ 138,333	\$ -	0.146320	\$ -	14	\$ 18,551	0.146320	\$ -
15	\$ 87,013	\$ 138,333	\$ -	0.128904	\$ -	15	\$ 14,285	0.128904	\$ -
16	\$ 67,000	\$ 138,333	\$ -	0.110084	\$ -	16	\$ 10,999	0.110084	\$ -
17	\$ 51,590	\$ 138,333	\$ -	0.095459	\$ -	17	\$ 8,489	0.095459	\$ -
18	\$ 38,724	\$ 138,333	\$ -	0.082792	\$ -	18	\$ 6,521	0.082792	\$ -
19	\$ 30,588	\$ 138,333	\$ -	0.071806	\$ -	19	\$ 5,021	0.071806	\$ -
20	\$ 23,558	\$ 138,333	\$ -	0.062277	\$ -	20	\$ 3,857	0.062277	\$ -
21	\$ 18,138	\$ 138,333	\$ -	0.054013	\$ -	21	\$ 2,977	0.054013	\$ -
22	\$ 13,984	\$ 138,333	\$ -	0.046846	\$ -	22	\$ 2,292	0.046846	\$ -
23	\$ 10,753	\$ 138,333	\$ -	0.040629	\$ -	23	\$ 1,766	0.040629	\$ -
24	\$ 8,279	\$ 138,333	\$ -	0.035238	\$ -	24	\$ 1,359	0.035238	\$ -
25	\$ 6,375	\$ 138,333	\$ -	0.030582	\$ -	25	\$ 1,047	0.030582	\$ -
26	\$ 4,909	\$ 138,333	\$ -	0.026507	\$ -	26	\$ 808	0.026507	\$ -
27	\$ 3,780	\$ 138,333	\$ -	0.022989	\$ -	27	\$ 621	0.022989	\$ -
28	\$ 2,910	\$ 138,333	\$ -	0.019939	\$ -	28	\$ 478	0.019939	\$ -
29	\$ 2,241	\$ 138,333	\$ -	0.017293	\$ -	29	\$ 368	0.017293	\$ -
30	\$ 1,728	\$ 138,333	\$ -	0.014998	\$ -	30	\$ 283	0.014998	\$ -
31	\$ 1,329	\$ 138,333	\$ -	0.013008	\$ -	31	\$ 218	0.013008	\$ -
32	\$ 1,023	\$ 138,333	\$ -	0.011282	\$ -	32	\$ 168	0.011282	\$ -
33	\$ 788	\$ 138,333	\$ -	0.009785	\$ -	33	\$ 129	0.009785	\$ -
34	\$ 607	\$ 138,333	\$ -	0.008486	\$ -	34	\$ 100	0.008486	\$ -
35	\$ 467	\$ 138,333	\$ -	0.007360	\$ -	35	\$ 77	0.007360	\$ -
36	\$ 360	\$ 138,333	\$ -	0.006384	\$ -	36	\$ 59	0.006384	\$ -
37	\$ 277	\$ 138,333	\$ -	0.005538	\$ -	37	\$ 45	0.005538	\$ -
38	\$ 213	\$ 138,333	\$ -	0.004802	\$ -	38	\$ 35	0.004802	\$ -
39	\$ 164	\$ 138,333	\$ -	0.004185	\$ -	39	\$ 27	0.004185	\$ -
40	\$ 128	\$ 138,333	\$ -	0.003612	\$ -	40	\$ 21	0.003612	\$ -
WORKING INTEREST APPRAISAL					ROYALTY INTEREST APPRAISAL				

NATURAL GAS PROPERTIES - JUVENILE									
2014									
DECLINE RATES		WORK INT		ROY INT		YR1		YR2	
YR 1	46%		\$ 15,115,808	\$	544,387	\$	3,993,688	\$	215,033
YR 2	28%		\$ 2,637,710	\$	109,717	\$	304,686	\$	43,338
YR3+	23%					\$	2,646,330	\$	159,124
						\$	588,923	\$	32,670
\$ 10,589,234									
2016 WORKING INTEREST									
YEAR	WORK INT INCOME	WORKING COST	NET INC	PRCT FCTR(18.0%)	DIS INC	YEAR	ROY INT INCOME	PRCT FCTR(18.0%)	DIS INC
1	\$ 4,208,722	\$ 142,630	\$ 4,066,092	0.931291	\$ 3,798,716	1	\$ 348,234	0.931291	\$ 329,852
2	\$ 3,114,454	\$ 142,630	\$ 2,971,825	0.807711	\$ 2,400,375	2	\$ 627,893	0.807711	\$ 506,994
3	\$ 2,096,130	\$ 142,630	\$ 1,953,500	0.700630	\$ 1,580,046	3	\$ 483,324	0.700630	\$ 338,583
4	\$ 1,346,560	\$ 142,630	\$ 1,203,930	0.607672	\$ 1,035,260	4	\$ 372,159	0.607672	\$ 228,113
5	\$ 1,421,851	\$ 142,630	\$ 1,279,221	0.526948	\$ 574,083	5	\$ 296,583	0.526948	\$ 151,004
6	\$ 1,094,825	\$ 142,630	\$ 952,196	0.457024	\$ 435,176	6	\$ 220,653	0.457024	\$ 100,844
7	\$ 348,016	\$ 142,630	\$ 205,386	0.398376	\$ 277,617	7	\$ 169,903	0.398376	\$ 87,348
8	\$ 349,122	\$ 142,630	\$ 206,492	0.343780	\$ 174,122	8	\$ 130,825	0.343780	\$ 44,975
9	\$ 99,624	\$ 142,630	\$ 35,994	0.298161	\$ 108,501	9	\$ 100,735	0.298161	\$ 30,035
10	\$ 784,864	\$ 142,630	\$ 642,234	0.258598	\$ 62,641	10	\$ 77,566	0.258598	\$ 20,058
11	\$ 396,348	\$ 142,630	\$ 253,718	0.224281	\$ 24,476	11	\$ 39,726	0.224281	\$ 13,396
12	\$ 228,186	\$ 142,630	\$ 85,556	0.194816	\$ 16,542	12	\$ 45,889	0.194816	\$ 3,946
13	\$ 175,703	\$ 142,630	\$ 33,073	0.166707	\$ 5,580	13	\$ 35,412	0.166707	\$ 5,974
14	\$ 135,292	\$ 142,630	\$ -	0.146320	\$ -	14	\$ 27,267	0.146320	\$ -
15	\$ 104,174	\$ 142,630	\$ -	0.126904	\$ -	15	\$ 20,998	0.126904	\$ -
16	\$ 80,214	\$ 142,630	\$ -	0.110084	\$ -	16	\$ 16,167	0.110084	\$ -
17	\$ 61,765	\$ 142,630	\$ -	0.095459	\$ -	17	\$ 12,448	0.095459	\$ -
18	\$ 47,559	\$ 142,630	\$ -	0.082792	\$ -	18	\$ 9,585	0.082792	\$ -
19	\$ 36,821	\$ 142,630	\$ -	0.071806	\$ -	19	\$ 7,381	0.071806	\$ -
20	\$ 26,198	\$ 142,630	\$ -	0.062277	\$ -	20	\$ 5,683	0.062277	\$ -
21	\$ 21,712	\$ 142,630	\$ -	0.054013	\$ -	21	\$ 4,376	0.054013	\$ -
22	\$ 16,716	\$ 142,630	\$ -	0.046846	\$ -	22	\$ 3,369	0.046846	\$ -
23	\$ 12,673	\$ 142,630	\$ -	0.040629	\$ -	23	\$ 2,694	0.040629	\$ -
24	\$ 9,912	\$ 142,630	\$ -	0.035238	\$ -	24	\$ 1,998	0.035238	\$ -
25	\$ 7,633	\$ 142,630	\$ -	0.030562	\$ -	25	\$ 1,538	0.030562	\$ -
26	\$ 5,677	\$ 142,630	\$ -	0.026507	\$ -	26	\$ 1,184	0.026507	\$ -
27	\$ 4,525	\$ 142,630	\$ -	0.022969	\$ -	27	\$ 912	0.022969	\$ -
28	\$ 3,485	\$ 142,630	\$ -	0.019939	\$ -	28	\$ 702	0.019939	\$ -
29	\$ 2,683	\$ 142,630	\$ -	0.017283	\$ -	29	\$ 541	0.017283	\$ -
30	\$ 2,066	\$ 142,630	\$ -	0.014998	\$ -	30	\$ 416	0.014998	\$ -
31	\$ 1,561	\$ 142,630	\$ -	0.013008	\$ -	31	\$ 321	0.013008	\$ -
32	\$ 1,225	\$ 142,630	\$ -	0.011282	\$ -	32	\$ 247	0.011282	\$ -
33	\$ 943	\$ 142,630	\$ -	0.009765	\$ -	33	\$ 190	0.009765	\$ -
34	\$ 726	\$ 142,630	\$ -	0.008486	\$ -	34	\$ 146	0.008486	\$ -
35	\$ 559	\$ 142,630	\$ -	0.007360	\$ -	35	\$ 113	0.007360	\$ -
36	\$ 431	\$ 142,630	\$ -	0.006384	\$ -	36	\$ 87	0.006384	\$ -
37	\$ 332	\$ 142,630	\$ -	0.005536	\$ -	37	\$ 57	0.005536	\$ -
38	\$ 255	\$ 142,630	\$ -	0.004802	\$ -	38	\$ 51	0.004802	\$ -
39	\$ 197	\$ 142,630	\$ -	0.004165	\$ -	39	\$ 40	0.004165	\$ -
40	\$ 151	\$ 142,630	\$ -	0.003612	\$ -	40	\$ 31	0.003612	\$ -
WORKING INTEREST APPRAVAL					ROYALTY INTEREST APPRAVAL				

43 0320160062

2014											
		WRK INT		\$ 8,083,437 \$ 408,188		YR1		\$ 3,192,988 \$ 160,443			
YR 1		48%		ROY INT		\$ 628,138 \$ 31,883		\$ 248,619 \$ 32,338			
YR 2		28%						\$ 2,382,788 \$ 116,728			
YR3+		23%						\$ 183,897 \$ 23,929			
\$ 8,263,614											
2014 WORKING INTEREST						2014 ROYALTY INTEREST					
YEAR	WRK INT INCOME	WORKING COST	NET INC	PRCT FCTR(18.0%)	DIS INC	YEAR	ROY INT INCOME	PRCT FCTR(18.0%)	DIS INC		
1	\$ 3,353,401	\$ 143,098	\$ 3,210,303	0.931291	\$ 2,989,728	1	\$ 280,846	0.931291	\$ 261,549		
2	\$ 2,481,517	\$ 143,098	\$ 2,338,418	0.807711	\$ 1,968,766	2	\$ 207,828	0.807711	\$ 167,863		
3	\$ 1,910,768	\$ 143,098	\$ 1,767,670	0.700530	\$ 1,238,306	3	\$ 160,026	0.700530	\$ 112,103		
4	\$ 1,471,291	\$ 143,098	\$ 1,328,193	0.607572	\$ 908,973	4	\$ 132,220	0.607572	\$ 74,865		
5	\$ 1,132,894	\$ 143,098	\$ 989,796	0.526948	\$ 521,571	5	\$ 94,879	0.526948	\$ 49,098		
6	\$ 872,329	\$ 143,098	\$ 729,230	0.457024	\$ 333,278	6	\$ 73,067	0.457024	\$ 33,389		
7	\$ 671,893	\$ 143,098	\$ 528,795	0.396378	\$ 209,523	7	\$ 56,254	0.396378	\$ 22,298		
8	\$ 517,204	\$ 143,098	\$ 374,106	0.343780	\$ 128,610	8	\$ 43,318	0.343780	\$ 14,891		
9	\$ 388,247	\$ 143,098	\$ 255,148	0.298161	\$ 78,075	9	\$ 33,353	0.298161	\$ 9,945		
10	\$ 308,660	\$ 143,098	\$ 193,552	0.258598	\$ 42,284	10	\$ 25,882	0.258598	\$ 6,841		
11	\$ 236,121	\$ 143,098	\$ 93,022	0.224281	\$ 20,883	11	\$ 19,775	0.224281	\$ 4,435		
12	\$ 181,913	\$ 143,098	\$ 38,714	0.194519	\$ 7,531	12	\$ 15,227	0.194519	\$ 2,982		
13	\$ 139,998	\$ 143,098	\$ -	0.168707	\$ -	13	\$ 11,726	0.168707	\$ -		
14	\$ 107,797	\$ 143,098	\$ -	0.146320	\$ -	14	\$ 9,028	0.146320	\$ -		
15	\$ 83,004	\$ 143,098	\$ -	0.126904	\$ -	15	\$ 3,952	0.126904	\$ -		
16	\$ 63,913	\$ 143,098	\$ -	0.110084	\$ -	16	\$ 5,353	0.110084	\$ -		
17	\$ 49,213	\$ 143,098	\$ -	0.096459	\$ -	17	\$ 1,122	0.096459	\$ -		
18	\$ 37,884	\$ 143,098	\$ -	0.082782	\$ -	18	\$ 3,174	0.082782	\$ -		
19	\$ 28,178	\$ 143,098	\$ -	0.071806	\$ -	19	\$ 2,444	0.071806	\$ -		
20	\$ 22,467	\$ 143,098	\$ -	0.062277	\$ -	20	\$ 1,882	0.062277	\$ -		
21	\$ 17,300	\$ 143,098	\$ -	0.054013	\$ -	21	\$ 1,449	0.054013	\$ -		
22	\$ 13,321	\$ 143,098	\$ -	0.046846	\$ -	22	\$ 1,118	0.046846	\$ -		
23	\$ 10,257	\$ 143,098	\$ -	0.040629	\$ -	23	\$ 859	0.040629	\$ -		
24	\$ 7,898	\$ 143,098	\$ -	0.035238	\$ -	24	\$ 681	0.035238	\$ -		
25	\$ 6,081	\$ 143,098	\$ -	0.030562	\$ -	25	\$ 509	0.030562	\$ -		
26	\$ 4,683	\$ 143,098	\$ -	0.026507	\$ -	26	\$ 392	0.026507	\$ -		
27	\$ 3,606	\$ 143,098	\$ -	0.022989	\$ -	27	\$ 302	0.022989	\$ -		
28	\$ 2,776	\$ 143,098	\$ -	0.019939	\$ -	28	\$ 233	0.019939	\$ -		
29	\$ 2,138	\$ 143,098	\$ -	0.017293	\$ -	29	\$ 179	0.017293	\$ -		
30	\$ 1,648	\$ 143,098	\$ -	0.014998	\$ -	30	\$ 138	0.014998	\$ -		
31	\$ 1,268	\$ 143,098	\$ -	0.013008	\$ -	31	\$ 108	0.013008	\$ -		
32	\$ 978	\$ 143,098	\$ -	0.011282	\$ -	32	\$ 82	0.011282	\$ -		
33	\$ 752	\$ 143,098	\$ -	0.009785	\$ -	33	\$ 53	0.009785	\$ -		
34	\$ 579	\$ 143,098	\$ -	0.008486	\$ -	34	\$ 38	0.008486	\$ -		
35	\$ 448	\$ 143,098	\$ -	0.007360	\$ -	35	\$ 27	0.007360	\$ -		
36	\$ 343	\$ 143,098	\$ -	0.006384	\$ -	36	\$ 23	0.006384	\$ -		
37	\$ 284	\$ 143,098	\$ -	0.005536	\$ -	37	\$ 12	0.005536	\$ -		
38	\$ 203	\$ 143,098	\$ -	0.004802	\$ -	38	\$ 17	0.004802	\$ -		
39	\$ 157	\$ 143,098	\$ -	0.004165	\$ -	39	\$ 13	0.004165	\$ -		
40	\$ 121	\$ 143,098	\$ -	0.003612	\$ -	40	\$ 10	0.003612	\$ -		
WORKING INTEREST APPRAISAL						ROYALTY INTEREST APPRAISAL					

43 0320160063

\$ 3,880,556

TY2016 WORKING INTEREST

YEAR	WRK INT INCOME	WORKING COST	NET INC	PRCT FCTR(18.0%)	WRK INC	YEAR	ROY INT INCOME	PRCT FCTR(18.0%)	ROY INC
1	\$ 2,041,501	\$ 139,718	\$ 3,801,783	0.931291	\$ 3,540,568	1	\$ 347,055	0.931291	\$ 302,587
2	\$ 2,918,711	\$ 139,718	\$ 2,778,993	0.807711	\$ 2,243,008	2	\$ 478,821	0.807711	\$ 389,749
3	\$ 2,245,067	\$ 139,718	\$ 2,108,149	0.700530	\$ 1,475,421	3	\$ 368,692	0.700530	\$ 258,280
4	\$ 1,729,318	\$ 139,718	\$ 1,589,600	0.607572	\$ 965,798	4	\$ 283,893	0.607572	\$ 172,485
5	\$ 1,231,575	\$ 139,718	\$ 1,191,857	0.528948	\$ 528,048	5	\$ 218,598	0.528948	\$ 115,190
6	\$ 1,025,313	\$ 139,718	\$ 985,594	0.467024	\$ 404,738	6	\$ 188,320	0.467024	\$ 88,928
7	\$ 739,491	\$ 139,718	\$ 649,772	0.398378	\$ 257,558	7	\$ 129,807	0.398378	\$ 51,373
8	\$ 607,908	\$ 139,718	\$ 468,190	0.343780	\$ 160,954	8	\$ 89,797	0.343780	\$ 34,308
9	\$ 488,088	\$ 139,718	\$ 328,371	0.298181	\$ 97,907	9	\$ 78,844	0.298181	\$ 22,912
10	\$ 380,429	\$ 139,718	\$ 220,710	0.258596	\$ 57,075	10	\$ 59,170	0.258596	\$ 15,301
11	\$ 277,530	\$ 139,718	\$ 137,812	0.224281	\$ 30,809	11	\$ 45,581	0.224281	\$ 10,218
12	\$ 213,689	\$ 139,718	\$ 73,960	0.194519	\$ 14,380	12	\$ 35,082	0.194519	\$ 8,824
13	\$ 164,648	\$ 139,718	\$ 24,829	0.168707	\$ 4,189	13	\$ 27,013	0.168707	\$ 4,557
14	\$ 128,702	\$ 139,718	\$ -	0.146320	\$ -	14	\$ 20,800	0.146320	\$ -
15	\$ 87,580	\$ 139,718	\$ -	0.126904	\$ -	15	\$ 16,018	0.126904	\$ -
16	\$ 75,121	\$ 139,718	\$ -	0.110084	\$ -	16	\$ 12,332	0.110084	\$ -
17	\$ 57,843	\$ 139,718	\$ -	0.095459	\$ -	17	\$ 9,496	0.095459	\$ -
18	\$ 44,639	\$ 139,718	\$ -	0.082792	\$ -	18	\$ 7,312	0.082792	\$ -
19	\$ 34,296	\$ 139,718	\$ -	0.071808	\$ -	19	\$ 5,630	0.071808	\$ -
20	\$ 26,407	\$ 139,718	\$ -	0.062277	\$ -	20	\$ 4,335	0.062277	\$ -
21	\$ 20,334	\$ 139,718	\$ -	0.054013	\$ -	21	\$ 3,338	0.054013	\$ -
22	\$ 15,657	\$ 139,718	\$ -	0.046846	\$ -	22	\$ 2,570	0.046846	\$ -
23	\$ 12,056	\$ 139,718	\$ -	0.040629	\$ -	23	\$ 1,979	0.040629	\$ -
24	\$ 9,283	\$ 139,718	\$ -	0.035238	\$ -	24	\$ 1,524	0.035238	\$ -
25	\$ 7,148	\$ 139,718	\$ -	0.030562	\$ -	25	\$ 1,173	0.030562	\$ -
26	\$ 5,504	\$ 139,718	\$ -	0.026507	\$ -	26	\$ 904	0.026507	\$ -
27	\$ 4,238	\$ 139,718	\$ -	0.022989	\$ -	27	\$ 698	0.022989	\$ -
28	\$ 3,269	\$ 139,718	\$ -	0.019939	\$ -	28	\$ 535	0.019939	\$ -
29	\$ 2,513	\$ 139,718	\$ -	0.017293	\$ -	29	\$ 412	0.017293	\$ -
30	\$ 1,935	\$ 139,718	\$ -	0.014998	\$ -	30	\$ 318	0.014998	\$ -
31	\$ 1,480	\$ 139,718	\$ -	0.013008	\$ -	31	\$ 245	0.013008	\$ -
32	\$ 1,147	\$ 139,718	\$ -	0.011282	\$ -	32	\$ 188	0.011282	\$ -
33	\$ 883	\$ 139,718	\$ -	0.009785	\$ -	33	\$ 145	0.009785	\$ -
34	\$ 680	\$ 139,718	\$ -	0.008488	\$ -	34	\$ 112	0.008488	\$ -
35	\$ 524	\$ 139,718	\$ -	0.007360	\$ -	35	\$ 86	0.007360	\$ -
36	\$ 403	\$ 139,718	\$ -	0.006384	\$ -	36	\$ 68	0.006384	\$ -
37	\$ 311	\$ 139,718	\$ -	0.005538	\$ -	37	\$ 51	0.005538	\$ -
38	\$ 239	\$ 139,718	\$ -	0.004802	\$ -	38	\$ 38	0.004802	\$ -
39	\$ 184	\$ 139,718	\$ -	0.004165	\$ -	39	\$ 30	0.004165	\$ -
40	\$ 142	\$ 139,718	\$ -	0.003612	\$ -	40	\$ 23	0.003612	\$ -

WORKING INTEREST APPRAISAL

ROYALTY INTEREST APPRAISAL

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'PITCHER' COUNTY, WV
WFLD CAP MODEL REPORT FOR - 2016

NR105: 13

ACCOUNT:1020149960

RESOURCE:OG OWNER:ANTEFC RESOURCES CORPORATI LOCATION:NICHOLSON UNIT 2H

STATUS:Z API#:09960

DATE:04/12/2017 WGS:365 BRMS: 13615.000 NCFS: 610585 RCPTS: 5569051 GWT: 3622069 OWT: 90904

SYSTEM RATES:

CAP RATE: 15.300 DECLINE FACTOR: 0.460 0.200 0.230 WELL/LIFE:99 EXPENSE: 0.2 150000 150000 15000

RATES USED:

CAP RATE: 15.300 DECLINE FACTOR: 0.460 0.290 0.230 WELL/LIFE:99 GS EXPENSE: 0.2 150000 150000 15000

SETTLED YEARS: 2

OL EXPENSE: 0.2 5750 5750 575

	GAS WORKING INTEREST				GAS ROYALTY INTEREST				OIL WORKING INTEREST				OIL ROYALTY INTEREST			
	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTO	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTO	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTO	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTO
1	2,155,131	2,035,225	1,895,386	0.931	540,882	539,729	502,645	0.93	123,899	115,386	77,058	0.80	95,402	95,402	77,058	0.80
2	1,659,451	1,539,544	1,243,507	0.808	416,479	415,326	335,463	0.80	73,460	51,461	34,367	0.70	56,564	56,564	34,367	0.70
3	1,277,777	1,157,871	811,123	0.701	320,689	319,536	223,844	0.70	56,564	34,367	15,327	0.45	22,951	22,951	15,327	0.45
4	983,888	863,982	524,931	0.608	246,931	245,777	149,327	0.60	43,554	15,327	10,236	0.39	10,236	10,236	10,236	0.39
5	757,594	637,688	336,038	0.527	190,137	188,983	99,584	0.52	33,537	15,327	6,836	0.29	6,836	6,836	6,836	0.29
6	583,347	463,441	211,804	0.457	146,405	145,252	66,383	0.45	25,823	15,327	4,565	0.25	4,565	4,565	4,565	0.25
7	449,178	329,271	130,516	0.396	112,732	111,578	44,227	0.39	19,884	15,327	3,049	0.22	3,049	3,049	3,049	0.22
8	345,867	225,960	77,681	0.344	86,804	85,650	29,445	0.34	15,311	11,789	1,360	0.19	1,360	1,360	1,360	0.19
9	266,317	146,411	43,684	0.259	66,839	65,685	19,565	0.25	11,789	9,078	1,360	0.16	9,078	9,078	9,078	0.16
10	205,064	85,158	22,021	0.224	51,466	50,312	13,011	0.22	9,078	6,990	1,360	0.14	6,990	6,990	6,990	0.14
11	157,900	37,993	8,521	0.195	39,629	38,475	8,629	0.19	6,990	5,12	1,360	0.12	5,12	5,12	5,12	0.12
12	121,583	1,676	0	0.169	30,514	29,361	5,711	0.16	5,12	4,144	1,360	0.11	4,144	4,144	4,144	0.11
13	93,619	0	0	0.169	18,092	16,938	3,769	0.16	4,144	3,191	1,360	0.10	3,191	3,191	3,191	0.10
14					13,931	12,777	1,054	0.10	3,191	2,457	1,360	0.09	2,457	2,457	2,457	0.09
15					10,727	9,573	678	0.09	2,457	1,892	1,360	0.08	1,892	1,892	1,892	0.08
16					8,260	7,106	431	0.08	1,892	1,457	1,360	0.07	1,457	1,457	1,457	0.07
17					6,360	5,206	269	0.07	1,457	1,122	1,360	0.06	1,122	1,122	1,122	0.06
18					4,897	3,743	163	0.06	1,122	864	1,360	0.05	864	864	864	0.05
19					3,771	2,617	95	0.05	864	665	1,360	0.04	665	665	665	0.04
20					2,903	1,750	51	0.04	665	512	1,360	0.03	512	512	512	0.03
21					2,236	1,082	23	0.03	512	394	1,360	0.03	394	394	394	0.03
22					1,721	568	6	0.03	394	304	1,360	0.03	304	304	304	0.03
23					1,326	172	0	0.03	304	234	1,360	0.03	234	234	234	0.03
24					1,021	0	0	0.03	234	0	1,360	0.03	0	0	0	0.03
25																

TOTAL: 1,373,169

1,508,401

347,342

GS EXPENSE: 119907 119907 119907
OL EXPENSE: 1154 1154 1154

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'RITCHIE' COUNTY, WV
YIELD CAP MODEL REPORT FOR - 2016

NR105: 14

ACCOUNT: 1020150002

RESOURCE: OG

OWNER: ANTERO RESOURCES CORPORATION

LOCATION: KUHM UNIT 1H 40958

STATUS: Z API#: 10002

DATE: 05/01/2013 DAYS: 365

BHLS: 8229.000 MCFS:

449510 RCPTS:

3940708 GWL:

2657280 OMI:

54544

SYSTEM RATES:

CAP RATE: 15.300 DECLINE RATE: 0.460

0.290

0.230 WELTLIFE: 99

EXPENSE:

0.2

150000

150000

15000

RATES USED:

CAP RATE: 15.300 DECLINE RATE: 0.460

0.290

0.230 WELTLIFE: 99

EXPENSE:

0.2

150000

150000

15000

SETTLED YEARS: 2

OL EXPENSE:

0.2

5750

5750

575

GAS WORKING INTEREST

GROSS INCOME
NET INCOME
DISCOUNT INCOME

GAS ROYALTY INTEREST

GROSS INCOME
NET INCOME
DISCOUNT INCOME
FACTORS

OIL WORKING INTEREST

GROSS INCOME
NET INCOME
DISCOUNT INCOME

OIL ROYALTY INTEREST

GROSS INCOME
NET INCOME
DISCOUNT INCOME
FACTORS

1	1,581,082	1,456,628	1,356,545	364,305	339,274	0.931	324,552	323,573	301,341	74,782	69,644	0.93
2	1,217,433	1,092,980	882,812	280,515	226,575	0.808	249,905	248,926	201,060	57,582	46,510	0.80
3	937,423	812,970	569,510	215,981	151,312	0.701	192,427	191,448	134,115	44,338	31,060	0.70
4	721,816	597,363	362,941	166,317	101,050	0.608	148,169	147,190	89,428	34,140	20,743	0.60
5	555,798	431,345	227,296	128,064	67,483	0.527	87,849	86,870	59,603	26,242	13,852	0.52
6	427,965	303,511	138,712	98,610	45,067	0.457	67,644	66,665	39,702	15,586	9,251	0.45
7	329,533	205,080	81,289	75,929	30,097	0.396	52,086	51,107	26,424	12,001	6,178	0.39
8	253,740	129,287	44,446	58,466	20,099	0.344	40,106	39,127	17,569	9,241	4,126	0.34
9	195,380	70,927	21,148	45,019	13,423	0.298	30,882	29,902	11,666	7,116	1,840	0.29
10	150,443	25,989	6,701	34,664	8,964	0.259	23,779	22,800	7,733	5,479	1,229	0.25
11	115,841	0	0	26,691	0	0.224	18,310	17,330	5,114	4,219	821	0.22
12							14,099	13,119	3,371	3,249	548	0.19
13							10,856	9,877	2,213	2,501	244	0.16
14							8,359	7,380	1,445	1,926	163	0.14
15							6,436	5,457	601	1,483	366	0.11
16							4,956	3,977	380	1,142	109	0.09
17							3,816	2,837	235	877	73	0.08
18							2,938	1,959	141	677	49	0.07
19							2,263	1,283	80	521	32	0.06
20							1,742	763	41	401	22	0.05
21							1,033	362	17	309	14	0.04
22							795	54	2	238	10	0.04
23								0				0.03
24												

TOTAL:

3,631,400

1,003,345

903,217

209,639

GS EXPENSE: 124453

124453

124453

OL EXPENSE: 979

979

979

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'RITCHIE' COUNTY, WV
YIELD CAP MODEL REPORT FOR - 2016

NR105: 16

ACCOUNT: 1020159961

STATUS: 2 API#: 009961

RESOURCE: OG OWNER: ANTERO RESOURCES CORPORATION LOCATION: NICHOLSON UNIT 1H 40371

SYSTEM RATES:

DATE: 02/29/2013 DAYS: 365 FBLS: 9449.000 MCFS: 432520 RCPTS: 3793642 GWT: 2453923 OWT: 63267

RATES USED:

CAP RATE: 15.300 DECLINE RATE: 0.460 0.290 0.230 WELL LIFE: 99 EXPENSE: 0.2 150000 150000 15000

SETTLED YEARS: 2 15.300 DECLINE RATE: 0.460 0.290 0.230 WELL LIFE: 99 GS EXPENSE: 0.2 150000 150000 15000

OL EXPENSE: 0.2 150000 150000 15000

	GAS WORKING INTEREST				GAS ROYALTY INTEREST				OIL WORKING INTEREST				OIL ROYALTY INTEREST			
	GROSS INCOME	NET INCOME	DISCOUNT INCOME	DISCOUNT INCOME	GROSS INCOME	NET INCOME	DISCOUNT INCOME	DISCOUNT INCOME	GROSS INCOME	NET INCOME	DISCOUNT INCOME	DISCOUNT INCOME	GROSS INCOME	NET INCOME	DISCOUNT INCOME	DISCOUNT INCOME
1	1,460,084	1,340,830	1,248,703	334,460	311,479	0.931	376,442	375,264	349,480	86,231	80,306	0.93	86,231	80,306	0.93	86,231
2	1,124,265	1,005,011	811,759	257,534	208,013	0.808	289,861	288,682	233,172	66,398	53,630	0.80	66,398	53,630	0.80	66,398
3	865,684	746,430	522,897	198,301	138,916	0.701	223,193	222,014	155,527	51,126	35,816	0.70	51,126	35,816	0.70	51,126
4	666,577	547,323	332,538	152,692	92,771	0.608	171,858	170,680	103,700	39,367	23,918	0.60	39,367	23,918	0.60	39,367
5	513,264	394,010	207,623	117,573	61,955	0.527	132,331	131,152	69,110	30,313	15,973	0.52	30,313	15,973	0.52	30,313
6	395,213	275,960	126,120	90,531	41,375	0.457	101,895	100,716	46,030	23,341	10,667	0.45	23,341	10,667	0.45	23,341
7	304,314	185,060	73,354	69,709	27,631	0.396	78,459	77,280	20,364	13,839	7,124	0.39	13,839	7,124	0.39	13,839
8	234,322	115,068	39,558	53,676	18,453	0.344	60,413	59,235	13,519	10,656	4,758	0.34	10,656	4,758	0.34	10,656
9	180,428	61,174	18,240	41,330	12,323	0.298	46,518	45,340	8,958	8,205	3,177	0.29	8,205	3,177	0.29	8,205
10	138,929	19,676	5,088	31,824	8,230	0.259	35,819	34,641	5,921	6,318	2,122	0.25	6,318	2,122	0.25	6,318
11	106,976	0	0	24,505	0.224	27,581	26,402	5,921	5,921	6,318	2,122	0.22	6,318	2,122	0.22	6,318
12							21,237	20,059	2,560	4,865	1,417	0.22	4,865	1,417	0.22	4,865
13							16,353	15,174	1,670	3,746	946	0.19	3,746	946	0.19	3,746
14							12,592	11,413	1,081	2,884	422	0.16	2,884	422	0.16	2,884
15							9,695	8,517	692	2,221	188	0.12	2,221	188	0.12	2,221
16							7,466	6,287	436	1,710	126	0.11	1,710	126	0.11	1,710
17							5,748	4,570	269	1,317	84	0.08	1,317	84	0.08	1,317
18							4,426	3,248	160	1,014	56	0.07	1,014	56	0.07	1,014
19							3,408	2,230	90	781	37	0.06	781	37	0.06	781
20							2,624	1,446	45	601	25	0.05	601	25	0.05	601
21							2,021	842	18	463	17	0.04	463	17	0.04	463
22							1,556	377	1	356	11	0.04	356	11	0.04	356
23							1,198	19	0	274	0	0.04	274	0	0.04	274
24							923	0	0	211	0	0.03	211	0	0.03	211

TOTAL: 3,287,890 921,145 1,047,337 241,735

GS EXPENSE: 119254

119254

OL EXPENSE: 1179

1179

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'RITCHIE' COUNTY, WV
YIELD CAP MODEL REPORT FOR - 2016

NR105: 17

ACCOUNT:1020159964

RESOURCE:OG OWNER:ANTERO RESOURCES CORPORATI LOCATION:O'NEIL UNIT 1H 40379

STATUS:Z API#:09964

DATE:05/01/2013 DAYS:365 HBLS: 12351.000 MCPS: 637072 RCPTS: 5455838 GMI: 360679 OWI: 85366

SYSTEM RATES:

CAP RATE: 15.300 DECLINE RATE: 0.460 0.290 0.230 WELL-LIFE:99 EXPENSE: 0.2 150000 150000 15000

RATES USED:

CAP RATE: 15.300 DECLINE RATE: 0.460 0.290 WELL-LIFE:99 GS EXPENSE: 0.2 150000 150000 15000

SETTLED YEARS: 2

OL EXPENSE: 0.2 5750 5750 575

	GAS WORKING INTEREST			GAS ROYALTY INTEREST			OIL WORKING INTEREST			OIL ROYALTY INTEREST		
	GROSS INCOME	NET INCOME	DISCOUNT INCOME	GROSS INCOME	DISCOUNT INCOME	FACTOR	GROSS INCOME	NET INCOME	DISCOUNT INCOME	GROSS INCOME	DISCOUNT INCOME	FACTOR
1	2,145,974	2,024,683	1,885,569	478,954	446,045	0.931	507,932	506,831	472,007	113,364	105,575	0.93
2	1,652,400	1,531,109	1,236,693	368,794	297,879	0.808	391,108	390,007	315,013	87,290	70,505	0.80
3	1,272,348	1,151,057	806,350	283,972	198,931	0.701	301,153	300,052	210,196	67,214	47,085	0.70
4	979,708	858,416	521,550	218,658	132,851	0.608	231,888	230,787	140,220	51,754	31,445	0.60
5	754,375	633,084	333,602	168,367	88,721	0.527	178,553	177,453	93,509	39,851	20,999	0.52
6	580,869	459,577	210,038	129,642	59,250	0.457	137,486	136,386	62,332	30,685	14,024	0.45
7	447,269	325,978	129,210	99,825	39,568	0.396	105,864	104,764	41,526	23,628	9,365	0.39
8	344,397	223,106	76,699	76,865	26,425	0.344	81,516	80,415	27,645	18,193	6,254	0.34
9	265,186	143,894	42,904	59,186	17,647	0.298	62,767	61,666	18,387	14,009	4,177	0.29
10	204,193	82,902	21,438	45,573	11,785	0.259	48,331	47,230	12,214	10,787	2,789	0.25
11	157,229	35,937	8,060	35,091	7,870	0.224	37,215	36,114	8,100	8,306	1,863	0.22
12	121,066	0	0	27,020	0	0.195	28,655	27,555	5,360	6,395	1,244	0.19
13							22,065	20,964	3,537	4,925	831	0.16
14							16,990	15,889	2,325	3,792	555	0.14
15							13,082	11,982	1,521	2,920	371	0.12
16							10,073	8,973	988	2,248	247	0.11
17							7,756	6,656	635	1,731	165	0.09
18							5,972	4,872	403	1,333	110	0.08
19							4,599	3,498	251	1,026	74	0.07
20							3,541	2,441	152	790	49	0.06
21							2,727	1,626	88	609	33	0.05
22							2,099	999	47	469	22	0.04
23							1,617	516	21	361	15	0.04
24							1,245	144	5	278	10	0.03
25							958	0	0	214	0	0.03

TOTAL: 5,272,133 1,326,971 1,416,479 317,808

GS EXPENSE: 121291 121291 121291
OL EXPENSE: 1100 1100 1100

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'RITCHIE' COUNTY, WV
YIELD CAP MODEL REPORT FOR - 2016

NR105: 18

ACCOUNT: 1020159966

STATUS: Z API#: 09966

RESOURCE: OG OWNER: ANTERO RESOURCES CORPORATION LOCATION: O'NEIL UNIT 2H 40380

SYSTEM RATES:

CAP RATE: 15.300 DECLINE RATE:

DATE: 05/01/2013 DAYS: 365

PBLS: 11653.000 NCFS:

557149 RCPTS:

4773020 GWT:

3126337 OWT:

RATES USED:

CAP RATE: 15.300 DECLINE RATE:

0.460

0.290

0.230 WELLLIFE: 99

GS EXPENSE:

OL EXPENSE:

77578

SETTLED YEARS: 2

0.460

0.290

0.230 WELLLIFE: 99

GS EXPENSE:

OL EXPENSE:

575

	GAS WORKING INTEREST				GAS ROYALTY INTEREST				OIL WORKING INTEREST				OIL ROYALTY INTEREST			
	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTO	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTO	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTO	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTO
1	1,860,171	1,739,992	1,620,439	415,166	386,640	0.931	461,590	460,447	428,810	103,021	95,942	0.93	1,860,171	1,739,992	1,620,439	415,166
2	1,432,331	1,312,153	1,059,930	319,678	258,207	0.808	355,424	354,281	286,157	79,326	64,072	0.80	1,432,331	1,312,153	1,059,930	319,678
3	1,102,895	982,717	688,422	246,152	172,437	0.701	273,677	272,533	190,918	61,081	42,789	0.70	1,102,895	982,717	688,422	246,152
4	849,229	729,051	442,951	139,537	115,157	0.608	210,731	209,588	127,340	47,032	28,576	0.60	849,229	729,051	442,951	139,537
5	653,907	533,728	281,247	115,943	76,905	0.527	161,120	161,120	84,902	36,215	19,083	0.52	653,907	533,728	281,247	115,943
6	503,508	387,701	175,151	112,376	51,359	0.457	124,263	123,799	56,579	27,885	12,744	0.45	503,508	387,701	175,151	112,376
7	387,701	267,523	106,040	86,530	34,299	0.396	96,206	95,062	37,681	21,472	8,511	0.39	387,701	267,523	106,040	86,530
8	298,530	178,351	61,314	66,628	22,905	0.344	74,078	72,935	25,074	16,533	5,684	0.34	298,530	178,351	61,314	66,628
9	229,868	109,690	33,705	51,304	15,297	0.298	43,921	42,778	11,062	7,803	2,535	0.29	229,868	109,690	33,705	51,304
10	176,998	56,820	13,693	39,504	10,215	0.259	33,819	32,676	7,329	4,843	1,131	0.25	176,998	56,820	13,693	39,504
11	136,289	16,110	3,613	30,418	6,822	0.224	26,041	24,898	4,843	3,190	547	0.22	136,289	16,110	3,613	30,418
12	104,942	0	0	23,422	0.195	20,051	18,908	3,190	2,092	1,364	337	0.19	104,942	0	0	23,422
13							15,440	14,296	2,092	1,364	337	0.16				
14							11,888	10,745	1,364	882	225	0.14				
15							9,154	8,011	882	564	150	0.12				
16							7,049	5,906	564	355	100	0.09				
17							5,427	4,284	355	218	45	0.07				
18							4,179	3,036	218	129	30	0.06				
19							3,218	2,075	129	72	20	0.05				
20							2,478	1,335	72	36	13	0.04				
21							1,908	765	36	13	0	0.04				
22							1,459	326	13	0	0	0.04				
23							1,131	0	0	0	0	0.03				
24																

TOTAL:

4,486,456

1,150,244

1,286,273

288,802

GS EXPENSE: 120178 120178 120178
OL EXPENSE: 1143 1143 1143

OCT 12, 2016
01:52 PM

'RITCHIE' COUNTY, WV
YIELD CAP MODEL REPORT FOR - 2016

NR105: 19

ACCOUNT: 1020159970

RESOURCE: CG OWNER: ANTERO RESOURCES CORPORATION LOCATION: PRUNTY UNIT 1H 40393

STATUS: Z API#: 009970

DATE: 08/01/2013 DAYS: 365

BRHS: 22492.000 WCCS: 1251917

RCPTS: 10945227

GRI: 7292713

OWI: 154250

SYSTEM RATES:

CAP RATE: 15.300

DECLINE RATE: 0.460

0.290

0.230

WELL LIFE: 99

EXPENSE: 0.2

150000

150000

RATES USED:

CAP RATE: 15.300

DECLINE RATE: 0.460

0.290

0.230

WELL LIFE: 99

EXPENSE: 0.2

150000

150000

SETTLED YEARS: 2

OL EXPENSE: 0.2

5750

5750

575

	GAS WORKING INTEREST			GAS ROYALTY INTEREST			OIL WORKING INTEREST			OIL ROYALTY INTEREST		
	GROSS INCOME	NET INCOME	DISCOUNT INCOME	GROSS INCOME	DISCOUNT INCOME	FACTOR	GROSS INCOME	NET INCOME	DISCOUNT INCOME	GROSS INCOME	DISCOUNT INCOME	FACTOR
1	4,339,164	4,215,352	3,925,719	1,036,271	965,070	0.931	917,790	916,786	853,795	219,185	204,125	0.93
2	3,341,156	3,217,344	2,928,684	797,929	644,496	0.808	706,698	705,694	569,997	168,772	136,319	0.80
3	2,572,690	2,448,878	2,175,513	614,405	430,409	0.701	544,158	543,154	380,495	129,955	91,037	0.70
4	1,980,972	1,857,160	1,628,358	473,092	287,437	0.608	419,001	417,997	253,964	100,065	60,797	0.60
5	1,525,348	1,401,536	1,218,537	364,281	191,957	0.527	322,631	321,627	169,481	77,050	40,601	0.52
6	1,174,518	1,050,706	880,198	280,496	128,193	0.457	248,426	247,422	113,078	59,329	27,115	0.45
7	904,379	780,567	609,400	215,982	85,611	0.396	191,288	190,284	75,424	45,683	18,108	0.39
8	696,372	572,560	412,394	166,306	57,173	0.344	147,292	146,288	50,291	35,176	12,093	0.34
9	536,206	412,394	289,067	128,056	38,181	0.298	113,415	112,411	33,517	27,085	8,076	0.29
10	412,879	289,067	194,105	98,603	25,498	0.259	87,329	86,325	22,323	20,856	5,393	0.25
11	317,917	194,105	120,984	75,924	17,028	0.224	67,244	66,240	14,856	16,059	3,602	0.22
12	244,796	120,984	83,534	58,462	11,372	0.195	51,778	50,774	9,876	12,365	2,405	0.19
13	188,493	83,534	50,912	45,015	7,594	0.169	39,869	38,865	6,557	9,521	1,606	0.16
14	145,139	50,912	31,121	34,662	5,072	0.146	30,699	29,695	4,345	7,331	1,073	0.14
15	111,757	31,121	18,201	26,690	0	0.127	23,638	22,634	2,872	5,645	716	0.12
16		0					18,201	17,198	1,893	4,347	478	0.11
17							14,015	13,011	1,242	3,347	320	0.09
18							10,792	9,788	810	2,577	213	0.08
19							8,310	7,306	525	1,984	142	0.07
20							6,398	5,394	336	1,528	95	0.06
21							4,927	3,923	212	1,177	64	0.05
22							3,794	2,790	131	906	42	0.04
23							2,921	1,917	78	698	28	0.04
24							2,249	1,245	44	537	19	0.03
25							1,732	728	32	414	13	0.03
26							1,334	330	9	318	8	0.02
27							1,027	23	1	245	6	0.02
28							791	0	0	189	0	0.02

TOTAL: 11,372,058 2,895,092

2,566,173

614,495

GS EXPENSE: 123812 123812 123812
OL EXPENSE: 1004 1004 1004

OCT 12, 2016
01:52 PM

'RITCHIE' COUNTY, WV
YIELD CAP MODEL REPORT FOR - 2016

NR105: 20

ACCOUNT: 1020159978

STATUS: Z API#: 09978

DATE: 03/01/2013 DAYS: 365

REFERENCE: OG OWNER: ANTERO RESOURCES CORPORATION LOCATION: PULLMAN UNIT 2H 40363

BLS: 5198.000 NCTS: 380901 RCPTS: 2910505 GWT: 2052249 GWT: 35095

SYSTEM RATES:

CAP RATE: 15.300 DECLINE RATE: 0.460

RATES USED:

CAP RATE: 15.300 DECLINE RATE: 0.460

SETTLED YEARS: 2

OL EXPENSE: 5750

5750

5750

575

	GAS WORKING INTEREST				GAS ROYALTY INTEREST				OIL WORKING INTEREST				OIL ROYALTY INTEREST			
	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTORS	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTORS	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTORS	GROSS INCOME	NET INCOME	DISCOUNT INCOME	FACTORS
1	1,221,088	1,092,994	1,017,895	257,762	240,052	0.931	208,819	207,980	193,690	44,081	41,052	0.93	44,081	41,052	0.93	0.93
2	940,238	812,143	655,977	198,477	160,312	0.808	160,791	159,951	129,194	33,942	27,415	0.80	33,942	27,415	0.80	0.80
3	723,983	595,889	417,438	152,827	107,060	0.701	123,809	122,969	86,144	26,135	18,309	0.70	26,135	18,309	0.70	0.70
4	557,467	429,373	260,875	117,677	71,497	0.608	95,333	94,493	57,411	20,124	12,227	0.60	20,124	12,227	0.60	0.60
5	429,250	301,155	158,693	90,611	47,747	0.527	73,406	72,567	38,239	15,496	8,165	0.52	15,496	8,165	0.52	0.52
6	330,522	202,428	92,514	69,771	31,887	0.457	56,523	55,683	25,449	11,932	5,453	0.45	11,932	5,453	0.45	0.45
7	254,502	126,408	50,105	53,723	21,295	0.396	43,523	42,683	16,919	9,187	3,642	0.39	9,187	3,642	0.39	0.39
8	195,967	67,872	23,333	41,367	14,221	0.344	33,512	32,673	11,232	7,074	2,432	0.34	7,074	2,432	0.34	0.34
9	150,894	22,800	5,798	31,853	9,497	0.298	25,805	24,965	7,444	5,447	1,624	0.29	5,447	1,624	0.29	0.29
10	116,189	0	0	24,527	0	0.259	19,870	19,030	4,921	4,194	1,085	0.25	4,194	1,085	0.25	0.25
11							15,300	14,460	3,243	3,230	724	0.22	3,230	724	0.22	0.22
12							11,781	10,941	2,128	2,487	484	0.19	2,487	484	0.19	0.19
13							9,071	8,231	1,389	1,915	323	0.16	1,915	323	0.16	0.16
14							6,985	6,145	899	1,474	216	0.14	1,474	216	0.14	0.14
15							5,378	4,539	576	1,135	144	0.12	1,135	144	0.12	0.12
16							4,141	3,302	363	874	96	0.11	874	96	0.11	0.11
17							3,189	2,349	224	673	64	0.09	673	64	0.09	0.09
18							2,455	1,616	134	518	43	0.08	518	43	0.08	0.08
19							1,891	1,051	75	399	29	0.07	399	29	0.07	0.07
20							1,456	616	38	237	19	0.06	237	19	0.06	0.06
21							863	281	15	182	13	0.05	182	13	0.05	0.05
22							655	0	0	140	0	0.04	140	0	0.04	0.04
23																

TOTAL:

2,593,639

703,569

573,783

123,567

GS EXPENSE: 128094

128094

128094

OL EXPENSE: 840

840

840

2014												
		WRK INT	\$	8,631,540	\$	1,351,670	YR1	\$	3,389,988	\$	326,010	
		ROY INT	\$	1,581,833	\$	295,747	YR2	\$	743,564	\$	116,030	
YR 1	48%								\$	2,483,789	\$	389,247
YR 2	29%								\$	540,089	\$	56,882
YR 3	23%											
2014 ROYALTY INTEREST												
YEAR	WRK INT INCOME	WORKING COST	NET INC	PRCT FCTR(18.0%)	DIS INC	YEAR	ROY INT INCOME	PRCT FCTR(18.0%)	DIS INC			
1	\$ 1,895,968	\$ 130,524	\$ 1,765,444	0.001291	\$ 3,508,724	1	\$ 359,394	0.001291	\$ 300,348			
2	\$ 2,383,016	\$ 130,524	\$ 2,252,492	0.007711	\$ 2,223,218	2	\$ 535,851	0.007711	\$ 512,665			
3	\$ 2,219,923	\$ 130,524	\$ 2,089,398	0.00530	\$ 1,463,686	3	\$ 489,682	0.00530	\$ 343,037			
4	\$ 1,709,340	\$ 130,524	\$ 1,578,816	0.007572	\$ 969,244	4	\$ 377,056	0.007572	\$ 229,088			
5	\$ 1,318,192	\$ 130,524	\$ 1,187,668	0.006948	\$ 624,785	5	\$ 290,333	0.006948	\$ 192,990			
6	\$ 1,013,468	\$ 130,524	\$ 882,944	0.007024	\$ 403,626	6	\$ 223,556	0.007024	\$ 102,171			
7	\$ 780,370	\$ 130,524	\$ 649,846	0.006378	\$ 257,685	7	\$ 172,138	0.006378	\$ 8,232			
8	\$ 600,685	\$ 130,524	\$ 470,161	0.0043780	\$ 161,701	8	\$ 132,648	0.0043780	\$ 45,687			
9	\$ 462,682	\$ 130,524	\$ 332,157	0.006181	\$ 99,036	9	\$ 102,061	0.006181	\$ 30,431			
10	\$ 356,268	\$ 130,524	\$ 225,741	0.005896	\$ 58,376	10	\$ 79,567	0.005896	\$ 30,322			
11	\$ 274,324	\$ 130,524	\$ 143,800	0.004281	\$ 32,262	11	\$ 60,512	0.004281	\$ 13,572			
12	\$ 211,229	\$ 130,524	\$ 80,705	0.004819	\$ 15,699	12	\$ 48,694	0.004819	\$ 9,083			
13	\$ 182,647	\$ 130,524	\$ 52,122	0.006707	\$ 5,419	13	\$ 36,877	0.006707	\$ 6,053			
14	\$ 125,236	\$ 130,524	\$ -	0.0048320	\$ -	14	\$ 27,826	0.0048320	\$ -			
15	\$ 98,433	\$ 130,524	\$ -	0.006904	\$ -	15	\$ 21,272	0.006904	\$ -			
16	\$ 74,254	\$ 130,524	\$ -	0.004084	\$ -	16	\$ 16,379	0.004084	\$ -			
17	\$ 57,176	\$ 130,524	\$ -	0.005456	\$ -	17	\$ 12,612	0.005456	\$ -			
18	\$ 44,026	\$ 130,524	\$ -	0.0062792	\$ -	18	\$ 9,711	0.0062792	\$ -			
19	\$ 33,899	\$ 130,524	\$ -	0.0071806	\$ -	19	\$ 7,476	0.0071806	\$ -			
20	\$ 26,102	\$ 130,524	\$ -	0.0062277	\$ -	20	\$ 5,758	0.0062277	\$ -			
21	\$ 20,099	\$ 130,524	\$ -	0.0054013	\$ -	21	\$ 4,434	0.0054013	\$ -			
22	\$ 16,476	\$ 130,524	\$ -	0.0046846	\$ -	22	\$ 3,414	0.0046846	\$ -			
23	\$ 11,917	\$ 130,524	\$ -	0.0046829	\$ -	23	\$ 2,629	0.0046829	\$ -			
24	\$ 9,176	\$ 130,524	\$ -	0.005238	\$ -	24	\$ 2,024	0.005238	\$ -			
25	\$ 7,065	\$ 130,524	\$ -	0.006562	\$ -	25	\$ 1,559	0.006562	\$ -			
26	\$ 5,440	\$ 130,524	\$ -	0.006507	\$ -	26	\$ 1,200	0.006507	\$ -			
27	\$ 4,189	\$ 130,524	\$ -	0.0022989	\$ -	27	\$ 924	0.0022989	\$ -			
28	\$ 3,226	\$ 130,524	\$ -	0.0019939	\$ -	28	\$ 712	0.0019939	\$ -			
29	\$ 2,484	\$ 130,524	\$ -	0.007293	\$ -	29	\$ 548	0.007293	\$ -			
30	\$ 1,912	\$ 130,524	\$ -	0.004998	\$ -	30	\$ 422	0.004998	\$ -			
31	\$ 1,473	\$ 130,524	\$ -	0.0013008	\$ -	31	\$ 325	0.0013008	\$ -			
32	\$ 1,134	\$ 130,524	\$ -	0.0011282	\$ -	32	\$ 250	0.0011282	\$ -			
33	\$ 873	\$ 130,524	\$ -	0.009785	\$ -	33	\$ 193	0.009785	\$ -			
34	\$ 672	\$ 130,524	\$ -	0.008486	\$ -	34	\$ 148	0.008486	\$ -			
35	\$ 518	\$ 130,524	\$ -	0.007380	\$ -	35	\$ 114	0.007380	\$ -			
36	\$ 399	\$ 130,524	\$ -	0.006384	\$ -	36	\$ 88	0.006384	\$ -			
37	\$ 307	\$ 130,524	\$ -	0.005536	\$ -	37	\$ 68	0.005536	\$ -			
38	\$ 236	\$ 130,524	\$ -	0.004802	\$ -	38	\$ 52	0.004802	\$ -			
39	\$ 182	\$ 130,524	\$ -	0.004165	\$ -	39	\$ 40	0.004165	\$ -			
40	\$ 140	\$ 130,524	\$ -	0.003812	\$ -	40	\$ 31	0.003812	\$ -			
WORKING INTEREST APPRAISAL						ROYALTY INTEREST APPRAISAL						

2014									
YR 1		40%	WRK INT	\$ 5,510,381	\$ 1,293,338	YR1	\$ 2,178,600	\$ 510,869	
YR 2		29%	ROY INT	\$ 1,238,840	\$ 290,298		\$ 448,882	\$ 114,888	
YR3+		13%				YR2	\$ 1,610,684	\$ 378,043	
							\$ 381,828	\$ 84,884	
\$ 8,577,125									
TY2018 WORKING INTEREST									
YEAR	WRK INT INCOME	WORKING COST	NET INC	PRCT FCTR(16.0%)	DIS INC	YEAR	ROY INT INCOME	PRCT FCTR(16.0%)	DIS INC
1	\$ 2,587,469	\$ 122,579	\$ 2,584,890	0.931291	\$ 2,389,859	1	\$ 603,220	0.931291	\$ 561,773
2	\$ 1,988,727	\$ 122,579	\$ 1,866,148	0.807711	\$ 1,507,308	2	\$ 448,382	0.807711	\$ 380,548
3	\$ 1,531,320	\$ 122,579	\$ 1,408,741	0.700530	\$ 968,865	3	\$ 343,714	0.700530	\$ 240,782
4	\$ 1,179,116	\$ 122,579	\$ 1,056,537	0.607572	\$ 641,923	4	\$ 284,660	0.607572	\$ 180,900
5	\$ 907,920	\$ 122,579	\$ 785,341	0.526948	\$ 410,834	5	\$ 203,788	0.526948	\$ 107,286
6	\$ 699,098	\$ 122,579	\$ 576,519	0.457024	\$ 283,483	6	\$ 156,917	0.457024	\$ 71,715
7	\$ 538,308	\$ 122,579	\$ 415,728	0.396378	\$ 164,785	7	\$ 120,828	0.396378	\$ 47,893
8	\$ 414,485	\$ 122,579	\$ 291,916	0.343780	\$ 100,355	8	\$ 93,038	0.343780	\$ 31,704
9	\$ 319,181	\$ 122,579	\$ 196,602	0.298181	\$ 59,813	9	\$ 71,539	0.298181	\$ 21,257
10	\$ 245,754	\$ 122,579	\$ 123,175	0.256598	\$ 31,053	10	\$ 55,161	0.256598	\$ 13,284
11	\$ 189,231	\$ 122,579	\$ 66,652	0.224281	\$ 14,949	11	\$ 42,474	0.224281	\$ 7,228
12	\$ 145,708	\$ 122,579	\$ 23,129	0.194518	\$ 4,469	12	\$ 32,705	0.194518	\$ 1,302
13	\$ 112,195	\$ 122,579	\$ -	0.168707	\$ -	13	\$ 25,183	0.168707	\$ -
14	\$ 88,390	\$ 122,579	\$ -	0.148320	\$ -	14	\$ 18,391	0.148320	\$ -
15	\$ 68,620	\$ 122,579	\$ -	0.128904	\$ -	15	\$ 14,931	0.128904	\$ -
16	\$ 51,221	\$ 122,579	\$ -	0.110084	\$ -	16	\$ 11,487	0.110084	\$ -
17	\$ 36,440	\$ 122,579	\$ -	0.095459	\$ -	17	\$ 8,853	0.095459	\$ -
18	\$ 30,389	\$ 122,579	\$ -	0.082792	\$ -	18	\$ 6,815	0.082792	\$ -
19	\$ 23,384	\$ 122,579	\$ -	0.071806	\$ -	19	\$ 5,249	0.071806	\$ -
20	\$ 18,006	\$ 122,579	\$ -	0.062277	\$ -	20	\$ 4,041	0.062277	\$ -
21	\$ 13,864	\$ 122,579	\$ -	0.054013	\$ -	21	\$ 3,112	0.054013	\$ -
22	\$ 10,876	\$ 122,579	\$ -	0.046846	\$ -	22	\$ 2,398	0.046846	\$ -
23	\$ 8,220	\$ 122,579	\$ -	0.040628	\$ -	23	\$ 1,845	0.040628	\$ -
24	\$ 6,330	\$ 122,579	\$ -	0.035238	\$ -	24	\$ 1,421	0.035238	\$ -
25	\$ 4,874	\$ 122,579	\$ -	0.030562	\$ -	25	\$ 1,094	0.030562	\$ -
26	\$ 3,753	\$ 122,579	\$ -	0.026607	\$ -	26	\$ 842	0.026607	\$ -
27	\$ 2,890	\$ 122,579	\$ -	0.022988	\$ -	27	\$ 649	0.022988	\$ -
28	\$ 2,228	\$ 122,579	\$ -	0.019939	\$ -	28	\$ 499	0.019939	\$ -
29	\$ 1,713	\$ 122,579	\$ -	0.017293	\$ -	29	\$ 385	0.017293	\$ -
30	\$ 1,318	\$ 122,579	\$ -	0.014968	\$ -	30	\$ 298	0.014968	\$ -
31	\$ 1,018	\$ 122,579	\$ -	0.013008	\$ -	31	\$ 228	0.013008	\$ -
32	\$ 782	\$ 122,579	\$ -	0.011282	\$ -	32	\$ 178	0.011282	\$ -
33	\$ 602	\$ 122,579	\$ -	0.009785	\$ -	33	\$ 135	0.009785	\$ -
34	\$ 484	\$ 122,579	\$ -	0.008488	\$ -	34	\$ 104	0.008488	\$ -
35	\$ 387	\$ 122,579	\$ -	0.007360	\$ -	35	\$ 80	0.007360	\$ -
36	\$ 275	\$ 122,579	\$ -	0.006384	\$ -	36	\$ 62	0.006384	\$ -
37	\$ 212	\$ 122,579	\$ -	0.005535	\$ -	37	\$ 48	0.005535	\$ -
38	\$ 163	\$ 122,579	\$ -	0.004802	\$ -	38	\$ 37	0.004802	\$ -
39	\$ 128	\$ 122,579	\$ -	0.004185	\$ -	39	\$ 28	0.004185	\$ -
40	\$ 97	\$ 122,579	\$ -	0.003612	\$ -	40	\$ 22	0.003612	\$ -
WORKING INTEREST APPRAISAL					ROYALTY INTEREST APPRAISAL				

43 1020160017

1 Since August 1, 2015 falling on Saturday, August 1, 2015

2014									
YR 1		46%	WRK INT	\$	7,430,942	\$	1,388,166	YR1	\$
YR 2		20%	ROY INT	\$	1,538,819	\$	287,078	YR2	\$
YR3		23%						YR3	\$
8,709,980									
TY2014 WORKING INTEREST									
YEAR	WRK INT INCOME	WORKING COST	NET INC	PRCT FCTR(16.0%)	DIS INC	TY2014 ROYALTY INTEREST			
1	\$ 3,483,624	\$ 127,295	\$ 3,356,228	0.831291	\$ 3,126,625	1	\$ 720,437	0.931291	\$
2	\$ 2,577,807	\$ 127,295	\$ 2,450,512	0.807711	\$ 1,979,306	2	\$ 533,123	0.807711	\$
3	\$ 1,984,912	\$ 127,295	\$ 1,857,616	0.760530	\$ 1,301,316	3	\$ 410,505	0.760530	\$
4	\$ 1,528,382	\$ 127,295	\$ 1,401,087	0.687572	\$ 351,281	4	\$ 316,089	0.687572	\$
5	\$ 1,178,854	\$ 127,295	\$ 1,049,559	0.526948	\$ 553,063	5	\$ 243,388	0.526948	\$
6	\$ 96,178	\$ 127,295	\$ 778,882	0.457024	\$ 355,968	6	\$ 187,409	0.457024	\$
7	\$ 87,757	\$ 127,295	\$ 570,462	0.398378	\$ 126,118	7	\$ 144,305	0.398378	\$
8	\$ 57,273	\$ 127,295	\$ 409,977	0.343780	\$ 140,942	8	\$ 111,116	0.343780	\$
9	\$ 113,700	\$ 127,295	\$ 295,405	0.298161	\$ 85,385	9	\$ 85,568	0.298161	\$
10	\$ 119,549	\$ 127,295	\$ 191,264	0.258596	\$ 49,457	10	\$ 65,880	0.258596	\$
11	\$ 245,283	\$ 127,295	\$ 117,957	0.224281	\$ 28,482	11	\$ 50,729	0.224281	\$
12	\$ 168,888	\$ 127,295	\$ 81,572	0.194619	\$ 11,977	12	\$ 39,080	0.194619	\$
13	\$ 146,428	\$ 127,295	\$ 19,133	0.168707	\$ 3,059	13	\$ 30,078	0.168707	\$
14	\$ 111,980	\$ 127,295	\$ -	0.145320	\$ -	14	\$ 23,159	0.145320	\$
15	\$ 98,224	\$ 127,295	\$ -	0.126904	\$ -	15	\$ 17,832	0.126904	\$
16	\$ 86,395	\$ 127,295	\$ -	0.095489	\$ -	16	\$ 13,731	0.095489	\$
17	\$ 51,122	\$ 127,295	\$ -	0.082782	\$ -	17	\$ 10,573	0.082782	\$
18	\$ 39,364	\$ 127,295	\$ -	0.071806	\$ -	18	\$ 8,141	0.071806	\$
19	\$ 30,310	\$ 127,295	\$ -	0.062277	\$ -	19	\$ 8,269	0.062277	\$
20	\$ 23,339	\$ 127,295	\$ -	0.054013	\$ -	20	\$ 4,827	0.054013	\$
21	\$ 17,971	\$ 127,295	\$ -	0.046846	\$ -	21	\$ 3,717	0.046846	\$
22	\$ 13,838	\$ 127,295	\$ -	0.040629	\$ -	22	\$ 2,982	0.040629	\$
23	\$ 10,855	\$ 127,295	\$ -	0.035238	\$ -	23	\$ 2,204	0.035238	\$
24	\$ 8,204	\$ 127,295	\$ -	0.030562	\$ -	24	\$ 1,897	0.030562	\$
25	\$ 6,317	\$ 127,295	\$ -	0.028507	\$ -	25	\$ 1,307	0.028507	\$
26	\$ 4,864	\$ 127,295	\$ -	0.022889	\$ -	26	\$ 775	0.022889	\$
27	\$ 3,748	\$ 127,295	\$ -	0.019939	\$ -	27	\$ 596	0.019939	\$
28	\$ 2,884	\$ 127,295	\$ -	0.017293	\$ -	28	\$ 459	0.017293	\$
29	\$ 2,221	\$ 127,295	\$ -	0.014998	\$ -	29	\$ 354	0.014998	\$
30	\$ 1,710	\$ 127,295	\$ -	0.013008	\$ -	30	\$ 272	0.013008	\$
31	\$ 1,317	\$ 127,295	\$ -	0.011282	\$ -	31	\$ 210	0.011282	\$
32	\$ 1,014	\$ 127,295	\$ -	0.009785	\$ -	32	\$ 181	0.009785	\$
33	\$ 781	\$ 127,295	\$ -	0.008406	\$ -	33	\$ 124	0.008406	\$
34	\$ 601	\$ 127,295	\$ -	0.007360	\$ -	34	\$ 98	0.007360	\$
35	\$ 463	\$ 127,295	\$ -	0.006384	\$ -	35	\$ 74	0.006384	\$
36	\$ 356	\$ 127,295	\$ -	0.005536	\$ -	36	\$ 57	0.005536	\$
37	\$ 274	\$ 127,295	\$ -	0.004802	\$ -	37	\$ 44	0.004802	\$
38	\$ 211	\$ 127,295	\$ -	0.004165	\$ -	38	\$ 34	0.004165	\$
39	\$ 163	\$ 127,295	\$ -	0.003612	\$ -	39	\$ 28	0.003612	\$
40	\$ 125	\$ 127,295	\$ -			40			
WORKING INTEREST APPRAISAL									
ROYALTY INTEREST APPRAISAL									

43 1020160019

2014									
YR 1	48%	WKN INT	\$ 6,800,967	\$ 1,104,886	YR1	\$ 2,486,362	\$ 434,438		
YR 2	28%	ROY INT	\$ 1,484,389	\$ 238,228		\$ 876,212	\$ 94,090		
YR 3+	13%				YR2	\$ 1,987,323	\$ 222,888		
						\$ 428,617	\$ 88,633		
\$ 7,716,028									
2015 WORKING INTEREST									
YEAR	WKN INT INCOME	WORKING COST	NET INC	PROT FCTR(16.0%)	DIS INC	YEAR	ROY INT INCOME	PROT FCTR(16.0%)	DIS INC
1	\$ 3,122,812	\$ 129,840	\$ 2,992,972	0.931291	\$ 2,787,328	1	\$ 873,311	0.931291	\$ 827,048
2	\$ 2,310,681	\$ 129,840	\$ 2,181,041	0.807711	\$ 1,781,650	2	\$ 498,250	0.807711	\$ 402,442
3	\$ 1,779,378	\$ 129,840	\$ 1,649,538	0.700530	\$ 1,165,551	3	\$ 383,682	0.700530	\$ 268,760
4	\$ 1,370,121	\$ 129,840	\$ 1,240,281	0.607572	\$ 753,560	4	\$ 295,412	0.607572	\$ 179,484
5	\$ 1,054,993	\$ 129,840	\$ 925,153	0.528948	\$ 487,508	5	\$ 227,468	0.528948	\$ 119,864
6	\$ 812,345	\$ 129,840	\$ 682,505	0.457024	\$ 311,921	6	\$ 175,150	0.457024	\$ 80,048
7	\$ 625,506	\$ 129,840	\$ 495,665	0.396378	\$ 196,471	7	\$ 134,665	0.396378	\$ 53,168
8	\$ 481,639	\$ 129,840	\$ 351,799	0.343780	\$ 120,941	8	\$ 103,846	0.343780	\$ 35,700
9	\$ 370,862	\$ 129,840	\$ 241,022	0.298161	\$ 71,063	9	\$ 79,962	0.298161	\$ 23,841
10	\$ 285,564	\$ 129,840	\$ 155,724	0.258596	\$ 40,270	10	\$ 61,571	0.258596	\$ 15,922
11	\$ 219,884	\$ 129,840	\$ 90,044	0.224281	\$ 20,195	11	\$ 47,409	0.224281	\$ 10,633
12	\$ 169,311	\$ 129,840	\$ 39,471	0.194519	\$ 7,678	12	\$ 36,505	0.194519	\$ 7,101
13	\$ 130,369	\$ 129,840	\$ 929	0.168707	\$ 99	13	\$ 28,109	0.168707	\$ 4,742
14	\$ 100,384	\$ 129,840	\$ -	0.146320	\$ -	14	\$ 21,644	0.146320	\$ -
15	\$ 77,298	\$ 129,840	\$ -	0.126904	\$ -	15	\$ 16,668	0.126904	\$ -
16	\$ 59,518	\$ 129,840	\$ -	0.110064	\$ -	16	\$ 12,833	0.110064	\$ -
17	\$ 45,829	\$ 129,840	\$ -	0.095469	\$ -	17	\$ 9,881	0.095469	\$ -
18	\$ 35,288	\$ 129,840	\$ -	0.082792	\$ -	18	\$ 7,508	0.082792	\$ -
19	\$ 27,172	\$ 129,840	\$ -	0.071808	\$ -	19	\$ 5,369	0.071808	\$ -
20	\$ 20,922	\$ 129,840	\$ -	0.062277	\$ -	20	\$ 4,511	0.062277	\$ -
21	\$ 16,110	\$ 129,840	\$ -	0.054013	\$ -	21	\$ 3,474	0.054013	\$ -
22	\$ 12,405	\$ 129,840	\$ -	0.046846	\$ -	22	\$ 2,875	0.046846	\$ -
23	\$ 9,552	\$ 129,840	\$ -	0.040629	\$ -	23	\$ 2,059	0.040629	\$ -
24	\$ 7,355	\$ 129,840	\$ -	0.035238	\$ -	24	\$ 1,586	0.035238	\$ -
25	\$ 5,583	\$ 129,840	\$ -	0.030562	\$ -	25	\$ 1,221	0.030562	\$ -
26	\$ 4,351	\$ 129,840	\$ -	0.026507	\$ -	26	\$ 940	0.026507	\$ -
27	\$ 3,358	\$ 129,840	\$ -	0.022989	\$ -	27	\$ 724	0.022989	\$ -
28	\$ 2,585	\$ 129,840	\$ -	0.019939	\$ -	28	\$ 567	0.019939	\$ -
29	\$ 1,991	\$ 129,840	\$ -	0.017293	\$ -	29	\$ 429	0.017293	\$ -
30	\$ 1,533	\$ 129,840	\$ -	0.014998	\$ -	30	\$ 331	0.014998	\$ -
31	\$ 1,160	\$ 129,840	\$ -	0.013008	\$ -	31	\$ 254	0.013008	\$ -
32	\$ 908	\$ 129,840	\$ -	0.011282	\$ -	32	\$ 196	0.011282	\$ -
33	\$ 700	\$ 129,840	\$ -	0.009785	\$ -	33	\$ 151	0.009785	\$ -
34	\$ 539	\$ 129,840	\$ -	0.008466	\$ -	34	\$ 116	0.008466	\$ -
35	\$ 415	\$ 129,840	\$ -	0.007360	\$ -	35	\$ 89	0.007360	\$ -
36	\$ 319	\$ 129,840	\$ -	0.006384	\$ -	36	\$ 69	0.006384	\$ -
37	\$ 246	\$ 129,840	\$ -	0.005536	\$ -	37	\$ 53	0.005536	\$ -
38	\$ 189	\$ 129,840	\$ -	0.004802	\$ -	38	\$ 41	0.004802	\$ -
39	\$ 146	\$ 129,840	\$ -	0.004165	\$ -	39	\$ 31	0.004165	\$ -
40	\$ 112	\$ 129,840	\$ -	0.003612	\$ -	40	\$ 24	0.003612	\$ -
WORKING INTEREST APPRAVAL					ROYALTY INTEREST APPRAVAL				

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2014									
WRK INT					ROY INT				
YR1	48%			\$ 7,408,878	\$ 879,580	YR1	\$ 2,925,322	\$ 347,428	
YR2	29%			\$ 1,648,108	\$ 197,787	YR2	\$ 687,717	\$ 78,114	
YR3+	23%					YR3	\$ 2,184,738	\$ 257,094	
							\$ 488,710	\$ 57,804	
\$ 3,093,658									
TY2018 WORKING INTEREST					TY2018 ROYALTY INTEREST				
YEAR	WRK INT INCOME	WORKING COST	NET INC	PRCT FCTR(16.0%)	DIS INC	YEAR	ROY INT INCOME	PRCT FCTR(16.0%)	DIS INC
1	\$ 3,272,748	\$ 134,687	\$ 3,138,061	0.931291	\$ 2,922,449	1	\$ 735,831	0.931291	\$ 685,273
2	\$ 2,421,834	\$ 134,687	\$ 2,287,147	0.807711	\$ 1,847,354	2	\$ 544,515	0.807711	\$ 439,611
3	\$ 1,864,812	\$ 134,687	\$ 1,730,125	0.700530	\$ 1,212,004	3	\$ 419,278	0.700530	\$ 293,716
4	\$ 1,435,905	\$ 134,687	\$ 1,301,218	0.607572	\$ 790,584	4	\$ 322,843	0.607572	\$ 198,150
5	\$ 1,105,647	\$ 134,687	\$ 970,960	0.526948	\$ 511,645	5	\$ 243,569	0.526948	\$ 130,963
6	\$ 851,348	\$ 134,687	\$ 716,661	0.457024	\$ 327,531	6	\$ 184,414	0.457024	\$ 87,481
7	\$ 655,538	\$ 134,687	\$ 520,851	0.396378	\$ 208,454	7	\$ 147,368	0.396378	\$ 58,422
8	\$ 504,784	\$ 134,687	\$ 370,097	0.343780	\$ 127,225	8	\$ 113,489	0.343780	\$ 39,015
9	\$ 398,669	\$ 134,687	\$ 263,982	0.298181	\$ 75,727	9	\$ 87,587	0.298181	\$ 28,055
10	\$ 309,275	\$ 134,687	\$ 174,588	0.258596	\$ 42,562	10	\$ 67,288	0.258596	\$ 17,400
11	\$ 230,442	\$ 134,687	\$ 95,755	0.224281	\$ 21,478	11	\$ 51,812	0.224281	\$ 11,820
12	\$ 177,440	\$ 134,687	\$ 42,753	0.194619	\$ 8,318	12	\$ 39,895	0.194619	\$ 7,780
13	\$ 138,829	\$ 134,687	\$ 1,942	0.168707	\$ 328	13	\$ 30,719	0.168707	\$ 5,183
14	\$ 105,204	\$ 134,687	\$ -	0.148320	\$ -	14	\$ 23,654	0.148320	\$ -
15	\$ 81,007	\$ 134,687	\$ -	0.128904	\$ -	15	\$ 18,213	0.128904	\$ -
16	\$ 62,378	\$ 134,687	\$ -	0.110084	\$ -	16	\$ 14,024	0.110084	\$ -
17	\$ 48,029	\$ 134,687	\$ -	0.095459	\$ -	17	\$ 10,799	0.095459	\$ -
18	\$ 36,982	\$ 134,687	\$ -	0.082792	\$ -	18	\$ 8,315	0.082792	\$ -
19	\$ 28,477	\$ 134,687	\$ -	0.071806	\$ -	19	\$ 6,403	0.071806	\$ -
20	\$ 21,927	\$ 134,687	\$ -	0.062277	\$ -	20	\$ 4,930	0.062277	\$ -
21	\$ 16,884	\$ 134,687	\$ -	0.054013	\$ -	21	\$ 3,798	0.054013	\$ -
22	\$ 13,000	\$ 134,687	\$ -	0.046846	\$ -	22	\$ 2,923	0.046846	\$ -
23	\$ 10,010	\$ 134,687	\$ -	0.040829	\$ -	23	\$ 2,251	0.040829	\$ -
24	\$ 7,708	\$ 134,687	\$ -	0.036238	\$ -	24	\$ 1,733	0.036238	\$ -
25	\$ 5,935	\$ 134,687	\$ -	0.030562	\$ -	25	\$ 1,334	0.030562	\$ -
26	\$ 4,570	\$ 134,687	\$ -	0.026507	\$ -	26	\$ 1,028	0.026507	\$ -
27	\$ 3,519	\$ 134,687	\$ -	0.022969	\$ -	27	\$ 791	0.022969	\$ -
28	\$ 2,710	\$ 134,687	\$ -	0.019939	\$ -	28	\$ 598	0.019939	\$ -
29	\$ 2,088	\$ 134,687	\$ -	0.017293	\$ -	29	\$ 469	0.017293	\$ -
30	\$ 1,607	\$ 134,687	\$ -	0.014998	\$ -	30	\$ 361	0.014998	\$ -
31	\$ 1,237	\$ 134,687	\$ -	0.013008	\$ -	31	\$ 279	0.013008	\$ -
32	\$ 953	\$ 134,687	\$ -	0.011282	\$ -	32	\$ 214	0.011282	\$ -
33	\$ 733	\$ 134,687	\$ -	0.009785	\$ -	33	\$ 155	0.009785	\$ -
34	\$ 565	\$ 134,687	\$ -	0.008486	\$ -	34	\$ 127	0.008486	\$ -
35	\$ 435	\$ 134,687	\$ -	0.007360	\$ -	35	\$ 98	0.007360	\$ -
36	\$ 335	\$ 134,687	\$ -	0.006364	\$ -	36	\$ 75	0.006364	\$ -
37	\$ 258	\$ 134,687	\$ -	0.005536	\$ -	37	\$ 58	0.005536	\$ -
38	\$ 199	\$ 134,687	\$ -	0.004802	\$ -	38	\$ 45	0.004802	\$ -
39	\$ 153	\$ 134,687	\$ -	0.004165	\$ -	39	\$ 34	0.004165	\$ -
40	\$ 118	\$ 134,687	\$ -	0.003612	\$ -	40	\$ 28	0.003612	\$ -
WORKING INTEREST APPRAISAL					ROYALTY INTEREST APPRAISAL				

43 1020160046

2014									
YR 1	4%	WRK INT	\$	4,331,823	\$	584,374	YR1	\$	1,710,842
YR 2	2%	ROY INT	\$	977,087	\$	131,818	YR2	\$	386,941
YR3	2%						YR3	\$	1,286,104
								\$	288,587
									230,828
									52,068
									170,815
									38,830
\$ 4,503,041									
TY2016 WORKING INTEREST									
YEAR	WRK INT INCOME	WORKING COST	NET INC	PRCT FCTR(18.0%)	DIS INC	YEAR	ROY INT INCOME	PRCT FCTR(18.0%)	DIS INC
1	\$ 1,941,779	\$ 132,852	\$ 1,808,927	0.931291	\$ 1,684,637	1	\$ 438,010	0.931291	\$ 407,914
2	\$ 1,438,917	\$ 132,852	\$ 1,304,064	0.807711	\$ 1,053,307	2	\$ 324,127	0.807711	\$ 281,801
3	\$ 1,108,428	\$ 132,852	\$ 973,573	0.700530	\$ 882,017	3	\$ 249,578	0.700530	\$ 174,837
4	\$ 851,948	\$ 132,852	\$ 719,096	0.607572	\$ 438,902	4	\$ 192,175	0.607572	\$ 118,760
5	\$ 658,000	\$ 132,852	\$ 523,148	0.528848	\$ 275,672	5	\$ 147,975	0.528848	\$ 77,975
6	\$ 505,120	\$ 132,852	\$ 372,268	0.457024	\$ 170,135	6	\$ 113,941	0.457024	\$ 52,074
7	\$ 398,942	\$ 132,852	\$ 266,090	0.396378	\$ 101,508	7	\$ 87,734	0.396378	\$ 34,776
8	\$ 298,486	\$ 132,852	\$ 165,633	0.343780	\$ 57,285	8	\$ 67,565	0.343780	\$ 23,224
9	\$ 230,604	\$ 132,852	\$ 87,752	0.298161	\$ 29,148	9	\$ 52,018	0.298161	\$ 15,510
10	\$ 177,565	\$ 132,852	\$ 44,713	0.258598	\$ 11,563	10	\$ 40,054	0.258598	\$ 10,385
11	\$ 138,725	\$ 132,852	\$ 3,873	0.224281	\$ 369	11	\$ 30,841	0.224281	\$ 8,917
12	\$ 105,278	\$ 132,852	\$ -	0.194519	\$ -	12	\$ 23,748	0.194519	\$ -
13	\$ 81,064	\$ 132,852	\$ -	0.168707	\$ -	13	\$ 18,286	0.168707	\$ -
14	\$ 62,420	\$ 132,852	\$ -	0.146320	\$ -	14	\$ 14,080	0.146320	\$ -
15	\$ 48,083	\$ 132,852	\$ -	0.126904	\$ -	15	\$ 10,842	0.126904	\$ -
16	\$ 37,009	\$ 132,852	\$ -	0.110084	\$ -	16	\$ 8,348	0.110084	\$ -
17	\$ 28,497	\$ 132,852	\$ -	0.095459	\$ -	17	\$ 6,428	0.095459	\$ -
18	\$ 21,842	\$ 132,852	\$ -	0.082792	\$ -	18	\$ 4,950	0.082792	\$ -
19	\$ 18,898	\$ 132,852	\$ -	0.071808	\$ -	19	\$ 3,811	0.071808	\$ -
20	\$ 13,010	\$ 132,852	\$ -	0.062277	\$ -	20	\$ 2,935	0.062277	\$ -
21	\$ 10,017	\$ 132,852	\$ -	0.054013	\$ -	21	\$ 2,280	0.054013	\$ -
22	\$ 7,713	\$ 132,852	\$ -	0.046846	\$ -	22	\$ 1,740	0.046846	\$ -
23	\$ 5,939	\$ 132,852	\$ -	0.040629	\$ -	23	\$ 1,340	0.040629	\$ -
24	\$ 4,573	\$ 132,852	\$ -	0.035238	\$ -	24	\$ 1,032	0.035238	\$ -
25	\$ 3,521	\$ 132,852	\$ -	0.030582	\$ -	25	\$ 794	0.030582	\$ -
26	\$ 2,711	\$ 132,852	\$ -	0.026507	\$ -	26	\$ 612	0.026507	\$ -
27	\$ 2,088	\$ 132,852	\$ -	0.022988	\$ -	27	\$ 471	0.022988	\$ -
28	\$ 1,608	\$ 132,852	\$ -	0.019939	\$ -	28	\$ 363	0.019939	\$ -
29	\$ 1,238	\$ 132,852	\$ -	0.017293	\$ -	29	\$ 279	0.017293	\$ -
30	\$ 953	\$ 132,852	\$ -	0.014998	\$ -	30	\$ 215	0.014998	\$ -
31	\$ 734	\$ 132,852	\$ -	0.013008	\$ -	31	\$ 168	0.013008	\$ -
32	\$ 585	\$ 132,852	\$ -	0.011282	\$ -	32	\$ 127	0.011282	\$ -
33	\$ 435	\$ 132,852	\$ -	0.009788	\$ -	33	\$ 98	0.009788	\$ -
34	\$ 335	\$ 132,852	\$ -	0.008486	\$ -	34	\$ 78	0.008486	\$ -
35	\$ 258	\$ 132,852	\$ -	0.007380	\$ -	35	\$ 58	0.007380	\$ -
36	\$ 199	\$ 132,852	\$ -	0.006364	\$ -	36	\$ 45	0.006364	\$ -
37	\$ 153	\$ 132,852	\$ -	0.005536	\$ -	37	\$ 35	0.005536	\$ -
38	\$ 118	\$ 132,852	\$ -	0.004802	\$ -	38	\$ 27	0.004802	\$ -
39	\$ 91	\$ 132,852	\$ -	0.004165	\$ -	39	\$ 20	0.004165	\$ -
40	\$ 70	\$ 132,852	\$ -	0.003612	\$ -	40	\$ 8	0.003612	\$ -
WORKING INTEREST APPRAISAL									
ROYALTY INTEREST APPRAISAL									

43 10 2016 9996



Chase Tower, Eighth Floor
P.O. Box 1588
Charleston, WV 25326-1588
(304) 353-8000 (304) 353-8180 Fax
www.stepToe-johnson.com

Writer's Contact Information

February 10, 2016

VIA FACSIMILE/CERTIFIED MAIL TO FOLLOW

Tracy McDonald
Clerk of the Ritchie County Commission
115 East Main Street, Room 201
Harrisville, WV 26326

Re: Antero Resources Corporation
Notice of Protest and Election to have matter
heard by the Board of Assessment Appeals

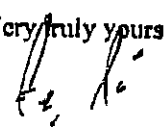
Dear Ms. McDonald:

This firm serves as West Virginia tax counsel to Antero Resources Corporation. Attached for filing on behalf of Antero Resources Corporation please find the company's Notice of Protest and Election to have matter heard by the Board of Assessment Appeals. Please contact me if you have any questions regarding this matter or if any further information or actions is required to lodge this appeal and secure a hearing date in October.

A copy of this filing is also being provided to the Assessor and to the Tax Commissioner as indicated below.

Thank you for your assistance.

Very truly yours,


Craig A. Griffith

cc: Arlene Mossor
Ritchie County Assessor
115 East Main Street, Room 203
Harrisville, WV 26326
(via facsimile and certified mail)

Mark Matkovich
State Tax Commissioner
PO Box 11771
Charleston, WV 25339-1171
(via facsimile and certified mail)





February 10, 2016

Antero Resources
1615 Wynkoop Street
Denver, CO 80202
Office 303.357.7310
Fax 303.357.7315

VIA FACSIMILE/CERTIFIED MAIL TO FOLLOW

Tracy McDonald
Clark of the Ritchie County Commission
115 East Main Street, Room 201
Harrisville, WV 26326

Re: Antero Resources Corporation
Notice of Protest and Election to have matter
heard by the Board of Assessment Appeals

Dear Ms. McDonald:

In accordance with W.Va. Code §§ 11-3-23a, 11-3-24 and 11-3-24b, Antero Resources Corporation hereby protests the assessment of its property identified on the attached spreadsheet.

Generally stated, the primary reason for Antero Resources Corporation's filing of this notice of protest is that the assessments of the properties at issue do not reflect the true and actual value of the properties due to the use of inaccurate operating expenses. The Property Tax Division did not use the actual operating expenses provided by Antero Resources Corporation in the appraisal of its wells and as a result, the assessed value for the wells is overstated. Antero Resources Corporation reserves the right to raise additional grounds during the appeal process. Please note that with respect to each property identified on the attached spreadsheet, the State Appraised Value, the Taxpayer's Value and the Value the Taxpayer Believes to be in Controversy are all indicated.

Furthermore, please be advised that Antero Resources Corporation elects to have this matter heard in October of 2016 when the County Commission sits as the Board of Assessment Appeals.

Antero Resources Corporation acknowledges that it will timely pay first and second half installment payments of taxes levied for the current tax year on or before they become due and that any reduction in assessed value that is administratively or judicially determined in a decision that becomes final will result in a credit being established against taxes that become due for a tax year subsequent to the tax year in which the decision becomes final, except otherwise stated in the decision or as otherwise provided in Chapter 11, Article 3 of the West Virginia Code.

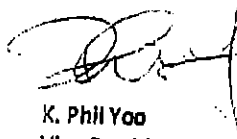
February 10, 2016

Page 2

Ms. McDonald

A copy of this letter is also being provided to the County Assessor and State Tax Commissioner.

Best regards,
Antero Resources Corporation



K. Phil Yoo
Vice President of Accounting and Chief
Accounting Officer

CC: Arlene Mossor
Ritchie County Assessor
115 East Main Street, Room 203
Harrisville, WV 26326
(via facsimile and certified mail)

Mark W. Matkovich
State Tax Commissioner
West Virginia Department of Tax & Revenue
PO Box 11771
Charleston, WV 25339-1771
(via facsimile and certified mail)

Kirsten Evans
Director
Altus Group US Inc.
910 Ridgebrook Road, Suite 200
Sparks, MD 21152

Antara Resources Corporation
Tax Year 7/1/15-6/30/16
Ritchie County, WV

Account #	API #	Property Description	State Appraised Value	Taxpayer Value	Value the Taxpayer Believes to Be in Controversy
1020149960	085-09960	NICHOLSON UNIT 2H	6,813,991	4,432,767	2,381,224
1020159961	085-09961	NICHOLSON UNIT 1H 40371	4,433,217	2,841,770	1,591,447
0320159963	085-09963	ANNA UNIT 2H 40324	6,766,223	4,251,817	2,514,406
1020159964	085-09964	O'NEIL UNIT 1H 40379	6,686,592	4,124,290	2,564,302
1020159966	085-09966	O'NEIL UNIT 2H 40380	5,772,729	3,617,974	2,154,755
1020159970	085-09970	PRUNTY UNIT 1H 40393	13,938,228	8,454,652	5,483,576
1020159976	085-09978	PULLMAN UNIT 2H 40383	3,263,358	2,058,974	1,204,384
1020169998	085-09996	SNOODGRASS UNIT 2H (40654)	4,503,041	1,168,596	3,334,445
1020169999	085-09999	DEBERRY UNIT 1H (40401)	8,583,011	2,647,389	5,935,626
1020150002	089-10002	KUHN UNIT 1H 40956	4,594,637	2,913,904	1,680,733
1020160005	085-10005	IRELAND UNIT 1H (40972)	9,811,251	3,116,276	6,694,973
1020160017	089-10017	ALLSTATE UNIT 2H (40538)	6,577,125	2,624,517	3,952,606
1020160019	085-10019	MCCABE UNIT 3H (40537)	8,709,950	3,933,798	4,776,152
1020150023	089-10023	CONSTABLE UNIT 1H 40431	15,692,042	9,314,567	6,337,475
0320160027	085-10027	BELLE UNIT 1H (40459)	8,857,189	2,859,069	5,998,116
0320160028	085-10028	BELLE UNIT 2H (40644)	5,953,786	1,925,322	4,028,464
0320160029	089-10029	BELLE UNIT 3H (40554)	8,427,646	3,131,376	5,296,270
0320150036	085-10036	BLANCHE UNIT 1H 40993	11,801,733	7,243,364	4,558,369
1020160045	085-10045	LANGFORD UNIT 2H (40687)	7,715,025	1,118,151	6,596,874
1020160046	085-10046	RUFUS UNIT 1H (40510)	8,093,655	1,443,196	6,650,457
0320160060	085-10060	HENDERSHOT UNIT 1H (40642)	8,731,251	3,100,938	5,630,313
0320160082	085-10061	HORNET UNIT 1H (45573)	10,589,234	2,616,106	7,973,128
0320160063	085-10063	HORNET UNIT 2H (45568)	8,263,514	1,842,182	6,421,332
0320160088	085-10088	HENDERSHOT UNIT 2H (40643)	9,880,555	3,536,193	6,344,362
			194,400,979	84,317,207	110,083,772



Clerk of the County Commission

Tracie D. McDonald

Ritchie County Courthouse
115 East Main Street, Room 201
Harrisville, West Virginia

Phone (304) 643-2164

Fax (304) 643-2906

June 14th, 2016

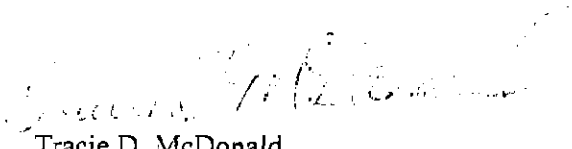
Steptoe & Johnson PLLC
PO Box 1588
Charleston WV 25326

Dear Mr. Griffith

The County Commission of Ritchie County has scheduled their October Board of Appeals on Thursday, October 20th, 2016. You are to appear before them at 11:00 a.m. to discuss your concerns about your real estate taxes.

If I can be of further assistance please contact me at (304) 643-2164 ext. 226.

Please disregard the previous letter.


Tracie D. McDonald
County Clerk



ANTERO RESOURCES
1815 WYNKOOP STREET
DENVER, COLORADO 80202

Page 1 of 1

Vendor Name	Vendor No	Date	Check Number	Check Total
SHERIFF OF RITCHIE COUNTY	28803	Aug-29-2018	137654	\$498,956.14

INV #	INV DATE	DESCRIPTION	AMOUNT	DISCOUNTS	NET AMOUNT
08262016-1	08/26/16	Please see the attached spreadsheet	498,956.14		498,956.14

TOTAL INVOICES PAID

498,956.14 0.00 498,956.14

DETACH AND RETAIN FOR TAX PURPOSES



ANTERO RESOURCES
1815 WYNKOOP STREET
DENVER, COLORADO 80202

Wells Fargo
Denver, CO

Check No. 137554

11-24
412

400 - AP ACCT WELLS FARGO

PAY TO THE ORDER OF
EXACTLY \$498,956dols14cts

Four Hundred Ninety Eight Thousand Nine Hundred Fifty Six Dollars and Fourteen Cents

COPY
NON-NEGOTIABLE

Valid After 90 Days		
CHECK NUMBER	DATE	PAY EXACTLY
137554	Aug-29-2016	\$498,956.14

TO
THE
ORDER
OF

SHERIFF OF RITCHIE COUNTY
115 E MAIN STREET-RM 204
HARRISVILLE, WV 26362



Antero Resources Corporation
Ritchie County, WV
2016 Tax Year
Accounts Included in Tax Bill Payment

County Name	District	Tax Account Number	Tax Ticket	Due Date	Full Year Tax Due	Owner Name
Ritchie	10-Union	00150023	310567	9/1/2016	202,906.82	Antero
Ritchie	10-Union	20159970	310558	9/1/2016	180,689.82	Antero
Ritchie	03-Clay	16010045	310568	9/1/2016	97,754.92	Antero
Ritchie	10-Union	15010063	302117	9/1/2016	9,864.48	Marcellus Roy Int Suspense
Ritchie	10-Union	10010023	312511	9/1/2016	1,461.68	Miner Lora Edith
Ritchie	10-Union	19799966	313526	9/1/2016	1,202.42	Staphens Christine Ann
Ritchie	10-Union	09010019	313596	9/1/2016	439.68	Summerfield AW Hrs
Ritchie	10-Union	20099672	300251	9/1/2016	414.96	Antero Bluestone
Ritchie	10-Union	06010019	313226	9/1/2016	331.02	Sheldon Family
Ritchie	10-Union	20092118	300250	9/1/2016	300.22	Antero Bluestone
Ritchie	10-Union	19949968	312433	9/1/2016	248.82	Matheny John O
Ritchie	10-Union	20099961	313531	9/1/2016	228.86	Stricklin C A
Ritchie	10-Union	05010019	312512	9/1/2016	223.82	Miner Lora Edith
Ritchie	10-Union	20009960	310719	9/1/2016	214.62	Brake Bird Prunty Hrs
Ritchie	10-Union	78009960	313523	9/1/2016	181.14	Stephens Chris Ann
Ritchie	10-Union	09010023	313227	9/1/2016	179.28	Sheldon Family
Ritchie	10-Union	20093918	300252	9/1/2016	166.74	Antero Bluestone
Ritchie	10-Union	19879966	312884	9/1/2016	149.32	Prunty Wilson Hrs
Ritchie	10-Union	90009961	310720	9/1/2016	145.04	Brake Bird Prunty Hrs
Ritchie	10-Union	45009961	313524	9/1/2016	122.42	Stephens Chris Ann
Ritchie	10-Union	20079970	311101	9/1/2016	110.76	Cunningham Audre L
Ritchie	10-Union	14010002	311382	9/1/2016	102.12	Ferrell M A Helrs
Ritchie	10-Union	19779966	313603	9/1/2016	99.54	Summers Richard Oeana
Ritchie	10-Union	19789966	313602	9/1/2016	99.52	Summers Michael David
Ritchie	10-Union	19789966	313602	9/1/2016	99.52	Summers Michael David
Ritchie	10-Union	11010023	312191	9/1/2016	99.50	Kibler Eva Mae
Ritchie	10-Union	20089960	313887	9/1/2016	96.76	Wise Owen Troxil
Ritchie	10-Union	20159960	310507	9/1/2016	89.82	Allstate Energy Corp
Ritchie	10-Union	83009960	312712	9/1/2016	70.80	Nemisis Shrine Masonic
Ritchie	10-Union	20109966	310649	9/1/2016	70.00	Bergerowski Donnita S
Ritchie	10-Union	20109966	310649	9/1/2016	70.00	Bergerowski Donnita S
Ritchie	10-Union	20069961	314019	9/1/2016	65.38	Zinn Earnest E SR
Ritchie	10-Union	20089961	313886	9/1/2016	65.38	Wise Dwen Troxil
Ritchie	10-Union	20149961	310505	9/1/2016	60.72	Allstate Energy Corp
Ritchie	10-Union	19919966	312714	9/1/2016	60.16	Nemisis Shrine Masonic
Ritchie	10-Union	58009961	312713	9/1/2016	47.86	Nemisis Shrine Masonic
Ritchie	10-Union	86009960	312436	9/1/2016	35.78	Matheny O
Ritchie	10-Union	62009961	312435	9/1/2016	24.18	Matheny O
Ritchie	10-Union	20029970	312434	9/1/2016	23.58	Matheny John O
Ritchie	10-Union	96009960	311212	9/1/2016	18.12	Dolles Mery Maxine
Ritchie	10-Union	71009960	314032	9/1/2016	15.98	Zinn James
Ritchie	10-Union	54009961	312883	9/1/2016	14.50	Prunty Wilson Hrs
Ritchie	10-Union	85009961	311213	9/1/2016	12.22	Dolles Mery Maxina
Ritchie	10-Union	26009961	314031	9/1/2016	10.78	Zinn James
Ritchie	10-Union	19939970	313777	9/1/2016	10.40	Welleman April O
Ritchie	10-Union	20139970	310647	9/1/2016	10.40	Bergerowski Donnita S
Ritchie	10-Union	81009960	312885	9/1/2016	10.08	Prunty Wilson Hrs
Ritchie	10-Union	74009960	313895	9/1/2016	8.50	Witham Mary Ellen
Ritchie	10-Union	80009960	313064	9/1/2016	8.50	Roberts Eva Braden
Ritchie	10-Union	19859966	313065	9/1/2016	7.22	Roberts Eva Braden

Antero Resources Corporation
Ritchie County, WV
2016 Tax Year
Accounts Included In Tax Bill Payment

County Name	District	Tax Account Number	Tax Ticket	Due Date	Full Year Tax Due	Owner Name
Ritchie	10-Union	19859966	313065	9/1/2016	7.22	Roberts Eva Braden
Ritchie	10-Union	90009960	312106	9/1/2016	7.10	Junker Pearl Braden
Ritchie	10-Union	95009960	311423	9/1/2016	7.10	Fry May Braden
Ritchie	10-Union	20049960	310543	9/1/2016	7.10	Amos Gillian
Ritchie	03-Clay	70009960	314036	9/1/2016	6.04	Zinn Nancy Louise
Ritchie	10-Union	20009966	311425	9/1/2016	6.00	Fry May Braden
Ritchie	10-Union	20139966	310542	9/1/2016	6.00	Amos Gillian
Ritchie	10-Union	20139966	310542	9/1/2016	6.00	Amos Gillian
Ritchie	10-Union	36009961	313896	9/1/2016	5.74	Witham Mary Ellenor
Ritchie	10-Union	52009961	313066	9/1/2016	5.74	Roberts Eva Braden
Ritchie	10-Union	93009960	311550	9/1/2016	5.34	Hart Michael Jack
Ritchie	10-Union	75009960	313778	9/1/2016	5.04	Wallaman April D
Ritchie	10-Union	73009960	313260	9/1/2016	4.98	Sloter Zane Braden
Ritchie	10-Union	91009960	312105	9/1/2016	4.98	Junker Gary Lee
Ritchie	10-Union	92009960	311879	9/1/2016	4.98	Hollehan Satty Braden
Ritchie	10-Union	98009960	310920	9/1/2016	4.98	Cassell Harrison S JR
Ritchie	10-Union	79009961	311424	9/1/2016	4.78	Fry May Braden
Ritchie	10-Union	20049961	310541	9/1/2016	4.78	Amos Gillian
Ritchie	10-Union	66009961	312108	9/1/2016	4.78	Junkers Pearl Braden
Ritchie	10-Union	47009961	313257	9/1/2016	4.76	Sloter Gay Braden
Ritchie	10-Union	19749966	313889	9/1/2016	4.70	Wiseman Derrell E II
Ritchie	10-Union	19729966	313893	9/1/2016	4.70	Wiseman Paul D
Ritchie	10-Union	19729966	313893	9/1/2016	4.70	Wiseman Paul D
Ritchie	10-Union	72009960	314030	9/1/2016	4.28	Zinn Flex Hrs
Ritchie	10-Union	19989966	312103	9/1/2016	4.22	Junker Gar Lea
Ritchie	10-Union	19989966	312103	9/1/2016	4.22	Junker Gar Lea
Ritchie	10-Union	20069966	310921	9/1/2016	4.22	Cassell Harrison S JR
Ritchie	10-Union	20069966	310921	9/1/2016	4.22	Cassell Harrison S JR
Ritchie	10-Union	23009961	314035	9/1/2016	4.08	Zinn Nancy Louise
Ritchie	10-Union	77009961	311549	9/1/2016	3.60	Hart Michael Jack
Ritchie	10-Union	20019960	310715	9/1/2016	3.54	Braden Nelle G
Ritchie	10-Union	82009961	311271	9/1/2016	3.40	Earhart Harold
Ritchie	10-Union	41009961	313779	9/1/2016	3.40	Wallaman April D
Ritchie	10-Union	20009961	310648	9/1/2016	3.40	Bergerowski Donnita S
Ritchie	10-Union	19009961	314041	9/1/2016	3.40	Zinn Troy R
Ritchie	10-Union	24009961	314034	9/1/2016	3.40	Zinn Marion Day
Ritchie	10-Union	24009961	314034	9/1/2016	3.40	Zinn Marion Day
Ritchie	10-Union	46009961	313258	9/1/2016	3.36	Sloter Zane Braden
Ritchie	10-Union	67009961	312104	9/1/2016	3.36	Junker Gary Lea
Ritchie	10-Union	88009961	310919	9/1/2016	3.36	Cassell Harrison S JR
Ritchie	10-Union	20099966	310716	9/1/2016	3.00	Braden Nelle G
Ritchie	10-Union	27009961	314029	9/1/2016	2.88	Zinn Flex Hrs
Ritchie	10-Union	91009961	310714	9/1/2016	2.38	Braden Nelle G
Ritchie	10-Union	20039961	310544	9/1/2016	1.96	Amos Henry
Ritchie	10-Union	48009961	313240	9/1/2016	1.96	Shutts Mary
Ritchie	10-Union	48009961	313240	9/1/2016	1.96	Shutts Mary
Ritchie	10-Union	39009961	313888	9/1/2016	1.14	Wiseman Darrell E II
Ritchie	10-Union	39009961	313888	9/1/2016	1.14	Wiseman Darrell E II
Ritchie	03-Clay	20129966	310545	9/1/2016	1.00	Amos Henry
Ritchie	10-Union	19829966	313239	9/1/2016	1.00	Shutt Mary

Antero Resources Corporation
 Ritchie County, WV
 2016 Tax Year
 Accounts Included in Tax Bill Payment

County Name	District	Tax Account Number	Tax Ticket	Due Date	Full Year Tax: Due	Owner Name
Ritchie	10-Union	19829966	313239	9/1/2016	1.00	Shutt Mary
Ritchie	10-Union	32009961	314014	9/1/2016	0.90	Zinn Cora
Ritchie	10-Union	32009961	314014	9/1/2016	0.90	Zinn Cora
Ritchie	10-Union	29009961	314020	9/1/2016	0.38	Zinn Earnest E SR
Ritchie	03-Clay	22009961	314037	9/1/2016	0.18	Zinn Stephanie Annette
					498,956.14	



ANTERO RESOURCES
1515 WYNKOOP STREET
DENVER, COLORADO 80202

Page 1 of 1

Vendor Name	Vendor No	Date	Check Number	Check Total	
SHERIFF OF RITCHIE COUNTY	28603	Aug-29-2016	137555	\$434,829.88	
INV #	INV DATE	DESCRIPTION	AMOUNT	DISCOUNTS	NET AMOUNT
08262016-2	08/26/16	Please see the attached spreadsheet	434,829.68		434,829.68

TOTAL INVOICES PAID >>>>

434,829.68 0.00 434,829.68

DETACH AND RETAIN FOR TAX PURPOSES



ANTERO RESOURCES
1515 WYNKOOP STREET
DENVER, COLORADO 80202

Wells Fargo
Denver, CO

Check No. 137555

11-36
412

400 - AP ACC1 WELLS FARGO

PAY TO THE ORDER OF **\$434,829.88**

Four Hundred Thirty Four Thousand Eight Hundred Twenty Nine Dollars and Sixty Eight CENTS

Valid After 90 Days		
CHECK NUMBER	DATE	PAY EXACTLY
137555	Aug-29-2016	\$434,829.88

TO
THE
ORDER
OF

SHERIFF OF RITCHIE COUNTY
115 E MAIN STREET-RM 204
HARRISVILLE, WV 26362

Antero Resources Corporation
Ritchie County, WV
2016 Tax Year
Accounts Included in Tax Bill Payment

County Name	District	Tax Account Number	Tax Ticket	Due Date	Full Year Tax Due	Owner Name
Ritchie	10-Union	20169996	310560	9/1/2016	58,375.62	Antero
Ritchie	10-Union	20159961	310562	9/1/2016	57,470.46	Antero
Ritchie	10-Union	20159978	310557	9/1/2016	42,304.88	Antero
Ritchie		20159999	312426	9/1/2016	29,881.78	Marcellus Roy Int Suspense
Ritchie	03-Clay	15010062	302118	9/1/2016	29,871.00	Marcellus Roy Int Suspense
Ritchie	03-Clay	15010046	312424	9/1/2016	25,912.68	Marcellus Roy Int Suspense
Ritchie	03-Clay	15010027	302113	9/1/2016	24,742.56	Marcellus Roy Int Suspense
Ritchie	10-Union	15010045	312422	9/1/2016	23,710.98	Marcellus Roy Int Suspense
Ritchie	10-Union	15010029	302115	9/1/2016	23,652.48	Marcellus Roy Int Suspense
Ritchie	10-Union	15010088	302116	9/1/2016	22,786.42	Marcellus Roy Int Suspense
Ritchie	10-Union	13010005	312425	9/1/2016	22,086.04	Marcellus Roy Int Suspense
Ritchie	10-Union	15010017	312421	9/1/2018	21,187.62	Marcellus Roy Int Suspense
Ritchie	10-Union	15010060	302114	9/1/2016	20,323.04	Marcellus Roy Int Suspense
Ritchie	10-Union	15010028	302112	9/1/2016	17,199.26	Marcellus Roy Int Suspense
Ritchie	10-Union	20159996	312423	9/1/2016	15,324.88	Marcellus Roy Int Suspense
					<u>434,829.68</u>	

Antero

ANTERO RESOURCES
1815 WYNKOOP STREET
DENVER, COLORADO 80202

Page 1 of 1

Vendor Name	Vendor No.	Date	Check Number	Check Total	
SHERIFF OF RITCHIE COUNTY	28603	Aug-28-2018	137556	\$493,190.46	
INV #	INV DATE	DESCRIPTION	AMOUNT	DISCOUNTS	NET AMOUNT
08262016-3	08/26/16	Please see the attached spreadsheet	493,190.46		493,190.46

TOTAL INVOICES PAID

493,190.46

0.00

493,190.46

DETACH AND RETAIN FOR TAX PURPOSES

Antero

ANTERO RESOURCES
1815 WYNKOOP STREET
DENVER, COLORADO 80202

Wells Fargo
Denver, CO

Check No. 137556

11-24
412

400 - AP ACCT WELLS FARGO

PAY EXACTLY \$493,190.46

Four Hundred Ninety Three Thousand One Hundred Ninety Dollars and Forty Six Cents

COPY
NON-NEGOTIABLE

Valid After 90 Days

CHECK NUMBER	DATE	PAY EXACTLY
137556	AUG-28-2016	\$493,190.46

TO
THE
ORDER
OF

SHERIFF OF RITCHIE COUNTY
115 E MAIN STREET-RM 204
HARRISVILLE, WV 26362

Antero Resources Corporation
 Ritchie County, WV
 2016 Tax Year
 Accounts Included In Tax Bill Payment

County Name	District	Tax Account Number	Tax Ticket	Due Date	Full Year Tax Due	Owner Name
Ritchie	03-Clay	10360036	300248	9/1/2016	152,992.96	Antero
Ritchie	10-Union	16010062	300258	9/1/2016	137,274.60	Antero
Ritchie	03-Clay	16010088	300255	9/1/2016	128,087.56	Antero
Ritchie	10-Union	20159966	310556	9/1/2016	74,835.34	Antero
					<u>493,190.46</u>	



ANTERO RESOURCES
1815 WYNKOOP STREET
DENVER, COLORADO 80202

Page 1 of 1

Vendor Name	Vendor No	Date	Check Number	Check Total	
SHERIFF OF RITCHIE COUNTY	28603	Aug-29-2016	137557	\$491,446.38	
INV #	INV DATE	DESCRIPTION	AMOUNT	DISCOUNTS	NET AMOUNT
08262016-4	08/26/16	Please see the attached spreadsheet	491,446.38	0.00	491,446.38

TOTAL INVOICES PAID

491,446.38

0.00

491,446.38

DETACH AND RETAIN FOR TAX PURPOSES



ANTERO RESOURCES
1815 WYNKOOP STREET
DENVER, COLORADO 80202

Wells Fargo
Denver, CO

Check No. 137557

11-24
413

400 - AP ACCT WELLS FARGO

PAY TO THE ORDER OF
EXACTLY \$491,446.38

Four Hundred Ninety One Thousand Four Hundred Forty Six Dollars and Thirty Eight Cents

COPY
NON-NEGOTIABLE

Valid After 60 Days

CHECK NUMBER	DATE	PAY EXACTLY
137557	Aug-29-2016	\$491,446.38

TO
THE
ORDER
OF

SHERIFF OF RITCHIE COUNTY
115 E MAIN STREET-RM 204
HARRISVILLE, WV 26362

Antero Resources Corporation
 Ritchie County, WV
 2016 Tax Year
 Accounts Included In Tax Bill Payment

County Name	District	Tax Account		Tax Ticket	Tax Year	Due Date	Full Year Tax:		Owner Name
		Number					Due		
Ritchie	10-Union	16010005		310566	2016	9/1/2016	126,691.34	Antero	
Ritchie	03-Clay	16010027		300249	2016	9/1/2016	114,821.02	Antero	
Ritchie	10-Union	16010060		300257	2016	9/1/2016	113,188.46	Antero	
Ritchie	10-Union	16010028		300261	2016	9/1/2016	77,182.52	Antero	
Ritchie	10-Union	00150002		310554	2016	9/1/2016	59,563.04	Antero	
							<u>491,446.38</u>		

Antero

ANTERO RESOURCES
1616 WYNKOOP STREET
DENVER, COLORADO 80202

Page 1 of 1

Vendor Name	Vendor No	Date	Check Num Bt	Check Total
SHERIFF OF RITCHIE COUNTY	28603	Aug-28-2016	137558	\$452,842.84

INV #	INV DATE	DESCRIPTION	AMOUNT	DISCOUNTS	NET AMOUNT
08262016-5	08/26/16	Please see the attached spreadsheet	452,942.84	0.00	452,942.84

TOTAL INVOICES PAID ----->

452,942.84 0.00 452,942.84

DETACH AND RETAIN FOR TAX PURPOSES



ANTERO RESOURCES
1616 WYNKOOP STREET
DENVER, COLORADO 80202

Wells Fargo
Denver, CO

Check No. 137558

11-24
412

400 - AP ACCT WELLS FARGO

EXACTLY \$452,942.84

Four Hundred Fifty Two Thousand Nine Hundred Forty Two Dollars and Eighty Four Cents

COPY
NON-NEGOTIABLE

Valid After 90 Days		
CHECK NUMBER	DATE	PAY EXACTLY
137558	Aug-29-2016	\$452,842.84

TO
THE
ORDER
OF

SHERIFF OF RITCHIE COUNTY
115 E MAIN STREET-RM 204
HARRISVILLE, WV 26362

Antero Resources Corporation
 Ritchie County, WV
 2016 Tax Year
 Accounts Included in Tax Bill Payment

County Name	District	Tax Account Number	Tax Ticket	Due Date	Full Year Tax Due	Owner Name
Ritchie	10-Union	16010046	310564	9/1/2016	104,922.90	Antero
Ritchie	03-Clay	20149960	310559	9/1/2016	88,333.86	Antero
Ritchie	03-Clay	20159963	300253	9/1/2016	87,714.62	Antero
Ritchie	03-Clay	20159964	310563	9/1/2016	86,708.24	Antero
Ritchie	03-Clay	16010017	310555	9/1/2016	85,263.22	Antero
					<u>452,942.84</u>	



ANTERO RESOURCES
1615 WYNKOOP STREET
DENVER, COLORADO 80202

Page 1 of 1

Vendor Name	Vendor No	Date	Check Number	Check Total
SHERIFF OF RITCHIE COUNTY	28603	Aug-29-2016	137559	\$440,297.30

INV #	INV DATE	DESCRIPTION	AMOUNT	DISCOUNTS	NET AMOUNT
08262016-E	08/26/16	Please see the attached spreadsheet	440,297.30	0.00	440,297.30

TOTAL INVOICES PAID →

440,297.30

D.00 440,297.30

DETACH AND RETAIN FOR TAX PURPOSES



ANTERO RESOURCES
1615 WYNKOOP STREET
DENVER, COLORADO 80202

Wells Fargo
Denver, CO

Check No. 137559

11-24
412

400 - AP ACCT WELLS FARGO

PAY TO THE ORDER OF
EXACTLY \$440,297dols30cts

Four Hundred Forty Thousand Two Hundred Ninety Seven Dollars and Thirty Cents

COPY
NON-NEGOTIABLE

Valid After 60 Days

CHECK NUMBER	DATE	PAY EXACTLY
137559	Aug-26-2016	\$440,297.30

TO
THE
ORDER
OF

SHERIFF OF RITCHIE COUNTY
115 E MAIN STREET-RM 204
HARRISVILLE, WV 26362

Antero Resources Corporation
 Ritchie County, WV
 2016 Tax Year
 Accounts Included in Tax Bill Payment

County Name	District	Tax Account Number	Tax Ticket	Due Date	Full Year Tax Due	Owner Name
Ritchie	03-Clay	16010019	310565	9/1/2016	112,912.32	Antero
Ritchie	03-Clay	20169999	310561	9/1/2016	111,007.46	Antero
Ritchie	03-Clay	16010029	300260	9/1/2016	109,252.64	Antero
Ritchie	03-Clay	16010063	300256	9/1/2016	107,124.88	Antero
					440,297.30	

Well Code	NRA Account #	County	API #	Production Start Year	Gas	MCL	Total Gas Receipts	Total Oil Receipts	LOE Expenses	Gas	Oil	Gas	Transportation Expenses	Processing Expenses (Rate 2)	Total Operating Expenses	Operating Expenses as a Percentage of Revenue	State Allowed Operating Expenses	State Allowed Operating Expenses as a % of MCL Receipts	Well Type	
40309	17-000156468	Harrison	47-033-05048	2013	3,142,510	1,45,055	3,142,510	1,45,055	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	Marcellus, Horizontal
40311	09-000156097	Doddridge	47-033-05097	2013	3,142,510	1,45,055	3,142,510	1,45,055	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	Marcellus, Horizontal
40312	17-000156077	Harrison	47-033-05077	2013	3,142,510	1,45,055	3,142,510	1,45,055	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	Marcellus, Horizontal
40324	45-000159963	Bitche	47-085-09963	2013	3,142,510	1,45,055	3,142,510	1,45,055	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	277,163	Marcellus, Horizontal
				Total	12,449,045	5,782,065	18,231,110	5,782,065	1,144,680	1,144,680	1,144,680	1,144,680	1,144,680	1,144,680	1,144,680	1,144,680	1,144,680	1,144,680	1,144,680	

State allowed operating expenses for Marcellus wells are 20% of the value of the production, all with similar natural gas receipts.
Data above shows 4 similar wells. All in their second year of production, all with similar natural gas receipts.
Differences in the data set are whether the well produces NGL and Oil as well as Natural Gas.
Concerns:
Wells that produce oil, even at an immaterial amount, are assigned a lower operating expense than wells that do not, even when natural gas receipts are the same.
The actual operating expense for each well is only 1.8% of the value of the production, however, if you look at the allowed operating expense compared to actual the State's calculation is significantly underestimating operating expense.
The State's calculation will be accurate for the added operating expense incurred in producing NGL receipts.
The case of operating expense coupled with the production of oil and NGL has the well with the highest total receipts receiving the lowest operating expense allowance in the State's calculation. The State's calculation implies that it costs less to operate a well with 25 MCL receipts than it costs to operate a well with 50 MCL receipts.
Once the case is examined, the State's value calculation assumes that the operating expense incurred in year one or year two, or even year three in the exact same number that the company will incur in future years, when the reality is that over 73% of the operating expense is incurred in year one or year two.
The State's calculation doesn't work if you want to put actual operating expenses in the formula. You need to declare the number of use an operating expense that is between the rate cap and actual.



Antero Resources Corporation
2016 Tax Year
State Tax Department's Value Calculation for Well 40234

NATURAL OIL/GAS DEMONSTRATION APPRAISAL.....FLUSH WELL (Year 2)

	DECLINE RATES	2014	GAS INCOME	OIL INCOME		GAS CAP IN	OIL CAP IN
YR 1	58%	WRK INT	\$ 4,317,391	\$ 261,339		\$ 2,566,848	\$ 159,496
YR 2	29%	ROY INT	\$ 663,287	\$ 52,258		\$ 513,644	\$ 31,092
YR3+	23%						

\$ 8,763,169					TY2016 WORKING INT				TY2016 ROYALTY INT				\$ 1,516,202
YEAR	WRK INT INC	WRK COST	NET INC	% FCTR(16.3)	DIS INC	YEAR	ROY INT INC	% FCTR(16.3)	DIS INC				
1	\$ 2,724,344	\$ 141,787	\$ 2,582,577	0.931291	\$ 2,405,131	1	\$ 544,735	0.931291	\$ 507,307				
2	\$ 2,097,746	\$ 141,707	\$ 1,955,978	0.807711	\$ 1,579,865	2	\$ 419,448	0.807711	\$ 338,791				
3	\$ 1,815,284	\$ 141,787	\$ 1,473,497	0.700630	\$ 1,032,229	3	\$ 322,674	0.700630	\$ 226,253				
4	\$ 1,243,753	\$ 141,787	\$ 1,101,966	0.807572	\$ 869,536	4	\$ 246,690	0.807572	\$ 151,097				
5	\$ 997,690	\$ 141,787	\$ 815,923	0.528848	\$ 429,949	5	\$ 191,491	0.528848	\$ 100,806				
6	\$ 737,421	\$ 141,787	\$ 586,654	0.467024	\$ 272,228	6	\$ 147,448	0.467024	\$ 87,387				
7	\$ 567,814	\$ 141,787	\$ 426,048	0.398378	\$ 186,678	7	\$ 113,535	0.398378	\$ 46,003				
8	\$ 437,217	\$ 141,787	\$ 295,450	0.343780	\$ 101,570	8	\$ 87,422	0.343780	\$ 30,054				
9	\$ 336,657	\$ 141,787	\$ 194,860	0.296161	\$ 58,109	9	\$ 87,315	0.296161	\$ 20,071				
10	\$ 259,226	\$ 141,787	\$ 117,459	0.258598	\$ 30,374	10	\$ 51,633	0.258598	\$ 13,404				
11	\$ 199,804	\$ 141,787	\$ 57,837	0.224281	\$ 12,972	11	\$ 39,911	0.224281	\$ 8,951				
12	\$ 153,896	\$ 141,787	\$ 11,928	0.194518	\$ 2,320	12	\$ 30,731	0.194518	\$ 5,678				
13	\$ 118,346	\$ 141,787	\$ -	0.168707	\$ -	13	\$ 23,663	0.168707	\$ -				
14	\$ 91,128	\$ 141,787	\$ -	0.148320	\$ -	14	\$ 16,221	0.148320	\$ -				
15	\$ 70,167	\$ 141,787	\$ -	0.128904	\$ -	15	\$ 14,030	0.128904	\$ -				
16	\$ 54,028	\$ 141,787	\$ -	0.110084	\$ -	16	\$ 10,803	0.110084	\$ -				
17	\$ 41,802	\$ 141,787	\$ -	0.095458	\$ -	17	\$ 8,318	0.095458	\$ -				
18	\$ 32,033	\$ 141,787	\$ -	0.082792	\$ -	18	\$ 6,405	0.082792	\$ -				
19	\$ 24,886	\$ 141,787	\$ -	0.071806	\$ -	19	\$ 4,932	0.071806	\$ -				
20	\$ 18,993	\$ 141,787	\$ -	0.062277	\$ -	20	\$ 3,798	0.062277	\$ -				
21	\$ 14,824	\$ 141,787	\$ -	0.054013	\$ -	21	\$ 2,924	0.054013	\$ -				
22	\$ 11,261	\$ 141,787	\$ -	0.046846	\$ -	22	\$ 2,252	0.046846	\$ -				
23	\$ 8,671	\$ 141,787	\$ -	0.040628	\$ -	23	\$ 1,734	0.040628	\$ -				
24	\$ 6,676	\$ 141,787	\$ -	0.035238	\$ -	24	\$ 1,335	0.035238	\$ -				
25	\$ 5,141	\$ 141,787	\$ -	0.030582	\$ -	25	\$ 1,028	0.030582	\$ -				
26	\$ 3,958	\$ 141,787	\$ -	0.026507	\$ -	26	\$ 792	0.026507	\$ -				
27	\$ 3,048	\$ 141,787	\$ -	0.022869	\$ -	27	\$ 609	0.022869	\$ -				
28	\$ 2,347	\$ 141,787	\$ -	0.019939	\$ -	28	\$ 469	0.019939	\$ -				
29	\$ 1,807	\$ 141,787	\$ -	0.017283	\$ -	29	\$ 381	0.017283	\$ -				
30	\$ 1,392	\$ 141,787	\$ -	0.014998	\$ -	30	\$ 278	0.014998	\$ -				
31	\$ 1,071	\$ 141,787	\$ -	0.013008	\$ -	31	\$ 214	0.013008	\$ -				
32	\$ 825	\$ 141,787	\$ -	0.011282	\$ -	32	\$ 165	0.011282	\$ -				
33	\$ 635	\$ 141,787	\$ -	0.009785	\$ -	33	\$ 127	0.009785	\$ -				
34	\$ 489	\$ 141,787	\$ -	0.008488	\$ -	34	\$ 98	0.008488	\$ -				
35	\$ 377	\$ 141,787	\$ -	0.007360	\$ -	35	\$ 75	0.007360	\$ -				
36	\$ 290	\$ 141,787	\$ -	0.006384	\$ -	36	\$ 58	0.006384	\$ -				
37	\$ 223	\$ 141,787	\$ -	0.005538	\$ -	37	\$ 45	0.005538	\$ -				
38	\$ 172	\$ 141,787	\$ -	0.004802	\$ -	38	\$ 34	0.004802	\$ -				
39	\$ 132	\$ 141,787	\$ -	0.004165	\$ -	39	\$ 26	0.004165	\$ -				
40	\$ 102	\$ 141,787	\$ -	0.003812	\$ -	40	\$ 20	0.003812	\$ -				

WORKING INTEREST APPRAISAL

Assessment Ratio 80.08%
Tax Estimate 0.025

\$ 8,763,169
\$ 4,067,696
\$ 101,447

ROYALTY INTEREST APPRAISAL

\$ 1,516,262
\$ 908,121
\$ 22,728

Craig Griffith

From: Craig Griffith
Sent: Tuesday, November 17, 2015 1:22 PM
To: Amburgey, Jeff A; Hoover, Cindi R
Cc: Nancy Sitton; Megan K. Lusby; Kirsten Evans; Todd Workman
Subject: Antero Materials
Attachments: Antero WV Operating Expenses 11.17.15.xlsx; Antero POAs 11-16-15 - Signed.pdf

Jeff and Cindi,

Attached are the materials for Antero that we'd like to discuss on today's 3:30 cali, and at next week's face to face meeting. Look forward to talking with you.

Craig Griffith

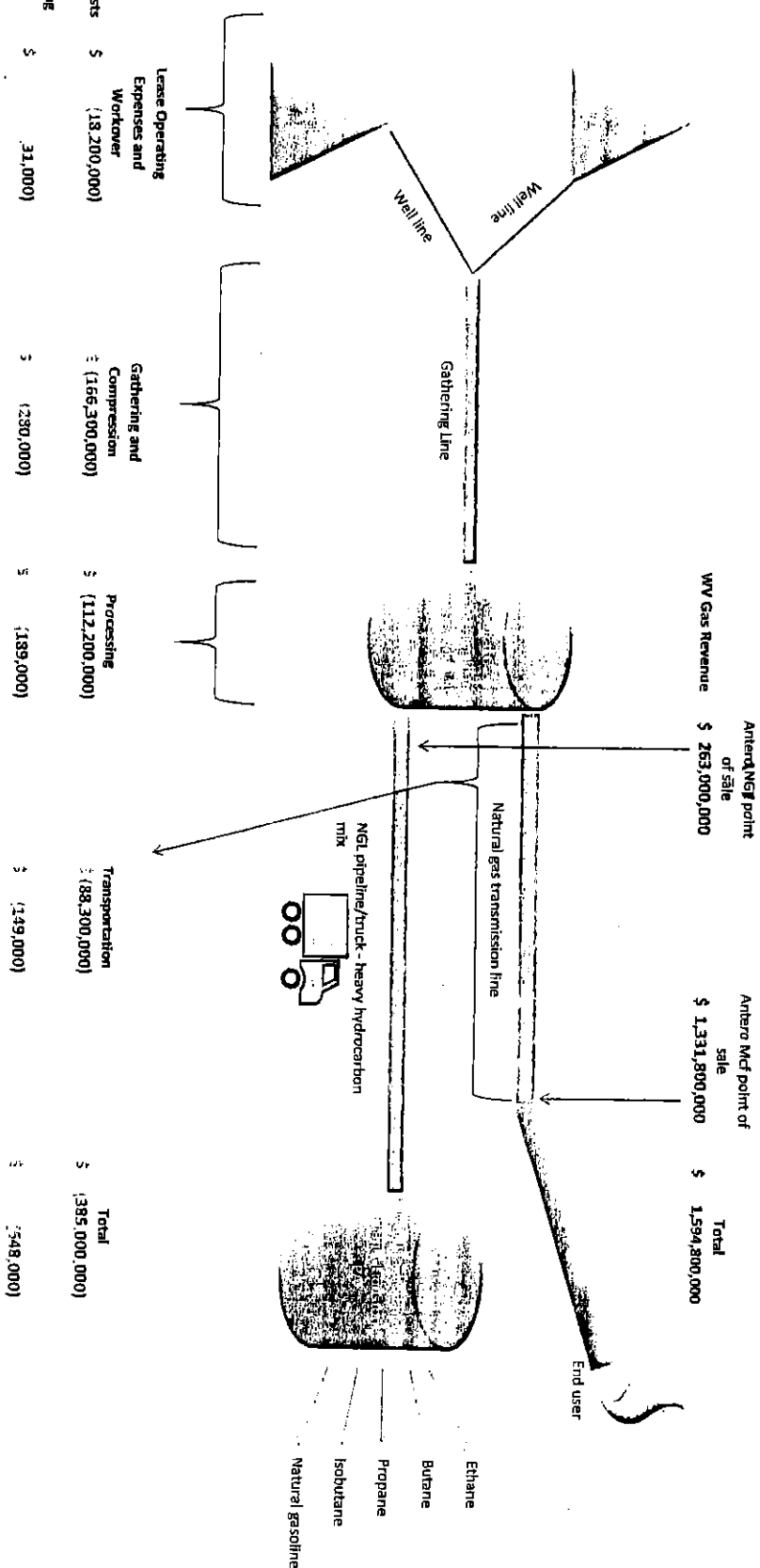
Member

Stephoe & Johnson PLLC
P.O. Box 1588, Charleston, WV 25326-1588
Overnight
Chase Tower, 8th Floor
707 Virginia Street, East, Charleston, WV 25301
O: 304-353-8190 F: 304-353-8180 C: 304-376-6526

Craig.Griffith@Stephoe-Johnson.com
www.stephoe-johnson.com



Antero Resources Corporation
Simple Diagram of Natural Gas Sales Including Natural Gas Liquid Processing & Fractionation
2014 (rounded)



Note: All of the amounts are based on the original TY2016 WV Oil and Gas Return and do not contemplate annualization for new wells. The average operating cost per well is a straight average cost based on the producing wells reported on the TY2016 WV Oil and Gas Return for Antero.

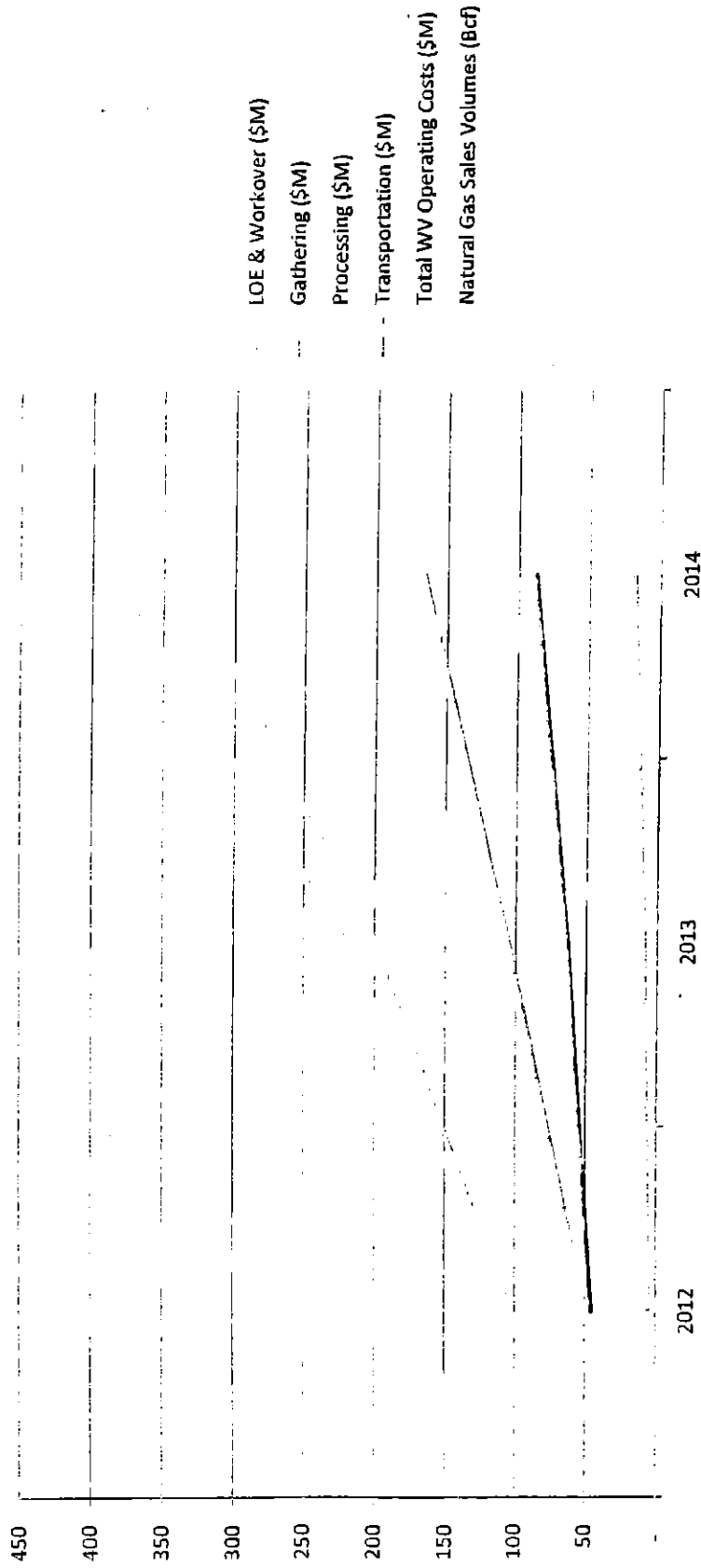
Antero Resources Corporation
2014 West Virginia Operating Expenses By Account

Stage	Expense	Acct #	Account Name	2014 WV Operating Expenses	Notes
Pre-Processing	LOE & Workover	400 500 010	LOE SURVEYS, PERMITS, ROW	282,878	
Pre-Processing	LOE & Workover	400 500 020	LOE COMPRESSOR RENTAL	17,485	
Pre-Processing	LOE & Workover	400 500 030	LOE COMPRESSOR SUPPLIES	(15,126)	
Pre-Processing	LOE & Workover	400 500 040	LOE ELECTRICITY	69,555	
Pre-Processing	LOE & Workover	400 500 060	LOE SICKLINE / WIRELINE SVCS	3,233	
Pre-Processing	LOE & Workover	400 500 090	LOE COMPANY LABOR - GENERAL	1,477,979	
Pre-Processing	LOE & Workover	400 500 100	LOE CONTRACT PUMPING	954,529	
Pre-Processing	LOE & Workover	400 500 110	LOE WELL SERVICING	1,339	
Pre-Processing	LOE & Workover	400 500 120	LOE CONTRACT SVCS / LABOR	2,536,718	
Pre-Processing	LOE & Workover	400 500 130	LOE CONTRACT SUPERVISION	10,318	
Pre-Processing	LOE & Workover	400 500 140	LOE COMPANY LABOR PUMPER	11,569	
Pre-Processing	LOE & Workover	400 500 150	LOE COMPANY ROUSTABOUTS	1,596	
Pre-Processing	LOE & Workover	400 500 160	LOE COMMUNICATIONS	2,449	
Pre-Processing	LOE & Workover	400 500 170	LOE EQUIPMENT RENTAL	1,010,353	Contains generators, trailers, frac tanks, pumps, cranes, lights, gas monitors, etc. (no vehicles)
Pre-Processing	LOE & Workover	400 500 180	LOE EQUIPMENT - COMPANY	1,377	
Pre-Processing	LOE & Workover	400 500 190	LOE AUTOMATION & INSTRUMENTATION	266,775	
Pre-Processing	LOE & Workover	400 500 200	LOE METERS & ASSEMBLIES	554	
Pre-Processing	LOE & Workover	400 500 210	LOE METER READING, CHARTS, SUPPLIES	3,348	
Pre-Processing	LOE & Workover	400 500 220	LOE METER CALIBRATION / TEST	14,413	
Pre-Processing	LOE & Workover	400 500 250	LOE WATER DISPOSAL / TRUCKING	2,548,524	
Pre-Processing	LOE & Workover	400 500 260	LOE TRANSFER OIL	76,993	
Pre-Processing	LOE & Workover	400 500 280	LOE CONTRACT ENGINEERING SVCS	211,881	
Pre-Processing	LOE & Workover	400 500 310	LOE CONSULTANT & PROFESSIONAL SVCS	204,214	
Pre-Processing	LOE & Workover	400 500 320	LOE PULLING SERVICES	12,628	
Pre-Processing	LOE & Workover	400 500 340	LOE POWER & FUEL	24,624	
Pre-Processing	LOE & Workover	400 500 350	LOE SUPPLIES/MATERIALS	1,156,952	
Pre-Processing	LOE & Workover	400 500 360	LOE TRUCKING & HAULING	1,299,624	
Pre-Processing	LOE & Workover	400 500 370	LOE WELDING SERVICES	19,337	
Pre-Processing	LOE & Workover	400 500 380	LOE CHEMICAL TREATMENT / METHANOL	40,294	
Pre-Processing	LOE & Workover	400 500 390	LOE SWABBING & SOAP STICKS	119,549	
Pre-Processing	LOE & Workover	400 500 410	LOE LOCATION & ROAD MAINTENANCE	2,314,357	
Pre-Processing	LOE & Workover	400 500 450	LOE REPAIRS / SEPARATORS	2,533	
Pre-Processing	LOE & Workover	400 500 470	LOE REPAIRS / WELL AUTOMATION	143	
Pre-Processing	LOE & Workover	400 500 480	LOE REPAIRS / CHEMICAL PUMPS	687	
Pre-Processing	LOE & Workover	400 500 500	LOE REPAIRS / WELLHEADS	1,023	
Pre-Processing	LOE & Workover	400 500 510	LOE REPAIRS / FLOWLINS & VIVS	112,413	
Pre-Processing	LOE & Workover	400 500 520	LOE REPAIRS / PUMPING UNIT	3,354	
Pre-Processing	LOE & Workover	400 500 590	LOE REPAIRS / COMPRESSORS	26,909	
Pre-Processing	LOE & Workover	400 500 600	LOE REPAIRS / OTHER	8,293	
Pre-Processing	LOE & Workover	400 500 620	LOE YARD LSE & SURFACE RENTALS	20,935	

Antero Resources Corporation
2014 West Virginia Operating Expenses by Account

Stage	Expense	Acct #	Account Name	2014 WV Operating Expenses	Notes
Pre-Processing	LOE & Workover	400.500.630	LOE SURFACE PROPERTY DAMAGES	2,867	
Pre-Processing	LOE & Workover	400.500.640	LOE CHEMICALS / OILS / LUBRICANTS	4,379	
Pre-Processing	LOE & Workover	400.500.650	LOE ENVIRONMENTAL SERVICES	2,275,461	
Pre-Processing	LOE & Workover	400.500.660	LOE TANK BATTERY CHARGES	1,996	
Pre-Processing	LOE & Workover	400.500.700	LOE GAS MEASUREMENT & GATHER	698	
Pre-Processing	LOE & Workover	400.500.701	LOE GATH CONTRACT LABOR/SVCS	45,869	
Pre-Processing	LOE & Workover	400.500.702	LOE GATH MAINTENANCE	15,149	
Pre-Processing	LOE & Workover	400.500.710	LOE FIXED RATE OVERHEAD	4,521	
Pre-Processing	LOE & Workover	400.500.760	LOE COMPRESSION CHARGES	2,156	
Pre-Processing	LOE & Workover	400.500.900	LOE MISCELLANEOUS	8,705	
Pre-Processing	LOE & Workover	400.500.999	LOE NON-OP OTHER EXPENSES	8,622	
Pre-Processing	LOE & Workover	400.510.050	WOE CONTRACT LABOR	628,029	
Pre-Processing	LOE & Workover	400.510.170	WOE WATER / FLUID DISPOSAL	27,386	
Pre-Processing	LOE & Workover	400.510.260	WOE TRUCKING / HAULING	59,349	
Pre-Processing	LOE & Workover	400.510.280	WOE RENTAL EQUIPMENT	278,308	
Pre-Processing	LOE & Workover	400.510.290	WOE PARTS / SUPPLIES / CHEMICALS	832	
	LOE & Workover Total			18,220,935	
Pre-Processing	Gathering	400.530.030	GTH GATHERING	98,080,827	Includes Antero and 3rd Party gathering; occurs between the wellhead and the processing plant
Pre-Processing	Gathering	400.530.080	COMPRESSION FEES	68,134,686	Includes Antero and 3rd party compression fees
Pre-Processing	Gathering	400.530.091	Price differential offset	5,098	
Pre-Processing	Gathering	400.530.100	EXTRACTION EXPENSE	128,066	
	Gathering Total			166,348,677	
Processing	Processing	400.530.900	PROCESSING FEES	112,207,134	Processing expenses incurred to get production to marketable point; Related to processing by MarkWest (3rd party) at Sherwood processing plant (West Union, WV)
	Processing Total			112,207,134	
Post-Processing	Transportation	400.530.050	TRANSPORTATION	88,276,282	Third party fees charged for transportation services from the processing plant to the point of sale, often on larger pipeline, such as EQT
	Transportation Total			88,276,282	
	Grand Total			385,053,027	

Antero WV Operating Expenses (in millions of dollars) and Gas Sales Volumes (in Bcf)



Year	Natural Gas Sales Volume (Bcf)	LOE & Workover (\$M)	Gathering (\$M)	Processing (\$M)	Transportation (\$M)	Total WV Operating Costs (\$M)
2012	104	6	50	-	46	102
2013	200	10	106	40	64	219
2014	334	18	166	112	88	385

Craig Griffith

From: Nancy Sitton <nancy.sitton@altusgroup.com>
Sent: Thursday, November 19, 2015 10:56 AM
To: jeff.a.amburgey@wv.gov; Hoover, Cindi R
Cc: Craig Griffith; Kirsten Evans
Subject: Antero Operating Expenses
Attachments: Antero 10K 12.31.14.pdf; Antero Op Exp - Comparison to Form 10-K - 11.19.15.xlsx

Jeff and Cindi,

Thank you again for taking the time to discuss Antero's operating expenses this past Tuesday. You mentioned that you were going to take a look at the Form 10-K before Monday's meeting, so I have attached a comparison of operating expenses per the 10-K vs. reported WV operating expenses. The differences between the two totals and the reports they are based on are noted in the file.

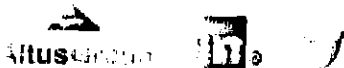
Also, Antero is using Crestwood and Summit Midstream for its third party gathering.

Please let us know if you have any questions about this or the information provided on Tuesday.

Thank you,
Nancy

Nancy Sitton, CPA
Manager, State & Local Tax and Advisory, Altus Group US Inc.

D: 410.568.0771 T: 410.568.0800 ext 3771 M: 703.999.3780 F: 410.568.0801
910 Ridgebrook Road, Suite 200, Sparks, Maryland, 21152 USA



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Antero Resources Corporation
2014 WV Operating Expenses

Expense Type	Total 10-K 2014 (Note 4)		Antero Well Loss Reporting (Note 2)				Total 2014 WV Operating Expenses		
	Oil	WV	PA	Total	WV Non-Producing Wells	WV Non-Operated Wells	WV Fuel Loss	WV Antero Midstream Operating Expenses (Note 4)	
Lease Operating Expenses	5,875,480	18,352,526	268,308	24,496,313	15,095	115,496			
Gathering (Note 5)	101,054,547	432,273,060	540,868	533,868,476	11,208	2,377,600	74,930,009	11,877,849	
Total	106,930,026	450,625,587	809,176	558,364,789	27,303	2,493,096	74,930,009	11,877,849	366,832,093
									385,053,027

Note 1 > Due to a 2-3 month lag time in reporting, the 2014 operating expenses reported on the Form 10-K include an accrual for operating expenses incurred late in 2014 that were not booked prior to year end. Additionally, the operating expenses reported on the Form 10-K have been adjusted to reflect Antero's portion only, so the expenses passed on to other working interest owners have been excluded.

Note 2 > This reporting is based on activity date and reflects actual expenses incurred in 2014. The expense amounts reflect the full invoice amount paid by Antero, so there is no adjustment for cost sharing with other working interest owners. Antero books OIE and gathering costs down to the well level.

Note 3 > This is the cost of the fuel lost between the wellhead and the processing plant to get production to point of sale. The amount paid to Antero by the customer reflects the netting of this lost fuel, however, Antero's book revenue does not (book revenue is grossed up and this is removed as expense). Accordingly, the fuel loss was netted against book revenue for return reporting purposes in order to reflect the amount paid to Antero; also, the fuel loss was excluded from operating expenses so that it was not double counted.

Note 4 > This reflects operating expenses incurred by Antero Midstream related to gathering and compression of Antero's production.

Note 5 > The Form 10-K total and Antero Well Level Reporting totals do not include any gathering service charges from Antero Midstream.

ANTERO RESOURCES CORP

FORM 10-K (Annual Report)

Filed 02/25/15 for the Period Ending 12/31/14

Address 1615 WYNKOOP STREET
DENVER, CO 80202
Telephone 303-357-7325
CIK 0001433270
Symbol AR
SIC Code 1311 - Crude Petroleum and Natural Gas
Fiscal Year 12/31

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

FORM 10 -K

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

For the fiscal year ended December 31, 2014

or

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

Commission File No. 001 -36120

ANTERO RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware
 (State or other jurisdiction of
 incorporation or organization)

80 -0162034
 (IRS Employer
 Identification No.)

161 S Wynkoop Street
 Denver Colorado
 (Address of principal executive offices)

80202
 (Zip Code)

(303) 357 -7310

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Stock, Par Value \$0.01 Per Share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: None.

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☐ Yes ☐ No

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

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

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 ☐

Smaller reporting company ☐

(Do not check if a
 smaller reporting company)

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, was approximately \$3.6 billion.

The registrant had 262,073,239 shares of common stock outstanding as of February 19, 2015.

Documents incorporated by reference: Portions of the registrant's proxy statement for its annual meeting of stockholders to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year end are incorporated by reference into Part III of this Annual Report on Form 10-K.

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CAUTIONARY STATEMENT REGARDING FORWARD -LOOKING STATEMENTS

The information in this report includes "forward -looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this Annual Report on Form 10 -K, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward -looking statements. When used, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward -looking statements, although not all forward -looking statements contain such identifying words. These forward -looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward -looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors" in this Annual Report on Form 10 -K. These forward -looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

Forward -looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- realized natural gas, natural gas liquids ("NGLs"), and oil prices;
- timing and amount of future production of natural gas, NGLs, and oil;
- hedging strategy and results;
- ability to utilize or monetize our firm transportation commitments;
- future drilling plans;
- competition and government regulations;
- pending legal or environmental matters;
- marketing of natural gas, NGLs, and oil;
- leasehold or business acquisitions;
- costs of developing our properties ;
- the operations of Antero Midstream Partners LP;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

We caution you that these forward -looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of natural gas, NGLs, and oil. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, marketing and transportation risks, regulatory changes, the uncertainty inherent in estimating natural gas, NGLs, and oil reserves and in projecting

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future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under the heading "Item 1A. Risk Factors" in this Annual Report on Form 10 -K.

Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs, and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities, or changes in commodity prices, may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, NGLs, and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward -looking statements.

All forward -looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward -looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward -looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report on Form 10 -K.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and gas industry:

"*Basin* ." A large natural depression on the earth's surface in which sediments, generally brought by water, accumulate.

"*Bbl* ." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate, NGLs, or water.

"*Bcf* ." One billion cubic feet of natural gas.

"*Bcfe* ." One billion cubic feet of natural gas equivalent with one barrel of oil, condensate or NGLs converted to six thousand cubic feet of natural gas.

"*Btu* ." British thermal unit.

"*Completion* ." The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"*DD&A* ." Depreciation, depletion, and amortization.

"*Delineation* ." The process of placing a number of wells in various parts of a reservoir to determine its boundaries and production characteristics.

"*Developed acreage* ." The number of acres that are allocated or assignable to productive wells or wells capable of production.

"*Development well* ." A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

"*Dry hole* ." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"*Exploratory well* ." A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

"*Field* ." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"*Formation* ." A layer of rock which has distinct characteristics that differs from nearby rock.

"*Gross acres or gross wells* ." The total acres or wells, as the case may be, in which a working interest is owned.

"*Horizontal drilling* ." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"*MBbl* ." One thousand barrels of crude oil, condensate or NGLs.

"*Mcf* ." One thousand cubic feet of natural gas.

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" *MMBbl* ." One million barrels of crude oil, condensate or NGLs.

" *MMBtu* ." One million British thermal units.

" *MMcf* ." One million cubic feet of natural gas.

" *MMcf/d* ." MMcf per day.

" *MMcfe* ." One million cubic feet of natural gas equivalent with one barrel of oil, condensate or NGLs converted to six thousand cubic feet of natural gas.

" *MMcfe/d* ." MMcfe per day.

" *NGLs* ." Natural gas liquids. Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

" *NYMEX* ." The New York Mercantile Exchange.

" *Net acres* ." The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% working interest in 100 acres owns 50 net acres.

" *Net well* ." The percentage ownership interest in a well that an owner has based on the working interest. An owner who has a 50% working interest has a 0.50 net well.

" *Potential well locations* ." Total gross resource play locations that we may be able to drill on our existing acreage. Actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors.

" *Productive well* ." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

" *Prospect* ." A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

" *Proved developed reserves* ." Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

" *Proved reserves* ." The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

" *Proved undeveloped reserves ("PUD")* ." Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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"PV -10." When used with respect to natural gas and oil reserves, PV -10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development and abandonment costs, using prices and costs in affect at the determination date, before income taxes, and without giving effect to non -property -related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV -10 is not a financial measure calculated in accordance with generally accepted accounting principles ("GAAP") and generally diffars from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include tha effects of income taxes on future net revenues. Neither PV -10 nor Standardized Measure represents an estimate of the fair market value of our natural gss and oil properties. We and others in the industry use PV -10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

"Recompletion." The process of re -entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"Reservoir." A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"Spacing." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40 -acre spacing, or distance between two horizontal well legs, and is often established by regulatory agencies.

"Standardized measure." Discounted future net cash flows estimated by applying year -end prices to the estimated future production of year -end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period -end costs to determine pre -tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre -tax cash inflows over our tax basis in the natural gas and oil properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"Undeveloped acreage." Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas, NGLs, and oil regardless of whether such acreage contains proved reserves.

"Unit." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"Working interest." The right granted to the lessee of a property to explore for and to produce and own natural gas or other minerals. The working interest owners bear the exploration, development, and operating coats on either a cash, penalty, or carried basis.

"WTI." West Texas Intermediate light sweet crude oil.

PART I

Items 1 and 2. Business and Properties

Our Company

Antero Resources Corporation is an independent oil and natural gas company engaged in the exploration, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. As of December 31, 2014, we held approximately 543,000 net acres of oil and gas properties located in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. Our corporate headquarters are in Denver, Colorado.

The following table provides a summary of selected data for our Appalachian Basin natural gas, NGLs, and oil assets as of the date and for the period indicated.

	At December 31, 2014					Three months ended December 31, 2014
	Proved Reserves (Bcfe) ⁽¹⁾	PV-10 (in millions) ⁽²⁾	Net proved developed wells ⁽³⁾	Total net acres ⁽⁴⁾	Gross potential drilling locations	Average net daily production (MMcfe/d)
Appalachian Basin:						
Marcellus Shale	11,918	\$ 9,920	367	395,000	3,191	1,074
Upper Devonian	8	\$ 8	2	—	1,116	—
Deep Utica Shale rights	—	—	—	—	—	—
Utica Shale	757	\$ 1,392	53	148,000	1,024	191
Total	12,683	\$ 11,320	422	543,000	5,331	1,265

- (1) Estimated proved reserve volumes and values were calculated assuming ethane rejection and using the unweighted twelve-month average of the first-day-of-the-month reference prices for the period ended December 31, 2014, which were \$4.07 per MMBtu for natural gas, \$45.89 per Bbl for NGLs and \$81.48 per Bbl for oil for the Appalachian Basin based on a \$94.42 WTI reference price.
- (2) PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to standardized measure, please see "—Our Properties and Operations—Estimated Proved Reserves."
- (3) Does not include certain shallow vertical wells that were acquired in conjunction with leasehold acreage acquisitions.
- (4) Net acres allocable to the Upper Devonian and the deep Utica Shale rights are included in the net acres allocated to the Marcellus Shale, because these multi-horizon shale formations are generally attributable to the same leases.
- (5) See "Item 1A. Risk Factors" for risks and uncertainties related to developing our potential well locations.

Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas and NGLs resource plays to profitably grow our reserves and production, primarily on our existing multi-year project inventory.

We have assembled a portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Marcellus Shale and Utica Shale of the Appalachian Basin. From 2008 through December 31, 2014, our drilling operations in the Appalachian Basin have had a 100% success rate. We have approximately 5,331 potential horizontal well locations on our existing leasehold acreage, both proven and unproven.

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We have secured sufficient long-term firm takeaway capacity on major pipelines that are in existence or currently under construction in each of our core operating areas to accommodate our current development plans.

We operate in the following industry segments: (i) the exploration, development and production of natural gas, NGLs, and oil, (ii) gathering and compression, (iii) fresh water distribution, and (iv) marketing of excess firm transportation capacity. All of our operations are conducted in the United States. Financial information for our industry segment operations is located under "Note 13: Segment Information".

2014 Developments and Highlights

Energy Industry Environment

Recently, global energy commodity prices have declined precipitously as a result of several factors including increased worldwide supplies, a stronger U.S. dollar, relatively mild weather in the U.S., and strong competition among oil producing countries for market share. Specifically, prices for WTI have declined from approximately \$106.00 per Bbl in June 2014 to less than \$50.00 per Bbl in January 2015. Henry Hub natural gas has traded around \$3.00 per MMBtu in January 2015 compared to prices a year ago in January 2014 of around \$4.40 per MMBtu. In response to these market conditions and concerns about access to capital markets, U.S. exploration and development companies have significantly reduced capital spending plans. Our capital budget for 2015 is \$1.8 billion (not including the capital budget of Antero Midstream Partners LP), a 41% reduction from our final 2014 capital budget. We plan to operate an average of 14 drilling rigs in 2015 down from 21 at December 31, 2014 and to complete 130 horizontal Marcellus and Utica wells in 2015, down from 177 in 2014. We believe that our 2015 capital budget will be fully funded through operating cash flow and available borrowing capacity under our revolving credit facility. We will continue to monitor commodity prices and may revise the capital budget if conditions warrant.

Initial Public Offering of Subsidiary

On November 10, 2014, our subsidiary, Antero Midstream Partners LP ("Antero Midstream"), completed its initial public offering ("IPO"). We contributed midstream gathering and compression assets to Antero Midstream as well as rights to develop additional midstream infrastructure to service our growing production. Additionally, Antero Midstream has an option to purchase our fresh water distribution systems at fair market value. A total of 46 million common units representing limited partner interests were sold in the IPO at a price to the public of \$25.00 per common unit. After subtracting underwriting discounts and offering costs, net proceeds received by Antero Midstream were approximately \$1.1 billion. Antero Midstream used approximately \$843 million of the net proceeds to repay indebtedness assumed from us and to reimburse us for certain capital expenditures incurred. Antero Midstream retained \$250 million of the net proceeds for general partnership purposes. After completion of the IPO, we own approximately 69.7% of the outstanding limited partner interests in Antero Midstream and the public owns the remaining 30.3% of the limited partner interests in Antero Midstream.

Reserves, Production, and Financial Results

As of December 31, 2014, our estimated proved reserves were 12.7 Tcfe, consisting of 10.5 Tcf of natural gas, 330 MMBbl of NGLs and 28 MMBbl of oil. As of December 31, 2014, 83% of our estimated proved reserves by volume were natural gas, 16% were NGLs, and 1% was oil. Proved developed reserves were 3.8 Tcfe, or 30% of total proved reserves.

For the year ended December 31, 2014, our production totaled 368 Bcfe, or 1,007 MMcf per day. The 2014 production levels represent a 93% increase over 2013 levels. The average price received for 2014 production before the effects of realized hedge gains was \$4.73 per Mcfe compared to \$4.31 in 2013. The 10% increase was primarily attributable to the increased proportion of NGLs and oil production to total production in 2014 compared to the prior year. Average prices after the effects of cash settled commodity hedges were \$5.10 per Mcfe for 2014 compared to \$5.17 per Mcfe for 2013.

For the year ended December 31, 2014, we generated cash flow from operations of \$998 million, net income of \$674 million, and Adjusted EBITDAX of \$1.2 billion. Net income in 2014 included (i) unrealized hedge gains of \$732 million (i i) a noncash charge of \$112 million for equity-based compensation, (i i i) a noncash tax expense of \$446 million, (i v) a charge of \$20 million for redemption premiums and the write-off of unamortized deferred financing charges and premium associated with the retirement of \$260 million of our 7.25% senior notes due 2019, and (v) income from discontinued operations of \$2 million. See "Item 6. Selected Financial Data" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss).

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2014 Capital Spending and 2015 Capital Budget

For the year ended December 31, 2014, our total capital expenditures were approximately \$4.1 billion, including drilling and completion costs of \$2.5 billion, gathering and compression project costs of \$558 million, fresh water distribution project costs of \$197 million, \$841 million of leasehold costs (including \$415 million of acquisitions and \$426 million on land), and other capital expenditures of \$13 million. Our capital budget for 2015 is \$1.8 billion and includes: \$1.6 billion for drilling and completion; \$50 million for fresh water distribution infrastructure; and \$150 million for core leasehold acreage acquisitions. We do not budget for producing property acquisitions. All of the \$1.6 billion allocated for drilling and completion is allocated to our operated drilling in liquids-rich gas areas. Approximately 60% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 40% is allocated to the Utica Shale. During 2015, we plan to operate an average of nine drilling rigs in the Marcellus Shale and five drilling rigs in the Utica Shale. Additionally, the capital budget for Antero Midstream for 2015 is a range of \$425 million to \$450 million. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, commodity prices, and liquidity.

Hedge Position

At December 31, 2014, we had entered into hedging contracts for January 1, 2015 through December 31, 2020 for 1.758 Tcf of our projected natural gas production at a weighted average index price of \$4.41 per MMBtu, 1.1 million Bbls of oil at a weighted average price of \$64.58 per Bbl, and 352.6 million gallons of propane at a weighted average price of \$0.61 per gallon. These hedging contracts include contracts for the year ending December 31, 2015 of approximately 423.4 Bcf of natural gas at a weighted average index price of \$4.34 per MMBtu, 1.1 million Bbls of oil at a weighted average price of \$64.58 per Bbl, and 352.6 million gallons of propane at a weighted average price of \$0.61 per gallon. We believe this hedge position provides protection to cash flows supporting our future operations and capital spending plans for 2015 through 2020.

Credit Facilities

The current borrowing base under our revolving credit facility is \$4.0 billion and lender commitments are \$4.0 billion. The borrowing base under our revolving credit facility is redetermined semi-annually and is based on the estimated future cash flows from our proved reserves and our hedge positions. The next redetermination is scheduled to occur in October 2015. Our revolving credit facility provides for a maximum availability of \$4.0 billion. At December 31, 2014, we had \$1.73 billion of borrowings and \$387 million of letters of credit outstanding under the revolving credit facility. Our revolving credit facility matures in May 2019. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations—Senior Secured Revolving Credit Facility" for a description of our revolving credit facility.

On November 10, 2014, in connection with the closing of the Antero Midstream IPO, Antero Midstream entered into a revolving credit facility agreement that provides for lender commitments of \$1.0 billion. The facility will mature on November 10, 2019. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations—Midstream Credit Facility" for a description of this revolving credit facility.

Issuance of \$1.1 Billion 5.125% Senior Notes Due 2022

On May 6, 2014, we issued \$600 million of 5.125% senior notes due 2022 (the "2022 notes") at par. Net proceeds from the offering of \$592 million were used to retire the remaining \$260 million principal amount of our 7.25% notes due 2019 and for general corporate purposes, including paying down amounts outstanding under our revolving credit facility and funding our drilling and development program. We incurred a loss on early extinguishment of debt of \$20 million on the retirement of the 7.25% notes. On September 18, 2014, we issued an additional \$500 million of the 2022 notes at 100.5% of par. The net proceeds from the additional issuance of 2022 notes were used to pay down amounts outstanding under our revolving credit facility.

As of December 31, 2014, we had three series of senior notes outstanding totaling \$2.6 billion in aggregate principal amount. The notes have maturity dates ranging from December 1, 2020 to December 1, 2022, and interest rates ranging from 5.125% to 6.00%.

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Our Properties and Operations

Estimated Proved Reserves

The information with respect to our estimated proved reserves presented below has been prepared in accordance with the rules and regulations of the SEC.

Reserves Presentation

The following table summarizes our estimated proved reserves and related standardized measure and PV -10 at December 31, 2012, 2013, and 2014. Our estimated proved reserves are based on evaluations prepared by our internal reserve engineers, which have been audited by our independent engineers, DeGolyer and MacNaughton ("D&M"). We refer to D&M as our independent engineers. A copy of the summary report of D&M with respect to our reserves at December 31, 2014 is filed as Exhibit 99.1 to this Annual Report on Form 10 -K. The information in the following table does not give any effect to or reflect our commodity hedges. Reserves at December 31, 2012 were prepared assuming ethane recovery from our production process, while reserves at December 31, 2013 and 2014 were prepared assuming ethane rejection. When ethane is rejected at the processing plant, it is left in the gas stream and sold with the methane gas.

	At December 31,		
	2012	2013	2014
Estimated proved reserves:			
Proved developed reserves:			
Natural gas (Bcf)	828	1,818	3,285
NGLs (MMBbl)	36	33	80
Oil (MMBbl)	1	2	6
Total equivalent proved developed reserves (Bcfe)	1,047	2,022	3,803
Proved undeveloped reserves:			
Natural gas (Bcf)	2,866	4,936	7,250
NGLs (MMBbl)	167	105	250
Oil (MMBbl)	2	8	22
Total equivalent proved undeveloped reserves (Bcfe)	3,882	5,610	8,880
Total estimated proved reserves (Bcfe)	4,929	7,632	12,683
Proved developed producing (Bcfe)	935	1,771	3,508
Proved developed non-producing (Bcfe)	112	251	295
Percent developed	21 %	27 %	30 %
PV-10 (in millions) ⁽¹⁾	\$1,923	\$5,998	\$11,320
Standardized measure (in millions) ⁽¹⁾	\$1,601	\$4,510	\$ 7,635

- (1) Pre-tax PV -10 was prepared using average yearly prices computed using SEC rules, discounted at 10% per annum, without giving effect to taxes. Pre-tax PV -10 is a non -GAAP financial measure. We believe that the presentation of pre-tax PV -10 is relevant and useful to our investors as supplemental disclosure to the standardized measure of future net cash flows, or after tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, pre-tax PV -10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, pre-tax PV -10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the pre-tax PV -10 amount is the discounted amount of estimated future income taxes. For more information about the calculation of standardized measure, see footnote 18 to our consolidated financial statements included in Item 8 of this Annual Report on Form 10 -K.

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The following sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows before income tax (PV -10), the present value of those net cash flows after income tax (standardized measure) and the prices used in projecting future net cash flows at December 31, 2012 , 2013 , and 2014 :

(In millions, except per Mcf data)	At December 31,		
	2012 ⁽¹⁾	2013 ⁽²⁾	2014 ⁽³⁾
Future net cash flows	\$ 7,221	\$ 18,797	\$ 33,698
Present value of future net cash flows:			
Before income tax (PV-10)	\$ 1,923	\$ 5,998	\$ 11,320
Income taxes	\$ (322)	\$ (1,488)	\$ (3,685)
After income tax (Standardization measure)	\$ 1,601	\$ 4,510	\$ 7,635

- (1) 12 -month average prices used at December 31, 2012 were \$2.78 per MMBtu for natural gas, \$19.61 per Bbl for NGLs, and \$85.05 per Bbl for oil for the Appalachian Basin based on a \$95.05 WTI reference price.
- (2) 12 -month average prices used at December 31, 2013 were \$3.65 per MMBtu for natural gas, \$47.13 per Bbl for NGLs, and \$87.00 per Bbl for oil for the Appalachian Basin based on a \$97.17 WTI reference price.
- (3) 12 -month average prices used at December 31, 2014 were \$4.07 per MMBtu for natural gas, \$45.89 per Bbl for NGLs, and \$81.48 per Bbl for oil for the Appalachian Basin based on a \$94.42 WTI reference price .

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Prices for 2012 , 2013, and 2014 were based on 12 -month unweighted average of the first -day -of -the -month pricing, without escalation. Costs are based on costs in effect for the applicable year without escalation. There can be no assurance that the proved reserves will be produced as estimated or that the prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Changes in Proved Reserves During 2014

The following table summarizes the changes in our estimated proved reserves during 2014 (in Bcfe):

Proved reserves, December 31, 2013	7,632
Extensions, discoveries, and other additions	6,444
Purchase of reserves	29
Performance revisions	361
Revisions due to 5-year development rule	(1,417)
Price revisions	2
Production	(368)
Proved reserves, December 31, 2014	<u>12,683</u>

Extensions, discoveries, and other additions during 2014 of 6,444 Bcfe were added through delineation and developmental drilling in the Marcellus and Utica Shales. Purchases of 29 Bcfe relate to five horizontal producing wells acquired as part of our leasehold acquisition efforts. Performance revisions of 361 Bcfe relate to improved well performance from shorter stage length completions. Downward revisions of 1,417 Bcfe were due to the reclassification of 191 dry gas locations to the probable category because they are no longer expected to be drilled within five years of initial booking. Upward price revisions of 2 Bcfe were due to increases in the reference price for natural gas, partially offset by decreases in the reference prices for NGLs and oil. Our estimated proved reserves as of December 31, 2014 totaled approximately 12.7 Tcfe and increased by 66% over the prior year .

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Proved Undeveloped Reserves

Proved undeveloped reserves are included in the previous table of total proved reserves. The following table summarizes the changes in our estimated proved undeveloped reserves during 2014 (in Bcfe):

Proved undeveloped reserves, December 31, 2013	5,610
Extension, discoveries, and other additions	5,570
Reclassifications to proved developed reserves	(1,112)
Performance revisions	228
Revisions due to 5-year development rule	(1,417)
Price revisions	1
Proved undeveloped reserves, December 31, 2014	<u>8,880</u>

Extensions, discoveries, and other additions during 2014 of 5,570 Bcfe of proved undeveloped reserves were added through delineation and developmental drilling in the Marcellus and Utica Shales. Development drilling resulted in the reclassification of 1,112 Bcfe to proved developed reserves. Performance revisions of 228 Bcfe relate to improved well performance from shorter stage length completions. Downward revisions of 1,417 Bcfe due were due to the reclassification of 191 dry gas wells to the probable category because they are no longer expected to be drilled within five years of initial booking, as our drilling plans are more focused on our liquids-rich acreage. Upward price revisions of 1 Bcfe were due to increases in the reference price for natural gas, partially offset by decreases in the reference prices for NGLs and oil. Proved undeveloped reserves include reserves that are expected to be drilled and developed within five years; wells that are not drilled within five years from booking are reclassified from proved reserves to probable reserves.

During the year ended December 31, 2014, we converted approximately 1,112 Bcfe of proved undeveloped reserves to proved developed reserves at a total capital cost of approximately \$ 991 million. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2014 are approximately \$8.2 billion over the next five years, which we expect to finance through cash flow from operations, borrowings under our revolving credit facility, and other sources of capital financing. Our drilling programs to date have focused on proving our undeveloped leasehold acreage through delineation drilling. While we will continue to drill leasehold delineation wells and build on our current leasehold position, we will also continue drilling our proved undeveloped reserves. All of our proved undeveloped reserves are expected to be developed over the next five years. See "Item 1A. Risk Factors—The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced."

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2012, 2013, and 2014 included in this Annual Report on Form 10-K were prepared by our internal reserve engineers in accordance with petroleum engineering and evaluation standards published by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Our internally prepared reserve estimates were audited by our independent reserve engineers. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering unconventional resources. The technical persons responsible for overseeing the audit of our reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our internal staff of petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserve auditing process. Periodically, our technical team meets with the independent reserve engineers to review properties and discuss methods and assumptions used by us to prepare reserve estimates. Our internally prepared reserve estimates and related reports are reviewed and approved by our Vice President of Reserves, Planning & Midstream, Ward D. McNeilly, and our Vice President of Production, Kevin J. Kilstrom. Mr. McNeilly has been with the Company since October 2010. Mr. McNeilly has 35 years of experience in oil and gas operations, reservoir management, and strategic planning. From 2007 to October 2010 Mr. McNeilly was the Operations Manager for BHP Billiton's Gulf of Mexico operations. From 1996 through 2007, Mr. McNeilly served in various North Sea and Gulf of Mexico Deepwater operations and asset management positions with Amoco and then BP. From 1979 through 1996 Mr. McNeilly served in various domestic and international operations and reservoir and asset management positions with Amoco. Mr. McNeilly holds a B.S. in Geological Engineering from the Mackay School of Mines at the University of Nevada.

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Mr. Kilstrom has served as Vice President of Production since June 2007. Mr. Kilstrom was a Manager of Petroleum Engineering with AGL Energy of Sydney, Australia from 2006 to 2007. Prior to AGL, Mr. Kilstrom was with Marathon Oil as an Engineering Consultant and Asset Manager from 2003 to 2006 and as a Business Unit Manager for Marathon's Powder River coal bed methane assets from 2001 to 2003. Mr. Kilstrom also served as a member of the board of directors of three Marathon subsidiaries from October 2003 through May 2005. Mr. Kilstrom was an operations manager and reserve engineer at Pennaco Energy from 1999 to 2001. Mr. Kilstrom was at Amoco for more than 22 years prior to 1999 where he served in various operating roles with a focus on unconventional resources. Mr. Kilstrom holds a B.S. in Engineering from Iowa State University and an M.B.A. from DePaul University. Our senior management also reviews our reserve estimates and related reports with Mr. McNeilly and Mr. Kilstrom and other members of our technical staff. Additionally, our senior management reviews and approves any significant changes to our proved reserves on a quarterly basis.

Proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, we and the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data, micro-seismic data and well-test data. Probable reserves are reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves which may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by us. Possible reserves are reserves that are less certain to be recovered than probable reserves. Estimates of possible reserves are also inherently imprecise. Estimates of probable and possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

Methodology Used to Apply Reserve Definitions

In the Marcellus Shale, our estimated reserves are based on information from our large, operated proved developed producing reserve base, as well as information from other operators in the area, which can be used to confirm or supplement our internal estimates. Typically, proved undeveloped properties are booked based on applying the estimated lateral length to the average Bcf per 1,000 feet from our proved developed producing wells.

We may attribute up to 11 proved undeveloped locations based on one proved developed producing well where analysis of geologic and engineering data can be estimated with reasonable certainty to be commercially recoverable. However, the ratio of proved undeveloped locations generated will be lower when multiple proved developed wells are drilled on a single pad. In addition, we have applied the concept of a Highly-Developed Area, or HDA, to certain areas of our Marcellus Shale acreage whereby undeveloped properties are booked as proved reserves so long as well count is sufficient for statistical analysis and certain land, geologic, engineering and commercial criteria are met.

Although our operating history in the Utica Shale is more limited than our Marcellus Shale operations, we expect to be able to apply a similar methodology once the well count is sufficient for statistical analysis. The primary differences between the two areas are that (i) we have not established an HDA in the Utica Shale and (ii) each proved developed producing well in the Utica Shale only generates four direct offset well locations in the Utica Shale due to less relative maturity.

Identification of Potential Well Locations

Our identified potential well locations include locations to which proved, probable or possible reserves were attributable based on SEC pricing as of December 31, 2014. We prepare internal estimates of probable and possible reserves but have not included disclosure of such reserves in this report.

Production, Revenues, and Price History

Because natural gas, NGLs, and oil are commodities, the price that we receive for our production is largely a function of market supply and demand. While demand for natural gas in the United States has increased materially since 2000, natural gas and NGLs supplies have also increased significantly as a result of horizontal drilling and fracture stimulation technologies which have

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been used to find and recover large amounts of oil and gas from various shale formations throughout the United States. Demand is impacted by general economic conditions, weather and other seasonal conditions. Over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. The significant commodity price declines in late 2014 and early 2015 are the most recent example of such volatility. A substantial or extended decline in gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of reserves that may be economically produced and our ability to access capital markets. See "Item 1A. Risk Factors—Natural gas, NGLs, and oil prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

The following table sets forth information regarding our production, revenues and realized prices, and production costs from continuing operations in the Appalachian Basin for the years ended December 31, 2012, 2013 and 2014. For additional information on price calculations, see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Continuing Operations Data—Appalachian Basin

	Year ended December 31,		
	2012	2013	2014
Production data:			
Natural gas (Bcf)	87	177	317
NGLs (MBbl)	71	2,123	7,102
Oil (MBbl)	19	226	1,311
Combined (Bcfe)	87	191	368
Daily combined production (MMcfe/d)	239	522	1,007
Average prices before effects of hedges:			
Natural gas (per Mcf)	\$ 2.99	\$ 3.90	\$ 4.10
NGLs (per Bbl)	\$52.07	\$52.61	\$46.23
Oil (per Bbl)	\$80.34	\$91.27	\$81.65
Combined average sales prices before effects of cash settled derivatives (per Mcf) ⁽¹⁾	\$ 3.03	\$ 4.31	\$ 4.73
Combined average sales prices after effects of cash settled derivatives (per Mcf) ⁽¹⁾	\$ 5.08	\$ 5.17	\$ 5.10
Average Costs (per Mcf):			
Lease operating	\$ 0.07	\$ 0.05	\$ 0.08
Gathering, compression, processing, and transportation	\$ 1.04	\$ 1.15	\$ 1.26
Production and ad valorem taxes	\$ 0.23	\$ 0.26	\$ 0.24
Depletion, depreciation, amortization, and accretion	\$ 1.17	\$ 1.23	\$ 1.30
General and administrative (before equity-based compensation)	\$ 0.52	\$ 0.32	\$ 0.28

- (1) Average prices shown reflect both of the before and after effects of our realized commodity hedging transactions. Our calculation of such effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate them as hedges.

Discontinued Operations Data—Arkoma and Piceance Basins

The table above does not include 2012 production of 35 Bcfe or revenue of \$125 million from discontinued operations from the Arkoma and Piceance Basin properties which were sold in 2012. See footnote 3 to the consolidated financial statements included in Item 8 of this Annual Report on Form 10-K for the results of discontinued operations.

Productive Wells

As of December 31, 2014, we had a total of 634 gross (593 net) producing wells, averaging a 93% working interest, in the Marcellus Shale. This well count includes 363 gross (353 net) horizontal wells, and 271 gross and (239 net) shallow vertical wells that were acquired in conjunction with leasehold acreage acquisitions. In the Utica Shale we had 53 gross (44 net) producing

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horizontal wells at December 31, 2014, averaging an 83% working interest. Our wells are gas wells, many of which also produce oil, condensate and NGLs. Additionally, at December 31, 2014 we had 102 gross horizontal wells (93 net) waiting on completion or pipeline connection.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of December 31, 2014. A majority of our developed acreage is subject to liens securing our revolving credit facility. Approximately 50% of our Marcellus acreage and 21% of our Utica acreage is held by production. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table.

Basin	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Marcellus	58,021	56,843	475,776	338,018	533,797	394,861
Utica Shale	12,491	9,439	161,985	138,903	174,476	148,342
Other	—	—	6,609	6,599	6,609	6,599
Total	70,512	66,282	644,370	483,520	714,882	549,802

The following table provides a summary of our current gross and net acreage by county in the Marcellus Shale and the Utica Shale.

County	Marcellus	
	Gross Acres	Net Acres
Doddridge, WV	190,683	135,480
Gilmer, WV	11,887	8,201
Harrison, WV	119,806	101,569
Lewis, WV	89	65
Marion, WV	3,800	3,655
Monongalia, WV	1,649	1,467
Pleasants, WV	4,844	2,604
Ritchie, WV	86,173	62,453
Tyler, WV	78,560	50,293
Wetzel, WV	7,233	3,709
Fayette, PA	7,364	5,423
Greene, PA	974	454
Washington, PA	13,601	12,552
Westmoreland, PA	7,134	6,936
Total Marcellus Shale	533,797	394,861

	Utica	
	Gross Acres	Net Acres
Athens, OH	84	84
Belmont, OH	17,771	16,907
Guernsey, OH	10,342	8,435
Harrison, OH	577	577
Monroe, OH	58,207	53,438
Noble, OH	84,428	66,470
Washington, OH	3,067	2,431
Total Utica Shale	174,476	148,342
Total Marcellus and Utica Shale	708,273	543,203

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Undeveloped Acreage Expirations

The following table sets forth the number of total gross and net undeveloped acres as of December 31, 2014 that will expire over the next three years unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such acreage is extended or renewed.

	Marcellus		Utica		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
2015	31,095	21,383	5,226	3,384	36,321	24,767
2016	16,424	9,644	20,519	13,529	36,943	23,173
2017	65,811	41,427	58,048	50,742	123,859	92,169

Drilling Activity

The following table sets forth the results of our drilling activity for wells drilled and completed during the years ended December 31, 2012, 2013, and 2014. Gross wells reflect the sum of all wells in which we own an interest and includes historical drilling activity in the Appalachian, Arkoma, and Piceance Basins. Net wells reflect the sum of our working interests in gross wells.

	Year ended December 31,					
	2012		2013		2014	
	Gross	Net	Gross	Net	Gross	Net
Marcellus						
Development wells:						
Productive	48	45	49	48	77	76
Dry	—	—	—	—	—	—
Total development wells	48	45	49	48	77	76
Exploratory wells:						
Productive	15	15	63	62	43	42
Dry	—	—	—	—	—	—
Total exploratory wells	15	15	63	62	43	42
Utica						
Development wells:						
Productive	—	—	3	3	11	10
Dry	—	—	—	—	—	—
Total development wells	—	—	3	3	11	10
Exploratory wells:						
Productive	1	1	13	10	23	19
Dry	—	—	—	—	—	—
Total exploratory wells	1	1	13	10	23	19
Arkoma, Piceance, and Other						
Development wells:						
Productive	58	46	—	—	—	—
Dry	—	—	—	—	—	—
Total development wells	58	46	—	—	—	—
Exploratory wells:						
Productive	6	1	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	6	1	—	—	—	—
Total						
Development wells:						
Productive	106	91	52	51	88	86
Dry	—	—	—	—	—	—
Total development wells	106	91	52	51	88	86
Exploratory wells:						
Productive	22	17	76	72	66	61
Dry	—	—	—	—	—	—
Total exploratory wells	22	17	76	72	66	61

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The figures in the table above do not include 102 gross wells (93 net) waiting on completion or pipeline connections at December 31, 2014.

Delivery Commitments

We have entered into various firm sales contracts to deliver and sell gas. We believe we will have sufficient production quantities to meet substantially all of such commitments, but may be required to purchase gas from third parties to satisfy shortfalls should they occur.

As of December 31, 2014 , our firm sales commitments through 2019 included:

Year Ending December 31,	Volume of Natural Gas (Mmcft/d)	Firm Transport Capacity Utilized (MMcft/d)	Volume of Ethane (Bbl/day)
2015	570,000	290,000	—
2016	880,000	650,000	2,900
2017	800,000	670,000	11,500
2018	930,000	810,000	11,500
2019	880,000	780,000	11,500

As provided in the table above, we utilize a part of our firm transportation capacity to deliver gas under the majority of these firm sales contracts. We have firm transportation contracts that require us to deliver products to pipeline transporters or pay demand charges for shortfalls. The minimum demand fees are reflected in our table of contractual obligations. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations." If our production quantities are insufficient to meet such commitments, we may purchase third party products or market our excess firm transportation capacity to third parties.

Midstream Operations

Our exploration and development activities are supported by the natural gas gathering and compression assets of our subsidiary, Antero Midstream, as well as by third -party gathering, compression, processing, and transportation arrangements. Unlike many producing basins in the United States, certain portions of the Appalachian Basin do not have sufficient midstream infrastructure to support the existing and expected increasing levels of production. Our relationship with Antero Midstream allows us to obtain the necessary gathering and compression capacity for our production .

Prior to the Antero Midstream IPO, we committed to developing the necessary midstream infrastructure to support our drilling schedule and production growth. We accomplish this goal through a combination of internal asset developments and contractual relationships with third -party midstream service providers. As part of our internal developments, we invested a significant amount of capital in building low - and high -pressure gathering lines, compressor stations and fresh water pipeline systems. In the past we have monetized certain midstream infrastructure assets for a significant return on investment and redeployed the proceeds into our ongoing operations. In 2014, we spent approximately \$755 million on midstream gas, condensate and fresh water infrastructure.

As of December 31, 2014, our subsidiary, Antero Midstream , owned and operated 153 miles of gas gathering pipelines in the Marcellus Shale. We also have access to additional low -pressure and high -pressure pipelines owned and operated by Crestwood, Energy Transfer Partners L.P. and Summit Midstream. As of December 31, 2014, Antero Midstream owned and operated five compressor stations and utilized 16 additional third -party compressor stations in the Marcellus Shale. The gathering, compression and dehydration services provided by third parties are contracted on a fixed -fee basis.

As of December 31, 2014, Antero Midstream Partners LP owned and operated 96 miles of low -pressure, high -pressure and condensate pipelines in the Utica Shale, and we owned and operated 8 miles of high-pressure pipelines. As of December 31, 2014, we utilized 4 third -party compressor stations in the Utica Shale.

Pursuant to our gathering and compression services agreement with Antero Midstream, we dedicated substantially all of our current and future acreage for gathering and compression services for 20 years. All of our existing acreage is dedicated to Antero Midstream for gathering and compression services except for acreage attributable to third party commitments in effect prior to the

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Antero Midstream IPO, which includes 131,000 Marcellus Shale net leasehold acres characterized by dry gas and liquids rich reserves that have been previously dedicated to third party gatherers. In addition to our existing acreage dedication, the agreement provides that any acreage we acquire in the future will be dedicated to Antero Midstream for gathering and compression services. Antero Midstream also provides condensate gathering services to us under the gathering and compression agreement.

Natural Gas Processing

Many of our wells in the Marcellus and Utica Shales allow us to produce liquids rich natural gas that contains a significant amount of NGLs. Natural gas containing significant amounts of NGLs must be processed, which involves the removal and separation of NGLs from the wellhead natural gas.

NGLs are valuable commodities once removed from the natural gas stream and fractionated into their key components. Fractionation refers to the process by which a NGLs stream is separated into individual NGLs products such as ethane, propane, normal butane, isobutane, and natural gasoline. Fractionation occurs by heating the mixed NGL stream to allow for the separation of the component parts based on the specific boiling points of each product. Each of the individual products have their own market price.

The combination of infrastructure constraints in the Appalachian region and low ethane prices has resulted in many producers "rejecting" rather than "recovering" ethane. Ethane rejection occurs when ethane is left in the wellhead gas stream when the gas is processed, rather than being separated out and sold as a liquid after fractionation. When ethane is left in the gas stream, the Btu content of the residue gas at the tailgate of the processing plant is higher. Producers will elect to "reject" ethane when the price received for the ethane in the gas stream is greater than the net price received for the ethane being sold as a liquid after fractionation. When ethane is recovered, the Btu content of the residue gas is lower, but a producer is then able to recover the value of the ethane sold as a separate product.

Given the existing commodity price environment and the current limited ethane market in the northeast, we are currently rejecting ethane when processing our liquids rich gas. However, we realize a significant pricing upgrade when selling the remaining NGL products stream at current prices. We will elect to recover ethane when ethane prices result in a value for the ethane that is greater than the Btu equivalent residue gas and incremental recovery costs.

Through third-party contractual relationships, we have obtained committed cryogenic processing capacity for our Marcellus and Utica Shale production. For example, we have contracted with MarkWest to provide processing capacity as follows:

	Plant Processing Capacity (MMcf/d)	Contracted Firm Processing Capacity (MMcf/d)	Anticipated Date of Completion
Marcellus Shale:			
Sherwood I	200	200	In service
Sherwood II	200	200	In service
Sherwood III	200	150	In service
Sherwood IV	200	200	In service
Sherwood V	200	200	In service
Sherwood VI	200	200	Second Quarter 2015
Sherwood VII	200	200	Second Quarter 2016
Marcellus Shale Total	1,400	1,350	
Utica Shale:			
Seneca I	200	150	In service
Seneca II ⁽¹⁾	200	50	In service
Seneca III	200	200	In service
Seneca IV	200	200	Second Quarter 2015
Utica Shale Total	800	600	

(1) We have 50 MMcf/d of firm processing capacity at the Seneca II processing facility through the term of our agreement with MarkWest. We have an additional 50 MMcf/d of interim capacity at the Seneca II processing facility until the second quarter of 2015, the Seneca IV in-service date.

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Transportation and Takeaway Capacity

Our primary firm transportation commitments include the following:

- We have entered into firm transportation agreements with various pipelines that enable us to deliver natural gas to the Midwest, Gulf Coast, Eastern Regional, and Mid-Atlantic markets.
- We have several firm transportation contracts with pipelines that have capacity to deliver natural gas to the Chicago and Michigan markets. The Chicago directed pipelines include the Midwestern Gas Transmission pipeline ("MGT"), the Natural Gas Pipeline Company of America pipeline ("NGPL"), and the ANR Pipeline Company pipeline ("ANR-Chicago"), via interconnects with the Rockies Express Pipeline ("REX").
 - The firm transportation contract on REX provides firm capacity for 600,000 MMBtu per day. We have 165,000 MMBtu per day of firm transportation on MGT which will increase by an additional 125,000 MMBtu per day in November 2015. We have 235,000 MMBtu per day of firm transportation on NGPL which will increase by 75,000 MMBtu per day in November 2016. We also have 200,000 MMBtu per day of firm transportation on ANR-Chicago to deliver natural gas to Chicago in the summer and Michigan in the winter. The contracts expire at various dates from 2021 through 2034.
- To access the Gulf Coast market and Eastern Regional market, we have firm transportation contracts with various pipelines. These contracts include firm capacity on the Columbia Gas Transmission pipeline ("TCO"), Columbia Gulf Transmission pipeline ("Columbia Gulf"), Tennessee Gas Pipeline Company pipeline ("Tennessee"), ANR Pipeline Company pipeline ("ANR-Gulf"), and Equitrans pipeline ("EQT"). This diverse portfolio of firm capacity gives us the flexibility to move natural gas to favorably priced markets.
 - We have several firm transportation contracts on TCO for volumes that total to approximately 582,000 MMBtu per day. Of the 582,000 MMBtu per day of firm capacity on TCO, we have the ability to utilize 530,000 MMBtu per day of capacity on Columbia Gulf, which provides access to the Gulf Coast markets. These contracts expire at various dates from 2017 through 2025.
 - We have a firm transportation contract with TCO to transport natural gas in the western and eastern direction on TCO's WB system. The firm transportation contract on TCO's WB system provides firm capacity in the western direction for volumes that increase from 590,000 MMBtu per day in November 2015 to 790,000 MMBtu per day in November 2017. This west directed firm capacity provides access to the Gulf Coast market via the Tennessee pipeline. The transportation contract on TCO's WB system also provides firm capacity in the eastern direction to a purchaser under a firm sales contract at the Loudoun, VA delivery point for ultimate delivery to the Cove Point LNG facility for 330,000 MMBtu per day upon the in-service date of the facility, estimated to be the fourth quarter of 2017. These contracts expire at various dates from 2030 through 2037.
 - We have a firm transportation contract for 600,000 MMBtu per day beginning in April 2015 on ANR-Gulf to deliver natural gas from Ohio to the Gulf Coast markets. This contract expires in 2045.
 - We have a firm transportation contract for 800,000 MMBtu per day estimated to be in-service in late 2016 or early 2017 on the Energy Transfer Rover Pipeline which will connect the Marcellus and Utica Shale assets to Midwest and Gulf Coast markets, or for export to Canadian markets via our existing firm transportation on ANR Chicago and ANR Gulf. This contract expires in 2031.
 - We have firm transportation contracts for volumes that increase from 192,000 MMBtu per day in late 2014 to 250,000 MMBtu per day in July 2015 on EQT to deliver Marcellus natural gas to other various delivery points in the Appalachian Basin. The contracts expire at various dates from 2021 through 2025.
- We have a firm transportation contract for 20,000 Bbl per day on the Enterprise Products Partners ATEX pipeline ("ATEX"), to take ethane from Appalachia to Mont Belvieu, Texas. The ATEX firm transportation commitment expires in 2028.

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- We have firm transportation contracts for 11,500 Bbl per day of ethane and for 50,000 Bbl per day of propane or butane on the Sunoco pipeline (or "Mariner East 2"), from Houston, Pennsylvania to Marcus Hook near Philadelphia, PA. The expected in-service date of Mariner East 2 is late 2016. These contracts expire on the tenth anniversary from the in-service date. The Mariner East 2 provides access to international markets via trans ocean cargo carriers.

Under firm transportation contracts, we are obligated to deliver minimum daily volumes or pay fees for any deficiencies in deliveries. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations" for information on our minimum fees for such contracts. Based on current projected 2015 annual production levels, we estimate that we could incur marketing expense of \$100 million to \$150 million for unused and un-marketed transportation capacity. We continue to actively market any excess capacity in order to offset minimum commitment fees.

Fresh Water Distribution

We own two independent fresh water distribution systems that distribute fresh water from the Ohio River and several regional water sources for well completion operations in the Marcellus and Utica Shales. These systems consist of permanent buried pipelines, movable surface pipelines and fresh water storage facilities, as well as pumping stations to transport the fresh water throughout the pipeline networks. To the extent necessary, we move surface pipelines to well pads for service completion operations in concert with our drilling program. As of December 31, 2014, we have the ability to store a total of 3.5 million barrels of fresh water in 30 impoundments. We believe our water distribution system eliminated over 400,000 water truck trips in our operating areas during 2014.

Due to the extensive geographic distribution of our water pipeline systems in both West Virginia and Ohio, we have provided water delivery services to a neighboring oil and gas producer within and adjacent to our operating area, and are able to provide water delivery services to other oil and gas producers in the area, subject to commercial arrangements, in an effort to further reduce water truck traffic.

As of December 31, 2014 in West Virginia, we owned and operated 103 miles of buried fresh water pipelines that service our drilling activities in the Marcellus Shale, as well as 22 centralized water storage facilities equipped with transfer pumps. As of December 31, 2014 in Ohio, we owned and operated 49 miles of buried fresh water pipelines that service our drilling activities in the Utica Shale, as well as 8 centralized water storage facilities equipped with transfer pumps.

In connection with the Antero Midstream IPO, we granted Antero Midstream an option to purchase our fresh water distribution systems at fair market value.

Major Customers

For the year ended December 31, 2014, sales to South Jersey Resources Group LLC, Sequent Energy Management L.P., and Nextera Energy Powermarketing LLC represented 29%, 16%, and 12% of our total sales, respectively. For the year ended December 31, 2013, sales to South Jersey Resources Group LLC, Sequent Energy Management L.P., and Nextera Energy Powermarketing LLC represented 30%, 14%, and 8% of our total sales, respectively. For the year ended December 31, 2012, sales to South Jersey Resources Group, LLC, Nextera Energy Powermarketing LLC and Dominion Field Services Inc. represented 23%, 13% and 10% of our total sales, respectively. Although a substantial portion of our production is purchased by these major customers, we do not believe the loss of any one or several customers would have a material adverse effect on our business, as we believe other customers or markets would be accessible to us.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, often in the case of undeveloped properties, cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use, or affect the value of, the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;

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- obligations or duties under applicable laws;
- development obligations under natural gas leases; or
- net profits interests.

Seasonality

Demand for natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. Cold winters such as that experienced in 2013 -2014 can significantly increase demand and price fluctuations. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do. Many of these companies not only explore for and produce natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit, and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas properties.

Regulation of the Oil and Natural Gas Industry

General

Our oil and natural gas operations are subject to extensive, and frequently changing, laws and regulations related to the production, transportation and sale of oil, natural gas and NGLs. We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, such laws and regulations are frequently amended or reinterpreted. Additional proposals and proceedings that affect the oil and natural gas industries are regularly considered by Congress, federal agencies, the states, and the courts. We cannot predict when or whether any such proposals may become effective. Therefore, we are unable to predict the future costs or impact of compliance. The regulatory burden on the industry increases the cost of doing business and affects profitability. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Regulation of Production of Natural Gas and Oil

We own interests in properties located onshore in three U.S. states, and our production activities on these properties are subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. These statutes and regulations address requirements related to permits for drilling of wells, bonding to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, the plugging and abandonment of wells, venting or flaring of natural gas, and the ratable or fair apportionment of production from fields and individual wells. In addition, all of the states in which we own and operate properties have regulations governing environmental and conservation matters, including provisions for the handling and disposing or discharge of waste materials, the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, and the size of drilling and spacing units or proration units and the density of wells that may be drilled. Some states also have the power to prorate production to the market demand for oil and gas. The

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effect of these regulations is to limit the amount of natural gas and oil that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas, and NGLs within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Transportation of Natural Gas

The transportation and sale for resale of natural gas in interstate commerce are regulated by the Federal Energy Regulatory Commission, or FERC, under the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or NGPA, and regulations issued under those statutes. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. Although FERC has not made any formal determinations with respect to any of our facilities, we believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Sales of Natural Gas, NGLs, and Oil

The prices at which we sell natural gas, NGLs, and oil is not currently subject to federal regulation and, for the most part, is not subject to state regulation. FERC, however, regulates interstate natural gas transportation rates, and terms and conditions of transportation service, which affects the marketing of the natural gas we produce, as well as the prices we receive for sales of our natural gas. Similarly, the price we receive from the sale of oil and NGLs is affected by the cost of transporting those products to market. FERC regulates the transportation of oil and liquids on interstate pipelines under the provision of the Interstate Commerce Act, the Energy Policy Act of 1992 and regulations issued under those statutes. Intrastate transportation of oil, NGLs, and other products, is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. In addition, while sales by producers of natural gas and all sales of crude oil, condensate, and NGLs can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

With regard to our physical sales of these energy commodities and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC as described below, the U.S. Commodity Futures Trading Commission under Commodity Exchange Act, or CEA, and the Federal Trade Commission, or FTC. We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation. Should we violate the anti-market manipulation laws and regulations, we could be subject to fines and penalties as well as related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

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The Domenici Barton Energy Policy Act of 2005, or EPAAct of 2005 amended the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provided FERC with additional civil penalty authority. In Order No. 670, FERC promulgated rules implementing the anti-market manipulation provision of the EPAAct of 2005, which make it unlawful to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704 described below. Under the EPAAct of 2005, FERC has the power to assess civil penalties of up to \$1,000,000 per day for each violation of the NGA and the NGPA.

Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity. In November 2009, the FTC issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to \$1,000,000 per violation per day. Together with FERC, these agencies have imposed broad rules and regulations prohibiting fraud and manipulation in oil and gas markets and energy futures markets.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

Our natural gas, NGLs, and oil exploration and production operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing occupational safety and health and the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or other regulated activity commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling and completion process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits, establish specific safety and health criteria addressing worker protection and impose substantial liabilities for pollution resulting from operations or failure to comply with applicable laws and regulations. In addition, these laws and regulations may restrict the rate of production.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, also known as the "Superfund" law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain

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classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us as owners under CERCLA. In addition, despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses crude oil and natural gas, we generate materials in the course of our operations that may be regulated as hazardous substances; however, we are unaware of any liabilities for which we may be held responsible that would materially and adversely affect us.

The Resource Conservation and Recovery Act, or RCRA, and analogous state laws, impose detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the U.S. Environmental Protection Agency, or the EPA, or state agencies under RCRA's less stringent nonhazardous solid waste provisions, state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas exploration, development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as waste solvents, laboratory wastes and waste compressor oils that may become regulated as hazardous wastes if such wastes have hazardous characteristics. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or waste pit closure operations to prevent future contamination.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Obtaining permits has the potential to delay the development of natural gas and oil projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. We believe that we maintain all required discharge permits necessary to conduct our operations, and further believe we are in substantial compliance with the terms thereof. We are currently undertaking a review of recently acquired natural gas properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans implementing the physical and operation controls imposed by these plans, the costs of which are not expected to be substantial.

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Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. The EPA has issued final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAP, programs. These rules restrict volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, pneumatic controllers and storage vessels. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of natural gas and oil projects and increase our costs of development and production, which costs could be significant. However, we do not believe that compliance with such requirements will have a material adverse effect on our operations.

Regulation of "Greenhouse Gas" Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish PSD (Prevention of Significant Deterioration) construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. Recently, the EPA finalized modifications to its GHG reporting rules that would require covered entities to report emissions on an individual GHG basis. In addition, the EPA has proposed a rule that would expand the agency's reporting requirements to cover completions and workovers from hydraulically fractured oil wells. These changes to EPA's GHG emissions reporting rule could result in increased compliance costs. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could also adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure

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through a cased and cemented wellbore into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations as does most of the domestic oil and natural gas industry. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act, or the SDWA, over certain hydraulic fracturing activities involving the use of diesel fuels and issued permitting guidance in February 2014 regarding the use of diesel fuels in hydraulic fracturing fluids. Also, in May 2014, the EPA proposed rules under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing.

In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have sought to ban hydraulic fracturing altogether. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and a draft final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review sometime in the first half of 2015. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards sometime in 2015. In addition, the U.S. Department of the Interior published a revised proposed rule in May 2013 that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. Other governmental agencies, including the U.S. Department of Energy have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. In addition, the Obama Administration is expected to release a series of new regulations on the oil and gas industry in 2015, including federal standards limiting methane emissions.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended, or OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations and similar state statutes and regulations require that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the applicable worker health and safety requirements.

Endangered Species Act

The federal Endangered Species Act, or ESA, was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on natural gas and oil leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the northern long-eared bat, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for natural gas and oil development. Moreover, as a result of a settlement, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse

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impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2014, nor do we anticipate that such expenditures will be material in 2015.

Employees

As of December 31, 2014, we had 444 full-time employees, including 48 in executive, finance, treasury and administration, 19 in geology, 168 in production and engineering, 70 in midstream, 87 in land, and 52 in accounting. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We utilize the services of independent contractors to perform various field and other services.

Address, Internet Website and Availability of Public Filings

Our principal executive offices are located at 1615 Wynkoop Street, Denver, Colorado 80202 and our telephone number is (303) 357-7310. Our website is located at www.anteroresources.com.

We furnish or file with the Securities and Exchange Commission (the "SEC") our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, and our Current Reports on Form 8-K. We make these documents available at www.anteroresources.com under the "Investors Relations" link as soon as reasonably practicable after they are filed with the SEC.

Information on our website is not incorporated into this Annual Report on Form 10-K or our other filings with the SEC and is not a part of our other filings.

Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occur, our business, financial condition or results of operations could suffer.

Natural gas, NGLs, and oil prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our natural gas, NGLs, and oil production heavily influence our revenue, profitability, access to capital and future rate of growth. Natural gas, NGLs, and oil are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for natural gas, NGLs and oil;
- the price and quantity of imports of foreign natural gas, including liquefied natural gas;
- political conditions in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the level of global exploration and production;
- the level of global inventories;
- prevailing prices on local price indexes in the areas in which we operate;

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- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Recently, global energy commodity prices have declined precipitously as a result of several factors including increased worldwide supplies, a stronger U.S. dollar, relatively mild weather in the U.S., and strong competition among oil producing countries for market share. Specifically, prices for WTI have declined from approximately \$106.00 per Bbl in June 2014 to less than \$50.00 per Bbl in January 2015. Henry Hub natural gas has traded around \$3.00 per MMBtu in January 2015 compared to prices a year ago in January 2014 of around \$4.40 per MMBtu.

Lower commodity prices reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of natural gas, NGLs and oil that we can produce economically.

If commodity prices further decrease, a significant portion of our exploitation, development and exploration projects could become uneconomic. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our exploitation, development, and exploration projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our natural gas reserves.

The natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the exploitation, development, and acquisition of natural gas reserves. Our cash flow used in investing activities related to capital and exploration expenditures was approximately \$4.1 billion in 2014. Our board of directors has approved a capital budget for 2015 of \$1.8 billion that includes \$1.6 billion for drilling and completion, \$50 million for fresh water distribution and \$150 million for core leasehold acreage acquisitions. Our capital budget excludes acquisitions. We expect to fund these capital expenditures with cash generated by operations and borrowings under our revolving credit facility or capital market transactions; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological, and competitive developments. A further reduction in commodity prices from current levels may result in an additional decrease in our actual capital expenditures, which would negatively impact our ability to grow production. For additional discussion of the risks regarding our ability to obtain funding, please read "Item 1A. Risk Factors – The borrowing base under our revolving credit facility is subject to semi-annual redetermination by our lenders, which could result in a reduction of our borrowing base. This may hinder or prevent us from meeting our future capital needs." The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves; and

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- our ability to borrow under our revolving credit facility, including any potential decrease in the borrowing base.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our revolving credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

Drilling for and producing natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- further or prolonged declines in oil, NGLs, and natural gas prices;
- limitations in the market for oil, NGLs, and natural gas;
- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures or accidents;
- adverse weather conditions, such as blizzards, tornados, hurricanes and ice storms;
- issues related to compliance with environmental regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- limited availability of financing at acceptable terms; and
- title problems.

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

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our revolving credit facility and our senior notes depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a

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level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the senior notes.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance our indebtedness, including the senior notes. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets, including the market for senior unsecured notes, and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including the indentures governing our senior notes, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our revolving credit facility and the indentures governing our senior notes currently restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

The borrowing base under our revolving credit facility may be reduced in light of recent commodity price declines, which could hinder or prevent us from meeting our future capital needs.

The borrowing base under our revolving credit facility is currently \$4.0 billion, and lender commitments under our revolving credit facility are \$4.0 billion. Our borrowing base is redetermined by the lenders twice per year, and the next scheduled borrowing base redetermination is expected to occur in October 2015. Our borrowing base may decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for any other reason. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, we may be unable to meet our obligations as they come due and could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

We are required to pay fees to our service providers based on minimum volumes under long-term contracts regardless of actual volume throughput.

We have various firm transportation and gas processing, gathering and compression service agreements in place, each with minimum volume delivery commitments. Lower commodity prices may lead to reductions in our drilling program, which may result in insufficient production to utilize our full firm transportation capacity. Our firm transportation agreements expire at various dates from 2018 to 2045, and our gas processing, gathering, and compression services agreements expire at various dates from 2016 to 2027. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput. As of December 31, 2014, our long-term contractual obligations under agreements with minimum volume commitments totaled approximately \$16 billion over the term of the contracts. If we have insufficient production to meet the minimum volumes, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing all of which may have a material adverse effect on our results or operations.

Based on current projected 2015 annual production levels, we estimate that we could incur marketing expense of \$100 million to \$150 million for unused and un-marketed transportation capacity.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our revolving credit facility contains a number of significant covenants (in addition to covenants restricting the incurrence of additional indebtedness), including restrictive covenants that may limit our ability to, among other things:

- sell assets;

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- make loans to others;
- make investments;
- enter into mergers;
- make certain payments;
- hedge future production;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The indentures governing our senior notes contain similar restrictive covenants. In addition, our revolving credit facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions, together with those in the indentures governing our senior notes, may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the indentures governing our senior notes and our revolving credit facility impose on us.

Our revolving credit facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine on a semi-annual basis based upon projected revenues from the natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to an increase, then the borrowing base will be the lowest borrowing base acceptable to such lenders. For additional discussion of the risks regarding our ability to obtain funding under our revolving credit facility, please read "Item 1A. Risk Factors – A sustained decline of oil and natural gas prices may affect our ability to obtain funding, obtain funding on acceptable terms or obtain funding under our revolving credit facility. This may hinder or prevent us from meeting our future capital needs."

A breach of any covenant in our revolving credit facility would result in a default under that agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

Currently, we receive significant incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at effective prices consistent with those we have received to date and natural gas prices do not improve, our cash flows may be adversely impacted. Additionally, if development drilling costs increase significantly in the future, our hedged revenues may not be sufficient to cover our costs.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, as of December 31, 2014, we had entered into a number of hedge contracts for approximately 1.8 Tcfe of our projected natural gas, NGLs, and oil production through December 31, 2020. We are currently realizing a significant benefit from these hedge positions. For example, for the years ended December 31, 2013 and 2014, we received approximately \$164 million and \$136 million, respectively, in revenues from cash settled derivatives pursuant to our hedges, which represented approximately 13% and 5%, respectively, of our total revenues for such periods. Many of the hedge agreements that resulted in these realized gains for the years ended December 31, 2013 and 2014 were executed at times when spot and future prices were higher than prices that we are currently able to obtain in the futures market, and the price at which we have been able to hedge future production has decreased as a result. A sustained decrease in commodity prices may adversely affect our ability hedge future production, particularly on a local basis. If we are unable to enter into new hedge contracts in the future at favorable pricing and for a sufficient amount of our production, our financial condition and results of operations could be materially adversely affected.

Additionally, since we hedge a significant part of our estimated future production, we have fixed a significant part of our future revenue stream. For example, for the years ended December 31, 2013 and 2014, approximately 81% and 73%, respectively, of

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our production was covered by our hedge contracts. If development drilling costs increase significantly because of inflation, increased demand for oilfield services, increased costs to comply with regulations governing our industry or other factors, future hedged revenues may not be sufficient to cover our costs.

In certain circumstances we may have to make cash payments under our hedging arrangements and these payments could be significant.

If natural gas or oil prices exceed the price at which we have hedged our commodities, we will be obligated to make cash payments to our hedge counterparties, which could, in certain circumstances, be significant. As of December 31, 2014, we had entered into hedging contracts through December 31, 2020 covering a total of approximately 1.8 Tcfe of our projected natural gas, NGLs, and oil production at a weighted average price of \$4.43 per Mcfe. If we have to post cash collateral to meet our obligations under such arrangements, our cash otherwise available for use in our operations would be reduced.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas, we enter into derivative instrument contracts for a significant portion of our natural gas production, including fixed -price swaps. As of December 31, 2014, we had entered into hedging contracts through December 31, 2020 covering a total of approximately 1.8 Tcfe of our projected natural gas, NGLs, and oil production at an average index price of \$4.43 per MMBtu. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates.

In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for natural gas, which could also have an adverse effect on our financial condition.

Our hedging transactions expose us to counterparty credit risk.

As of December 31, 2014, the estimated fair value of our commodity derivative contracts was approximately \$1.6 billion. Any default by the counterparties to these derivative contracts when they become due would have a material adverse effect on our financial condition and results of operations. The fair value of our commodity derivative contracts at December 31, 2014 includes the following values by bank counterparty: Credit Suisse — \$268 million; Barclays — \$257 million; JP Morgan — \$253 million; BNP Paribas — \$233 million; Citigroup — \$231 million; Wells Fargo — \$211 million; Scotiabank — \$77 million; Fifth Third Bank — \$31 million; Toronto Dominion Bank — \$28 million; Bank of Montreal — \$4 million. The credit ratings of certain of these banks have been downgraded because of the sovereign debt crisis in Europe.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

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Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary.

The process also requires economic assumptions about matters such as natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust our reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated natural gas reserves. We generally base the estimated discounted future net cash flows from our reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Our identified potential well locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill our potential well locations.

Our management team has specifically identified and scheduled certain well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential well locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

As of December 31, 2014, we had 5,331 identified potential horizontal well locations. As a result of the limitations described above, we may be unable to drill many of our potential well locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. For more information on our identified potential well locations, see "Item 1. Business and Properties—Our Properties and Operations—Estimated Proved Reserves—Identification of Potential Well Locations."

Approximately 88% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

Approximately 88% of our net leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. In addition, approximately 50% and 79% of our natural gas leases related to our Marcellus and Utica acreage, respectively, require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

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Our producing properties are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. At December 31, 2014, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

Insufficient processing or takeaway capacity in the Appalachian Basin could cause significant fluctuations in our realized natural gas and NGLs prices.

The Appalachian Basin natural gas and NGLs business environment has historically been characterized by periods during which production has surpassed local processing and takeaway capacity, resulting in substantial discounts in the price received. Although additional Appalachian Basin takeaway capacity has been added in recent periods, we do not believe the existing and expected capacity will be sufficient to keep pace with the increased production caused by recent drilling activity in the area. For example, in the past we have experienced capacity constraints in the Marcellus Shale due to delays in the completion of third -party gathering and compression infrastructure.

If we are unable to secure additional gathering, compression and processing capacity and long -term firm takeaway capacity on major pipelines that are in existence or currently under construction in our core operating area to accommodate our growing production and to manage basis differentials, it could have a material adverse effect on our financial condition and results of operations.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. Leases in the Appalachian Basin are particularly vulnerable to title deficiencies due the long history of land ownership in the area, resulting in extensive and complex chains of title. Additionally, there are claims against us alleging that certain acquired leases that are held by production are invalid due to production from the producing horizons being insufficient to hold title to the formation rights that we have purchased. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we do typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

At December 31, 2014, 70% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 8.9 Tcfe of estimated proved undeveloped reserves will require an estimated \$8.2 billion of development capital over the next five years. Moreover, the development of probable and possible reserves will require additional capital expenditures and such reserves are less certain to be recovered than proved reserves. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV -10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

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If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A writedown constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploitation, development and exploration activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through joint interest receivables (\$116 million at December 31, 2014) and the sale of our natural gas production (\$192 million in receivables at December 31, 2014), which we market to energy marketing companies, end users, and refineries. Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our natural gas receivables with several significant customers. The largest purchaser of our natural gas during the twelve months ended December 31, 2014 purchased approximately 29% of our operated production. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our exploration, development and production activities. These delays, costs and liabilities could arise under a wide range of federal, regional, state and local laws and regulations relating to protection of the environment and worker health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time resulting in longer waiting periods to receive permits and other regulatory approvals. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

For example, in June 2013 and January 2014, we received orders for compliance from federal regulatory agencies, including the EPA, relating to certain of our activities in West Virginia. The orders allege that certain of our operations at several well sites are in non-compliance with certain environmental regulations, such as unpermitted discharges of fill material into wetlands or waters of the United States that are potentially in violation of the Clean Water Act. We have responded to all pending orders and are actively

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cooperating with the relevant agencies. No fine or penalty relating to these matters has been proposed at this time, but the Company believes that these actions will result in monetary sanctions exceeding \$100,000. In addition, we expect to incur additional costs to remediate these well locations in order to bring them into compliance with applicable environmental laws and regulations. We have not, however, been required to suspend our operations at these locations to date and our management team does not expect these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental and worker health and safety impacts of our operations. We have been named from time to time as a defendant in litigation related to such matters. For example, we have been named as the defendant in separate lawsuits in Colorado, West Virginia and Pennsylvania in which the plaintiffs have alleged that our oil and natural gas activities exposed them to hazardous substances and damaged their properties. The plaintiffs have requested unspecified damages and other injunctive or equitable relief. We are not yet able to estimate what our aggregate exposure for monetary or other damages resulting from these or other similar claims might be. Also, new laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be adversely affected.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing natural gas, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting natural gas and oil related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and

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- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

We may be limited in our ability to choose gathering operators and processing and fractionation services providers in our areas of operations pursuant to our agreements with Antero Midstream.

Pursuant to the gas gathering and compression agreement that we have entered into with Antero Midstream, we have dedicated the gathering and compression of all of our current and future natural gas production in West Virginia, Ohio and Pennsylvania to Antero Midstream, so long as such production is not otherwise subject to a pre-existing dedication. Further, pursuant to the right of first offer that we have entered into with Antero Midstream, Antero Midstream has a right to bid to provide certain processing and fractionation services in respect of all of our current and future gas production (as long as it is not subject to a pre-existing dedication) and will be entitled to provide such services if its bid matches or is more favorable to us than terms proposed by other parties. As a result, we will be limited in our ability to use other gathering operators in West Virginia, Ohio and Pennsylvania, even if such operators are able to offer us more favorable pricing or more efficient service. We will also be limited in our ability to use other processing and fractionation services providers in any area to the extent Antero Midstream is able to offer a competitive bid.

Properties that we decide to drill may not yield natural gas or oil in commercially viable quantities.

Properties that we decide to drill that do not yield natural gas or oil in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield natural gas or oil in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether natural gas or oil will be present or, if present, whether natural gas or oil will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a

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disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our revolving credit facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions. Our revolving credit facility and the indentures governing our senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

Market conditions or operational impediments may hinder our access to natural gas, NGLs, and oil markets or delay our production.

Market conditions or the unavailability of satisfactory natural gas, NGLs, and oil transportation arrangements may hinder our access to natural gas, NGLs, and oil markets or delay our production. The availability of a ready market for our natural gas and oil production depends on a number of factors, including the demand for and supply of natural gas, NGLs, and oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas, NGLs, and oil pipelines or gathering system capacity. In addition, if natural gas, NGLs, or oil quality specifications for the third-party natural gas, NGLs, or oil pipelines with which we connect change so as to restrict our ability to transport natural gas, NGLs, or oil, our access to natural gas, NGLs, and oil markets could be impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production and transportation of, natural gas, NGLs, and oil. Failure to comply with such laws and regulations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations.

Changes to existing or new regulations may unfavorably impact us, could result in increased operating costs and have a material adverse effect on our financial condition and results of operations. Such potential regulations could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which could in turn have a material adverse effect on our financial condition, results of operations and cash flows.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel, and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers, and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

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A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. Although the FERC has not made any formal determinations with respect to any of our facilities, we believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC, the courts or Congress.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

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

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. Moreover, the Obama Administration is expected to release a series of new regulations on the oil and gas industry in 2015, including federal standards limiting emissions of methane, a GHG. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations. Recently, the EPA finalized modifications to its GHG reporting rules that would require covered entities to report emissions on an individual GHG basis. In addition, the EPA has proposed a rule that would expand the agency's reporting requirements to cover completions and workovers from hydraulically fractured oil wells. These changes to EPA's GHG emissions reporting rule could result in increased compliance costs.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could also adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

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Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and issued permitting guidance in February 2014 regarding the use of diesel fuels in fracturing fluids. In May 2012, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Furthermore, the EPA has adopted regulations requiring the reduction of volatile organic compound emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing activities. These regulations require the operator to recover rather than vent gas and natural gas liquids that return to the surface during well completion operations. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have sought to ban hydraulic fracturing altogether. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration - wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review sometime in the first half of 2015. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards sometime in the first half of 2015. In addition, the U.S. Department of the Interior published a revised proposed rule in May 2013 that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These activities could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms, and could ultimately make it more difficult or costly for us to perform hydraulic fracturing activities and increase our costs of compliance and doing business.

Competition in the natural gas industry is intense, making it more difficult for us to acquire properties, market natural gas and secure trained personnel.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

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Terrorist or cyber –attacks and threats could have a material adverse effect on our business, financial condition or results of operations.

Terrorist or cyber –attacks may significantly affect the energy industry, including our operations and those of our customers, as well as general economic conditions, consumer confidence and spending and market liquidity. Strategic targets, such as energy –related assets, may be at greater risk of future attacks than other targets in the United States. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel, including Paul M. Rady, our Chairman and Chief Executive Officer, and Glen C. Warren, Jr., our President and Chief Financial Officer, could have a material adverse effect on our business, financial condition and results of operations.

Seasonal weather conditions and regulations related to the protection of wildlife adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Natural gas operations in our operating areas can be adversely affected by seasonal weather conditions and regulations designed to protect various wildlife. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, during 2014, we had estimated average outstanding borrowings under our revolving credit facility of approximately \$1.083 billion, and the impact of a 1.0% increase in interest rates on this amount of indebtedness would result in increased interest expense for that period of approximately \$11 million and a corresponding decrease in our net income before the effects of income taxes. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis.

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Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.

The Fiscal Year 2016 Budget proposed by the President of the United States recommends the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies, and legislation has been introduced in Congress that would implement many of these proposals. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities for oil and gas production; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development, and any such change could negatively affect our financial condition and results of operations.

In May 2014, the Ohio State House passed House Bill 375, which introduced a severance tax on production from horizontally fractured wells at a rate of 2.5 percent of wellhead gross receipts. The Ohio State Senate has yet to consider this proposal. It is unclear whether this or any similar Ohio legislation will be enacted or when such legislation could be made effective.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

In March 2011, we received orders for compliance from federal regulatory agencies, including the EPA, relating to certain of our activities in West Virginia. The orders allege that certain of our operations at several well sites are in non-compliance with certain environmental regulations, such as unpermitted discharges of fill material into wetlands or waters of the United States that are potentially in violation of the Clean Water Act. No fine or penalty relating to these matters has been proposed at this time, but the Company believes that these actions will result in monetary sanctions exceeding \$100,000. We are unable to estimate the total amount of such monetary sanctions or costs to remediate these locations in order to bring them into compliance with applicable environmental laws and regulations. We have not, however, been required to suspend our operations at these locations to date and management does not expect these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

We have been named in separate lawsuits in Colorado, West Virginia, Ohio, and Pennsylvania in which the plaintiffs have alleged that our oil and natural gas activities exposed them to hazardous substances and damaged their properties and their persons. The plaintiffs have requested unspecified damages and other injunctive or equitable relief. We deny as such allegations and intend to vigorously defend ourselves against these actions. We are unable to estimate the amount of monetary damages, if any, that might result from these claims.

We are party to various other legal proceedings and claims in the ordinary course of our business. We believe certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on our consolidated financial position, results of operations or liquidity.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

We have one class of common shares outstanding, our par value \$0.01 per share common stock. Our common stock is traded on the New York Stock Exchange under the symbol "AR". On February 19, 2015, our common stock was held by 3 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

The table below reflects the high and low intraday sales prices per share of the Common Stock on the New York Stock Exchange for each period presented.

	Common Stock	
	High	Low
2014:		
Quarter ended December 31, 2014	\$56.81	\$37.85
Quarter ended September 30, 2014	\$66.10	\$53.42
Quarter ended June 30, 2014	\$67.92	\$56.28
Quarter ended March 31, 2014	\$68.43	\$53.61
2013:		
For the period from October 10, 2013 through December 31, 2013	\$63.57	\$51.56

Prior to our IPO on October 10, 2013, there was no public market for our Common Stock.

Issuer Purchases of Equity Securities

The following table sets forth our share repurchase activity for each period presented:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares that May Yet be Purchased Under the Plan
October 1, 2014 - October 31, 2014	2,060	\$ 51.99	—	N/A
November 1, 2014 - November 30, 2014	255	\$ 52.03	—	N/A
December 1, 2014 - December 31, 2014	671	\$ 41.85	—	N/A

Shares purchased represent shares of our common stock transferred to us in order to satisfy tax withholding obligations incurred upon the vesting of restricted stock and restricted stock units held by our employees.

Dividend Restrictions

Our ability to pay dividends is governed by (i) the provisions of Delaware corporation law, (ii) our Certificate of Incorporation and Bylaws, (iii) indentures related to our 6.00% senior notes due 2020, 5.375% senior notes due 2021, and 5.125% senior notes due 2022, and (iv) our revolving credit facility. We have not paid or declared any dividends on our Common Stock. The future payment of cash dividends on our Common Stock, if any, is within the discretion of the Board of Directors and will depend on our earnings, capital requirements, financial condition, and other relevant factors. There is no assurance that we will pay any cash dividends on our Common Stock. We do not anticipate declaring or paying any cash dividends to holders of our Common Stock in the foreseeable future.

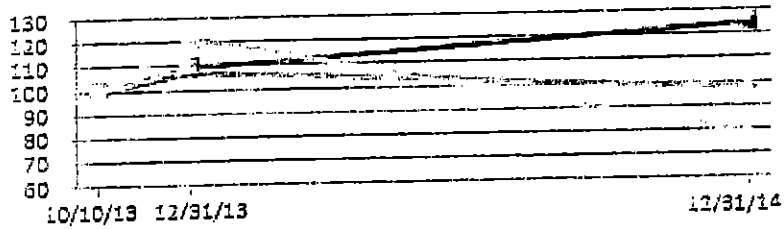
Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of \$100 on October 10, 2013 in each of Antero Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration and Production Index. We believe the Dow Jones

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U.S. Exploration and Production Index is meaningful because it is an independent, objective view of the performance of similarly-sized energy companies.

Comparison of Cumulative Total Returns Among Antero Resources Corporation, the S&P 500 Index, and the Dow Jones US Exploration and Production Index



— Dow Jones US Exploration and Production
- - - Standard & Poors 500
... Antero Resources

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Item 6. Selected Financial Data

The following table shows our selected historical consolidated financial data, for the periods ended and as of the dates indicated, for Antero Resources Corporation and its subsidiaries.

The selected statement of operations data for the years ended December 31, 2012, 2013, and 2014 and the balance sheet data as of December 31, 2013 and 2014 are derived from our audited consolidated financial statements included in Item 8 of this Annual Report on Form 10 -K. The selected statement of operations data for the years ended December 31, 2009 and 2010 and the balance sheet data as of December 31, 2010, 2011, and 2012 are derived from our audited consolidated financial statements not included in Item 8 of this Annual Report on Form 10 -K.

The statement of operations data for all periods presented has been recast to present the results of operations from our Piceance Basin and Arkoma Basin operations in discontinued operations. The losses on the sales of these properties are also included in discontinued operations in 2012, with adjustments in 2013 and 2014 due to the resolution of certain liabilities recorded at the time of the sales and the settlement of final purchase price adjustments. The results from continuing operations reflect our remaining operations in the Appalachian Basin. No part of our general and administrative expenses or interest expense was allocated to discontinued operations.

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The selected financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included elsewhere in this report.

(In thousands, except per share amounts)	Year ended Dec 31,				
	2010	2011	2012	2013	2014
Statement of operations data:					
Operating revenues:	\$ 47,392	195,116	259,743	689,198	1,301,349
Natural gas sales	—	—	3,719	111,663	328,323
NGLs sales	39	173	1,520	20,584	107,080
Oil sales	—	—	—	—	22,075
Gathering, compression, and water distribution	—	—	—	—	33,604
Marketing	77,599	496,064	179,546	491,689	868,201
Commodity derivative fair value gains	—	—	291,190	—	40,000
Gain on sale of assets	125,030	691,353	735,718	1,313,134	2,720,632
Total operating revenues					
Operating expenses:	\$ 1,158	4,608	6,243	9,439	29,341
Lease operating	9,237	37,315	91,094	218,428	461,413
Gathering, compression, processing, and transportation	2,885	11,915	20,210	50,481	87,918
Production and ad valorem taxes	—	—	—	—	103,435
Marketing	2,350	4,034	14,675	22,272	27,893
Exploration	6,076	4,664	12,070	10,928	15,198
Impairment of unproved properties	18,522	55,716	102,026	233,876	477,896
Depletion, depreciation, and amortization	11	76	101	1,065	1,271
Accretion of asset retirement obligations	—	—	—	—	—
General and administrative (including \$365,280 and \$112,252 of equity-based compensation expense in 2013 and 2014, respectively)	24,496	33,342	45,284	425,438	216,533
Loss on sale of compressor station	—	8,700	—	—	—
Total operating expenses	64,735	160,370	291,703	971,927	1,420,898
Operating income	60,293	530,983	444,013	341,207	1,299,734
Other Expenses:	\$ (56,463)	(74,404)	(97,510)	(136,617)	(160,051)
Interest expense	—	—	—	(42,567)	(20,386)
Loss on early extinguishment of debt	(2,677)	(94)	—	—	—
Interest rate derivative fair value losses	(59,140)	(74,498)	(97,510)	(179,184)	(180,437)
Total other expenses	1,155	456,483	346,505	162,023	1,119,297
Income before income taxes and discontinued operations	\$ (939)	(185,297)	(121,229)	(186,210)	(445,672)
Income tax expense	216	271,188	225,276	(24,187)	673,625
Income (loss) from continuing operations					
Discontinued operations:					
Income (loss) from results of operations and sale of discontinued operations, net of income tax	228,412	121,490	(510,345)	5,257	2,210
Net income (loss) and comprehensive income (loss) including noncontrolling interest	228,628	392,678	(285,069)	(18,930)	675,835
Net income and comprehensive income attributable to noncontrolling interest	—	—	—	—	2,248
Net income (loss) attributable to Antero Resources Corporation	\$ 228,628	392,678	(285,069)	(18,930)	673,587
Earnings (loss) per share:					
Continuing operations(1)	\$ —	1.04	0.86	(0.09)	2.56
Discontinued operations(1)	\$ 0.87	0.46	(1.95)	0.02	0.01
Total	\$ 0.87	1.50	(1.09)	(0.07)	2.57
Earnings (loss) per share—assuming dilution:					
Continuing operations(1)	\$ —	1.04	0.86	(0.09)	2.56
Discontinued operations(1)	\$ 0.87	0.46	(1.95)	0.02	0.01
	\$ 0.87	1.50	(1.09)	(0.07)	2.57

- (1) Earnings (loss) from continuing operations per common share from and earnings (loss) from continuing operations per common share—assuming dilution for each of the years in the four year period ended December 31, 2013 were calculated as if the shares issued in the Corporate Reorganization and IPO described in Note 1 were outstanding for the entire period. Earnings (loss) from continuing operations per common share and earnings (loss) from continuing operations per common share—assuming dilution were less than \$0.01 per share for the year ended December 31, 2010.

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(In thousands)	Year ended Dec 31,				
	2010	2011	2012	2013	2014
Balance sheet data (at period end):					
Cash and cash equivalents	\$ 8,988	3,343	18,989	17,487	245,979
Other current assets	147,917	330,299	255,617	316,077	1,006,181
Total current assets	156,905	333,642	274,606	333,564	1,252,160
Natural gas properties, at cost (successful efforts method):					
Unproved properties	737,358	834,255	1,243,237	1,513,136	2,060,936
Producing properties	1,762,206	2,497,306	1,682,297	3,621,672	6,515,221
Fresh water distribution systems	—	—	6,835	231,684	421,012
Gathering systems and facilities	85,404	142,241	168,930	584,626	1,197,239
Other property and equipment	5,975	8,314	9,517	15,757	37,687
	2,590,943	3,482,116	3,110,816	5,966,875	10,232,095
Less accumulated depletion, depreciation, and amortization	(431,181)	(601,702)	(173,343)	(407,219)	(879,643)
Property and equipment, net	2,159,762	2,880,414	2,937,473	5,559,656	9,352,452
Other assets	169,620	574,744	406,714	720,361	968,883
Total assets	\$2,486,287	3,788,800	3,618,793	6,613,581	11,573,495
Current liabilities	\$ 152,483	255,058	376,296	622,229	1,155,105
Long-term indebtedness	652,632	1,317,330	1,444,058	2,078,999	4,362,550
Other long-term liabilities	86,185	257,606	124,702	313,693	582,010
Total equity	1,594,987	1,958,806	1,673,737	3,598,660	5,473,830
Total liabilities and equity	\$2,486,287	3,788,800	3,618,793	6,613,581	11,573,495
Other financial data:					
Adjusted EBITDAX from continuing operations	\$ 27,824	160,259	284,710	649,358	1,161,767
Adjusted EBITDAX from discontinued operations	\$ 169,854	180,562	149,605	—	—
Total EBITDAX	\$ 197,678	340,821	434,315	649,358	1,161,767
Net cash provided by operating activities	\$ 127,791	266,307	332,255	534,707	998,121
Net cash used in investing activities	\$ (230,672)	(901,249)	(463,491)	(2,673,592)	(4,089,650)
Net cash provided by financing activities	\$ 101,200	629,297	146,882	2,137,383	3,320,021
Capital expenditures	\$ 390,974	903,422	1,682,549	2,671,573	4,086,568

"Adjusted EBITDAX" is a non-GAAP financial measure that we define as net income (loss) before interest expense, interest income, derivative fair value gains or losses (excluding net cash receipts or payments on derivative instruments included in derivative fair value gains or losses), taxes, impairments, depletion, depreciation, amortization, exploration expense, franchise taxes, equity-based compensation, loss on early extinguishment of debt, and gain or loss on sale of assets. "Adjusted EBITDAX," as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing, and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. Adjusted EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting and by our lenders pursuant to covenants under our revolving credit facility and the indentures governing our senior notes.

There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDAX reported by different companies. The following table represents a reconciliation of our net income (loss) from continuing operations to Adjusted EBITDAX from continuing operations, a reconciliation of our net income (loss) from discontinued operations to Adjusted EBITDAX from

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discontinued operations, and a reconciliation of our total Adjusted EBITDAX to net cash provided by operating activities per our consolidated statements of cash flows, in each case for the periods presented:

(in thousands)	Year ended December 31,				
	2010	2011	2012	2013	2014
Net income (loss) from continuing operations	\$ 216	271,188	225,276	(24,187)	673,625
Commodity derivative fair value gains(1)	(77,599)	(496,064)	(179,546)	(491,689)	(868,201)
Net cash receipts on settled derivative instruments(1)	15,063	49,944	178,491	163,570	135,784
(Gain) loss on sale of assets	—	8,700	(291,190)	—	(40,000)
Interest expense	59,140	74,498	97,510	136,617	160,051
Loss on early extinguishment of debt	—	—	—	42,567	20,386
Income tax expense	939	185,297	121,229	186,210	445,672
Depreciation, depletion, amortization, and accretion	18,533	55,792	102,127	234,941	479,167
Impairment of unproved properties	6,076	4,664	12,070	10,928	15,198
Exploration expense	2,350	4,034	14,675	22,272	27,893
Equity-based compensation expense	—	—	—	365,280	112,252
State franchise taxes and other	3,106	2,206	4,068	2,849	2,188
Less net income attributable to noncontrolling interest	—	—	—	—	2,248
Adjusted EBITDAX from continuing operations	27,824	160,259	284,710	649,358	1,161,767
Net income (loss) from discontinued operations	228,412	(21,490)	(510,345)	5,257	2,210
Commodity derivative fair value gains	(166,685)	(180,130)	(46,358)	—	—
Net cash receipts on settled derivative instruments	58,650	66,654	92,166	—	—
Loss (gain) on sale of assets	(147,559)	—	795,945	(8,506)	(3,564)
Income tax expense (benefit)	29,070	45,155	(272,553)	3,249	1,354
Depreciation, depletion, amortization, and accretion	115,739	115,164	89,124	—	—
Impairment of unproved properties	29,783	6,387	962	—	—
Exploration expense	22,444	5,842	664	—	—
Adjusted EBITDAX from discontinued operations	169,854	180,562	149,605	—	—
Total adjusted EBITDAX	197,678	340,821	434,315	649,358	1,161,767
Interest expense	(59,140)	(74,498)	(97,510)	(136,617)	(160,051)
Exploration expense	(24,794)	(9,876)	(15,339)	(22,272)	(27,893)
Changes in current assets and liabilities	(698)	8,309	9,887	41,914	17,803
Net income attributable to noncontrolling interest	—	—	—	—	2,248
State franchise taxes	(3,106)	(2,206)	(4,068)	(2,849)	(2,188)
Other noncash items	17,851	3,757	4,970	5,173	6,433
Net cash provided by operating activities	\$ 127,791	266,307	332,255	534,707	998,121

- (1) The adjustments for the derivative fair value (gains) losses and net cash received on settled commodity derivative instruments have the effect of adjusting net income (loss) from operations for changes in the fair value of unsettled derivative instruments, which are recognized at the end of each accounting period. As a result, commodity derivative gains and losses are reflected on a cash basis in the calculation of Adjusted EBITDAX for derivatives which settled during the period.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes included elsewhere in this report. The following discussion contains "forward -looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors that could cause actual results to vary from our expectations include changes in natural gas, NGLs and oil prices, the timing of planned capital expenditures, our ability to fund our development programs, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward -looking events discussed may not occur. See "Cautionary Statement Regarding Forward -Looking Statements." Also, see the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors." We do not undertake any obligation to publicly update any forward -looking statements except as otherwise required by applicable law.

In this section, references to "Antero," "Antero Resources," "we," "us," and "our" refer to Antero Resources Corporation and its subsidiaries, unless otherwise indicated or the context otherwise requires.

Our Company

Antero Resources Corporation is an independent oil and natural gas company engaged in the exploitation, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas resource plays to profitably grow our reserves and production, primarily on our existing multi-year project inventory.

We have assembled a portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Marcellus Shale and Utica Shale of the Appalachian Basin. As of December 31, 2014, we held approximately 395,000 net acres in the southwestern core of the Marcellus Shale and approximately 148,000 net acres in the core of the Utica Shale. In addition, we estimate that approximately 191,000 net acres of our Marcellus Shale leasehold are prospective for the slightly shallower Upper Devonian Shale. Finally, we own the deep rights on approximately 171,000 net acres of our Marcellus Shale acreage that we believe is prospective for the dry gas Utica Shale.

As of December 31, 2014, our estimated proved reserves were approximately 12.7 Tcfe, consisting of 10.5 Tcf of natural gas, 330 MMBbl of NGLs, and 28 MMBbl of oil. This represents a 66 % increase from proved reserve volumes at December 31, 2013. These reserve estimates have been prepared by our internal reserve engineers and management and audited by our independent reserve engineers. As of December 31, 2014, we had approximately 5,331 potential horizontal well locations on our existing leasehold acreage, both proven and unproven.

We believe we have secured sufficient long-term firm takeaway capacity on major pipelines that are operating or are currently under construction in each of our core operating areas to accommodate our current development plans.

We operate in the following industry segments: (i) the exploration, development and production of natural gas, NGLs, and oil, (ii) gathering and compression, (iii) fresh water distribution, and (iv) marketing of excess firm transportation capacity. All of our operations are conducted in the United States.

Energy Industry Environment

Recently, global energy commodity prices have declined precipitously as a result of several factors including increased worldwide supplies, a stronger U.S. dollar, relatively mild weather in the U.S., and strong competition among oil producing countries for market share. Specifically, prices for WTI have declined from approximately \$106.00 per Bbl in June 2014 to less than \$50.00 per Bbl in January 2015. Henry Hub natural gas has traded around \$3.00 per MMBtu in January 2015 compared to prices a year ago in January 2014 of around \$4.40 per MMBtu. In response to these market conditions and concerns about access to capital markets, U.S. exploration and development companies have significantly reduced capital spending plans. Our capital budget for 2015 is \$1.8 billion.

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(not including the capital budget of Antero Midstream Partners LP), a 41% reduction from our final 2014 capital budget. We plan to operate an average of 14 drilling rigs in 2015 down from 21 at December 31, 2014 and to complete 130 horizontal Marcellus and Utica wells in 2015, down from 177 in 2014. We believe that our 2015 capital budget will be fully funded through operating cash flow and available borrowing capacity under our revolving credit facility. We will continue to monitor commodity prices and may revise the capital budget if conditions warrant.

Source of Our Revenues

Our revenues are primarily derived from the sale of natural gas and oil production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our production revenues derive entirely from the continental United States. During 2014 our revenues from production were comprised of approximately 75% from the sale of natural gas and 25% from the sale of NGLs and oil. Natural gas, NGLs, and oil prices are inherently volatile and are influenced by many factors outside of our control. All of our production is derived from natural gas wells, some of which also produce NGLs, after processing, and limited quantities of oil. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we use derivative instruments to hedge future sales prices on a significant portion of our production. We currently use fixed-price natural gas, propane, and oil swaps in which we receive a fixed price for future production in exchange for a payment of the variable market price received at the time future production is sold. At the end of each period, we estimate the fair value of these swaps and, because we have not elected hedge accounting, we recognize the changes in the fair value of commodity derivative instruments in earnings at the end of each accounting period. We expect continued volatility in the prices we receive for our production and the fair value of our swaps.

Principal Components of Our Cost Structure

- *Lease operating expenses.* These are the day to day operating costs incurred to maintain production of our natural gas, NGLs, and oil. Such costs include labor-related costs to monitor producing wells, produced water recycling, monitoring, pumping, maintenance, repairs, and workover expenses. Cost levels for these expenses can vary based on supply and demand for oilfield services.
- *Gathering, compression, processing and transportation.* These are costs incurred to bring natural gas, NGLs, and oil to the market. Such costs include the costs to operate and maintain our low- and high-pressure gathering and compression systems as well as fees paid to third parties who operate low- and high-pressure gathering systems that transport our gas. They also include costs to process and extract NGLs from our produced gas and to transport our NGLs and oil to market. We often enter into fixed price long-term contracts that secure transportation and processing capacity which may include minimum volume commitments, the cost for which is included in these expenses to the extent that they are not excess capacity.
- *Production and ad valorem taxes.* Production and ad valorem taxes consist of severance and ad valorem taxes. Severance taxes are paid on produced natural gas, NGLs, and oil based on a percentage of realized prices (not hedged prices) and at fixed per unit rates established by federal, state or local taxing authorities. Ad valorem taxes are paid based on the value of our property and equipment in service.
- *Marketing expenses.* In 2014, we began to purchase and sell third-party natural gas and ethane, and market our excess firm transportation capacity, in order to utilize our excess firm transportation capacity. Marketing costs include firm transportation costs related to capacity contracted for in advance of having sufficient production and infrastructure to fully utilize the capacity and the costs of third-party purchased gas and ethane. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity on major pipelines.
- *Exploration expense.* These are geological and geophysical costs and include seismic costs, costs of unsuccessful exploratory dry holes and costs related to unsuccessful leasing efforts.
- *Impairment of unproved and proved properties.* These costs include unproved property impairment and costs associated with lease expirations. We would also record impairment charges for proved properties if the carrying value were to exceed estimated future cash flows. Through December 31, 2014, we have not recorded any impairment for proved properties.

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- *Depletion, depreciation, and amortization.* Depletion, depreciation, and amortization, or DD&A, includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs, and oil. As a "successful efforts" company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and allocate these costs to each unit of production using the units of production method.
- *General and administrative expense.* These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees, and legal compliance expenses. General and administrative expense also includes noncash equity-based compensation expense. See note 1 to the consolidated financial statements included elsewhere in this report.
- *Interest expense.* We finance a portion of our working capital requirements and acquisitions with borrowings under our revolving credit facility, which has a variable rate of interest based on LIBOR or the prime rate. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. At December 31, 2014 we had a fixed interest rate of 6.00% on our senior notes due 2020 having a principal balance of \$525 million, a fixed interest rate of 5.375% on our senior notes due 2021 having a principal balance of \$1 billion, and a fixed interest rate of 5.125% on our senior notes due 2022 having a principal balance of \$1.1 billion. We expect to continue to incur significant interest expense as we continue to grow.
- *Income tax expense.* We are subject to state and federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs and the deferral of unsettled commodity hedge gains for tax purposes until they are settled in an exchange of cash. We do pay some state income or franchise taxes where state income or franchise taxes are determined on a basis other than income. We have recorded deferred income tax expense to the extent our deferred tax liabilities exceed our deferred tax assets. Our deferred tax assets and liabilities result from temporary differences between tax and financial statement income primarily from derivatives, oil and gas properties, and net operating loss carryforwards. We have generated net operating loss carryforwards that expire at various dates from 2024 through 2034. We recorded valuation allowances for deferred tax assets at December 31, 2014 of approximately \$27 million primarily for state loss carryforwards for which we do not believe we will realize a benefit. The amount of deferred tax assets considered realizable, however, could change in the near term as we generate taxable income or estimates of future taxable income are reduced.

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Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2014

The Company has four operating segments: (1) exploration and production, (2) gathering and compression, (3) fresh water distribution, and (4) marketing. Revenues from the gathering and compression and fresh water distribution operations are primarily derived from intersegment transactions for services provided to our exploration and production operations. Marketing revenues are primarily derived from activities to purchase and sell third-party natural gas and to market excess firm transportation capacity to third parties. Marketing of excess firm transportation capacity began in the second quarter of 2014, and was subsequently determined to be a new reportable segment. Prior to 2013, the Company's gathering and compression and fresh water distribution operations were immaterial and were considered ancillary to the Company's exploration and production activities. The operating results and assets of the Company's reportable segments were as follows for the years ended December 31, 2013 and 2014

Following is an analysis of operating income for the various segments for the years ended December 31, 2013 and 2014:

	Exploration and production	Gathering and compression	Fresh water distribution	Elimination of intersegment transactions	Consolidated total
2013:					
Sales and revenues:					
Third-party	\$ 1,313,134	—	—	—	1,313,134
Intersegment	—	22,363	35,871	(58,234)	—
	<u>\$ 1,313,134</u>	<u>22,363</u>	<u>35,871</u>	<u>(58,234)</u>	<u>1,313,134</u>
Operating expenses:					
Lease operating	\$ 9,439	—	3,843	(3,843)	9,439
Gathering, compression, processing, and transportation	238,712	2,079	—	(22,363)	218,428
Depletion, depreciation, and amortization	219,757	11,346	2,773	—	233,876
General and administrative expense (before equity-based compensation)	50,442	7,193	2,523	—	60,158
Equity-based compensation expense	340,931	15,931	8,418	—	365,280
Other operating expenses	82,787	—	1,959	—	84,746
Total	<u>942,068</u>	<u>36,549</u>	<u>19,516</u>	<u>(26,206)</u>	<u>971,927</u>
Operating income (loss)	<u>\$ 371,066</u>	<u>(14,186)</u>	<u>16,355</u>	<u>(32,028)</u>	<u>341,207</u>

	Exploration and production	Gathering and compression	Fresh water distribution	Marketing	Elimination of intersegment transactions	Consolidated total
2014:						
Sales and revenues:						
Third-party	\$2,644,953	6,810	15,265	53,604	—	2,720,632
Intersegment	195	88,936	156,660	—	(245,791)	—
	<u>\$2,645,148</u>	<u>95,746</u>	<u>171,925</u>	<u>53,604</u>	<u>(245,791)</u>	<u>2,720,632</u>
Operating expenses:						
Lease operating	\$ 28,041	—	34,737	—	(33,437)	29,341
Gathering, compression, processing, and transportation	536,879	13,497	—	—	(88,963)	461,413
Depletion, depreciation, and amortization	424,684	36,972	16,240	—	—	477,896
General and administrative expense (before equity-based compensation)	85,701	13,416	5,332	—	(168)	104,281
Equity-based compensation expense	100,634	8,619	2,999	—	—	112,252
Other operating expenses	128,419	1,973	1,888	103,435	—	235,715
Total	<u>1,304,358</u>	<u>74,477</u>	<u>61,196</u>	<u>103,435</u>	<u>(122,568)</u>	<u>1,420,898</u>
Operating income (loss)	<u>\$1,340,790</u>	<u>21,269</u>	<u>110,729</u>	<u>(49,831)</u>	<u>(123,223)</u>	<u>1,299,734</u>

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The following table sets forth selected operating data for the year ended December 31, 2013 compared to the year ended December 31, 2014:

(In thousands, except per unit and production data)	Year ended December 31,		Amount of Increase (Decrease)	Percent Change
	2013	2014		
Operating revenues:				
Natural gas sales	\$ 689,198	\$ 1,301,349	\$ 612,151	89 %
NGLs sales	111,663	328,323	216,660	194 %
Oil sales	20,584	107,080	86,496	420 %
Gathering, compression, and water distribution	—	22,075	22,075	"
Marketing	—	53,604	53,604	"
Commodity derivative fair value gains	491,689	868,201	376,512	77 %
Gain on sale of gathering system	—	40,000	40,000	"
Total operating revenues	<u>1,313,134</u>	<u>2,720,632</u>	<u>1,407,498</u>	107 %
Operating expenses:				
Lease operating	9,439	29,341	19,902	211 %
Gathering, compression, processing, and transportation	218,428	461,413	242,985	111 %
Production and ad valorem taxes	50,481	87,918	37,437	74 %
Marketing	—	103,435	103,435	"
Exploration	22,272	27,893	5,621	25 %
Impairment of unproved properties	10,928	15,198	4,270	39 %
Depletion, depreciation, and amortization	233,876	477,896	244,020	104 %
Accretion of asset retirement obligations	1,065	1,271	206	19 %
General and administrative (before equity-based compensation)	60,158	104,281	44,123	73 %
Equity-based compensation	365,280	112,252	(253,028)	(69)%
Total operating expenses	<u>971,927</u>	<u>1,420,898</u>	<u>448,971</u>	46 %
Operating income	<u>341,207</u>	<u>1,299,734</u>	<u>958,527</u>	281 %
Other Expenses:				
Interest expense	(136,617)	(160,051)	(23,434)	17 %
Loss on early extinguishment of debt	(42,567)	(20,386)	22,181	(52)%
Total other expenses	<u>(179,184)</u>	<u>(180,437)</u>	<u>(1,253)</u>	1 %
Income from continuing operations before income taxes and discontinued operations	162,023	1,119,297	957,274	591 %
Income tax expense	<u>(186,210)</u>	<u>(445,672)</u>	<u>(259,462)</u>	139 %
Income (loss) from continuing operations	(24,187)	673,625	697,812	"
Income from discontinued operations	5,257	2,210	(3,047)	(58)%
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(18,930)	675,835	694,765	"
Net income and comprehensive income attributable to noncontrolling interest	—	2,248	2,248	"
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	<u>\$ (18,930)</u>	<u>\$ 673,587</u>	<u>\$ 692,517</u>	"
Adjusted EBITDAX (1)	<u>\$ 649,358</u>	<u>\$ 1,161,767</u>	<u>\$ 512,409</u>	79 %

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(in thousands, except per unit and production data)	Year ended December 31,		Amount of Increase (Decrease)	Percent Change
	2013	2014		
Production data:				
Natural gas (Bcf)	177	317	140	80 %
NGLs (MBbl)	2,123	7,102	4,979	235 %
Oil (MBbl)	226	1,311	1,085	482 %
Combined (Bcfe)	191	368	177	93 %
Daily combined production (MMcfe/d)	522	1,007	485	93 %
Average prices before effects of hedges(2):				
Natural gas (per Mcf)	\$ 3.90	\$ 4.10	\$ 0.20	5 %
NGLs (per Bbl)	\$ 52.61	\$ 46.23	\$ (6.38)	(12)%
Oil (per Bbl)	\$ 91.27	\$ 81.65	\$ (9.62)	(11)%
Combined (per Mcfe)	\$ 4.31	\$ 4.73	\$ 0.42	10 %
Average realized prices after effects of hedges(2):				
Natural gas (per Mcf)	\$ 4.82	\$ 4.52	\$ (0.30)	(6)%
NGLs (per Bbl)	\$ 52.61	\$ 46.23	\$ (6.38)	(12)%
Oil (per Bbl)	\$ 99.06	\$ 84.66	\$ (14.40)	(15)%
Combined (per Mcfe)	\$ 5.17	\$ 5.10	\$ (0.07)	(1)%
Average Costs (per Mcfe):				
Lease operating	\$ 0.05	\$ 0.08	\$ 0.03	60 %
Gathering, compression, processing, and transportation	\$ 1.15	\$ 1.26	\$ 0.11	10 %
Production and ad valorem taxes	\$ 0.26	\$ 0.24	\$ (0.02)	(8)%
Depletion, depreciation, amortization, and accretion	\$ 1.23	\$ 1.30	\$ 0.07	6 %
General and administrative (before equity-based compensation)	\$ 0.32	\$ 0.28	\$ (0.04)	(13)%

- (1) See "Item 6. Selected Financial Data" included elsewhere in this report for a definition of EBITDAX (a non -GAAP measure) and a reconciliation of EBITDAX to net income (loss) from continuing operations.
 - (2) Average sales prices shown in the table reflect both the before and after effects of our cash settled derivatives. Our calculation of such after effects includes gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil and NGLs production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.
- * Not meaningful or applicable.

Discussion of Consolidated Results for 2014 Compared to 2013

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from \$821 million for the year ended December 31, 2013 to \$1.737 billion for the year ended December 31, 2014, an increase of \$915 million, or 111%. Our production increased by 93% over that same period, from 191 Bcfe, or 522 MMcfe per day, for the year ended December 31, 2013 to 368 Bcfe, or 1,007 MMcfe per day, for the year ended December 31, 2014. Net equivalent prices before the effects of realized hedge gains increased from \$4.31 per Mcfe for the year ended December 31, 2013 to \$4.73 for the year ended December 31, 2014, an increase of 10%. The 10% increase in net equivalent prices for the year ended December 31, 2014 compared to the prior year resulted from an increase in the mix of production of NGLs and oil compared to the prior year as well as increases in the prices of natural gas, which were partially offset by decreases in the prices of NGLs and oil. Increased production volumes accounted for an approximate \$762 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price), and increases in our equivalent prices accounted for an approximate \$153 million increase in year-over-year revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from an increase in the number of producing wells as a result of our ongoing drilling program. Based on our current drilling and completion plans for 2015 and the increasing size of our production base, we expect the rate of growth in both our production and our product revenues to decline from the rate of growth realized in 2014. Average prices after the effects of cash settled commodity hedges were \$5.17 per Mcfe for 2013 compared to \$5.10 per Mcfe for 2014.

Commodity derivative fair value gains. To achieve more predictable cash flows, and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas, NGLs, and oil production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment, and all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations. For the years ended December 31, 2013

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and 2014, our hedges resulted in derivative fair value gains of \$492 million and \$268 million, respectively. The derivative fair value gains included \$164 million and \$136 million of cash settlements received on derivatives for the years ended December 31, 2013 and 2014, respectively. Commodity derivative fair value gains or losses will vary based on future commodity prices and have no cash flow impact until the derivative contracts are settled. Derivative asset or liability positions at the end of any accounting period may reverse to the extent natural gas, NGLs, and oil strip prices increase or decrease from their levels at the end of the accounting period, or as gains or losses are realized through settlement. We expect continued volatility in commodity prices and the related fair value of our derivative instruments.

Gathering, compression, and water distribution. Beginning in the fourth quarter of 2013, we began to recognize our midstream gathering, compression, and water distribution operations as reportable segments. Gathering, compression, and water distribution fees of \$22 million (net of intercompany eliminations of \$246 million) during the year ended December 31, 2014 represent the portion of such fees that are charged to outside working interest owners and other third parties. Such fees were immaterial in the prior year and were netted against gathering expenses.

Gain on sale of gathering system. In 2012, we closed the sale of a portion of our Marcellus Shale gathering system assets in West Virginia along with exclusive rights to gather our gas for a 20 year period within an area of dedication (AOD) to a joint venture owned by Crestwood Midstream Partners and Crestwood Holdings Partners LLC (together "Crestwood"). Under the terms of the contract, we earned additional proceeds of \$40 million if certain volume thresholds were met by December 31, 2014. As the volume thresholds were fully met during 2014, we recorded an additional \$40 million of gain on the sale of assets in 2014 and a receivable from Crestwood for a like amount.

Lease operating expenses. Lease operating expenses increased from \$9.4 million (net of intercompany eliminations of \$4 million) for the year ended December 31, 2013 to \$29.3 million (net of intercompany eliminations of \$33 million) for the year ended December 31, 2014, an increase of 211%. The increase is a result of the increase in the number of producing wells. On a per unit basis, lease operating expenses increased from \$0.05 per Mcfe for the year ended December 31, 2013 to \$0.08 for the year ended December 31, 2014. Lease operating expenses per unit have increased as a larger proportion of wells have been on production for longer periods of time compared to the prior year. Further, per unit costs have also increased as a larger proportion of our wells produce condensate at the wellhead. Lease operating expenses are expected to continue to slowly increase on a per unit basis as properties mature and production declines on a per well basis.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from \$218 million (net of intercompany eliminations of \$22 million) for the year ended December 31, 2013 to \$461 million (net of intercompany eliminations of \$89 million) for the year ended December 31, 2014. The increase in these expenses is a result of the increase in production, firm transportation commitments, and third-party gathering, compression and processing expenses. On a per-unit basis, total gathering, compression, processing and transportation expenses increased from \$1.15 per Mcfe for the year ended December 31, 2013 to \$1.26 for the year ended December 31, 2014 as a larger proportion of our gas was processed compared to the prior year.

We have entered into contracts for significant firm transportation volumes in advance of having sufficient production to fully utilize the capacity. Based on current projected 2015 annual production levels, we estimate that we could incur marketing expense of \$100 million to \$150 million for unused and un-marketed transportation capacity.

Production and ad valorem tax expense. Total production and ad valorem taxes increased from \$50 million for the year ended December 31, 2013 to \$88 million for the year ended December 31, 2014, primarily as a result of increased production and a larger midstream asset base subject to ad valorem taxes. Production taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging were 5.1% for the year ended December 31, 2014 compared to 6.1% 2013. Production taxes decreased as a percentage of revenues as production from Ohio increased. Ohio has a lower severance tax rate than West Virginia. Legislative proposals in the State of Ohio to increase severance taxes on production from horizontally drilled wells could increase our future production tax rates if such legislation is enacted.

Exploration expense. Exploration expense of \$22 million for the year ended December 31, 2013 increased to expense of \$28 million for the year ended December 31, 2014 primarily because of an increase in unsuccessful lease acquisitions due to an increase in lease acquisition efforts.

Impairment of unproved properties. Impairment of unproved properties was approximately \$1.5 million for the year ended December 31, 2014 compared to \$1.1 million in 2013. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks or

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future plans to develop the acreage, and recognize impairment costs accordingly.

DD&A. DD&A increased from \$234 million for the year ended December 31, 2013 to \$478 million for the year ended December 31, 2014, primarily because of increased production. DD&A per Mcfe increased by 6%, from \$1.23 per Mcfe during the year ended December 31, 2013 to \$1.30 per Mcfe during the year ended December 31, 2014, primarily due to increased depreciation on growing midstream assets and facilities.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. No impairment expenses were recorded for the year ended December 31, 2013 or 2014 for proved properties.

General and administrative and equity-based compensation expense. General and administrative expense (before equity-based compensation expense) increased from \$60 million for the year ended December 31, 2013 to \$104 million for the year ended December 31, 2014, primarily as a result of increased staffing levels and related salary and benefits expenses, as well as increases in legal and other general corporate expenses, all of which are due to our increase in development activities and production levels. On a per unit basis, general and administrative expense before equity-based compensation decreased by 13% from \$0.32 per Mcfe during the year ended December 31, 2013 to \$0.28 per Mcfe during the year ended December 31, 2014 primarily due to a 93% increase in production. We had 233 employees as of December 31, 2013 and 444 employees as of December 31, 2014.

Noncash equity-based compensation expense decreased from \$365 million for the year ended December 31, 2013 to \$112 million for the year ended December 31, 2014. Noncash equity-based compensation expense included charges of \$365 million and \$84 million for the years ended December 31, 2013 and 2014, respectively, for the amortization of expense related to the vesting of profits interests issued upon the completion of our IPO in 2013. See note 1 to the consolidated financial statements included elsewhere in this report for more information on the vested profits interest charges.

Interest expense. Interest expense increased from \$137 million for the year ended December 31, 2013 to \$160 million for the year ended December 31, 2014, primarily due to increased indebtedness. Interest expense includes approximately \$6 million and \$8 million of non-cash amortization of deferred financing costs for the years ended December 31, 2013 and 2014, respectively.

Income tax expense. Income tax expense increased from \$186 million for the year ended December 31, 2013 to \$446 million for the year ended December 31, 2014 because of the increase in pre-tax income compared to the prior year. Equity-based compensation expense of \$365 million in 2013 and \$84 million in 2014 related to the vested profits interests charge is not deductible for federal or state income taxes and, along with the effect of state taxes, largely accounts for the difference between the federal tax rate of 35% and the rates at which income tax expense was provided for the years ended December 31, 2013 and 2014.

At December 31, 2014, we had approximately \$1.1 billion of U.S. federal net operating loss carryforwards (NOLs) and approximately \$1.0 billion of state NOLs, which expire from 2024 through 2034. From time to time there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs; such legislation could significantly affect our future taxable position if passed. The impact of any change will be recorded in the period that any such legislation might be enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The financial statements include unrecognized benefits at December 31, 2014 of \$11 million that, if recognized, would result in a reduction of current income taxes payable and an increase in noncurrent deferred tax liabilities. As of December 31, 2014, we have accrued approximately \$0.8 million of interest on unrecognized tax benefits.

During 2014, the Internal Revenue Service completed its examination of the tax returns of Antero Resources Finance Corporation (which was merged with Antero Resources Corporation in December 2013) for its tax years 2011 and 2012. There were no adjustments to our tax returns as a result of the examination. The Company's state tax returns are being examined by West Virginia taxing authorities for tax years 2010 through 2012. The Company does not expect any material adjustments to tax liabilities will result from the examination.

Income from discontinued operations. In 2012, the Company sold its Piceance Basin assets in Colorado and its Arkoma Basin assets in Oklahoma. Total proceeds from the sales, including liquidation of related hedge positions, were approximately \$843 million and pre-tax losses on the asset sales of approximately \$796 million were recorded in 2012. Pre-tax losses were adjusted

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downward in 2013 and 2014 by \$8.5 million and \$3.6 million for the resolution of certain liabilities recorded at the time of the sales and settlement of final contractual purchase price adjustments .

Adjusted EBITDAX. Adjusted EBITDAX increased from \$649 million for the year ended December 31, 2013 to \$1.162 billion for the year ended December 31, 2014 , an increase of 79% . The increase in Adjusted EBITDAX was primarily due to a 93% increase in production, which was partially offset by a 1% decrease in the average per Mcfe price received after the impact of cash settled derivatives, net of the related increases in cash operating and general and administrative expenses. See "Item 6. Selected Financial Data" included elsewhere in this report for a definition of EBITDAX (a non -GAAP measure) and a reconciliation of EBITDAX to net income (loss) from continuing operations.

Discussion of Segment Results for 2014 Compared to 2013

Gathering and Compression

Revenue for the gathering and compression segment increased from \$ 22 . 4 million for the year ended December 31, 2013 to \$95.7 million for the year ended December 31, 2014, an increase of \$73.3 million , or 327%. Gathering revenues increased by \$68.1 million from the prior year and compression revenues increased by \$5.2 million as additional wells on production increased throughput volumes. During 2014, we added twelve high-pressure gathering lines, a condensate gathering system, and three Antero compressor stations. Gathering throughput volumes increased from 73.1 Bcf, or 200 MMcf per day, in 2013 to 349.7 Bcf, or 958 MMcf per day in 2014. Compression throughput volumes increased from 9.9 Bcf, or 27 MMcf per day, in 2013 to 38.1 Bcf, or 104 MMcf per day, in 2014. Total operating expenses related to gathering and compression increased from \$36.5 million in 2013 to \$74.5 million in 2014 as a result of the increased throughput volumes.

Fresh Water Distribution

Revenue for the fresh water distribution segment increased from \$35.9 million for the year ended December 31 , 2013 to \$ 171.9 million for the year ended December 31 , 2014 , an increase of \$136.0 million . The increase was due driven by the build out of the water system and resulting increased use of the water system in our hydraulic fracturing activities and the addition of a third-party customer. The volume of water delivered through the system increased from 10.5 MMBbls in 2013 to 48.7 MMBbls in 2014. Operating expenses for the fresh water distribution system increased from \$19.5 million in 2013 to \$61.2 million in 2014 as a result of the increased use of the system.

Marketing

In 2014, we began to purchase and sell third-party natural gas and NGLs and market our excess firm transportation capacity in order to optimize the revenues from these assets. Marketing revenues of \$54 million and expenses of \$103 million for the year ended December 31, 2014 relate to these activities. Marketing costs include firm transportation costs related to current excess capacity as well as the cost of third-party purchased gas and NGLs. This includes firm transportation costs of \$4.3 million for the year ended December 31, 2014 related to an ethane transportation contract which is not being utilized because we are not currently recovering ethane. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity to favorable markets.

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Year Ended December 31, 2012 Compared to Year Ended December 31, 2013

The following table sets forth selected operating data for the year ended December 31, 2012 compared to the year ended December 31, 2013 :

(in thousands, except per unit and production data)	Year ended December 31,		Amount of	Percent Change
	2012	2013	Increase (Decrease)	
Operating revenues:				
Natural gas sales	\$ 259,743	689,198	429,455	165 %
NGL sales	3,719	111,663	107,944	2,903 %
Oil sales	1,520	20,584	19,064	1,254 %
Commodity derivative fair value gains	179,546	491,689	312,143	174 %
Gain on sale of assets	291,190	—	(291,190)	*
Total operating revenues	735,718	1,313,134	577,416	78 %
Operating expenses:				
Lease operating	6,243	9,439	3,196	51 %
Gathering, compression, processing, and transportation	91,094	218,428	127,334	140 %
Production and ad valorem taxes	20,210	50,481	30,271	150 %
Exploration	14,675	22,272	7,597	52 %
Impairment of unproved properties	12,070	10,928	(1,142)	(9)%
Depletion, depreciation, and amortization	102,026	233,876	131,850	129 %
Accretion of asset retirement obligations	101	1,063	964	954 %
General and administrative (before equity-based compensation)	45,284	60,158	14,874	33 %
Equity-based compensation	—	365,280	365,280	*
Total operating expenses	291,703	971,927	680,224	233 %
Operating income	444,015	341,207	(102,808)	(23)%
Other Expenses:				
Interest expense	(97,510)	(136,617)	(39,107)	40 %
Loss on early extinguishment of debt	—	(42,567)	(42,567)	*
Total other expenses	(97,510)	(179,184)	(81,674)	84 %
Income before income taxes and discontinued operations	346,505	162,023	(184,482)	(53)%
Income tax expense	(121,229)	(186,210)	(64,981)	54 %
Income (loss) from continuing operations	225,276	(24,187)	(249,463)	*
Income (loss) from discontinued operations	(510,345)	5,257	515,602	*
Net loss and comprehensive loss	\$ (285,069)	(18,930)	266,139	*
Adjusted EBITDAX from continuing operations (1)	\$ 284,710	\$ 649,358	\$ 364,648	128 %
Adjusted EBITDAX from discontinued operations (1)	149,605	—	(149,605)	*
Adjusted EBITDAX (1)	\$ 434,315	\$ 649,358	\$ 215,043	128 %
Production data:				
Natural gas (Bcf)	87	177	90	103 %
NGLs (MBbl)	71	2,123	2,051	2,872 %
Oil (MBbl)	19	226	207	1,094 %
Combined (Bcfe)	87	191	103	118 %
Daily combined production (MMcfe/d)	239	522	283	119 %
Average prices before effects of hedges(2):				
Natural gas (per Mcf)	\$ 2.99	\$ 3.90	\$ 0.91	30 %
NGLs (per Bbl)	\$ 52.07	\$ 52.61	\$ 0.54	1 %
Oil (per Bbl)	\$ 80.34	\$ 91.27	\$ 10.93	14 %
Combined (per Mcfe)	\$ 3.03	\$ 4.31	\$ 1.28	42 %
Average realized prices after effects of hedges(2):				
Natural gas (per Mcf)	\$ 5.05	\$ 4.82	\$ (0.23)	(5)%
NGLs (per Bbl)	\$ 52.07	\$ 52.61	\$ 0.54	1 %
Oil (per Bbl)	\$ 80.34	\$ 99.06	\$ 18.72	23 %
Combined (per Mcfe)	\$ 5.08	\$ 5.17	\$ 0.09	2 %
Average Costs (per Mcfe):				
Lease operating	\$ 0.07	\$ 0.05	\$ (0.02)	(29)%
Gathering, compression, processing, and transportation	\$ 1.04	\$ 1.15	\$ 0.11	11 %
Production and ad valorem taxes	\$ 0.23	\$ 0.26	\$ 0.03	13 %
Depletion, depreciation, amortization, and accretion	\$ 1.17	\$ 1.23	\$ 0.06	5 %

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- (1) See "Item 6. Selected Financial Data" included elsewhere in this report for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

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- (2) Average sales prices shown in the table reflect both the before and after effects of our cash settled derivatives. Our calculation of such after effects includes gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil and NGL production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.
- * Not meaningful or applicable.

Natural gas, NGLs, and oil sales. Combined revenues from production of natural gas, NGLs, and oil increased from \$265 million for the year ended December 31, 2012 to \$821 million for the year ended December 31, 2013, an increase of \$556 million, or 210%. Our production increased by 119% from 87 Bcfe, or 239 MMcfe per day, in 2012 to 191 Bcfe, or 522 MMcfe per day, in 2013. Increased production volumes increased revenues by \$313 million, or 118%, (calculated as the increase in year -to -year volumes times the prior year average price), and combined commodity price increases accounted for a \$243 million, or 92% increase in revenues (calculated as the change in year -to -year average combined price times current year production volumes).

Commodity derivative fair value gains. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas and oil production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment, and all mark -to -market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our results of operations. For the years ended December 31, 2012 and 2013, our hedges resulted in derivative fair value gains of \$180 million and \$492 million, respectively. The derivative fair value gains included \$178 million and \$164 million of cash settlements received on derivatives for the years ended December 31, 2012 and 2013, respectively. Commodity derivative fair value gains or losses will vary based on future commodity prices and have no cash flow impact until the derivative contracts are settled. We expect continued volatility in the fair value of our derivative instruments.

Gain on sale of Appalachian gathering assets. On March 26, 2012, we closed the sale of a portion of our Marcellus Shale gathering system assets along with exclusive rights to gather and compress our gas for a 20 -year period within an area of dedication ("AOD") to a joint venture owned by Crestwood Midstream Partners and Crestwood Holdings Partners LLC (together, "Crestwood") for \$375 million (excluding customary purchase price adjustments). A gain on the sale of the assets of \$291 million was recorded in 2012. Under the terms of the contract, we earned additional proceeds of \$40 million if certain volume thresholds were met by December 31, 2014. As the volume thresholds were fully met during 2014, we recorded an additional \$40 million of gain on the sale of assets in 2014 and a receivable from Crestwood for a like amount.

Lease operating expenses. Lease operating expenses increased from \$6 million for the year ended December 31, 2012 to \$9 million in 2013, primarily as a result of increased production. On a per -Mcfe basis, lease operating expenses decreased by 29%, from \$0.07 per Mcfe in 2012 to \$0.05 per Mcfe in 2013. Lease operating expenses increase as a larger proportion of wells have been on production for longer periods of time compared to 2012. Lease operating expenses are expected to continue to slowly increase on a per unit basis as the properties mature and production declines on a per well basis.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from \$91 million for the year ended December 31, 2012 to \$218 million in 2013. The increase in these expenses resulted from the increase in production, firm transportation commitments, and third -party compression and gathering expenses. On a per -Mcfe basis, total gathering, compression, processing and transportation expenses increased from \$1.04 per Mcfe for 2012 to \$1.15 in 2013 due to additional processing costs and firm transportation commitments.

Production and ad valorem tax expense. Total production taxes increased from \$20 million for the year ended December 31, 2012 to \$50 million for the year ended December 31, 2013, primarily as a result of increased production. Production taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging were 6.1% for the year ended December 31, 2013 compared to 7.6% for the year ended December 31, 2012. Production taxes decreased as a percentage of revenues as production increased in Ohio, which has a lower severance tax rate than West Virginia, and per unit taxes also decreased as a percentage of revenues as prices increased. Ad valorem taxes increased because of the construction of the water distribution assets. Legislative proposals in the State of Ohio to increase severance taxes on production from horizontally fractured wells could increase our future production tax rates, if such legislation is enacted.

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Exploration expense. Exploration expense increased from \$15 million for the year ended December 31, 2012 to \$22 million for the year ended December 31, 2013 primarily because of an increase in the cost of unsuccessful lease acquisition efforts as we materially increased the number of contract lease brokers providing services to us in the Appalachian Basin.

Impairment of unproved properties. Impairment of unproved properties was approximately \$11 million for the year ended December 31, 2013 compared to \$12 million for the year ended December 31, 2012. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage and recognize impairment costs accordingly.

DD&A. DD&A increased from \$102 million for the year ended December 31, 2012 to \$234 million for the year ended December 31, 2013, an increase of \$132 million, as a result of increased production in 2013 compared to 2012. DD&A per Mcfe increased 5%, from \$1.17 per Mcfe during 2012 to \$1.23 per Mcfe during 2013 as a result of increased depreciation on growing gathering and water systems and facilities and increased proved property costs subject to depletion.

We evaluate the impairment of our proved natural gas, NGLs, and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. There were no impairment expenses recorded for the years ended December 31, 2012 or 2013 for proved properties. As of December 31, 2013, no significant exploratory well costs had been deferred for over one year pending proved reserves determination.

General and administrative expense. General and administrative expense (before equity-based compensation) increased from \$45 million for the year ended December 31, 2012 to \$60 million during 2013, an increase of \$15 million. The increase is due to increased costs related to salaries, employee benefits, contract personnel and other general business expenses required to support the growth of our capital expenditure program and production levels. The number of our full-time employees grew from 150 at December 31, 2012 to 233 at December 31, 2013. On a per-Mcfe basis, general and administrative expense (before equity-based compensation) decreased by 38%, from \$0.52 per Mcfe during the year ended December 31, 2012 to \$0.32 per Mcfe during 2013 primarily due to a 119% growth in production. No portion of general and administrative expenses was allocated to discontinued operations as we did not expect any reduction of such expenses as a result of the sale of the Arkoma and Piceance properties. When all discontinued operations are included, general and administrative expenses were \$0.37 per Mcfe in 2012.

In 2013, we recognized noncash equity-based compensation expense of approximately \$365 million, almost all of which was related to the interests of our employees in Antero Employee Holdings LLC ("Employee Holdings"), which owns interests in Antero Investment LLC ("Antero Investment"). Prior to our IPO, the interests of Employee Holdings were subject to performance and service conditions which could be met generally only in the event of a liquidation or distribution event. In connection with our IPO, the terms of the Antero Investment operating agreement provided for a mechanism by which the shares of our common stock to be allocated amongst the members of Antero Investment, including Employee Holdings, will be specifically determined. As a result, the satisfaction of all performance and service conditions relative to the membership interests of Employee Holdings in Antero Investment became probable. Accordingly, we recognized approximately \$365 million of equity-based compensation expense in 2013 relative to these interests and will recognize approximately another \$121 million over the remaining expected service period. The equity-based compensation relative to these interests is treated as a capital contribution from Antero Investment in our financial statements and is not deductible for Federal or state income tax purposes in 2013 or in the future.

Interest expense and loss on early extinguishment of debt. Interest expense increased from \$98 million for the year ended December 31, 2012 to \$137 million for the year ended December 31, 2013, an increase of \$39 million as a result of an increase in the amount of senior notes outstanding and the average balance of the revolving credit facility outstanding during 2013 compared to 2012. During 2013, we incurred a loss of \$43 million on the early extinguishment of debt resulting from (i) the retirement of \$140 million of the 7.25% senior notes due 2019 from the proceeds of our IPO and (ii) the retirement of the 9.375% senior notes due 2017 having a principal amount of \$525 million from the proceeds of the issuance of the 5.375% notes due 2021. The loss of \$43 million is comprised of redemption premiums of \$35 million and the write-off of deferred financing costs and unamortized premium and discounts of \$8 million.

Income tax expense. Income tax expense related to continuing operations was \$186 million (84% of pre-tax income) in 2013 compared to \$121 million (35% of pre-tax income) in 2012. Income tax expense increased from 35% of pre-tax income to 115% of pre-tax income because the equity-based compensation expense recognized in 2013, related to the allocation of shares among the members of Antero Investment and Employee Holdings, is a nondeductible permanent difference between our taxable income and income recognized for financial statements. Although we have accrued \$11 million at December 31, 2013 for unrecognized tax

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benefits, no taxes were due at the end of either December 31, 2012 or 2013. We have not generated current taxable income in either the current or prior years, which is primarily attributable to the differing book and tax treatment of unrealized derivative gains and intangible drilling costs. At December 31, 2013, we had approximately \$1.2 billion of U.S. federal and state net operating loss carryforwards, which expire starting in 2024 and continue through 2033. At December 31, 2013, we recorded valuation allowances of approximately \$27 million for deferred tax assets primarily related to state loss carryforwards in states where we no longer operate. From time to time there has been proposed legislation in the U.S. Congress to delay or limit future deductions for intangible drilling costs; such legislation could significantly affect our future taxable position if passed. The impact of any change will be recorded in the period that such legislation might be enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more -likely- than -not- to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The financial statements include unrecognized benefits at December 31, 2013 of \$11 million that, if recognized, would result in a reduction of current income taxes payable and an increase in noncurrent deferred tax liabilities. No impact to our 2013 effective tax rate would result. As of December 31, 2013, approximately \$0.5 million of interest has been accrued on unrecognized tax benefits.

The tax returns of Antero Resources Finance Corporation (which was merged with the Antero Resources Corporation in December 2013) are being examined by the Internal Revenue Service for its tax years 2011 and 2012. The Company's state tax returns are being examined by West Virginia taxing authorities for tax years 2010 through 2012. The Company does not expect any material adjustments to tax liabilities will result from either the federal or the state examination.

Income (loss) from discontinued operations. Income (loss) from discontinued operations includes the results of operations from the Arkoma Basin and Piceance Basin operations (including revenues and direct operating expenses and allocated income tax expense, but not general and administrative or interest expenses) and, in 2012, the loss on the sale of these assets. An analysis of these operations is included in note 3 to the consolidated financial statements included elsewhere in this report. Income (loss) from discontinued operations was \$(510) million in 2012, primarily as a result of the loss on the sale of the properties of \$796 million and a \$273 million tax benefit from the loss. Income from discontinued operations of \$5 million in 2013 resulted from the reduction of various liability provisions made in connection with the sale of \$8 million, net of tax benefits of \$3 million and final purchase price adjustments.

Adjusted EBITDAX from continuing and discontinued operations. Adjusted EBITDAX from continuing operations increased to \$649 million for the year ended December 31, 2013 from \$285 million for the year ended December 31, 2012, an increase of 128%. The increase in Adjusted EBITDAX resulted from a 119% increase in production, a 2% increase in the average per Mcfe price received after the impact of cash settled derivatives, net of the related increases in cash operating and general and administrative expenses. Adjusted EBITDAX from discontinued operations related to the Piceance and Arkoma Basin assets disposed of in 2012 was \$150 million for the year ended December 31, 2012. See "Item 6. Selected Financial Data" included elsewhere in this report for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

Capital Resources and Liquidity

Historically, our primary sources of liquidity have been through issuances of debt and equity securities, borrowings under our revolving credit facility, asset sales, and net cash provided by operating activities. During 2014, we raised capital through the issuance of \$1.1 billion of 5.125% senior notes due 2022, and the initial public offering of our subsidiary, Antero Midstream Partners LP, receiving net proceeds of \$1.1 billion. Our primary use of cash has been for the exploration, development and acquisition of natural gas, NGLs, and oil properties as well as for development of gathering, compression, and fresh water system infrastructure. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on the capital resources available to us.

As of December 31, 2014, we had 5,331 potential horizontal well locations, which will take many years to develop. More specifically, our proved undeveloped reserves will require an estimated \$8.2 billion of development capital over the next five years in order to fully develop the properties associated with our proved reserves. A significant portion of this capital requirement will be funded out of operating cash flows. However, we may be required to generate or raise significant capital to develop our proved undeveloped reserves.

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Our revolving credit facility has a borrowing base of \$4.0 billion and current lender commitments of \$4.0 billion. The borrowing base is determined every six months based on reserves, oil and gas commodity prices, and the value of our hedge portfolio. The next redetermination of the borrowing base is scheduled to occur in October 2015. For a discussion of the risks of a decrease in the borrowing base under our revolving credit facility, see "Item 1A. Risk Factors— The borrowing base under our revolving credit facility may be reduced in light of recent commodity price declines, which could hinder or prevent us from meeting our future capital needs." Our commodity hedge position provides us with additional liquidity as it provides us with the relative certainty of receiving a significant portion of our future expected revenues from operations despite potential declines in the price of natural gas, NGLs, or oil. Our ability to make significant additional acquisitions for cash would require us to obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us, or at all. Our revolving credit facility is funded by a syndicate of 29 banks. We believe that the participants in the syndicate have the capability to fund up to their current commitment. If one or more banks should not be able to do so, we may not have the full availability of our revolving credit facility.

On November 10, 2014, Antero Midstream completed its IPO of 46,000,000 common units representing limited partner interests at a price to the public of \$25.00 per Common Unit, including the exercise in full by the underwriters of their option to purchase an additional 6,000,000 common units. Antero Midstream owns gathering and compression assets that service our natural gas, NGLs, and condensate production. As of February 19, 2015, Antero and its affiliates owned 29,940,957 common units and all 75,940,957 subordinated units. The remaining 46,000,000 common units are held by the public.

The gross proceeds of the IPO were approximately \$1.2 billion. After subtracting underwriting discounts and offering expenses of approximately \$63 million, net proceeds received by Antero Midstream from its IPO were approximately \$1.1 billion. Antero Midstream used approximately \$843 million of the net proceeds to repay assumed indebtedness from Antero and reimburse Antero for certain capital expenditures incurred. Antero Midstream retained \$250 million of the net proceeds for general partnership purposes.

For the year ended December 31, 2014, our total capital expenditures were approximately \$4.1 billion, including drilling and completion costs of \$2.5 billion, gathering and compression project costs of \$558 million, fresh water distribution project costs of \$197 million, \$841 million on leasehold costs (including \$415 million of acquisitions and \$426 million on land), and other capital expenditures of \$13 million. Our capital budget for 2015 is \$1.8 billion, excluding the capital budget for Antero Midstream, and includes: \$1.6 billion for drilling and completion; \$50 million for fresh water distribution infrastructure; and \$150 million for core leasehold acreage acquisitions. We do not budget for producing property acquisitions. Substantially all of the \$1.6 billion allocated for drilling and completion is allocated to our operated drilling in liquids-rich gas areas. Approximately 60% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 40% is allocated to the Utica Shale. During 2015, we plan to operate an average of nine drilling rigs in the Marcellus Shale and five drilling rigs in the Utica Shale. Additionally, the capital budget of Antero Midstream for 2015 is from \$425 million to \$450 million. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

We believe that funds from operating cash flows and available borrowings under our revolving credit facility will be sufficient to meet our cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies for at least the next 12 months. For more information on our outstanding indebtedness, see "Debt Agreements and Contractual Obligations."

Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2012, 2013, and 2014:

(in thousands)	Year Ended December 31,		
	2012	2013	2014
Net cash provided by operating activities	\$ 332,255	\$ 534,707	\$ 998,121
Net cash used in investing activities	(463,491)	(2,673,592)	(4,089,650)
Net cash provided by financing activities	146,882	2,137,383	3,320,021
Net increase (decrease) in cash and cash equivalents	\$ 15,646	\$ (1,502)	\$ 228,492

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Cash Flow Provided by Operating Activities

Net cash provided by operating activities was \$332 million, \$535 million and \$998 million for the years ended December 31, 2012, 2013 and 2014, respectively. The increase in cash flows from operations from 2012 to 2013 and also from 2013 to 2014 was primarily the result of increased revenues from oil and gas production and cash settled derivatives, net of increased operating expenses and interest expense and changes in working capital.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for natural gas, NGLs, and oil prices. Prices for these commodities are determined primarily by prevailing market conditions. Factors including regional and worldwide economic activity, weather, infrastructure capacity to reach markets, and other variables influence market conditions for these products. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosure About Market Risk."

Cash Flow Used in Investing Activities

During the years ended December 31, 2012, 2013, and 2014, we used cash flows in investing activities of \$463 million, \$2.7 billion, and \$4.1 billion, respectively, as a result of our capital expenditures for drilling, development, acquisitions, and construction of midstream infrastructure. Net of proceeds from asset sales in 2012 of \$1.2 billion, capital expenditures for drilling, development, and acquisition were \$1.7 billion in 2012.

Our board of directors has approved a capital budget of \$1.8 billion for 2015, which does not include the capital budget of \$425 million to \$450 million for Antero Midstream, our consolidated subsidiary. Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If natural gas, NGLs, and oil prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we could choose to defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flow and other factors both within and outside our control.

Cash Flow Provided by Financing Activities

Net cash provided by financing activities in 2014 of \$3.3 billion was primarily the result of (i) proceeds from the issuance of senior notes of \$1.1 billion, (ii) net borrowings on our credit facilities of \$1.4 billion, (iii) proceeds from the Antero Midstream IPO of \$1.1 billion, net of (iv) \$309 for retirements of senior notes and payments for early redemption premiums and deferred financing costs. The increase in cash and cash equivalents of \$228 million in 2014 is primarily due to cash retained by Antero Midstream subsequent to its IPO. Antero Midstream had a cash balance of \$230 million as of December 31, 2014.

Net cash provided by financing activities in 2013 of \$2.1 billion was primarily the result of (i) proceeds from our IPO of \$1.6 billion, (ii) proceeds from the issuance of senior notes of \$1.2 billion, net of (iii) \$744 million for retirements of senior notes and payments for early redemption premiums and deferred financing costs.

Net cash provided by financing activities in 2012 of \$147 million was primarily the result of (i) \$300 million of cash provided by the issuance of senior notes, net of (ii) net repayments of our revolving credit facility of \$148 million and other items of \$5 million, including deferred financing costs.

Debt Agreements and Contractual Obligations

Senior Secured Revolving Credit Facility. Our revolving credit facility (the "Credit Facility") provides for a maximum amount of \$4.0 billion and at December 31, 2014 has a borrowing base of \$4.0 billion. The borrowing base is redetermined semi-annually and is dependent upon the amount of our proved oil and gas reserves and estimated cash flows from these reserves and our hedge positions. The next redetermination is scheduled to occur in October 2015. Current lender commitments are \$4.0 billion. At December 31, 2014, we had \$1.73 billion of borrowings and \$387 million of letters of credit outstanding under the Credit Facility. The Credit Facility matures on May 5, 2019.

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On November 10, 2014, the Company and Antero Water LLC ("Antero Water"), a wholly-owned subsidiary of the Company, entered into a new water credit facility (the "Water Facility"), in order to provide for separate borrowings attributable to our fresh water distribution business. In accordance with the Credit Facility and the Water Facility agreements, borrowings under the Water Facility reduce availability under the Credit Facility on a dollar-for-dollar basis. The Water Facility will mature at the earlier of the sale of Antero Water to Midstream Operating LLC (a subsidiary of Antero Midstream Partners LP), or May 12, 2016.

Principal amounts borrowed on the Credit Facility and Water Facility are payable on the maturity dates with such borrowings bearing interest that is payable quarterly. We have a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the LIBOR Rate administered by the ICE Benchmark Administration for one, two, three, six or twelve months plus an applicable margin ranging from 150 to 250 basis points, depending on the percentage of our borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points, depending on the percentage of our borrowing base utilized. The amounts outstanding under the Credit Facility are secured by a first priority lien on substantially all of our natural gas, NGLs, and oil properties and associated assets and are cross-guaranteed by each borrower entity along with each of their current and future wholly owned subsidiaries. The amounts outstanding under the Water Facility are secured by a first priority lien on substantially all of our water distribution assets and are cross-guaranteed by each borrower entity along with each of their current and future wholly owned subsidiaries. For information concerning the effect of changes in interest rates on interest payments under these facilities, see "Item 7A. Quantitative and Qualitative Disclosure About Market Risk." As of December 31, 2014, we had \$1.73 billion of borrowings and \$387 million letters of credit outstanding under the Credit Facility and Water Facility, with a weighted average interest rate of 2.06%.

The Credit Facility and Water Facility contain restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- pay dividends;
- hedge future production;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The Credit Facility and Water Facility also require us to maintain the following two financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (including any unused borrowing base under the facilities and excluding derivative assets) to our consolidated current liabilities, of not less than 1.0 to 1.0 as of the end of each fiscal quarter; and
- a minimum interest coverage ratio, which is the ratio of consolidated EBITDAX to consolidated interest expense over the most recent four quarters, of not less than 2.5 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2013 and 2014. The actual borrowing capacity available to use may be limited by these current ratio and minimum interest coverage ratio covenants. At December 31, 2014, our current ratio was 2.57 to 1.0 (based on the \$4.0 billion borrowing base in effect as of December 31, 2014) and our interest coverage ratio was 7.56 to 1.0.

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Midstream Credit Facility. On November 10, 2014, in connection with the closing of its IPO, Antero Midstream entered into a new revolving credit facility (the "Midstream Facility") among Antero Midstream, certain lenders party thereto, Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer and swing line lender, and 16 other financial institutions thereto. The Midstream Facility provides for lender commitments of \$1.0 billion and for a letter of credit sublimit of \$150 million. There were no borrowings or letters of credit outstanding under the Midstream Facility as of December 31, 2014. The Midstream Facility will mature on November 10, 2019.

Principal amounts borrowed are payable on the maturity date with such borrowings bearing interest that is payable quarterly. Antero Midstream has a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the LIBOR Rate administered by the ICE Benchmark Administration for one, two, three, six or twelve months plus an applicable margin ranging from 150 to 225 basis points, depending on the leverage ratio then in effect. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 125 basis points, depending on the leverage ratio then in effect.

The Midstream Facility is secured by mortgages on substantially all of Antero Midstream's and its restricted subsidiaries' properties – primarily assets used in the provision of gathering and compression services to the Company and third parties – and guarantees from its restricted subsidiaries. The Midstream Facility is not guaranteed by Antero Resources Corporation. Interest is payable at a variable rate based on LIBOR or the prime rate based on Antero Midstream's election at the time of borrowing. The Midstream Facility contains restrictive covenants that may limit Antero Midstream's ability to, among other things:

- ? incur additional indebtedness;
- ? sell assets;
- ? make loans to others;
- ? make investments;
- ? enter into mergers;
- ? make certain restricted payments;
- ? incur liens; and
- ? engage in certain other transactions without the prior consent of the lenders.

Borrowings under the Midstream Facility also require Antero Midstream to maintain the following financial ratios:

- ? an interest coverage ratio, which is the ratio of Antero Midstream's consolidated EBITDA to its consolidated current interest charges of at least 2.5 to 1.0 at the end of each fiscal quarter; provided that upon obtaining investment grade rating, the borrower may elect not to be subject to such ratio;
- ? a consolidated total leverage ratio, which is the ratio of consolidated debt to consolidated EBITDA, of not more than 5.0 to 1.0; provided that after electing to issue unsecured high yield notes, the consolidated total leverage ratio will not be more than 5.25 to 1.0, or, following the election of the borrower for two fiscal quarters after a material acquisition, 5.50 to 1.0; and
- ? if Antero Midstream elects to issue unsecured high yield notes, a consolidated senior secured leverage ratio, which is the ratio of consolidated senior secured debt to consolidated EBITDA, of not more than 3.75 to 1.0.

Antero Midstream was in compliance with such covenants and ratios as of December 31, 2014.

Senior Notes. We have \$525 million of 6.00% senior notes outstanding, which are due December 1, 2020. The 2020 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2020 notes rank pari passu to our other outstanding senior notes. The 2020 notes are guaranteed on a

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senior unsecured basis by our wholly-owned subsidiaries and certain of our future restricted subsidiaries. Interest on the 2020 notes is payable on June 1 and December 1 of each year. We may redeem all or part of the 2020 notes at any time on or after December 1, 2015 at redemption prices ranging from 104.50% on or after December 1, 2015 to 100.00% on or after December 1, 2018. In addition, on or before December 1, 2015, we may redeem up to 35% of the aggregate principal amount of the 2020 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 106.00% of the principal amount of the 2020 notes, plus accrued interest. At any time prior to December 1, 2015, we may redeem the 2020 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2020 notes plus a "make-whole" premium and accrued interest. If we undergo a change of control, the holders of the 2020 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2020 notes, plus accrued interest.

We also have \$1 billion of 5.375% senior notes outstanding, which are due November 1, 2021. The 2021 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2021 notes rank parri passu to our other outstanding senior notes. The 2021 notes are guaranteed by our wholly-owned subsidiaries and certain of our future restricted subsidiaries. Interest on the 2021 notes is payable on May 1 and November 1 of each year. We may redeem all or part of the 2021 notes at any time on or after November 1, 2016 at redemption prices ranging from 104.031% on or after November 1, 2016 to 100.00% on or after November 1, 2019. In addition, on or before November 1, 2016, we may redeem up to 35% of the aggregate principal amount of the 2021 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.375%. At any time prior to November 1, 2016, we may also redeem the 2021 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2021 notes plus a "make-whole" premium and accrued interest. If we undergo a change of control prior to May 1, 2015, we may redeem all, but not less than all, of the 2021 notes at a redemption price equal to 110% of the principal amount of the 2021 notes. If we undergo a change of control, we may be required to offer to purchase the 2021 notes from the holders at a price equal to 101% of the principal amount of the 2021 notes, plus accrued interest.

We also have \$1.1 billion of 5.125% senior notes outstanding, which are due December 1, 2022. The 2022 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2022 notes rank parri passu to our other outstanding senior notes. The 2022 notes are guaranteed by our wholly-owned subsidiaries and certain of our future restricted subsidiaries. Interest on the 2022 notes is payable on June 1 and December 1 of each year. We may redeem all or part of the 2022 notes at any time on or after June 1, 2017 at redemption prices ranging from 103.844% on or after June 1, 2017 to 100.00% on or after June 1, 2020. In addition, on or before June 1, 2017, we may redeem up to 35% of the aggregate principal amount of the 2022 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.125%. At any time prior to June 1, 2017, we may also redeem the 2022 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2022 notes plus a "make-whole" premium and accrued interest. If we undergo a change of control prior to December 1, 2015, we may redeem all, but not less than all, of the 2022 notes at a redemption price equal to 110% of the principal amount of the 2022 notes. If we undergo a change of control, the holders of the 2022 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2022 notes, plus accrued interest.

We used the proceeds from the issuances of the senior notes to repay borrowings outstanding under the Credit Facility, redeem previously issued senior notes, and for development of our oil and natural gas properties.

The senior notes indentures each contain restrictive covenants and restrict our ability to incur additional debt unless a pro forma minimum interest coverage ratio requirement of 2.25:1 is maintained. We were in compliance with such covenants as of December 31, 2013 and 2014.

Treasury Management Facility. We have a stand-alone revolving note with a lender under the Credit Facility which provides for up to \$25 million of cash management obligations in order to facilitate our daily treasury management. Borrowings under the revolving note are secured by the collateral for our revolving credit facility. Borrowings under the facility bear interest at the lender's prime rate plus 1.0%. The note matures on June 1, 2015. At December 31, 2013 and 2014, there were no outstanding borrowings under this facility.

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Contractual Obligations. A summary of our contractual obligations as of December 31, 2013 is provided in the following table (in millions).

(In millions)	Year						Total
	2015	2016	2017	2018	2019	Thereafter	
Credit Facility and Water Facility(1)	\$ —	115	—	—	1,615	—	1,730
Senior notes—principal(2)	—	—	—	—	—	2,625	2,625
Senior notes—interest(2)	142	142	142	142	142	279	989
Drilling rig and frac service commitments(3)	212	161	96	—	—	—	469
Firm transportation (4)	316	593	800	867	939	10,376	13,891
Gas processing, gathering, and compression services (5)	336	237	245	244	193	1,040	2,295
Office and equipment leases	9	9	8	6	4	11	47
Asset retirement obligations(6)	—	—	—	—	—	17	17
Total	\$ 1,015	1,257	1,291	1,259	2,893	14,348	22,063

- (1) Includes outstanding principal amounts at December 31, 2014. This table does not include future commitment fees, interest expense or other fees on our Credit Facility and Water Facility because they are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments, or future interest rates to be charged.
- (2) Includes the 6.00% notes due 2020, the 5.375% notes due 2021, and the 5.125% notes due 2022.
- (3) Includes contracts for the services of drilling rigs and frac fleets, which expire at various dates from March 2015 through September 2017. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.
- (4) Includes firm transportation agreements with various pipelines in order to facilitate the delivery of production to market. These contracts commit us to transport minimum daily natural gas or NGLs volumes at negotiated rates, or pay for any deficiencies at specified reservation fee rates. The amounts in this table represent our minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.
- (5) Contractual commitments for gas processing, gathering and compression services agreements represent minimum commitments under long-term gas processing agreements as well as various gas compression agreements. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.
- (6) Represents the present value of our estimated asset retirement obligations. Neither the ultimate settlement amounts nor the timing of our asset retirement obligations can be precisely determined in advance; however, we believe it is likely that a very small amount of these obligations will be settled within the next five years.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of

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our consolidated financial statements. See note 2 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Successful Efforts Method

The Company accounts for its natural gas and crude oil exploration and development activities under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete productive wells, development wells, and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when we determine that the well does not contain reserves in commercially viable quantities. The Company reviews exploration costs related to wells in progress at the end of each quarter and makes a determination, based on known results of drilling at that time, whether the costs should continue to be capitalized pending further well testing and results, or charged to expense. We have not incurred any such charges in the years ended December 31, 2012, 2013, and 2014. The sale of a partial interest in a proved property is accounted for as a cost recovery, and no gain or loss is recognized as long as this treatment does not significantly affect the units of production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Unproved properties with significant acquisition costs are assessed for impairment on a property by property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, and future plans to develop acreage. Other unproved properties are assessed for impairment on an aggregate basis. Unproved properties and the related costs are transferred to proved properties when reserves are discovered on or otherwise attributed to the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of cost without recognition of any gain or loss until the cost has been recovered. Impairment of unproved properties for leases which have expired, or are expected to expire, was \$12.1 million, \$10.9 million, and \$15.2 million for the years ended December 31, 2012, 2013, and 2014, respectively.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in anticipation of finding a gas and oil field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed if reserves are not found in economic quantities. Seismic costs can be substantial, which will result in additional exploration expenses when incurred. Additionally, the application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred.

Natural Gas, NGLs and Oil Reserve Quantities and Standardized Measure of Future Cash Flows

Our internal technical staff prepare the estimates of natural gas, NGLs, and oil reserves and associated future net cash flows and our independent reserve engineers audit these estimates. Current accounting guidance allows only proved natural gas, NGLs, and oil reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of natural gas, NGLs, and oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our independent reserve engineers and internal technical staff must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates consider recent production levels and other technical information about each field. Natural gas, NGLs, and oil reserve engineering is a subjective process of estimating underground accumulations of natural gas, NGLs, and oil that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, natural gas, NGLs, and oil prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates are generally different from the quantities of natural gas, NGLs, and oil that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Impairment of Proved Properties

We review our proved natural gas, NGLs, and oil properties for impairment on a geological reservoir basis whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our gas, NGLs, and oil properties and compare these future cash flows to the carrying amount of properties to

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determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved properties may be recorded. We did not record any impairment charges for proved properties during the years ended December 31, 2012, 2013, and 2014.

New Accounting Pronouncements

On May 28, 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers*, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. The ASU will replace most existing revenue recognition guidance in U.S. GAAP when it becomes effective. The new standard is effective for the Company on January 1, 2017. Early application is not permitted. The standard permits the use of either the retrospective or cumulative effect transition method. The Company is evaluating the effect that ASU 2014-09 will have on its consolidated financial statements and related disclosures. The Company has not yet selected a transition method nor has it determined the effect of the standard on its ongoing financial reporting.

Off-Balance Sheet Arrangements

As of December 31, 2014, we did not have any off-balance sheet arrangements other than operating leases and contractual commitments for drilling rigs, frac services, firm transportation, gas processing, and gathering and compression services. See "—Debt Agreements and Contractual Obligations—Contractual Obligations" for commitments under operating leases, drilling rig and frac service agreements, firm transportation agreements, gas processing, and gathering and compression service agreements.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward -looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, NGLs, and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward -looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity Hedging Activities

Our primary market risk exposure is in the price we receive for our natural gas, NGLs, and oil production. Realized pricing is primarily driven by spot regional market prices applicable to our U.S. natural gas production and the prevailing worldwide price for crude oil. Pricing for natural gas, NGLs, and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

To mitigate some of the potential negative impact on our cash flow caused by changes in commodity prices, we enter into financial commodity swap contracts to receive fixed prices for a portion of our natural gas, NGLs, and oil production when management believes that favorable future prices can be secured. We hedge part of our production at a fixed price for natural gas at our sales points (New York Mercantile Exchange ("NYMEX") less basis) to mitigate the risk of differentials to the sales point prices. Part of our production is also hedged at NYMEX prices.

Our financial hedging activities are intended to support natural gas, NGLs, and oil prices at targeted levels and to manage our exposure to natural gas, NGLs, and oil price fluctuations. The counterparty is required to make a payment to us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the fixed price is below the settlement price. These contracts may include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, cashless price collars that set a floor and ceiling price for the hedged production, or basis differential swaps. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we and the counterparty to the collars would be required to settle the difference. The Company was not party to any collars as of, or during the year ended, December 31, 2014.

At December 31, 2014, we had in place natural gas, oil, and propane swaps covering portions of our projected production from 2015 through 2020. Our commodity hedge position as of December 31, 2014 is summarized in note 8 to our consolidated financial statements included elsewhere herein. Our financial hedging activities are intended to support natural gas, NGLs, and oil prices at targeted levels and to manage our exposure to natural gas price fluctuations. As amended on February 17, 2015, our revolving credit facility allows us to hedge up to 75% of our projected oil and gas production for the next five years, and 65% of projected production in 2020. Based on our annual production and our fixed price swap contracts in place during 2014, our income before taxes for the year ended December 31, 2014 would have decreased by approximately \$13 million for each \$0.10 decrease per MMBtu in natural gas prices and \$1.00 decrease per Bbl in oil and NGLs prices.

All derivative instruments, other than those that meet the normal purchase and normal sales exception, are recorded at fair market value in accordance with U.S. GAAP and are included in our consolidated balance sheets as assets or liabilities. The fair values of our derivative instruments are adjusted for non -performance risk. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment; all mark -to -market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations. We present the total of realized and unrealized gains or losses on commodity derivatives in our operating revenues as "Commodity derivative fair value gains."

Mark -to -market adjustments of derivative instruments produce earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled. We expect continued volatility in the fair value of our derivative instruments. Our cash flow is only impacted when the associated derivative instrument contract is settled by making or receiving a payment to or from the counterparty. At December 31, 2013 and 2014, the estimated fair value of our commodity derivative instruments was a net asset of \$ 860 million and \$ 1.6 billion, respectively, comprised of current and noncurrent assets and current liabilities. None of these commodity derivative instruments were entered into for trading or speculative purposes.

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By removing price volatility from a portion of our expected natural gas production through December 2020, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flow for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices above the hedge prices.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts (\$ 1.6 billion at December 31, 2014), the sale of our oil and gas production (\$ 192 million at December 31, 2014) which we market to energy companies, end users and refineries, and joint interest receivables (\$116 million at December 31, 2014).

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have economic hedges in place with ten different counterparties, all of which are lenders under our Credit Facility. The fair value of our commodity derivative contracts of approximately \$ 1.6 billion at December 31, 2014 includes the following values by bank counterparty: Credit Suisse — \$268 million; Barclays — \$257 million; JP Morgan — \$253 million; BNP Paribas — \$233 million; Citigroup — \$231 million; Wells Fargo — \$211 million; Scotiabank — \$77 million; Fifth Third Bank — \$31 million; Toronto Dominion Bank — \$28 million; Bank of Montreal — \$4 million. The credit ratings of certain of these banks were downgraded in recent years because of the sovereign debt crisis in Europe. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at December 31, 2014 for each of the European and American banks. We believe that all of these institutions currently are acceptable credit risks. Other than as provided by our revolving credit facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of December 31, 2014, we did not have past-due receivables from, or payables to, any of the counterparties to our derivative contracts.

We are also subject to credit risk due to concentration of our receivables from several significant customers for sales of natural gas. We, generally, do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells.

Interest Rate Risks

Our primary exposure to interest rate risk results from outstanding borrowings under our Credit Facility and Water Facility, and the Midstream Facility of our subsidiary, Antero Midstream. Each of these credit facilities has a floating interest rate. The average annual interest rate incurred on this indebtedness for the year ended December 31, 2014 was approximately 1.99%. A 1.0% increase in each of the applicable average interest rates for the year ended December 31, 2014 would have resulted in an estimated \$11 million increase in interest expense for that period.

Item 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required for this Item are set forth beginning on page F -1 of this report and are incorporated herein by reference.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

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Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a -15(b) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a -15(e) and 15d -15(e) under the Exchange Act) as of the end of the period covered by this annual report. Our disclosure controls and procedures are designed to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2014.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a -15(f) and 15d -15(f) under the Exchange Act) during the fourth quarter of 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

The management of Antero Resources Corporation is responsible for establishing and maintaining adequate internal control over financial reporting for us as defined in Rules 13a -15(f) and 15d -15(f) of the Exchange Act. This system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Our internal control over financial reporting includes those policies and procedures that:

- (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of the assets;
- (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and Directors; and
- (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, a system of internal control over financial reporting can provide only reasonable assurance and may not prevent or detect all misstatements. Further, because of changes in conditions, effectiveness of internal controls over financial reporting may vary over time.

Under the supervision of, and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in *Internal Control—Integrated Framework* in 2013, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management of Antero Resources Corporation concluded that our internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by KPMG LLP, an independent registered public accounting firm which also audited our consolidated financial statements as of and for the year ended December 31, 2014, as stated in their report which appears on page F-3 in this report.

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Item 9B. Other Information

Disclosure Pursuant to Section 13(r) of the Exchange Act

Pursuant to Section 13(r) of the Securities Exchange Act of 1934, we, Antero Resources Corporation, may be required to disclose in our annual and quarterly reports to the Securities and Exchange Commission (the "SEC"), whether we or any of our "affiliates" knowingly engaged in certain activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by US economic sanctions. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable law. Because the SEC defines the term "affiliate" broadly, it includes any entity under common "control" with us (and the term "control" is also construed broadly by the SEC).

The description of the activities below has been provided to us by Warburg Pincus LLC ("WP"), affiliates of which: (i) beneficially own more than 10% of our outstanding common stock and/or are members of our board of directors and (ii) beneficially own more than 10% of the equity interests of, and have the right to designate members of the board of directors of Endurance International Group ("EIG") and Santander Asset Management Investment Holdings Limited ("SAMIH"). EIG and SAMIH may therefore be deemed to be under common "control" with us; however, this statement is not meant to be an admission that common control exists.

The disclosure below relates solely to activities conducted by EIG and SAMIH and its non-U.S. affiliates that may be deemed to be under common "control" with us. The disclosure does not relate to any activities conducted by Antero Resources Corporation or by WP and does not involve our or WP's management. Neither us nor WP has had any involvement in or control over the disclosed activities of SAMIH, and neither us nor WP has independently verified or participated in the preparation of the disclosure. Neither us nor WP is representing as to the accuracy or completeness of the disclosure nor do we or WP undertake any obligation to correct or update it.

As to EIG

We understand that EIG's affiliates intend to disclose in their next annual or quarterly SEC report that:

"On July 2, 2013, the billing information for a subscriber account, or the Subscriber Account, was updated to include Seyed Mahmoud Mohaddes, or Mohaddes. On September 16, 2013, the Office of Foreign Assets Control, or OFAC, designated Mohaddes as a Specially Designated National, or SDN, pursuant to 31 C.F.R. Part 560.304. On or around September 26, 2014, during a routine compliance scan of new and existing subscriber accounts, EIG discovered that Mohaddes, a SDN, was named as an account contact for the Subscriber Account. EIG promptly suspended the Subscriber Account, locked the domain name IOCUKLTLD.COM, which was registered to the Subscriber Account, and reported the domain name to OFAC as potentially the property of a SDN subject to blocking pursuant to Executive Order 13599. Since September 16, 2013, when Mohaddes was added to the SDN list, charges in the total amount of \$120.35 were made to the Subscriber Account for web hosting and domain privacy services. EIG has ceased billing for the Subscriber Account. To date, EIG has not received any correspondence from OFAC regarding this matter.

On July 10, 2014, OFAC designated each of Stars Group Holding, or Stars, and Teleserve Plus SAL, or Teleserve, as SDNs under Executive Order 13224, and their property became subject to blocking pursuant to the Global Terrorism Sanctions Regulations, 31 C.F.R. Part 594. On July 15, 2014, as part of EIG's compliance review processes, EIG discovered that the domain names associated with each of Stars, STARS.COM.NET, and Teleserve, TELESERVEPLUS.COM, or collectively, the Stars/Teleserve Domain Names, were registered through EIG's platform. EIG immediately took steps to suspend and lock the Stars/Teleserve Domain Names to prevent them from being transferred or resolving to a website, and EIG promptly reported the Domain Names as potentially blocked property to OFAC. EIG did not generate any revenue from the Stars/Teleserve Domain Names between when they were added to the SDN list on July 10, 2014 and when EIG discovered that they were registered through EIG's platform on July 15, 2014. To date, EIG has not received any correspondence from OFAC regarding the matter.

On July 15, 2014 during a compliance scan of all domain names on one of our platforms, EIG identified the domain name KAHANETZADAK.COM, or the Domain Name, which was listed as an 'also known as,' or AKA, of the entity Kahane Chai which operates as the American Friends of the United Yeshiva. Kahane Chai was designated as a SDN on November 2, 2001 pursuant to Executive Order 13224. Because the Domain Name was transferred into a

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customer account of one of EIG's resellers, there was no direct financial transaction between EIG and the registered owner of the Domain Name. The Domain Name was suspended upon EIG's discovering it on EIG's platform, and EIG reported the Domain Name to OFAC as potentially the property of a SDN. To date, EIG have not received any correspondence from OFAC regarding the matter."

As to SAMIH

We understand that SAMIH's affiliates intend to disclose in their next annual or quarterly SEC report that:

"Santander UK holds frozen savings and current accounts for three customers resident in the U.K. who are currently designated by the U.S. for terrorism. The accounts held by each customer were blocked after the customer's designation and remained blocked and dormant throughout 2014. No revenue has been generated by Santander UK on these accounts. The bank account held for one of these customers was closed in the fourth quarter of 2014.

An Iranian national, resident in the U.K., who is currently designated by the U.S. under the Iranian Financial Sanctions Regulations and the Weapons of Mass Destruction Proliferators Sanctions Regulations ("NPWMD sanctions program"), holds a mortgage with Santander UK that was issued prior to any such designation. No further drawdown has been made (or would be permitted) under this mortgage although Santander UK continues to receive repayment installments. In 2014, total revenue in connection with the mortgage was approximately £2,580 and net profits were negligible relative to the overall profits of Santander UK. The same Iranian national also holds two investment accounts with Santander Asset Management UK Limited. The accounts have remained frozen during 2014. The investment returns are being automatically reinvested, and no disbursements have been made to the customer. Total revenue for the Santander Group in connection with the investment accounts was £250 and net profits in 2014 were negligible relative to the overall profits of Banco Santander, S.A.

In addition, during the third quarter 2014, Santander UK identified two additional customers: a UK national designated by the U.S. under the NPWMD sanctions program held a business account. No transactions were made and the account was closed in the fourth quarter of 2014. No revenue or profit has been generated. A second UK national designated by the US for reasons of terrorism held a personal current account and a personal credit card account, both of which were closed in the third quarter of 2014. Although transactions took place on the current account during the third quarter of 2014, revenue and profits generated were negligible. No transactions took place on the credit card."

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

Pursuant to General Instruction G(3) to Form 10 -K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

Directors and Executive Officers

The following table sets forth names, ages and titles of our directors and executive officers as of December 31, 2014.

Name	Age	Title
Paul M. Rady	61	Chairman of the Board, Director and Chief Executive Officer
Glen C. Warren, Jr.	58	Director, President, Chief Financial Officer and Secretary
Kevin J. Kilstrom	60	Vice President—Production
Alvyn A. Schopp	56	Chief Administrative Officer and Regional Vice President
Ward D. McNeilly	64	Vice President—Reserves, Planning and Midstream
Peter R. Kagan	46	Director
W. Howard Keenan, Jr.	64	Director
Christopher R. Manning	47	Director
Richard W. Connor	65	Director
Robert J. Clark	69	Director
Benjamin A. Hardesty	65	Director
James R. Levy	38	Director

Set forth below is the description of the backgrounds of our directors and executive officers.

Paul M. Rady has served as Chief Executive Officer and Chairman of the Board of Directors since May 2004. Mr. Rady also served as Chief Executive Officer and Chairman of the Board of Directors of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Mr. Rady also serves as Chairman of the Board of Directors of the general partner of Antero Midstream Partners LP. Prior to Antero Resources Corporation, Mr. Rady served as President, CEO and Chairman of Pennaco Energy from 1998 until its sale to Marathon in early 2001. Prior to Pennaco, Mr. Rady was with Barrett Resources from 1990 until 1998 where he initially was recruited as Chief Geologist in 1990, then served as Exploration Manager, EVP Exploration, President, COO and Director and ultimately CEO. Mr. Rady began his career with Amoco where he served 10 years as a geologist focused on the Rockies and Mid-Continent. Mr. Rady holds a B.A. in Geology from Western State College of Colorado and M.Sc. in Geology from Western Washington University.

Mr. Rady's significant experience as a chief executive of oil and gas companies, together with his training as a geologist and broad industry knowledge, enable Mr. Rady to provide the board with executive counsel on a full range of business, strategic and professional matters.

Glen C. Warren, Jr. has served as President, Chief Financial Officer and Secretary and as a director since May 2004. Mr. Warren also served as President and Chief Financial Officer and as a director of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Mr. Warren also serves on the Board of Directors of the general partner of Antero Midstream Partners LP. Prior to Antero Resources Corporation, Mr. Warren served as EVP, CFO and Director of Pennaco Energy from 1998 until its sale to Marathon in early 2001. Mr. Warren spent 10 years as a natural resources investment banker focused on equity and debt financing and M&A advisory with Lehman Brothers, Dillon Read & Co. Inc. and Kidder, Peabody & Co. Mr. Warren began his career as a landman in the Gulf Coast region with Amoco, where he spent six years. Mr. Warren holds a B.A. from the University of Mississippi, a J.D. from the University of Mississippi School of Law and an M.B.A. from the Anderson School of Management at U.C.L.A.

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Mr. Warren's significant experience as a chief financial officer of oil and gas companies, together with his experience as an investment banker and broad industry knowledge, enable Mr. Warren to provide the board with executive counsel on a full range of business, strategic, financial and professional matters.

Kevin J. Kilstrom has served as Vice President of Production since June 2007. Mr. Kilstrom was a Manager of Petroleum Engineering with AGL Energy of Sydney, Australia from 2006 to 2007. Prior to AGL, Mr. Kilstrom was with Marathon Oil as an Engineering Consultant and Asset Manager from 2003 to 2006 and as a Business Unit Manager for Marathon's Powder River coal bed methane assets from 2001 to 2003. Mr. Kilstrom also served as a member of the board of directors of three Marathon subsidiaries from October 2003 through May 2005. Mr. Kilstrom was an Operations Manager and reserve engineer at Pennaco Energy from 1999 to 2001. Mr. Kilstrom was at Amoco for more than 22 years prior to 1999. Mr. Kilstrom holds a B.S. in Engineering from Iowa State University and an M.B.A. from DePaul University.

Alvyn A. Schopp has served as Chief Administrative Officer, Regional Vice President, and Treasurer since September 2013. Mr. Schopp also served as Vice President of Accounting and Administration and Treasurer from January 2005 to September 2013, as Controller and Treasurer from 2003 to 2005 and as Vice President of Accounting and Administration and Treasurer of our predecessor company, Antero Resources Corporation, from January 2005 until its ultimate sale to XTO Energy, Inc. in April 2005. From 1993 to 2000, Mr. Schopp was CFO, Director and ultimately CEO of T-Netix. From 1980 to 1993 Mr. Schopp was with KPMG LLP, most recently as a Senior Manager. Mr. Schopp holds a B.B.A. from Drake University.

Ward D. McNeilly serves as Vice President of Reserves, Planning & Midstream, and has been with the Company since October 2010. Mr. McNeilly has 34 years of experience in oil and gas asset management, operations, and reservoir management. From 2007 to October 2010, Mr. McNeilly was BHP Billiton's Gulf of Mexico Operations Manager. From 1996 through 2007, Mr. McNeilly served in various North Sea and Gulf of Mexico Deepwater operations and asset management positions with Amoco and then BP. Mr. McNeilly served in a number of different domestic and international positions with Amoco from 1979 to 1996. Mr. McNeilly holds a B.S. in Geological Engineering from the Mackay School of Mines at the University of Nevada.

Peter R. Kagan has served as a director since 2004. Mr. Kagan has been with Warburg Pincus since 1997 where he leads the firm's investment activities in energy and natural resources. He is a Partner of Warburg Pincus & Co. and a Managing Director of Warburg Pincus LLC. He is also a member of Warburg Pincus LLC's Executive Management Group. Mr. Kagan received a B.A. degree cum laude from Harvard College and J.D. and M.B.A. degrees with honors from the University of Chicago. Prior to joining Warburg Pincus, he worked in investment banking at Salomon Brothers in both New York and Hong Kong. Mr. Kagan currently also serves on the boards of directors of the following public companies: Laredo Petroleum, MEG Energy Corp. and Targa Resources Corp., as well as the boards of several private companies. Mr. Kagan also serves on the Board of Directors of the general partner of Antero Midstream Partners LP. In addition, he is a director of Resourcea for the Future and a trustee of Milton Academy.

Mr. Kagan has significant experience with energy companies and investments and broad knowledge of the oil and gas industry. We believe his background and skill set make Mr. Kagan well-suited to serve as a member of our board of directors.

W. Howard Keenan, Jr. has served as a director since 2004. Mr. Keenan has over thirty-five years of experience in the financial and energy businesses. Since 1997, he has been a Member of Yorktown Partners LLC, a private investment manager focused on the energy industry. Mr. Keenan also serves on the Board of Directors of the general partner of Antero Midstream Partners LP. From 1975 to 1997, he was in the Corporate Finance Department of Dillon, Read & Co. Inc. and active in the private equity and energy areas, including the founding of the first Yorktown Partners fund in 1991. He is serving or has served as a director of multiple Yorktown Partners portfolio companies. Mr. Keenan holds an B.A. degree cum laude from Harvard College and an M.B.A. degree from Harvard University.

Mr. Keenan has significant experience with energy companies and investments and broad knowledge of the oil and gas industry. We believe his background and skill set make Mr. Keenan well-suited to serve as a member of our board of directors.

Christopher R. Manning has served as a director since 2005. Mr. Manning has been a Partner with Trilantic Capital Partners since its formation and spin out from Lehman Brothers Merchant Banking in April 2009, and is currently a member of its Executive Committee and Chairman of Trilantic Energy Partners. His primary focus is on investments in the energy sector. Mr. Manning joined Lehman Brothers Merchant Banking in 2000 and was concurrently the Head of Lehman Brothers' Investment Management Division, including both the Asset Management and Private Equity businesses, in Asia-Pacific from 2006 to 2008. He was also a member of the Global Investment Management Division Executive Committee and the Private Equity Division Operating Committee. Prior to Lehman Brothers, Mr. Manning was the chief financial officer of The Wing Group, a developer of international power projects. Prior

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to The Wing Group, he was in the investment banking department of Kidder, Peabody & Co., where he worked on M&A and corporate finance transactions in the energy sector. Mr. Manning currently serves on the boards of The Crosa Group, Enduring Resources, LLC, Templar Energy LLC, Trail Ridge Energy Partners II LLC, Velvet Energy, Ltd., and Ward Energy Partners. Mr. Manning also serves on the Board of Directors of the general partner of Antero Midstream Partners LP. Mr. Manning was previously Chairman of the Board of LB Pacific and TLP Energy and a director of Mediterranean Resources and VantaCore Partners. Mr. Manning holds an M.B.A. from The Wharton School of the University of Pennsylvania and a B.B.A. from the University of Texas at Austin.

Mr. Manning has significant experience with energy companies and investments and broad knowledge of the oil and gas industry. We believe his background and skill set make Mr. Manning well-suited to serve as a member of our board of directors.

Richard W. Connor has served as a director and chairman of our audit committee since September 1, 2013. Prior to his retirement in September 2009, Mr. Connor was an audit partner with KPMG LLP, or KPMG, where he principally served publicly traded clients in the energy, mining, telecommunications, and media industries for 38 years. Mr. Connor was elected to the partnership in 1980 and was appointed to KPMG's SEC Reviewing Partners Committee in 1987 where he served until his retirement. From 1996 to September 2008, he served as the Managing Partner of KPMG's Denver office. Mr. Connor earned his B.S. degree in accounting from the University of Colorado. Mr. Connor is a member of the Board of Directors of Zayo Group LLC, a provider of bandwidth infrastructure and colocation services. Mr. Connor is also a director of Centerra Gold, Inc. (TSX: CGT), a Toronto-based gold mining company listed on the Toronto Stock Exchange. Mr. Connor also serves as a director and chairman of the audit committee of the general partner of Antero Midstream Partners LP.

Mr. Connor has experience in technical accounting and auditing matters, knowledge of SEC filing requirements and experience with a variety of energy clients. We believe his background and skill set make Mr. Connor well-suited to serve as a member of our board of directors and as chairman of our audit committee.

Robert J. Clark has served as a director, member of the audit committee and Chairman of the compensation committee since our initial public offering in October 2013. Mr. Clark has been Chairman and Chief Executive Officer of 3 Bear Energy, LLC, a midstream energy company with operations in the Rocky Mountains, since its formation in March 2013. Prior to the formation of 3 Bear Energy LLC, Mr. Clark formed, operated and subsequently sold Bear Tracker Energy in February 2013 (to Summit Midstream Partners, LP), a portion of Bear Cub Energy in April 2007 (to Regency Energy Partners, L.P.) and the remaining portion in December 2008 (to GeoPetro Resources Company) and Bear Paw Energy in 2001 (to ONEOK Partners, L.P., formerly Northern Border Partners, L.P.). Mr. Clark was President of SOCO Gas Systems, Inc. and Vice President - Gas Management for Snyder Oil Corporation from 1988 to 1995. Mr. Clark served as Vice President Gas - Gathering, Processing and Marketing of Ladd Petroleum Corporation, an affiliate of General Electric, from 1985 to 1988. Prior to 1985, Mr. Clark held various management positions with NICOR, Inc. Mr. Clark received his Bachelor of Science degree from Bradley University and his Master's Degree in Business Administration from Northern Illinois University. Mr. Clark is a member of the board of trustees of Bradley University and serves on the board of trustees of Children's Hospital Colorado Foundation.

Mr. Clark has significant experience with energy companies, with over 45 years of experience in the industry. We believe his background and skill set make Mr. Clark well-suited to serve as a member of our board of directors.

Benjamin A. Hardesty has served as a director, chairman of our nominating and governance committees, and member of our compensation committee since our initial public offering in October 2013. He has also served as a member of our audit committee since September 2014. Mr. Hardesty has been the owner of Alta Energy LLC, a consulting business focused on oil and natural gas in the Appalachian Basin and onshore United States since May 2010. Mr. Hardesty retired as president of Dominion E&P, Inc., a subsidiary of Dominion Resources Inc. (NYSE: D) engaged in the exploration and production of natural gas in North America, a position he had held since September 2007. Mr. Hardesty joined Dominion in 1995 and served as president of Dominion Appalachian Development, Inc. until 2000 and general manager and vice president—Northeast Gas Basins until 2007. Mr. Hardesty was a member of the board of directors of KLX, Inc. (NASDAQ:KLXI). From 1978 to 1995, Mr. Hardesty held operating and executive positions with Development Drilling Corp. and Stonewall Gas Company. Mr. Hardesty received his Bachelor of Science degree from West Virginia University and his Master of Science degree from The George Washington University. Mr. Hardesty served as an active duty officer in the U.S. Army Security Agency. Mr. Hardesty is a director emeritus and past president of the West Virginia Oil & Natural Gas Association and past president of the Independent Oil & Gas Association of West Virginia. Additionally, Mr. Hardesty is a trustee and past chairman of the Nature Conservancy of West Virginia and a member of the board of directors of the West Virginia Chamber of Commerce. Mr. Hardesty serves as a member of the Visiting Committee of the Petroleum Natural Gas Engineering Department of the Statler College of Engineering and Mineral Resources at West Virginia University.

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Mr. Hardesty has significant experience in the natural gas industry, including in our areas of operation. We believe his background and skill set make Mr. Hardesty well suited to serve as a member of our board of directors.

James R. Levy has served as a director and member of our audit and compensation committees since our initial public offering in October 2013. Mr. Levy joined Warburg Pincus in 2006 and focuses on investments in the energy industry. Mr. Levy is a Partner of Warburg Pincus & Co. and a Managing Director of Warburg Pincus LLC. Prior to joining Warburg Pincus, Mr. Levy worked as a private equity investor at Kohlberg & Company and in M&A advisory at Wasserstein Perella & Co. Mr. Levy currently serves on the board of directors of Laredo Petroleum and several private companies. He is a former director of Broad Oak Energy. Mr. Levy received a Bachelor of Arts degree from Yale University.

Mr. Levy has significant experience with energy companies and investments and broad knowledge of the oil and gas industry. We believe his background and skill set make Mr. Levy well -suited to serve as a member of our board of directors.

Item 11. Executive Compensation

Pursuant to General Instruction G(3) to Form 10 -K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Pursuant to General Instruction G(3) to Form 10 -K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

Item 13. Certain Relationships and Related Transactions and Director Independence

Pursuant to General Instruction G(3) to Form 10 -K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

Item 14. Principal Accountant Fees and Services

Pursuant to General Instruction G(3) to Form 10 -K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

Item 15. Exhibits and Financial Statement Schedules**(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules**

The consolidated financial statements are listed on the Index to Financial Statements to this report beginning on page F -1.

(a)(3) Exhibits.

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
2.1	Purchase and Sale Agreement, dated June 1, 2012, between Antero Resources Corporation and Vanguard Permian, LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on July 5, 2012)
2.2	Purchase and Sale Agreement by and among Antero Resources Piceance LLC, Antero Resources Pipeline LLC and Ursa Resources Group II LLC, dated as of November 1, 2012 (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 6, 2012).
3.1	Amended and Restated Certificate of Incorporation of Antero Resources Corporation (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
3.2	Amended and Restated Bylaws of Antero Resources Corporation (incorporated by reference to Exhibit 3.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
4.1	Indenture related to the 7.25% Senior Notes due 2019, dated as of August 1, 2011, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on August 1, 2011).
4.2	Form of 7.25% Senior Note due 2019 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 333-164876) filed on August 1, 2011).
4.3	First Supplemental Indenture related to the 7.25% Senior Notes due 2019, dated as of November 12, 2012, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
4.4	Second Supplemental Indenture related to the 7.25% Senior Notes due 2019, dated as of October 16, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
4.5	Third Supplemental Indenture related to the 7.25% Senior Notes due 2019, dated as of October 21, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
4.6	Fourth Supplemental Indenture related to the 7.25% Senior Notes due 2019, dated as of December 31, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.6 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
4.7	Fifth Supplemental Indenture related to the 7.25% Senior Notes due 2019, dated as of March 18, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).

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- 4.8 Indenture related to the 6.0% Senior Notes due 2020, dated as of November 19, 2012, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 20, 2012).
- 4.9 Form of 6.0% Senior Note due 2020 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 20, 2012).
- 4.10 First Supplemental Indenture related to the 6.0% Senior Notes due 2020, dated October 16, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.10 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
- 4.11 Second Supplemental Indenture related to the 6.0% Senior Notes due 2020, dated October 21, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.11 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
- 4.12 Third Supplemental Indenture related to the 6.0% Senior Notes due 2020, dated December 31, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.12 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
- 4.13 Fourth Supplemental Indenture related to the 6.0% Senior Notes due 2020, dated March 18, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).
- 4.14 Registration Rights Agreement related to the 6.0% Senior Notes due 2020, dated as of November 19, 2012, by and among Antero Resources LLC and the other parties named therein and Wells Fargo Securities as representative for the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 20, 2012).
- 4.15 Registration Rights Agreement related to the 6.0% Senior Notes due 2020, dated as of February 4, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and J.P. Morgan Securities LLC as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 333-164876) filed on February 4, 2013).
- 4.16 Indenture related to the 5.375% Senior Notes due 2021, dated as of November 5, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).
- 4.17 Form of 5.375% Senior Note due 2021 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).
- 4.18 First Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated as of December 31, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.17 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
- 4.19 Second Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated as of March 18, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).
- 4.20 Registration Rights Agreement related to the 5.375% Senior Notes due 2021, dated as of November 5, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and J.P. Morgan Securities LLC as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).

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- 4.21 Registration Rights Agreement, dated as of October 16, 2013, by and among Antero Resources Corporation and the owners of the membership interests in Antero Resources Investment LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
- 4.22 Indenture related to the 5.125% Senior Notes due 2022, dated as of May 6, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
- 4.23 Form of 5.125% Senior Note due 2022 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
- 4.24 First Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated as of November 24, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Antero Resource Corporation's Registration Statement on Form S-4 (Commission File No. 333-200605) filed on November 26, 2014).
- 4.25 Registration Rights Agreement related to the 5.125% Senior Notes due 2022, dated as of May 6, 2014, by and among Antero Resources Corporation and the other parties named therein and J.P. Morgan Securities LLC as representative for the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
- 4.26 Registration Rights Agreement related to the 5.125% Senior Notes due 2022, dated as of September 18, 2014, by and among Antero Resources Corporation and the other parties named therein and J.P. Morgan Securities LLC as representative for the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 24, 2014).
- 10.1 Contribution Agreement, dated as of October 16, 2013, by and between Antero Resources Corporation and Antero Resources Midstream LLC (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
- 10.2 Form of Indemnification Agreement (incorporated by reference to Exhibit 10.15 to Amendment No. 3 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on September 24, 2013).
- 10.3 Agreement and Plan of Merger, dated as of October 1, 2013, by and among Antero Resources Corporation, Antero Resources LLC and Antero Resources Investment LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on October 11, 2013).
- 10.4 Antero Resources Corporation Long-Term Incentive Plan, effective as of October 1, 2013 (incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-8 (Commission File No. 001- 36120) filed on October 11, 2013).
- 10.5 Limited Liability Company Agreement of Antero Resources Midstream LLC (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
- 10.6 Fourth Amended And Restated Credit Agreement dated as of November 4, 2010 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, N.A., as Syndication Agent, Bank of Scotland Plc, Union Bank, N.A., Credit Agricole Corporate and Investment Bank, BNP Paribas and Deutsche Bank Trust Company Americas, as Co-Documentation Agents and J.P. Morgan Securities LLC and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 8, 2010).
- 10.7 First Amendment to the Fourth Amended And Restated Credit Agreement, dated as of May 12, 2011, among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 333-164876) filed on May 16, 2011).

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- 10.8 Second Amendment to Fourth Amended And Restated Credit Agreement dated as of July 8, 2011 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on July 11, 2011).
- 10.9 Third Amendment to Fourth Amended And Restated Credit Agreement dated as of October 26, 2011 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on October 28, 2011).
- 10.10 Fourth Amendment to Fourth Amended And Restated Credit Agreement dated as of May 4, 2012 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on May 7, 2012).
- 10.11 Fifth Amendment to Fourth Amended and Restated Credit Agreement dated as of October 25, 2012 among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party hereto, and JP Morgan Chase Bank, N.A. as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on October 26, 2012).
- 10.12 Sixth Amendment to Fourth Amended and Restated Credit Agreement dated as of May 9, 2013 by and among Antero Resources Appalachian Corporation and JPMorgan Chase Bank, N.A., as administrative agent for the lenders, to increase the borrowing base and lender commitments and amend the current ratio covenant under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q (Commission File No. 333-164876) filed on May 13, 2013).
- 10.13 Seventh Amendment to Fourth Amended and Restated Credit Agreement dated as of June 27, 2013 by and among Antero Resources Corporation and JPMorgan Chase Bank, N.A., as administrative agent for the lenders, to increase the borrowing base and lender commitments and amend the current ratio covenant under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 333-164876) filed on August 9, 2013).
- 10.14 Eighth Amendment to Fourth Amended and Restated Credit Agreement dated as of August 29, 2013 by and among Antero Resources Corporation and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.23 to Registration Statement on Form S-1/A (Commission File No. 333-189284) filed on August 30, 2013).
- 10.15 Ninth Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 21, 2013, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 22, 2013).
- 10.16 Tenth Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 28, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).
- 10.17 Eleventh Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 28, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).

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- 10.18 Twelfth Amendment to Fourth Amended and Restated Credit Agreement, dated as of July 28, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on July 31, 2014).
- 10.19 Thirteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as September 8, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 10, 2014).
- 10.20 Fourteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as October 16, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 22, 2014).
- 10.21 Fifteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as November 10, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 17, 2014).
- 10.22 Credit Agreement, dated as of February 28, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).
- 10.23 First Amendment to Credit Agreement, dated as of May 5, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
- 10.24 Second Amendment to Credit Agreement, dated as of July 28, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on July 31, 2014).
- 10.25 Third Amendment to Credit Agreement, dated as of October 16, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 22, 2014).
- 10.26 Fourth Amendment to Credit Agreement, dated as of November 10, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.7 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 17, 2014).
- 10.27 Fifth Amendment to Credit Agreement, dated as of November 7, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.6 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 17, 2014).
- 10.28* Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement under the Antero Resources Corporation Long-Term Incentive Plan.
- 10.29 Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to Midstream Partners' Registration Statement on Form S-8 (Commission File No. 001-36719) filed on November 12, 2014).

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- 10.30 Form of Phantom Unit Grant Notice and Phantom Unit Agreement under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.4 to Midstream Partners' Registration Statement on Form S-8 (Commission File No. 001-36719) filed on November 12, 2014).
- 10.31 Form of Restricted Unit Grant Notice and Restricted Unit Agreement under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.4 to Midstream Partners' Registration Statement on Form S-8 (Commission File No. 001-36719) filed on November 12, 2014).
- 10.32 Letter Agreement dated June 29, 2012 by and among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation, Antero Resources Appalachian Corporation and JPMorgan Chase Bank N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on July 5, 2012).
- 10.33 Letter Agreement dated November 19, 2012 by and among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC, and Antero Resources Appalachian Corporation and JPMorgan Chase Bank N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on December 10, 2012).
- 10.34 Letter Agreement dated December 7, 2012 by and among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC, and Antero Resources Appalachian Corporation and JPMorgan Chase Bank N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 333-164876) filed on December 10, 2012).
- 10.35 Letter Agreement dated February 4, 2013 by and among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC, and Antero Resources Appalachian Corporation and JPMorgan Chase Bank, N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 333-164876) filed on February 4, 2013).
- 12.1* Computation of Ratio of Earnings to Fixed Charges.
- 21.1* Subsidiaries of Antero Resources Corporation.
- 23.1* Consent of KPMG, LLP.
- 23.2* Consent of DeGolyer and MacNaughton.
- 31.1* Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
- 31.2* Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
- 32.1* Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
- 32.2* Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
- 99.1* Report of DeGolyer and MacNaughton, dated as of January 19, 2015, for proved reserves as of December 31, 2014.
- 99.2 Report of DeGolyer and MacNaughton, dated as of January 15, 2014, for proved reserves as of December 31, 2013 (incorporated by reference to Exhibit 99.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on February 7, 2013).
- 99.3 Report of DeGolyer and MacNaughton for proved reserves as of December 31, 2012 relating to Marcellus and Upper Devonian resources in the Appalachian Basin (incorporated by reference to Exhibit 99.1 to Amendment No. 2 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).

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- 99.4 Report of DeGolyer and MacNaughton for probable reserves as of December 31, 2012 relating to Marcellus and Upper Devonian resources in the Appalachian Basin (incorporated by reference to Exhibit 99.2 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).
- 99.5 Report of DeGolyer and MacNaughton for possible reserves as of December 31, 2012 relating to Marcellus and Upper Devonian resources in the Appalachian Basin (incorporated by reference to Exhibit 99.3 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).
- 99.6 Report of DeGolyer and MacNaughton for proved reserves as of December 31, 2012 relating to Utica Shale resources in the Appalachian Basin (incorporated by reference to Exhibit 99.4 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).
- 99.7 Report of DeGolyer and MacNaughton for probable reserves as of December 31, 2012 relating to Utica Shale resources in the Appalachian Basin (incorporated by reference to Exhibit 99.5 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).
- 99.8 Report of DeGolyer and MacNaughton for possible reserves as of December 31, 2012 relating to Utica Shale resources in the Appalachian Basin (incorporated by reference to Exhibit 99.6 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).
- 101* The following financial information from this Form 10-K of Antero Resources Corporation for the year ended December 31, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations and Comprehensive Income (Loss), (iii) Consolidated Statements of Equity, (iv) Consolidated Statements of Cash Flows, and (v) Notes to the Consolidated Financial Statements, tagged as blocks of text.

The exhibits marked with the asterisk symbol (*) are filed or furnished with this Annual Report on Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ANTERO RESOURCES CORPORATION

By: /s/ GLEN C. WARREN, JR.
Glen C. Warren, Jr.
President, Chief Financial Officer and Secretary

Date: February 25, 2015

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Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant in the capacities and on the dates indicated.

Signature	Title	Date
<u>/s/ PAUL M. RADY</u> Paul M. Rady	Chairman of the Board, Director and Chief Executive officer (principal executive officer)	February 25, 2015
<u>/s/ GLEN C. WARREN, JR.</u> Glen C. Warren, Jr.	President, Director, Chief Financial Officer and Secretary (principal financial officer)	February 25, 2015
<u>/s/ K. PHIL YOO</u> K. Phil Yoo	Chief Accounting Officer and Corporate Controller (principal accounting officer)	February 25, 2015
<u>/s/ ROBERT J. CLARK</u> Robert J. Clark	Director	February 25, 2015
<u>/s/ RICHARD W. CONNOR</u> Richard W. Connor	Director	February 25, 2015
<u>/s/ BENJAMIN A. HARDESTY</u> Benjamin A. Hardesty	Director	February 25, 2015
<u>/s/ PETER R. KAGAN</u> Peter R. Kagan	Director	February 25, 2015
<u>/s/ W. HOWARD KEENAN, JR.</u> W. Howard Keenan, Jr.	Director	February 25, 2015
<u>/s/ JAMES R. LEVY</u> James R. Levy	Director	February 25, 2015
<u>/s/ CHRISTOPHER R. MANNING</u> Christopher R. Manning	Director	February 25, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Antero Resources Corporation:

We have audited the accompanying consolidated balance sheets of Antero Resources Corporation and subsidiaries (the Company) as of December 31, 2013 and 2014, and the related consolidated statements of operations and comprehensive income (loss), equity, and cash flows for each of the years in the three -year period ended December 31, 2014. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Antero Resources Corporation and subsidiaries as of December 31, 2013 and 2014, and the results of their operations and their cash flows for each of the years in the three -year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Antero Resources Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 25, 2015 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Denver, Colorado
February 25, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Antero Resources Corporation:

We have audited Antero Resources Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Antero Resources Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting within *Item 9A. Controls and Procedures*. Our responsibility is to express an opinion on Antero Resources Corporation's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that the transactions are recorded as necessary to permit preparation of financial statements in accordance with general accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Antero Resources Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Antero Resources Corporation and subsidiaries as of December 31, 2013 and 2014, and the related consolidated statements of operations and comprehensive income (loss), equity, and cash flows for each of the years in the three-year period ended December 31, 2014, and our report dated February 25, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Denver, Colorado
February 25, 2015

ANTERO RESOURCES CORPORATION

Consolidated Balance Sheets

December 31, 2013 and 2014

(In thousands, except share amounts)

	2013	2014
Assets		
Current assets:		
Cash and cash equivalents	\$ 17,487	245,979
Accounts receivable, net of allowance for doubtful accounts of \$1,251 in 2013 and 2014	30,610	116,203
Accrued revenue	96,825	191,558
Derivative instruments	183,000	692,554
Other	5,642	5,866
Total current assets	<u>333,564</u>	<u>1,252,160</u>
Property and equipment:		
Natural gas properties, at cost (successful efforts method):		
Unproved properties	1,513,136	2,060,936
Proved properties	3,621,672	6,515,221
Fresh water distribution systems	231,684	421,012
Gathering systems and facilities	584,626	1,197,239
Other property and equipment	15,757	37,687
	<u>5,966,875</u>	<u>10,232,095</u>
Less accumulated depletion, depreciation, and amortization	<u>(407,219)</u>	<u>(879,643)</u>
Property and equipment, net	<u>5,559,656</u>	<u>9,352,452</u>
Derivative instruments	677,780	899,997
Other assets, net	42,581	68,886
Total assets	<u>\$6,613,581</u>	<u>11,573,495</u>
Liabilities and Equity		
Current liabilities:		
Accounts payable	\$ 370,640	531,564
Accrued liabilities	77,126	168,614
Revenue distributions payable	96,589	182,352
Deferred income tax liability	69,191	260,373
Derivative instruments	646	—
Other	8,037	12,202
Total current liabilities	<u>622,229</u>	<u>1,155,105</u>
Long-term liabilities:		
Long-term debt	2,078,999	4,362,550
Deferred income tax liability	278,580	534,423
Other long-term liabilities	35,113	47,587
Total liabilities	<u>3,014,921</u>	<u>6,099,665</u>
Commitments and contingencies (notes 11 and 12)		
Equity:		
Stockholders' equity:		
Common stock, \$0.01 par value; authorized - 1,000,000,000 shares; issued and outstanding 262,049,659 shares and 262,071,642 shares, respectively	2,620	2,621
Preferred stock, \$0.01 par value; authorized - 50,000,000 shares; none issued	—	—
Additional paid-in capital	3,402,180	3,513,725
Accumulated earnings	193,860	867,447
Total stockholders' equity	<u>3,598,660</u>	<u>4,383,793</u>
Noncontrolling interest in consolidated subsidiary	—	1,090,037
Total equity	<u>3,598,660</u>	<u>5,473,830</u>
Total liabilities and equity	<u>\$6,613,581</u>	<u>11,573,495</u>

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION
Consolidated Statements of Operations and Comprehensive Income (Loss)
Years Ended December 31, 2012, 2013 and 2014
(In thousands, except share and per share amounts)

	2012	2013	2014
Revenue:			
Natural gas sales	\$ 259,743	689,198	1,301,349
Natural gas liquids sales	3,719	111,663	328,323
Oil sales	1,520	20,584	107,080
Gathering, compression, and water distribution	—	—	22,075
Marketing	—	—	53,604
Commodity derivative fair value gains	179,546	491,689	868,201
Gain on sale of gathering system	291,190	—	40,000
Total revenue	<u>735,718</u>	<u>1,313,134</u>	<u>2,720,632</u>
Operating expenses:			
Lease operating	6,243	9,439	29,341
Gathering, compression, processing, and transportation	91,094	218,428	461,413
Production and ad valorem taxes	20,210	50,481	87,918
Marketing	—	—	103,435
Exploration	14,675	22,272	27,893
Impairment of unproved properties	12,070	10,928	15,198
Depletion, depreciation, and amortization	102,026	233,876	477,896
Accretion of asset retirement obligations	101	1,065	1,271
General and administrative (including equity-based compensation expense of \$365,280 and \$112,252 in 2013 and 2014, respectively)	45,284	425,438	216,533
Total operating expenses	<u>291,703</u>	<u>971,927</u>	<u>1,420,898</u>
Operating income	<u>444,015</u>	<u>341,207</u>	<u>1,299,734</u>
Other expenses:			
Interest	(97,510)	(136,617)	(160,051)
Loss on early extinguishment of debt	—	(42,567)	(20,386)
Total other expenses	<u>(97,510)</u>	<u>(179,184)</u>	<u>(180,437)</u>
Income from continuing operations before income taxes and discontinued operations	346,505	162,023	1,119,297
Provision for income tax expense	<u>(121,229)</u>	<u>(186,210)</u>	<u>(445,672)</u>
Income (loss) from continuing operations	225,276	(24,187)	673,625
Discontinued operations:			
Income (loss) from sale of discontinued operations, net of income tax (expense) benefit of \$272,553, \$(3,249), and \$(1,354) in 2012, 2013, and 2014, respectively	<u>(510,345)</u>	<u>5,257</u>	<u>2,210</u>
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(285,069)	(18,930)	675,835
Net income and comprehensive income attributable to noncontrolling interest	—	—	2,248
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	<u>\$ (285,069)</u>	<u>(18,930)</u>	<u>673,587</u>
Earnings (loss) per common share:			
Continuing operations	\$ 0.86	(0.09)	2.56
Discontinued operations	(1.95)	0.02	0.01
Total	<u>\$ (1.09)</u>	<u>(0.07)</u>	<u>2.57</u>
Earnings (loss) per common share—assuming dilution			
Continuing operations	\$ 0.86	(0.09)	2.56
Discontinued operations	(1.95)	0.02	0.01
Total	<u>\$ (1.09)</u>	<u>(0.07)</u>	<u>2.57</u>
Weighted average number of shares outstanding:			
Basic	262,049,659	262,049,659	262,053,868
Diluted	262,049,659	262,049,659	262,068,106

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION
Consolidated Statements of Equity
Years ended December 31, 2012 , 2013 , and 2014
(In thousands , except share and unit amounts)

	Members' equity	Common Stock	Additional paid- in capital	Accumulated earnings	Noncontrolling Interests	Total equity
Balances, December 31, 2011	\$ 1,460,947	—	—	497,859	—	1,958,806
Net loss and comprehensive loss	—	—	—	(285,069)	—	(285,069)
Balances, December 31, 2012	1,460,947	—	—	212,790	—	1,673,737
Merger of Antero Resources LLC and Antero Resources Corporation	(1,460,947)	2,244	1,458,703	—	—	—
Issuance of 37,674,659 shares of \$0.01 par value common stock in public offering, net of underwriter discounts and offering costs of \$79,112	—	376	1,578,197	—	—	1,578,573
Equity-based compensation	—	—	365,280	—	—	365,280
Net loss and comprehensive loss	—	—	—	(18,930)	—	(18,930)
Balances, December 31, 2013	—	2,620	3,402,180	193,860	—	3,598,660
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	—	1	(142)	—	—	(141)
Equity-based compensation	—	—	111,687	—	565	112,252
Issuance of common units in subsidiary - Antero Midstream Partners LP	—	—	—	—	1,087,224	1,087,224
Net income and comprehensive income	—	—	—	673,587	2,248	675,835
Balances, December 31, 2014	\$ —	2,621	3,513,725	867,447	1,090,037	5,473,830

See accompanying notes to consolidated financial statements .

ANTERO RESOURCES CORPORATION
Consolidated Statements of Cash Flows
Years ended December 31, 2012, 2013, and 2014
(In thousands)

	2012	2013	2014
Cash flows from operating activities:			
Net income (loss) including noncontrolling interest	\$ (285,069)	(18,930)	675,835
Adjustment to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, amortization, and accretion	102,127	234,941	479,167
Impairment of unproved properties	12,070	10,928	15,198
Derivative fair value gain	(179,546)	(491,689)	(868,201)
Cash receipts for settled derivatives	178,491	163,570	135,784
Deferred income tax expense	106,229	190,210	445,672
Gain on sale of assets	(291,190)	—	(40,000)
Equity-based compensation expense	—	365,280	112,252
Loss on early extinguishment of debt	—	42,567	20,386
Loss (gain) on sale of discontinued operations	795,945	(8,506)	(3,564)
Depletion, depreciation, amortization, and impairment of unproved properties—discontinued operations	90,096	—	—
Derivative fair value gains—discontinued operations	(46,358)	—	—
Cash receipts for settled derivatives—discontinued operations	92,166	—	—
Deferred income tax benefit (expense)—discontinued operations	(272,553)	3,249	1,354
Other	4,960	1,173	6,433
Changes in assets and liabilities:			
Accounts receivable	5,511	(9,314)	(45,593)
Accrued revenue	(10,683)	(50,156)	(94,733)
Other current assets	(8,882)	19,543	(2,891)
Accounts payable	(2,117)	1,039	(11,710)
Accrued liabilities	14,790	26,803	85,953
Revenue distributions payable	11,268	50,552	85,763
Other	15,000	3,447	1,016
Net cash provided by operating activities	<u>332,255</u>	<u>534,707</u>	<u>998,121</u>
Cash flows used in investing activities:			
Additions to proved properties	(10,254)	(15,300)	(64,066)
Additions to unproved properties	(687,403)	(440,825)	(777,422)
Drilling and completion costs	(836,350)	(1,615,965)	(2,477,150)
Additions to fresh water distribution systems	(2,801)	(203,790)	(196,675)
Additions to gathering systems and facilities	(142,294)	(389,453)	(558,037)
Additions to other property and equipment	(3,447)	(6,240)	(13,218)
Decrease in notes receivable	4,889	4,555	2,667
Change in other assets	(3,707)	(6,574)	(5,749)
Proceeds from asset sales	1,217,876	—	—
Net cash used in investing activities	<u>(463,491)</u>	<u>(2,673,592)</u>	<u>(4,089,650)</u>
Cash flows from financing activities:			
Issuance of common stock	—	1,578,573	—
Issuance of common units in Antero Midstream Partners LP	—	—	1,087,224
Issuance of senior notes	300,000	1,231,750	1,102,500
Repayment of senior notes	—	(690,000)	(260,000)
Borrowings (repayments) on bank credit facility, net	(148,000)	71,000	1,442,000
Make-whole premium on debt extinguished	—	(33,041)	(17,383)
Payments of deferred financing costs	(5,926)	(20,899)	(31,543)
Other	308	—	(2,777)
Net cash provided by financing activities	<u>146,882</u>	<u>2,137,383</u>	<u>3,320,021</u>
Net increase (decrease) in cash and cash equivalents	<u>15,646</u>	<u>(1,502)</u>	<u>228,492</u>
Cash and cash equivalents, beginning of period	<u>3,343</u>	<u>18,989</u>	<u>17,487</u>
Cash and cash equivalents, end of period	<u>\$ 18,989</u>	<u>17,487</u>	<u>245,979</u>
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	\$ 90,122	117,832	163,055
Supplemental disclosure of noncash investing activities:			
Increase in accounts payable for additions to property and equipment	\$ 72,881	188,123	181,591

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements

Years Ended December 31, 2012, 2013, and 2014

(1) Organization

(a) Business and Organization

Antero Resources Corporation (by itself referred to as "Antero") and its consolidated subsidiaries (collectively referred to as the "Company") are engaged in the exploration, development, and acquisition of natural gas, natural gas liquids ("NGLs") and oil properties in the Appalachian Basin in West Virginia, Ohio, and Pennsylvania. The Company targets large, repeatable resource plays where horizontal drilling and advanced fracture stimulation technologies provide the means to economically develop and produce natural gas, NGLs, and oil from unconventional formations. The Company has fresh water distribution operations in the Appalachian Basin, as well as gathering and compression operations through its consolidated subsidiary, Antero Midstream Partners LP (referred to as "Antero Midstream"), a publicly-traded limited partnership. During 2012, the Company sold its Oklahoma Arkoma Basin properties and its Colorado Piceance Basin properties. The Company's corporate headquarters are in Denver, Colorado.

(b) Corporate Reorganization and Initial Public Offering

Prior to October 16, 2013, the Company's predecessor, Antero Resources LLC, filed reports with the Securities and Exchange Commission. Antero Resources LLC was formed in October 2009 by members of the Company's management team and its sponsor investors. Antero Resources LLC owned 100% of the outstanding shares of Antero Resources Appalachian Corporation, which was formed in March 2008 and renamed Antero Resources Corporation in June 2013. In connection with an initial public offering ("IPO") completed on October 16, 2013, all of the ownership interests in Antero Resources LLC were exchanged for similar interests in a newly formed limited liability company, Antero Resources Investment LLC ("Antero Investment"), and Antero Resources LLC was merged into Antero Resources Corporation. As a result of this reorganization, Antero Investment owned 100% of the issued and outstanding 224,375,000 shares of common stock of Antero Resources Corporation prior to the IPO.

On October 16, 2013, Antero Resources Corporation issued 37,674,659 additional shares of its common stock at \$44.00 per share in the IPO resulting in proceeds to the Company, net of underwriter discounts and expenses of the offering, of approximately \$1.6 billion.

(c) Equity-based Compensation Charge in Connection with the Reorganization

In connection with its formation in October 2009, Antero Resources LLC issued profits interests to Antero Resources Employee Holdings LLC ("Employee Holdings"), which is owned solely by certain of the Company's officers and employees. These profits interests provide for the participation in distributions upon liquidation events meeting certain requisite financial return thresholds. In turn, Employee Holdings issued membership interests to certain of the Company's officers and employees. The Employee Holdings interests in Antero Resources LLC were exchanged for similar interests in Antero Investment in connection with the corporate reorganization on October 16, 2013.

The limited liability company agreement of Antero Investment provides a mechanism that demonstrates how the shares of the Company's common stock will be allocated among the members of Antero Investment, including Employee Holdings. As a result of the adoption of the Antero Investment Limited Liability Company agreement, the satisfaction of all performance and service conditions relative to the profits interests awards held by Employee Holdings in Antero Investment became probable. Accordingly, the Company recognized approximately \$449 million of equity-based compensation expense for the vested profits interests through December 31, 2014 and will recognize approximately \$37 million over the remaining service period. Equity-based compensation expense for the profits interests during the years ended December 31, 2013 and 2014 was \$365.0 million and \$83.6 million, respectively. Because consideration for the profits interests awards is deemed given by Antero Investment, the charge to equity-based compensation expense is accounted for as a capital contribution by Antero Investment to the Company and credited to additional paid-in capital. All available profits interest awards were made prior to the date of the IPO, and no additional profits interest awards will be made.

(d) Antero Midstream Partners LP

In 2013, the Company formed a subsidiary, Antero Resources Midstream LLC ("ARM"). The Company owned all of the membership interests in ARM other than a special membership interest that was indirectly owned by Antero Investment. On November 10, 2014, ARM was converted to Antero Midstream, a limited partnership, in connection with its initial public offering (the "Antero Midstream IPO") of 46,000,000 common units representing limited partner interests at a price of \$25.00 per common unit. At

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

the closing of the Antero Midstream IPO, the Company contributed its gathering and compression assets to Midstream Operating LLC (referred to as "Midstream Operating"), a wholly-owned subsidiary of Antero Midstream, and the ownership of Midstream Operating was contributed to Antero Midstream. Upon completion of the Antero Midstream IPO, the public owned approximately 30.3% of the outstanding limited partner interests in Antero Midstream, and the Company and its affiliates owned the remaining approximately 69.7% limited partner interests. Antero Resources Midstream Management LLC (referred to as "Midstream Management"), a wholly-owned subsidiary of Antero Investment, owns the general partnership interest in Antero Midstream, which allows Midstream Management to manage the business and affairs of Antero Midstream. Midstream Management also holds the incentive distribution rights in Antero Midstream. Antero Midstream is an unrestricted subsidiary as defined by Antero Resources Corporation's bank credit facility and senior notes indentures and, as such, Antero Midstream is not a guarantor of Antero's obligations, and Antero is not a guarantor of Antero Midstream's obligations.

In conjunction with the closing of the Antero Midstream IPO, the following events occurred:

- Antero and Antero Midstream entered into a services agreement, pursuant to which Antero agreed to provide administrative, management, and other services to Antero Midstream and its subsidiaries in exchange for reimbursement of its direct expenses and an allocation of its indirect expenses attributable to the provision of such services.
- Antero Midstream and its subsidiary entered into a new revolving credit facility (the "Midstream Facility") with a syndicate of lenders. The Midstream Facility provides for lender commitments of \$1.0 billion which may be used to fund the operations of Antero Midstream. The Midstream Facility also provides for a letter of credit sublimit of \$150 million. Antero is not a guarantor of the obligations of Antero Midstream under the Midstream Facility.
- Antero and Antero Midstream entered into a 20-year gas gathering and compression agreement. Pursuant to the agreement, Antero agreed to dedicate all of its current and future acreage in West Virginia, Ohio, and Pennsylvania to Antero Midstream for gathering and compression services, so long as production is not otherwise subject to a pre-existing dedication to third-party gathering systems. Antero Midstream is entitled to receive specific fees for the services it provides to Antero, each of which are subject to price adjustments based on the consumer price index. In addition, if Antero acquires any gathering facilities, it is required to offer such gathering facilities to Antero Midstream at Antero's cost. Antero Midstream also has an option to gather and compress natural gas produced by Antero on any acreage it acquires in the future outside of West Virginia, Ohio, and Pennsylvania on the same terms and conditions.
- Antero Midstream granted a total of 2,361,440 phantom units to employees and officers of Antero. Additionally, Antero Midstream granted a total of 20,000 restricted units to its directors. See additional information relating to the recognition of expense under these awards in note 7.

The gross proceeds to Antero Midstream from its IPO were approximately \$1.2 billion. After subtracting underwriting discounts and offering expenses of approximately \$63 million, net proceeds received by Antero Midstream from the sale of 46,000,000 Common Units were approximately \$1.1 billion. Antero Midstream used approximately \$843 million of the net proceeds to repay assumed indebtedness from Antero and reimburse Antero for certain capital expenditures incurred. Antero Midstream retained \$250 million of the net proceeds for general partnership purposes.

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). In the opinion of management, the accompanying consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company's financial position as of December 31, 2013 and 2014, and the results of its operations and its cash flows for the years ended December 31, 2012, 2013, and 2014. The Company has no items of other comprehensive income or loss; therefore, its net income or loss is identical to its comprehensive income or loss.

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

As of the date these financial statements were filed with the Securities and Exchange Commission, the Company completed its evaluation of potential subsequent events for disclosure and no items requiring disclosure were identified, except for the increase in commitments under the revolving credit facility described in note 5(a) to the consolidated financial statements.

(b) Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Antero Resources Corporation, its wholly owned subsidiaries, and any entities in which the Company owns a controlling interest. All significant intercompany accounts and transactions have been eliminated in the Company's consolidated financial statements. Noncontrolling interest in the Company's consolidated financial statements represents interest in Antero Midstream which is owned by third-party individuals or entities. An affiliate of the Company owns the general partner interest in Antern Midstream, as well as all of the incentive distribution rights. Noncontrolling interest is included as a component of stockholders' equity in the Company's consolidated balance sheets.

(c) Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results could differ from those estimates.

The Company's consolidated financial statements are based on a number of significant estimates including estimates of gas and oil reserve quantities, which are the basis for the calculation of depreciation, depletion, amortization, and impairment of oil and gas properties. Reserve estimates by their nature are inherently imprecise. Other items in the Company's consolidated financial statements which involve the use of significant estimates include derivative assets and liabilities, accrued revenue, deferred income taxes, asset retirement obligations, stock based compensation, and commitments and contingencies.

(d) Risks and Uncertainties

Historically, the market for natural gas, NGLs, and oil has experienced significant price fluctuations. Price fluctuations can result from variations in weather, levels of production in the region, availability of transportation capacity to other regions of the country, and various other factors. Increases or decreases in the prices the Company receives for its production could have a significant impact on the Company's future results of operations.

(e) Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

(f) Oil and Gas Properties

The Company accounts for its natural gas and crude oil exploration and development activities under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete productive wells, development wells, and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the Company determines that the well does not contain reserves in commercially viable quantities. The Company incurred no such charges during the years ended December 31, 2012, 2013, and 2014. The Company reviews exploration costs related to wells -in -progress at the end of each quarter and makes a determination, based on known results of drilling at that time, whether the costs should continue to be capitalized pending further well testing and results, or charged to expense. The sale of a partial interest in a proved property is accounted for as a cost recovery, and no gain or loss is recognized as long as this treatment does not significantly affect the units -of -production amortization rate. A gain or loss is recognized for all other sales of producing properties.

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

Unproved properties with significant acquisition costs are assessed for impairment on a property -by -property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, and future plans to develop acreage. Other unproved properties are assessed for impairment on an aggregate basis. Unproved properties and the related costs are transferred to proved properties when reserves are discovered on or otherwise attributed to the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of cost without recognition of any gain or loss until the cost has been recovered. Impairment of unproved properties for leases which have expired, or are expected to expire, was \$12.1 million, \$10.9 million, and \$15.2 million for the years ended December 31, 2012, 2013, and 2014, respectively.

The Company reviews its proved oil and gas properties for impairment whenever events and circumstances indicate that the carrying value of the properties may not be recoverable. When determining whether impairment has occurred, the Company estimates the expected future cash flows of its oil and gas properties and compares such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company reduces the carrying amount of the properties to their estimated fair value. The factors used to determine fair value include estimates of proved reserves, future commodity prices, future production estimates, anticipated capital expenditures, and a commensurate discount rate. There were no impairments of proved natural gas properties during the years ended December 31, 2012, 2013, and 2014.

At December 31, 2014, the Company did not have significant capitalized costs related to exploratory wells -in -progress which were pending determination of proved reserves. The Company had no significant costs which have been deferred for longer than one year pending determination proved reserves at December 31, 2014.

The provision for depreciation, depletion, and amortization of oil and gas properties is calculated on a geological reservoir basis using the units -of -production method. Depreciation, depletion, and amortization expense for oil and gas properties was \$181.7 million, \$219.8 million, and \$418.7 million for the years ended December 31, 2012, 2013, and 2014, respectively.

(g) Gathering Pipelines, Compressor Stations, and Fresh Water Distribution Systems

Expenditures for construction, installation, major additions, and improvements to property, plant, and equipment that is not directly related to production are capitalized, whereas minor replacements, maintenance, and repairs are expensed as incurred. Gathering pipelines and compressor stations are depreciated using the straight -line method over their estimated useful lives of 20 years. Fresh water distribution systems are depreciated over useful lives of 5 to 20 years. Depreciation expense for gathering pipelines, compressor stations, and fresh water distribution systems was \$7.4 million, \$11.9 million, and \$53.2 million for the years ended December 31, 2012, 2013, and 2014, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

(h) Impairment of Long -Lived Assets Other than Oil and Gas Properties

The Company evaluates its long -lived assets other than natural gas properties for impairment when events or changes in circumstances indicate that the related carrying values of the assets may not be recoverable. Generally, the basis for making such assessments is undiscounted future cash flow projections for the unit being assessed. If the carrying values of the assets are deemed not recoverable, the carrying values are reduced to the estimated fair value, which is based on discounted future cash flows or other techniques, as appropriate. No impairments for such assets have been recorded through December 31, 2014.

(i) Other Property and Equipment

Other property and equipment assets are depreciated using the straight -line method over their estimated useful lives, which range from 2 to 20 years. Depreciation expense for other property and equipment was \$1.7 million, \$2.2 million, and \$5.9 million for the years ended December 31, 2012, 2013, and 2014, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

(j) Deferred Financing Costs

Deferred financing costs represent loan origination fees, initial purchasers' discounts, and other borrowing costs and are included in noncurrent other assets on the consolidated balance sheets. These costs are amortized over the term of the related debt instrument using the effective interest method. The Company charges expense for deferred financing costs remaining for debt

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

facilities that have been retired prior to their maturity date. At December 31, 2014, the Company had \$52 million of unamortized deferred financing costs included in other long-term assets. The amounts amortized and the write-off of previously deferred debt issuance costs were \$5.2 million, \$15.8 million, and \$11.0 million for the years ended December 31, 2012, 2013, and 2014, respectively.

(k) *Derivative Financial Instruments*

In order to manage its exposure to natural gas, NGLs, and oil price volatility, the Company enters into derivative transactions from time to time, including commodity swap agreements, basis swap agreements, collar agreements, and other similar agreements relating to the price risk associated with a portion of its production. To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligation. The Company actively monitors the creditworthiness of counterparties and assesses the impact, if any, on its derivative position.

The Company records derivative instruments on the consolidated balance sheets as either an asset or liability measured at fair value and records changes in the fair value of derivatives in current earnings as they occur. Changes in the fair value of commodity derivatives are classified as revenues on the Company's consolidated statements of operations. The Company's derivatives have not been designated as hedges for accounting purposes.

(l) *Asset Retirement Obligations*

The Company is obligated to dispose of certain long-lived assets upon their abandonment. The Company's asset retirement obligations ("ARO") relate primarily to its obligation to plug and abandon oil and gas wells at the end of their lives. The ARO is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted, risk-free interest rate. Revisions to estimated ARO can result from changes in retirement cost estimates and changes in the estimated timing of abandonment. The fair value of the liability is added to the carrying amount of the associated asset, and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for an amount other than the carrying amount of the liability, the Company will recognize a gain or loss on settlement.

The Company delivers natural gas through its gathering assets and delivers water through its water distribution assets and may become obligated by regulatory or other requirements to remove certain facilities or perform other remediation upon retirement of gathering pipelines and compressor stations. However, the Company cannot reasonably predict when production from existing reserves of the fields in which it operates will cease. In the absence of such information, management is not able to make a reasonable estimate of when future dismantlement and removal dates will occur; therefore, the Company has not recorded asset retirement obligations related to its gathering and water distribution assets.

(m) *Environmental Liabilities*

Environmental expenditures that relate to an existing condition caused by past operations, and that do not contribute to current or future revenue generation, are expensed as incurred. Liabilities are accrued when environmental assessments and/or clean up is probable, and the costs can be reasonably estimated. These liabilities are adjusted as additional information becomes available or circumstances change. As of December 31, 2013 and 2014, the Company did not have a material amount accrued for any environmental liabilities, nor has the Company been cited for any environmental violations that could have a material adverse effect on future capital expenditures or operating results of the Company.

(n) *Natural Gas, NGLs, and Oil Revenues*

Sales of natural gas, NGLs, and crude oil are recognized when the products are delivered to the purchaser and title transfers to the purchaser. Payment is generally received one month after the sale has occurred. Variances between estimated sales and actual amounts received are recorded in the month payment is received and are not material. The Company recognizes natural gas revenues based on its entitlement share of natural gas that is produced based on its working interests in the properties. The Company records a

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

revenue distribution payable to the extent it receives more than its proportionate share of natural gas revenues. At December 31, 2013 and 2014, the Company had no significant imbalance positions.

(o) Concentrations of Credit Risk

The Company's revenues are derived principally from uncollateralized sales to purchasers in the oil and gas industry. The concentration of credit risk in a single industry affects the Company's overall exposure to credit risk because purchasers may be similarly affected by changes in economic and other conditions. The Company has not experienced significant credit losses on its receivables.

The Company's sales to major customers (purchases in excess of 10% of total sales) for the years ended December 31, 2012, 2013, and 2014 are as follows (including sales in discontinued operations):

	<u>2012</u>	<u>2013</u>	<u>2014</u>
Company A	23 %	30 %	29 %
Company B	13	14	16
Company C	10	8	12
All others	<u>54</u>	<u>48</u>	<u>43</u>
	<u>100%</u>	<u>100%</u>	<u>100%</u>

Although a substantial portion of the Company's production is purchased by these major customers, it does not believe the loss of any one or several customers would have a material adverse effect on its business, as other customers or markets would be accessible.

The Company is also exposed to credit risk on its commodity derivative portfolio. Any default by the counterparties to these derivative contracts when they become due could have a material adverse effect on the Company's financial condition and results of operations. The Company has economic hedges in place with ten different counterparties, all but one of which is a lender under Antero's Credit Facility. The fair value of the Company's commodity derivative contracts of approximately \$1.6 billion at December 31, 2014 includes the following values by bank counterparty: Credit Suisse—\$268 million; Barclays—\$257 million; JP Morgan—\$253 million; BNP Paribas—\$233 million; Citigroup—\$231 million; Wells Fargo—\$211 million; Scotiabank—\$77 million; Fifth Third Bank—\$31 million; Toronto Dominion Bank—\$28 million; Bank of Montreal—\$4 million. The estimated fair value of commodity derivative assets has been risk adjusted using a discount rate based upon the respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at December 31, 2014 for each of the European and American banks. The Company believes that all of these institutions currently are acceptable credit risks.

The Company, at times, may have cash in banks in excess of federally insured amounts.

(p) Income Taxes

The Company recognizes deferred tax assets and liabilities for temporary differences resulting from net operating loss carryforwards for income tax purposes and the differences between the financial statement and tax basis of assets and liabilities. The effect of changes in the tax laws or tax rates is recognized in income in the period such changes are enacted. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Unrecognized tax benefits represent potential future tax obligations for uncertain tax positions taken on previously filed tax returns that may not ultimately be sustained. The Company recognizes interest expense related to unrecognized tax benefits in interest expense and fines and penalties for tax-related matters as income tax expense.

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

(q) Fair Value Measures

FASB ASC Topic 820, *Fair Value Measurements and Disclosures*, clarifies the definition of fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This guidance also relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis (e.g., those measured at fair value in a business combination, the initial recognition of asset retirement obligations, and impairments of proved oil and gas properties, and other long-lived assets). The fair value is the price that the Company estimates would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. A fair value hierarchy is used to prioritize inputs to valuation techniques used to estimate fair value. An asset or liability subject to the fair value requirements is categorized within the hierarchy 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 in its entirety requires judgment and considers factors specific to the asset or liability. The highest priority (Level 1) is given to unadjusted quoted market prices in active markets for identical assets or liabilities, and the lowest priority (Level 3) is given to unobservable inputs. Level 2 inputs are data, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. Instruments which are valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter commodity price swaps and basis swaps. Valuation models used to measure fair value of these instruments consider various Level 2 inputs including (i) quoted forward prices for commodities, (ii) time value, (iii) quoted forward interest rates, (iv) current market prices and contractual prices for the underlying instruments, (v) risk of nonperformance by the Company and the counterparty, and (vi) other relevant economic measures.

(r) Industry Segment and Geographic Information

Management has evaluated how the Company is organized and managed and has identified the following segments: (1) the exploration, development, and production of natural gas, NGLs, and oil, (2) gathering and compression, (3) fresh water distribution, and (4) marketing of excess firm transportation capacity. The Company identified marketing of excess firm transportation capacity as a new operating segment in 2014. Prior to 2013, the Company did not have any reportable segments.

All of the Company's assets are located in the United States and all of its revenues are attributable to customers located in the United States.

(s) Marketing Revenues and Expenses

In 2014, the Company commenced activities to purchase and sell third-party natural gas and NGLs, and to market its excess firm transportation capacity in order to utilize this excess capacity. Marketing revenues include sales of purchased third-party gas and NGLs, as well as revenues from the release of firm transportation capacity to others. Marketing expenses include the cost of purchased third-party natural gas and NGLs. The Company classifies firm transportation costs related to capacity contracted for in advance of having sufficient production and infrastructure to fully utilize the capacity (excess capacity) as marketing expenses since it is marketing this excess capacity to third parties. Firm transportation for which the Company has sufficient production capacity (even though it may not use the transportation capacity because of alternative delivery points with more favorable pricing) is considered unutilized capacity. The costs of unutilized capacity are charged to transportation expense.

(t) Earnings (loss) per common share

Earnings (loss) per common share for 2014 was calculated based on the weighted average number of shares outstanding of 262,053,868 shares. Earnings per common share—assuming dilution for 2014 was calculated based on the diluted weighted average number of shares outstanding of 262,068,106 shares, including 14,238 dilutive shares attributable to non-vested restricted stock and restricted stock unit awards. For the year ended December 31, 2014, 1,444,023 non-vested shares of restricted stock and restricted stock unit awards and 72,592 stock options were anti-dilutive and therefore excluded from the calculation of diluted earnings per share.

Earnings (loss) per common share and earnings (loss) per common share—assuming dilution for each of the two years ended December 31, 2013 were calculated as if the shares issued in the Corporate Reorganization and IPO described in Note 1 were outstanding for the entire period.

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

(3) Sale of Piceance and Arkoma Properties—Discontinued Operations

In 2012, the Company sold its Piceance Basin assets in Colorado and its Arkoma Basin assets in Oklahoma. Total proceeds from the sales, including liquidation of related hedge positions, were approximately \$843 million and pre-tax losses on the asset sales of approximately \$796 million were recorded in 2012. Pre-tax losses were adjusted downward in 2013 and 2014 by \$8.5 million and \$3.6 million for the resolution of certain liabilities recorded at the time of the sales and settlement of final contractual purchase price adjustments.

Results of operations and the loss on the sale of the Piceance Basin and Arkoma Basin assets are shown as discontinued operations on the accompanying Consolidated Statement of Operations and Comprehensive Income (Loss) and are comprised of the following (in thousands):

	Year ended December 31,		
	2012	2013	2014
Sales of oil, natural gas, and natural gas liquids	\$ 125,396	—	—
Commodity derivative fair value gains	46,358	—	—
Revenues	171,754	—	—
Operating expenses	158,707	—	—
Loss (gain) on sale of assets	795,945	(8,506)	(3,564)
Total expenses	954,652	(8,506)	(3,564)
Income (loss) from discontinued operations before income taxes	(782,898)	8,506	3,564
Income tax (expense) benefit	272,553	(3,249)	(1,354)
Net income (loss) from discontinued operations	<u>\$ (510,345)</u>	<u>5,257</u>	<u>2,210</u>

(4) Sale of Appalachian Gathering Assets

On March 26, 2012, the Company closed the sale of a portion of its Marcellus Shale gathering system assets in West Virginia along with exclusive rights to gather the Company's gas for a 20 year period within an area of dedication ("AOD") to a joint venture owned by Crestwood Midstream Partners and Crestwood Holdings Partners LLC (together "Crestwood") for \$375 million (subject to customary purchase price adjustments). The sale included approximately 25 miles of low pressure pipeline systems and gathering rights on 104,000 net acres held by the Company within a 250,000 acre AOD and had an effective date of January 1, 2012. Because the Company did not retain the substantial risks and rewards of ownership associated with the gathering rights and systems transferred to Crestwood, it recognized a gain on the sale of the gathering system and gathering rights of approximately \$291 million in 2012. Crestwood is obligated to incur all future capital costs to build out gathering systems and compression facilities within the AOD to connect the Company's wells as it executes its drilling program, and has assumed the various risks and rewards of the system build-out and operations. Other third-party producers also have access to the Crestwood systems. During the first seven years of the contract, the Company is committed to deliver minimum annual volumes into the gathering systems, with certain carryback and carryforward adjustments for overages or deficiencies.

Under the terms of the contract, the Company could earn additional proceeds of up to \$40 million if certain volume thresholds were met by December 31, 2014. The volume thresholds were fully met during 2014 and as such, the Company recorded an additional \$40 million of gain on the sale of assets in 2014 and a receivable from Crestwood for a like amount.

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

(5) Long -Term Debt

Long -term debt was follows at December 31, 2013 and 2014 (in thousands):

	2013	2014
Antero:		
Bank credit facility(a)	\$ 288,000	1,730,000
7.25% senior notes due 2019(c)	260,000	—
6.00% senior notes due 2020(d)	525,000	525,000
5.375% senior notes due 2021(e)	1,000,000	1,000,000
5.125% senior notes due 2022(f)	—	1,100,000
Net unamortized premium	5,999	7,550
	<u>\$ 2,078,999</u>	<u>4,362,550</u>
Antero Midstream Partners LP:		
Bank credit facility(b)		<u>\$ —</u>

(a) Senior Secured Revolving Credit Facility

Antero has a senior secured revolving bank credit facility (the "Credit Facility") with a consortium of bank lenders. The maximum amount of the Credit Facility was \$4.0 billion at December 31, 2014. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of Antero's proved properties and commodity hedge positions and are subject to regular semiannual redeterminations. At December 31, 2014, the borrowing base was \$4.0 billion, including \$500 million under the Water Facility, and lender commitments were \$3.0 billion, including \$200 million of commitments under the Water Facility. On February 17, 2015, lender commitments were increased to \$4.0 billion, including \$200 million of commitments under the Water Facility. The next redetermination of the borrowing base is scheduled to occur in October 2015. The maturity date of the Credit Facility is May 5, 2019.

On November 10, 2014, Antero and Antero Water entered into a new water credit facility (the "Water Facility"), in order to provide for separate borrowings attributable to Antero's fresh water distribution business, which contains covenants that are substantially identical to those under the Credit Facility. In accordance with the Credit Facility and the Water Facility agreements, borrowings under the Water Facility reduce availability under the Credit Facility on a dollar-for-dollar basis. The Water Facility will mature at the earlier of the sale of Antero Water to Antero Midstream, the sale of Antero Water's assets to Antero Midstream or May 12, 2016.

The Credit Facility and the Water Facility are ratably secured by mortgages on substantially all of Antero's properties and guarantees from Antero's restricted subsidiaries, as applicable. The Credit Facility and the Water Facility contain certain covenants, including restrictions on indebtedness and dividends, and, in the case of the Credit Facility, requirements with respect to working capital and interest coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate, determined by Antero's election at the time of borrowing. Antero was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2013 and 2014.

As of December 31, 2014, Antero had a total outstanding balance under the Credit Facility and Water Facility of \$1.73 billion, with a weighted average interest rate of 2.06 %, and outstanding letters of credit of \$ 387 million. As of December 31, 2013, Antero had an outstanding balance under the Credit Facility of \$288 million, with a weighted average interest rate of 1.61 %, and outstanding letters of credit of approximately \$32 million. Commitment fees on the unused portion of the Credit Facility and the Water Facility are due quarterly at rates ranging from 0.375% to 0.50% of the unused facility based on utilization.

(b) Senior Secured Revolving Credit Facility - Antero Midstream Partners LP

On November 10, 2014, Antero Midstream entered into a senior secured revolving bank credit facility (the "Midstream Facility") with a consortium of bank lenders. At December 31, 2014, the maximum amount of the facility was \$1.0 billion. The maturity date of the Midstream Facility is November 10, 2019.

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

The Midstream Facility is ratably secured by mortgages on substantially all of the properties of Antero Midstream and guarantees from Antero Midstream or its subsidiary, as applicable. The Midstream Facility contains certain covenants, including restrictions on indebtedness and dividends and requirements with respect to leverage and interest coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate, determined by election at the time of borrowing. Antero Midstream was in compliance with all of the financial covenants under the Midstream Facility as of December 31, 2014.

As of December 31, 2014, Antero Midstream did not have a balance outstanding under the Midstream Facility. Commitment fees on the unused portion of the Midstream Facility are due quarterly at rates ranging from 0.25% to 0.375% of the unused facility based on utilization.

(c) 7.25% Senior Notes Due 2019

On May 23, 2014, Antero redeemed the outstanding 7.25% senior notes due 2019 (the "2019 notes") having a principal balance of \$260 million at a redemption price of 100% of the principal amount plus a make-whole premium of \$17.4 million. The make-whole premium, along with the write-off of \$3 million of deferred financing costs, was charged to Loss on early extinguishment of debt in the accompanying statement of operations. The redemption was financed using a portion of the proceeds from the offering of Antero's 5.125% senior notes due 2022 (the "2022 notes") described below.

(d) 6.00% Senior Notes Due 2020

On November 19, 2012, Antero issued \$300 million of 6.00% senior notes due December 1, 2020 at par. On February 4, 2013, Antero issued an additional \$225 million of the 2020 notes at 103% of par. The 2020 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2020 notes rank pari passu to Antero's other outstanding senior notes. The 2020 notes are guaranteed on a senior unsecured basis by Antero's wholly-owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2020 notes is payable on June 1 and December 1 of each year. Antero may redeem all or part of the 2020 notes at any time on or after December 1, 2015 at redemption prices ranging from 104.500% on or after December 1, 2015 to 100.00% on or after December 1, 2018. In addition, on or before December 1, 2015, Antero may redeem up to 35% of the aggregate principal amount of the 2020 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 106.00% of the principal amount of the 2020 notes, plus accrued interest. At any time prior to December 1, 2015, Antero may redeem the 2020 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2020 notes plus a "make-whole" premium and accrued interest. If Antero undergoes a change of control, the holders of the 2020 notes will have the right to require Antero to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2020 notes, plus accrued interest.

(e) 5.375% Senior Notes Due 2021

On November 5, 2013, Antero issued \$1 billion of 5.375% senior notes due November 21, 2021 (the "2021 notes") at par. The 2021 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2021 notes rank pari passu to Antero's other outstanding senior notes. The 2021 notes are guaranteed on a full and unconditional and joint and several basis by Antero's wholly-owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2021 notes is payable on May 1 and November 1 of each year. Antero may redeem all or part of the 2021 notes at any time on or after November 1, 2016 at redemption prices ranging from 104.031% on or after November 1, 2016 to 100.00% on or after November 1, 2019. In addition, on or before November 1, 2016, Antero may redeem up to 35% of the aggregate principal amount of the 2021 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.375% of the principal amount of the 2021 notes, plus accrued interest. At any time prior to November 1, 2016, Antero may also redeem the 2021 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2021 notes, plus a "make-whole" premium and accrued interest. If Antero undergoes a change of control prior to May 1, 2015, it may redeem all, but not less than all, of the 2021 notes at a redemption price equal to 110% of the principal amount of the 2021 notes. If Antero undergoes a change of control, the holders of the 2021 notes will have the right to require Antero to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2021 notes, plus accrued interest.

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

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(f) 5.125% Senior Notes Due 2022

On May 6, 2014, Antero issued \$600 million of 5.125% senior notes due December 1, 2022 (the "2022 notes") at par. On September 18, 2014, Antero issued an additional \$500 million of the 2022 notes at 100.5% of par. The 2022 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2022 notes rank pari passu to Antero's other outstanding senior notes. The 2022 notes are guaranteed on a full and unconditional and joint and several basis by Antero's wholly-owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2022 notes is payable on June 1 and December 1 of each year. Antero may redeem all or part of the 2022 notes at any time on or after June 1, 2017 at redemption prices ranging from 103.844% on or after June 1, 2017 to 100.00% on or after June 1, 2020. In addition, on or before June 1, 2017, Antero may redeem up to 35% of the aggregate principal amount of the 2022 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.125% of the principal amount of the 2022 notes, plus accrued interest. At any time prior to June 1, 2017, Antero may also redeem the 2022 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2022 notes plus a "make-whole" premium and accrued interest. If Antero undergoes a change of control prior to December 1, 2015, it may redeem all, but not less than all, of the 2022 notes at a redemption price equal to 110% of the principal amount of the 2022 notes. If Antero undergoes a change of control, the holders of the 2022 notes will have the right to require Antero to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2022 notes, plus accrued interest.

(g) Treasury Management Facility

Antero has a stand-alone revolving note with a lender under the Credit Facility which provides for up to \$25.0 million of cash management obligations in order to facilitate Antero's daily treasury management. Borrowings under the revolving note are secured by the collateral for the revolving credit facility. Borrowings under the facility bear interest at the lender's prime rate plus 1.0%. The note matures on June 1, 2015. At December 31, 2014, there were no outstanding borrowings under this facility.

(6) Asset Retirement Obligations

The following is a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2013 and 2014 (in thousands).

	2013	2014
Asset retirement obligations—beginning of year	\$10,552	11,859
Obligations incurred for wells drilled and producing properties acquired	242	3,484
Accretion expense	1,065	1,271
Asset retirement obligations—end of year	<u>\$11,859</u>	<u>16,614</u>

Asset retirement obligations are included in other long-term liabilities on the consolidated balance sheets.

(7) Equity-Based Compensation

Antero is authorized to grant up to 16,906,500 shares of common stock to employees and directors of the Company under the Antero Resources Corporation Long-Term Incentive Plan (the "Plan"). The Plan allows equity-based compensation awards to be granted in a variety of forms, including stock options, stock appreciation rights, restricted stock awards, restricted stock unit awards, dividend equivalent awards, and other types of awards. The terms and conditions of the awards granted are established by the Compensation Committee of Antero's Board of Directors. A total of 14,819,823 shares are available for future grant under the Plan as of December 31, 2014.

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Notes to Consolidated Financial Statements (Continued)

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In connection with the Antero Midstream IPO, Midstream Management adopted the Antero Midstream Partners LP Long-Term Incentive Plan (the "Midstream Plan"), pursuant to which non-employee directors of Antero Midstream's general partner and certain officers, employees, and consultants of Antero Midstream's general partner and its affiliates (which include Antero) are eligible to receive awards representing ownership interests in Antero Midstream. An aggregate of 10,000,000 common units may be delivered pursuant to awards under the Midstream Plan, subject to customary adjustments. A total of 7,618,560 common units are available for future grant under the Midstream Plan as of December 31, 2014.

The Company's equity-based compensation expense is as follows for the year ended December 31, 2014 (in thousands):

	2013	2014
Profits interests awards (see note 1)	\$364,957	83,615
Restricted stock awards	219	25,624
Stock options	104	501
Antero Midstream Partners phantom and restricted unit awards	—	2,360
Common stock issued to directors in lieu of cash compensation	—	152
Total expense	<u>\$365,280</u>	<u>112,252</u>

Restricted Stock

Restricted stock and restricted stock unit awards vest subject to the satisfaction of service requirements. Expense related to each restricted stock and restricted stock unit award is recognized on a straight-line basis over the requisite service period of the entire award, less awards expected to be forfeited. The grant date fair values of these awards are determined based on the closing price of the Company's common stock on the date of the grant. A summary of restricted stock and restricted stock unit awards activity during the year ended December 31, 2014 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested, December 31, 2013	45,093	\$ 54.27	\$ 2,861
Granted	1,970,587	\$ 64.75	
Vested	(21,825)	\$ 57.06	
Forfeited	(10,182)	\$ 58.55	
Total awarded and unvested—December 31, 2014	<u>1,983,673</u>	<u>\$ 64.71</u>	<u>\$ 80,497</u>

Intrinsic values are based on the closing price of the Company's stock on the referenced dates. Unamortized expense of \$103.8 million at December 31, 2014 is expected to be recognized over approximately 3.3 years.

Stock Options

Stock options granted under the Plan to date vest over periods from one to four years and have a maximum contractual life of 10 years. Expense related to stock options is recognized on a straight-line basis over the requisite service period, less awards expected

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

to be forfeited. Stock options are granted with an exercise price equal to the market price of the Company's common stock on the date of grant. A summary of stock option activity for the year ended December 31, 2014 is as follows:

	Stock options	Weighted average exercise price	Weighted average remaining contractual life	Intrinsic value (in thousands)
Outstanding at December 31, 2013	70,339	\$ 54.15	9.79	\$ 653
Options granted	10,682	\$ 52.44		
Options exercised	—	—		
Options cancelled	—	—		
Options expired	—	—		
Outstanding at December 31, 2014	81,021	\$ 53.92	8.92	\$ —
Vested or expected to vest as of December 31, 2014	81,021	\$ 53.92	8.92	\$ —
Exercisable at December 31, 2014	25,339	\$ 54.15	8.78	\$ —

Intrinsic value is based on the exercise price of the options and the closing price of the Company's stock on the referenced dates.

A Black-Scholes option-pricing model is used to determine the grant-date fair value of stock options. Expected volatility was derived from the volatility of the historical stock prices of a peer group of similar publicly traded companies' stock prices. The risk-free interest rate was determined using the implied yield available for zero-coupon U.S. government issues with a remaining term approximating the expected life of the options. A dividend yield of zero was assumed.

The following table presents information regarding the weighted average fair value for options granted during 2013 and 2014 and the assumptions used to determine fair value.

	2013	2014
Dividend yield	— %	— %
Volatility	35 %	40 %
Risk-free interest rate	1.48 %	1.75 %
Expected life (years)	6.17	5.50
Weighted average fair value of options granted	\$ 20.20	\$ 20.55

As of December 31, 2014, there was \$1.0 million of unrecognized equity-based compensation expense related to nonvested stock options. That expense is expected to be recognized over a weighted average period of approximately 2.9 years.

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

Antero Midstream Partners Phantom and Restricted Unit Awards

On November 12, 2014, Antero Midstream granted 20,000 restricted units to the directors of Antero Midstream and 2,361,440 phantom units Antero's employees and officers. The restricted units and phantom units vest subject to the satisfaction of service requirements, upon the completion of which common units in Antero Midstream are delivered to the holder of the restricted units or phantom units. These restricted and phantom units are treated, for accounting purposes, as if Antero Midstream distributed the units to Antero. Antero recognizes compensation expense as the units are granted to employees, and a portion of the expense is allocated to Antero Midstream. These restricted units and phantom units are recognized as compensation expense within the Company's consolidated statements of operations deemed distributions to Antero Resources Corporation by Antero Midstream. Expense related to each restricted unit and phantom unit award is recognized on a straight-line basis over the requisite service period of the entire award. The grant date fair values of these awards are determined based on the closing price of Antero Midstream's common units on the date of grant. A summary of restricted unit and phantom unit awards activity during the year ended December 31, 2014 is as follows:

	Number of units	Weighted average grant date fair value	Aggregate intrinsic value (In thousands)
Total awarded and unvested, December 31, 2013	—	\$ —	
Granted	2,381,440	\$ 29.00	
Vested	—	\$ —	
Forfeited	—	\$ —	
Total awarded and unvested—December 31, 2014	<u>2,381,440</u>	<u>\$ 29.00</u>	<u>\$ 65,490</u>

Intrinsic values are based on the closing price of Antero Midstream's common units on the referenced dates. Unamortized expense of \$66.7 million at December 31, 2014 is expected to be recognized over a weighted average period of approximately 3.8 years.

(8) Financial Instruments

The carrying values of accounts receivable and accounts payable at December 31, 2013 and 2014 approximated market value because of their short-term nature. The carrying values of the amounts outstanding under the Credit Facility and Water Facility at December 31, 2013 and 2014 approximated fair value because the variable interest rates are reflective of current market conditions.

Based on Level 2 market data inputs, the fair value of the Company's senior notes was approximately \$1.9 billion at December 31, 2013 and \$2.5 billion at December 31, 2014.

See note 9 for information regarding the fair value of derivative financial instruments.

(9) Derivative Instruments**(a) Commodity Derivatives**

The Company periodically enters into natural gas, NGLs, and oil derivative contracts with counterparties to hedge the price risk associated with a portion of its production. These derivatives are not held for trading purposes. To the extent that changes occur in the market prices of natural gas, NGLs, and oil, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the change in market prices of natural gas, NGLs, and oil recognized upon the ultimate sale of The Company's production.

For the years ended December 31, 2012, 2013, and 2014, the Company was party to various natural gas, NGLs, and oil fixed price swap contracts. When actual commodity prices exceed the fixed price provided by the swap contracts, the Company pays the excess to the counterparty; when actual commodity prices are below the contractually provided fixed price, the Company receives the difference from the counterparty. In addition, the Company has entered into basis swap contracts in order to hedge the difference between the NYMEX index price and a local index price. When the actual differential exceeds the fixed price provided by the basis

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

swap contract, the Company receives the difference from the counterparty; when the differential is less than the fixed price provided by the basis swap contract, the Company pays the difference to the counterparty. The Company's natural gas, NGLs, oil, and basis swaps have not been designated as hedges for accounting purposes; therefore, all gains and losses were recognized in the Company's statements of operations.

As of December 31, 2014, the Company's fixed price natural gas, NGLs, and oil swap positions from January 1, 2015 through December 31, 2020 were as follows (abbreviations in the table refer to the index to which the swap position is tied:

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

TCO=Columbia Gas Transmission; NYMEX=Henry Hub; CGTLA=Columbia Gas Louisiana Onshore; CCG=Chicago City Gate; NYMEX-WTI=West Texas Intermediate; Mont Belvieu-TET=Mont Belvieu Propane);

	Natural gas MMBtu/day	Oil Bbls/day	Propane Bbls/day	Weighted average index price
Three months ending March 31, 2015:				
TCO (\$/MMBtu)	120,000	—	—	\$ 5.13
Dominion South (\$/MMBtu)	230,000	—	—	\$ 5.78
NYMEX (\$/MMBtu)	770,000	—	—	\$ 4.05
CGTLA (\$/MMBtu)	40,000	—	—	\$ 4.13
NYMEX-WTI (\$/Bbl)	—	3,000	—	\$ 63.55
Mont Belvieu-TET (\$/Gallon)	—	—	23,000	\$ 0.60
Total	<u>1,160,000</u>	<u>3,000</u>	<u>23,000</u>	
Three months ending June 30, 2015:				
TCO (\$/MMBtu)	120,000	—	—	\$ 4.86
Dominion South (\$/MMBtu)	230,000	—	—	\$ 5.41
NYMEX (\$/MMBtu)	770,000	—	—	\$ 3.75
CGTLA (\$/MMBtu)	40,000	—	—	\$ 3.86
NYMEX-WTI (\$/Bbl)	—	3,000	—	\$ 64.21
Mont Belvieu-TET (\$/Gallon)	—	—	23,000	\$ 0.60
Total	<u>1,160,000</u>	<u>3,000</u>	<u>23,000</u>	
Three months ending September 30, 2015:				
TCO (\$/MMBtu)	120,000	—	—	\$ 4.93
Dominion South (\$/MMBtu)	230,000	—	—	\$ 5.48
NYMEX (\$/MMBtu)	770,000	—	—	\$ 3.79
CGTLA (\$/MMBtu)	40,000	—	—	\$ 3.93
NYMEX-WTI (\$/Bbl)	—	3,000	—	\$ 64.84
Mont Belvieu-TET (\$/Gallon)	—	—	23,000	\$ 0.62
Total	<u>1,160,000</u>	<u>3,000</u>	<u>23,000</u>	
Three months ending December 31, 2015:				
TCO (\$/MMBtu)	120,000	—	—	\$ 5.14
Dominion South (\$/MMBtu)	230,000	—	—	\$ 5.74
NYMEX (\$/MMBtu)	770,000	—	—	\$ 3.92
CGTLA (\$/MMBtu)	40,000	—	—	\$ 4.09
NYMEX-WTI (\$/Bbl)	—	3,000	—	\$ 65.67
Mont Belvieu-TET (\$/Gallon)	—	—	23,000	\$ 0.64
Total	<u>1,160,000</u>	<u>3,000</u>	<u>23,000</u>	
Year ending December 31, 2016:				
TCO (\$/MMBtu)	60,000	—	—	\$ 4.91
Dominion South (\$/MMBtu)	272,500	—	—	\$ 5.35
NYMEX (\$/MMBtu)	440,000	—	—	\$ 4.00
CGTLA (\$/MMBtu)	170,000	—	—	\$ 4.09
2016 Total	<u>942,500</u>			
Year ending December 31, 2017:				
NYMEX (\$/MMBtu)	290,000	—	—	\$ 4.38
CGTLA (\$/MMBtu)	420,000	—	—	\$ 4.27
CCG (\$/MMBtu)	70,000	—	—	\$ 4.57
2017 Total	<u>780,000</u>			
Year ending December 31, 2018:				
NYMEX (\$/MMBtu)	<u>1,072,500</u>	—	—	\$ 4.50
Year ending December 31, 2019:				
NYMEX (\$/MMBtu)	<u>817,500</u>	—	—	\$ 4.41
Year ending December 31, 2020:				
NYMEX (\$/MMBtu)	<u>40,000</u>	—	—	\$ 4.41

As of December 31, 2014, the Company's natural gas basis swap positions, which settle on the pricing index to basis

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014
differential of TCO to the NYMEX Henry Hub natural gas price, are as follows:

	Natural gas MMBtu/day	Hedged Differential
Year ending December 31, 2015:	<u>390,000</u>	\$ (0.35)
Year ending December 31, 2016:	<u>220,000</u>	\$ (0.42)
Year ending December 31, 2017:	<u>107,500</u>	\$ (0.50)

(b) Summary

The following is a summary of the fair values of the Company's derivative instruments and where such values are recorded in the consolidated balance sheets as of December 31, 2013 and 2014. None of the Company's derivative instruments are designated as hedges for accounting purposes.

	December 31, 2013		December 31, 2014	
	Balance sheet location	Fair value (In thousands)	Balance sheet location	Fair value (In thousands)
Asset derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current assets	\$ 183,000	Current assets	\$ 692,554
Commodity contracts	Long-term assets	<u>677,780</u>	Long-term assets	<u>899,997</u>
Total asset derivatives		<u>860,780</u>		<u>1,592,551</u>
Liability derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current liabilities	646	Current liabilities	—
Commodity contracts	Long-term liabilities	<u>—</u>	Long-term liabilities	<u>—</u>
Total liability derivatives		<u>646</u>		<u>—</u>
Net derivatives		<u>\$ 860,134</u>		<u>\$ 1,592,551</u>

The following table presents the gross amounts of recognized derivative assets and liabilities, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets for the periods presented, all at fair value (in thousands):

December 31, 2013			December 31, 2014		
Gross amounts on balance sheet	Gross amounts offset on balance sheet	Net amounts of assets (liabilities) on balance sheet	Gross amounts on balance sheet	Gross amounts offset on balance sheet	Net amounts of assets on balance sheet

Commodity derivative assets	\$887,034	(26,254)	860,780	\$1,621,665	(29,114)	1,592,551
Commodity derivative liabilities	\$ (646)	—	(646)	\$ —	—	—

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

The following is a summary of derivative fair value gains and where such values are recorded in the consolidated statements of operations for the years ended December 31, 2012, 2013, and 2014 (in thousands):

	Statement of operations location	Year ended December 31,		
		2012	2013	2014
Commodity derivative fair value gains	Revenue	\$179,546	491,689	868,201
Commodity derivative fair value gains	Discontinued operations	46,358	—	—
Total commodity derivative fair value gains		<u>\$225,904</u>	<u>491,689</u>	<u>868,201</u>

The fair value of commodity derivative instruments was determined using Level 2 inputs.

(10) Income Taxes

For the years ended December 31, 2012, 2013, and 2014, income tax expense from continuing operations consisted of the following (in thousands):

	2012	2013	2014
Current income tax expense (benefit)	\$ 15,000	(4,000)	—
Deferred income tax expense	106,229	190,210	445,672
Total income tax expense from continuing operations	<u>\$121,229</u>	<u>186,210</u>	<u>445,672</u>

Income tax expense from continuing operations differs from the amount that would be computed by applying the U.S. statutory federal income tax rate of 35% to consolidated income for the years ended December 31, 2012, 2013, and 2014 as a result of the following (in thousands):

	2012	2013	2014
Federal income tax expense	\$121,276	56,708	391,754
State income tax expense, net of federal benefit	4,761	21,429	25,545
Nondeductible equity-based compensation	—	127,736	29,141
Noncontrolling interest in Antero Midstream Partners LP	—	—	(787)
Change in valuation allowance	(4,872)	(20,919)	(120)
Other	64	1,256	139
Total income tax expense from continuing operations	<u>\$121,229</u>	<u>186,210</u>	<u>445,672</u>

For the years ended December 31, 2012, 2013, and 2014, income tax expense (benefit) was allocated to continuing and discontinued operations as follows (in thousands):

	2012	2013	2014
Continuing operations	\$ 121,229	186,210	445,672
Discontinued operations and sale of discontinued operations	(272,553)	3,249	1,354
Total income tax expense (benefit)	<u>\$(151,324)</u>	<u>189,459</u>	<u>447,026</u>

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

Deferred income taxes reflect the impact of temporary differences between assets and liabilities for financial reporting purposes and such amounts as measured by tax laws. The tax effect of the temporary differences giving rise to net deferred tax assets and liabilities at December 31, 2013 and 2014 is as follows (in thousands):

	2013	2014
Deferred tax assets:		
Net operating loss carryforwards	\$ 449,961	431,681
Minimum tax credit carryforward	11,000	11,000
Equity-based compensation	—	10,032
Other	5,373	12,785
Total deferred tax assets	466,334	465,498
Valuation allowance	(26,759)	(26,639)
Net deferred tax assets	439,575	438,859
Deferred tax liabilities:		
Unrealized gains on derivative instruments	328,534	601,859
Oil and gas properties	458,812	600,050
Investment in Antero Midstream Partners LP	—	31,746
Total deferred tax liabilities	787,346	1,233,655
Net deferred tax liabilities	\$(347,771)	(794,796)

In assessing the realizability of deferred tax assets, management considers whether some portion or all of the deferred tax assets will be realized based on a more likely than not standard of judgment. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based upon the projections of future taxable income over the periods in which the deferred tax assets are deductible, management believes that the Company will not realize the benefits of certain of these deductible differences and has recorded a valuation allowance of approximately \$27 million at December 31, 2013 and 2014, which is primarily related to capital loss carryforwards and certain state NOL carryforwards related to states in which the Company no longer operates. The amount of the deferred tax asset considered realizable could be reduced in the near term if estimates of future taxable income during the carryforward period are revised.

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that it believes are more -likely than -not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The financial statements include unrecognized benefits at December 31, 2014 of \$ 11 million that, if recognized, would result in a reduction of noncurrent income taxes payable (included in other long -term liabilities) and an increase in noncurrent deferred tax liabilities. No impact to the Company's 2014 effective tax rate would result. As of December 31, 2014, interest of \$0.8 million has been accrued on unrecognized tax benefits. A reconciliation of beginning and ending amount of unrecognized tax benefits is as follows:

	2014
Balance at beginning of year	\$ 11,000
Revised estimate of unrecognized tax position	—
Balance at end of year	\$ 11,000

As of December 31, 2014, the Company's corporate subsidiaries have U.S. Federal and state net operating loss carryforwards (NOLs) of \$1.1 billion and \$1.0 billion, respectively, which expire at various dates from 2024 to 2034.

The tax years 2011 through 2014 remain open to examination by the U.S. Internal Revenue Service. The Company and its subsidiaries file tax returns with various state taxing authorities; these returns remain open to examination for tax years 2010 through 2014. During 2014, the tax returns of Antero Resources Finance Corporation (which was merged with the Antero Resources Corporation in December 2013) were examined by the Internal Revenue Service for its tax years 2011 and 2012. There were no adjustments to these tax returns as a result of the examination. The Company's state tax returns are being examined by West Virginia

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

taxing authorities for tax years 2010 through 2013. The Company does not expect any material adjustments to tax liabilities will result from the examination.

(11) Commitments

The following is a schedule of future minimum payments for firm transportation agreements, drilling and compression facility obligations, and leases that have remaining lease terms in excess of one year as of December 31, 2014 (in millions).

	Firm transportation	Gas processing, gathering and compression	Drilling rigs and frac services	Office and equipment	Total
	(a)	(b)	(c)	(d)	
Year ending December 31:					
2015	\$ 316	336	212	9	873
2016	593	237	161	9	1,000
2017	800	245	96	8	1,149
2018	867	244	—	6	1,117
2019	939	193	—	4	1,136
Thereafter	10,376	1,040	—	11	11,427
Total	<u>\$ 13,891</u>	<u>2,295</u>	<u>469</u>	<u>47</u>	<u>16,702</u>

(a) Firm Transportation

The Company has entered into firm transportation agreements with various pipelines in order to facilitate the delivery of its production to market. These contracts commit the Company to transport minimum daily natural gas or NGLs volumes at negotiated rates, or pay for any deficiencies at specified reservation fee rates. The amounts in this table represent minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest.

(b) Gas Processing and Compression Service Commitments

The Company has entered into various long-term gas processing agreements for certain of its production that will allow it to realize the value of its NGLs. The minimum payment obligations under the agreements are presented in the table.

The Company has various compressor service agreements with third parties that provide for payments based on volumes compressed and have minimum payment obligations which are presented in the table.

The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest.

(c) Drilling Rig Service Commitments

The Company has obligations under agreements with service providers to procure drilling rigs and compression and frac services. The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest.

(d) Office and Equipment Leases

The Company leases various office space and equipment, as well as field equipment, under operating lease arrangements. Rental expense under operating leases was \$1.1 million, \$1.8 million, and \$10.2 million for the years ended December 31, 2012, 2013, and 2014, respectively.

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

(12) Contingencies

The Company is party to various legal proceedings and claims in the ordinary course of its business. The Company believes that certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on the Company's consolidated financial position, results of operations, or liquidity.

(13) Segment Information

See note 2(r) for a description of the Company's determination of its reportable segments for 2014. Marketing of excess firm transportation capacity began in the second quarter of 2014, and was subsequently determined to be a new reportable segment. Prior to 2013, the Company's gathering and compression and fresh water distribution operations were immaterial and were considered ancillary to the Company's exploration and production activities.

Operating segments are evaluated based on their contribution to consolidated results, which is determined by their operating income. General and administrative expenses are allocated to the gathering and compression and fresh water distribution segments based on estimates of labor and overhead expenditures on those activities. General and administrative expenses related to the marketing segment are not allocated because they are immaterial. Other income, income taxes, and interest expense are primarily managed on a consolidated basis. Intersegment sales are at market value. Segment accounting policies are the same as those described in note 2 to the consolidated financial statements.

The operating results and assets of the Company's reportable segments were as follows for the years ended December 31, 2013 and 2014:

	Exploration and production	Gathering and compression	Fresh water distribution	Elimination of intersegment transactions	Consolidated total
2013:					
Sales and revenues:					
Third-party	\$ 1,313,134	—	—	—	1,313,134
Intersegment	—	22,363	35,871	(58,234)	—
	<u>\$ 1,313,134</u>	<u>22,363</u>	<u>35,871</u>	<u>(58,234)</u>	<u>1,313,134</u>
Operating expenses:					
Lease operating	\$ 9,439	—	3,843	(3,843)	9,439
Gathering, compression, processing, and transportation	238,712	2,079	—	(22,363)	218,428
Depletion, depreciation, and amortization	219,757	11,346	2,773	—	233,876
General and administrative expense	391,373	23,124	10,941	—	425,438
Other operating expenses	82,787	—	1,959	—	84,746
Total	<u>942,068</u>	<u>36,549</u>	<u>19,516</u>	<u>(26,206)</u>	<u>971,927</u>
Operating income (loss)	<u>\$ 371,066</u>	<u>(14,186)</u>	<u>16,355</u>	<u>(32,028)</u>	<u>341,207</u>
Segment assets	\$ 5,859,933	561,855	230,247	(38,454)	6,613,581
Capital expenditures for segment assets	\$ 2,110,358	389,453	203,790	(32,028)	2,671,573

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

	Exploration and production	Gathering and compression	Fresh water distribution	Marketing	Elimination of Intersegment transactions	Consolidated total
2014:						
Sales and revenues:						
Third-party	\$2,644,953	6,810	15,265	53,604	—	2,720,632
Intersegment	195	88,936	156,660	—	(245,791)	—
	<u>\$2,645,148</u>	<u>95,746</u>	<u>171,925</u>	<u>53,604</u>	<u>(245,791)</u>	<u>2,720,632</u>
Operating expenses:						
Lease operating	\$ 28,041	—	34,737	—	(33,437)	29,341
Gathering, compression, processing, and transportation	536,879	13,497	—	—	(88,963)	461,413
Depletion, depreciation, and amortization	424,684	36,972	16,240	—	—	477,896
General and administrative expense	186,335	22,035	8,331	—	(168)	216,533
Other operating expenses	128,419	1,973	1,888	103,435	—	235,715
Total	<u>1,304,358</u>	<u>74,477</u>	<u>61,196</u>	<u>103,435</u>	<u>(122,568)</u>	<u>1,420,898</u>
Operating income (loss)	<u>\$1,340,790</u>	<u>21,269</u>	<u>110,729</u>	<u>(49,831)</u>	<u>(123,223)</u>	<u>1,299,734</u>
Segment assets	\$9,920,331	1,411,470	422,885	10,456	(191,647)	11,573,495
Capital expenditures for segment assets	\$3,455,079	558,037	196,675	—	(123,223)	4,086,568

(14) Subsidiary Guarantors

Antero Resources Corporation (the Parent) and certain of its wholly owned subsidiaries each have fully and unconditionally guaranteed the Company's senior notes. Antero Midstream and its subsidiary have been designated unrestricted subsidiaries under the Credit Facility and the indentures governing the Company's senior notes, and do not guarantee any of Antero's obligations (see note 3). In the event a subsidiary guarantor is sold or disposed of (whether by merger, consolidation, the sale of a sufficient amount of its capital stock so that it no longer qualifies as a "Subsidiary" of the Company (as defined in the indentures governing the notes) or the sale of all or substantially all of its assets (other than by lease)) and whether or not the subsidiary guarantor is the surviving entity in such transaction to a person which is not the Company or a restricted subsidiary of the Company, such subsidiary guarantor will be released from its obligations under its subsidiary guarantee if the sale or other disposition does not violate the covenants set forth in the indentures governing the notes.

In addition, a subsidiary guarantor will be released from its obligations under the indentures and its guarantee, upon the release or discharge of the guarantee of other Indebtedness (as defined in the indentures governing the notes) that resulted in the creation of such guarantee, except a release or discharge by or as a result of payment under such guarantee; if the Company designates such subsidiary as an unrestricted subsidiary and such designation complies with the other applicable provisions of the indentures governing the notes or in connection with any covenant defeasance, legal defeasance or satisfaction and discharge of the notes.

The following Condensed Consolidating Balance Sheet at December 31, 2014, and the related statements of operations and comprehensive income (loss) and statements cash flows for the year ended December 31, 2014, present financial information for Antero Resources Corporation as the Parent on a stand-alone basis (carrying its investment in wholly-owned subsidiaries on the equity method), financial information for the subsidiary guarantors, financial information for the non-guarantor subsidiaries, and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. The guarantor and non-guarantor subsidiaries had no revenues, expenses, or cash flows during the year ended December 31, 2013, or for any year prior to 2013 and immaterial assets and liabilities at December 31, 2013. Antero's wholly-owned subsidiaries are not restricted from making distributions to the Parent.

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Condensed Consolidating Balance Sheet

December 31, 2014

(In thousands)

	Parent	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	\$ 15,787	—	230,192	—	245,979
Accounts receivable, net	116,203	—	—	—	116,203
Intercompany receivables	1,380	—	17,646	(19,026)	—
Accrued revenue	191,558	—	—	—	191,558
Derivative instruments	692,554	—	—	—	692,554
Other	5,348	1	518	(1)	5,866
Total current assets	1,022,830	1	248,356	(19,027)	1,252,160
Property and equipment:					
Natural gas properties, at cost (successful efforts method):					
Unproved properties	2,060,936	—	—	—	2,060,936
Proved properties	6,515,221	—	—	—	6,515,221
Fresh water distribution systems	421,012	—	—	—	421,012
Gathering systems and facilities	16,532	—	1,180,707	—	1,197,239
Other property and equipment	37,687	—	—	—	37,687
	9,051,388	—	1,180,707	—	10,232,095
Less accumulated depletion, depreciation, and amortization	(828,533)	—	(51,110)	—	(879,643)
Property and equipment, net	8,222,855	—	1,129,597	—	9,352,452
Derivative instruments	899,997	—	—	—	899,997
Investments in subsidiaries	137,423	—	—	(137,423)	—
Other assets, net	51,718	—	17,168	—	68,886
Total assets	\$ 10,334,823	1	1,395,121	(156,450)	11,573,495
Liabilities and Equity					
Current liabilities:					
Accounts payable	\$ 485,628	—	45,936	—	531,564
Intercompany payable	17,646	—	1,380	(19,026)	—
Accrued liabilities	163,268	—	5,346	—	168,614
Revenue distributions payable	182,352	—	—	—	182,352
Deferred income tax liability	260,373	—	—	—	260,373
Other	12,203	—	—	(1)	12,202
Total current liabilities	1,121,470	—	52,662	(19,027)	1,155,105
Long-term liabilities:					
Long-term debt	4,247,550	115,000	—	—	4,362,550
Deferred income tax liability	534,423	—	—	—	534,423
Other long-term liabilities	47,587	—	—	—	47,587
Total liabilities	5,951,030	115,000	52,662	(19,027)	6,099,665
Equity:					
Stockholders' equity:					
Parent net investment	—	(114,999)	—	114,999	—
Partners' capital	—	—	1,342,459	(1,342,459)	—
Common stock	2,621	—	—	—	2,621
Additional paid-in capital	3,513,725	—	—	—	3,513,725
Accumulated earnings	867,447	—	—	—	867,447
Total stockholders' equity	4,383,793	(114,999)	1,342,459	(1,227,460)	4,383,793
Noncontrolling interest in consolidated subsidiary	—	—	—	1,090,037	1,090,037
Total equity	4,383,793	(114,999)	1,342,459	(137,423)	5,473,830
Total liabilities and equity	\$ 10,334,823	1	1,395,121	(156,450)	11,573,495

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

Condensed Consolidating Statement of Operations and Comprehensive Income
Year ended December 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	Eliminations	Consolidated
Revenue:					
Natural gas sales	\$ 1,301,349	—	—	—	1,301,349
Natural gas liquids sales	328,323	—	—	—	328,323
Oil sales	107,080	—	—	—	107,080
Gathering, compression, and water distribution	20,284	—	25,178	(23,387)	22,075
Marketing	53,604	—	—	—	53,604
Commodity derivative fair value gains	868,201	—	—	—	868,201
Gain on sale of gathering system	40,000	—	—	—	40,000
Fee income	143	—	—	(143)	—
Total revenue	2,718,984	—	25,178	(23,530)	2,720,632
Operating expenses:					
Lease operating	29,341	—	—	—	29,341
Gathering, compression, processing, and transportation	480,367	—	4,460	(23,414)	461,413
Production and ad valorem taxes	85,945	—	1,973	—	87,918
Marketing	103,435	—	—	—	103,435
Exploration	27,893	—	—	—	27,893
Impairment of unproved properties	15,198	—	—	—	15,198
Depletion, depreciation, and amortization	471,372	—	6,524	—	477,896
Accretion of asset retirement obligations	1,271	—	—	—	1,271
General and administrative	212,316	—	4,333	(116)	216,533
Total operating expenses	1,427,138	—	17,290	(23,530)	1,420,898
Operating income	1,291,846	—	7,888	—	1,299,734
Other income (expenses):					
Interest	(159,585)	—	(466)	—	(160,051)
Loss on early extinguishment of debt	(20,386)	—	—	—	(20,386)
Equity in net income of subsidiaries	5,174	—	—	(5,174)	—
Total other expenses	(174,797)	—	(466)	(5,174)	(180,437)
Income from continuing operations before income taxes and discontinued operations	1,117,049	—	7,422	(5,174)	1,119,297
Provision for income tax expense	(445,672)	—	—	—	(445,672)
Income from continuing operations	671,377	—	7,422	(5,174)	673,625
Discontinued operations:					
Income from sale of discontinued operations, net of income taxes	2,210	—	—	—	2,210
Net income and comprehensive income including noncontrolling interest	673,587	—	7,422	(5,174)	675,835
Net income and comprehensive income attributable to noncontrolling interest	—	—	—	2,248	2,248
Net income and comprehensive income attributable to Antero Resources Corporation	\$ 673,587	—	7,422	(7,422)	673,587

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014
Condensed Consolidating Statement of Cash Flows
December 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	\$ 992,788	—	5,333	—	998,121
Cash flows from investing activities:					
Additions to proved properties	(64,066)	—	—	—	(64,066)
Additions to unproved properties	(777,422)	—	—	—	(777,422)
Drilling and completion costs	(2,477,150)	—	—	—	(2,477,150)
Additions to fresh water distribution systems	(196,675)	—	—	—	(196,675)
Additions to gathering systems and facilities	(543,196)	—	(14,841)	—	(558,037)
Additions to other property and equipment	(13,218)	—	—	—	(13,218)
Decrease in notes receivable	2,667	—	—	—	2,667
Change in other assets	(5,595)	—	(154)	—	(5,749)
Net distributions from subsidiaries	447,500	—	—	(447,500)	—
Net cash used in investing activities	(3,627,155)	—	(14,995)	(447,500)	(4,089,650)
Cash flows from financing activities:					
Distributions to Antero	—	(115,000)	(332,500)	447,500	—
Issuance of common units in Antero Midstream Partners LP	—	—	1,087,224	—	1,087,224
Issuance of senior notes	1,102,500	—	—	—	1,102,500
Repayment of senior notes	(260,000)	—	—	—	(260,000)
Borrowings (repayments) on bank credit facility, net	1,837,000	115,000	(510,000)	—	1,442,000
Make-whole premium on debt extinguished	(17,383)	—	—	—	(17,383)
Payments of deferred financing costs	(26,673)	—	(4,870)	—	(31,543)
Other	(2,777)	—	—	—	(2,777)
Net cash provided by financing activities	2,632,667	—	239,854	447,500	3,320,021
Net increase (decrease) in cash and cash equivalents	(1,700)	—	230,192	—	228,492
Cash and cash equivalents, beginning of period	17,487	—	—	—	17,487
Cash and cash equivalents, end of period	\$ 15,787	—	230,192	—	245,979

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

(15) Quarterly Financial Information (Unaudited)

The Company's quarterly consolidated financial information for the years ended December 31, 2013 and 2014 is summarized in the following table (in thousands, except per share amounts). The Company's quarterly operating results are affected by the volatility of commodity prices and the resulting effect on our production revenues and the fair value of commodity derivatives.

	First quarter	Second quarter	Third quarter	Fourth quarter
Year Ended December 31, 2013:				
Total operating revenues	\$ 61,454	\$387,144	\$384,522	\$ 480,014
Total operating expenses	109,923	138,758	161,914	561,332
Operating income (loss)	(48,469)	248,386	222,608	(81,318)
Income (loss) from continuing operations	(47,997)	131,193	117,794	(225,177)
Income from discontinued operations	—	—	3,100	2,157
Net income (loss) and comprehensive income (loss)	(47,997)	131,193	120,894	(223,020)
Earnings (loss) per common share:				
Continuing operations	\$ (0.18)	\$ 0.50	\$ 0.45	\$ (0.86)
Discontinued operations	—	—	0.01	0.01
Net income (loss)	<u>\$ (0.18)</u>	<u>\$ 0.50</u>	<u>\$ 0.46</u>	<u>\$ (0.85)</u>
Earnings (loss) per common share—diluted:				
Continuing operations	\$ (0.18)	\$ 0.50	\$ 0.45	\$ (0.86)
Discontinued operations	—	—	0.01	0.01
Net income (loss)	<u>\$ (0.18)</u>	<u>\$ 0.50</u>	<u>\$ 0.46</u>	<u>\$ (0.85)</u>
	First quarter	Second quarter	Third quarter	Fourth quarter
Year Ended December 31, 2014:				
Total operating revenues	\$ 164,981	\$311,338	\$762,490	\$1,481,823
Total operating expenses	269,060	316,641	381,091	454,106
Operating income (loss)	(104,079)	(5,303)	381,399	1,027,717
Income (loss) from continuing operations	(94,759)	(44,495)	203,909	608,970
Income from discontinued operations	—	2,210	—	—
Net income (loss) and comprehensive income (loss)	(94,759)	(42,285)	203,909	608,970
Net income attributable to noncontrolling interest	—	—	—	2,248
Net income (loss) attributable to Antero Resources Corporation	(94,759)	(42,285)	203,909	606,722
Earnings (loss) per common share:				
Continuing operations	\$ (0.36)	\$ (0.17)	\$ 0.78	\$ 2.31
Discontinued operations	—	0.01	—	—
Net income (loss)	<u>\$ (0.36)</u>	<u>\$ (0.16)</u>	<u>\$ 0.78</u>	<u>\$ 2.31</u>
Earnings (loss) per common share—diluted:				
Continuing operations	\$ (0.36)	\$ (0.17)	\$ 0.78	\$ 2.31
Discontinued operations	—	0.01	—	—
Net income (loss)	<u>\$ (0.36)</u>	<u>\$ (0.16)</u>	<u>\$ 0.78</u>	<u>\$ 2.31</u>

(16) Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The following is supplemental information regarding the Company's consolidated oil and gas producing activities. The amounts shown include the Company's net working interests in all of its oil and gas properties.

ANTERO RESOURCES CORPORATION**Notes to Consolidated Financial Statements (Continued)****Years Ended December 31, 2012, 2013, and 2014****(a) Capitalized Costs Relating to Oil and Gas Producing Activities**

	Year ended December 31,	
	2013	2014
	(In thousands)	
Proved properties	\$ 3,621,672	\$ 6,515,221
Unproved properties	<u>1,513,136</u>	<u>2,060,936</u>
	5,134,808	8,576,157
Accumulated depreciation and depletion	<u>(383,921)</u>	<u>(802,665)</u>
Net capitalized costs	<u>\$ 4,750,887</u>	<u>\$ 7,773,492</u>

(b) Costs Incurred in Certain Oil and Gas Activities

	Year ended December 31,		
	2012	2013	2014
Acquisition costs:			
Proved property	\$ 10,254	\$ 15,300	\$ 64,066
Unproved property	687,403	440,825	777,422
Development costs	678,276	780,583	1,536,193
Exploration costs	<u>158,074</u>	<u>835,382</u>	<u>940,957</u>
Total costs incurred	<u>\$1,534,007</u>	<u>\$2,072,090</u>	<u>\$3,318,638</u>

(c) Results of Operations (Including Discontinued Operations) for Oil and Gas Producing Activities

	Year ended December 31,		
	2012	2013	2014
Revenues	\$ 390,378	\$ 821,445	\$1,736,752
Operating expenses:			
Production expenses	185,505	278,348	578,672
Exploration expenses	15,339	22,272	27,893
Depreciation and depletion	181,664	219,830	418,744
Impairment of unproved properties	<u>13,032</u>	<u>10,928</u>	<u>15,198</u>
Results of operations before income tax expense			
(benefit)	(5,162)	290,067	696,245
Income tax (expense) benefit	<u>2,008</u>	<u>(110,805)</u>	<u>(263,126)</u>
Results of operations	<u>\$ (3,154)</u>	<u>\$ 179,262</u>	<u>\$ 433,119</u>

(d) Oil and Gas Reserves

The following table sets forth the net quantities of proved reserves and proved developed reserves during the periods indicated. This information includes the oil and gas segment's royalty and net working interest share of the reserves in oil and gas properties. Net proved oil and gas reserves for the year ended December 31, 2012, 2013, and 2014 were prepared by the Company's reserve engineers and audited by DeGolyer and MacNaughton (D&M) utilizing data compiled by the Company. There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and timing of future development costs. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. All reserves are located in the United States.

Proved reserves are the estimated quantities of crude oil, condensate, and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods. The Company estimates proved reserves using average prices received for the previous 12 months.

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

Proved undeveloped reserves include drilling locations that are more than one offset location away from productive wells and are reasonably certain of containing proved reserves and which are scheduled to be drilled within five years under the Company's development plans. The Company's development plans for drilling scheduled over the next five years are subject to many uncertainties and variables, including availability of capital; future oil and gas prices; and cash flows from operations, future drilling costs, demand for natural gas, and other economic factors.

	Natural gas (Bcf)	NGLs (MMBbl)	Oil and condensate (MMBbl)	Equivalents (Bcfe)
Proved reserves:				
December 31, 2011	3,931	164	17	5,017
Revisions	198	4	— (a)	222
Extensions, discoveries and other additions	1,242	115	3	1,951
Production	(87)	— (a)	— (a)	(87)
Sale of reserves in place	(1,590)	(80)	(17)	(2,174)
December 31, 2012	3,694	203	3	4,929
Revisions	152	(140)	— (a)	(788)
Extensions, discoveries and other additions	3,084	76	7	3,682
Production	(177)	(2)	— (a)	(191)
December 31, 2013	6,753	137	10	7,632
Revisions	(1,025)	(6)	— (a)	(1,054)
Extensions, discoveries and other additions	5,095	206	19	6,444
Purchases	29	—	—	29
Production	(317)	(7)	(1)	(368)
December 31, 2014	10,535	330	28	12,683

(a) Less than 1.0.

	Natural gas (Bcf)	NGLs (MMBbl)	Oil and condensate (MMBbl)	Equivalents (Bcfe)
Proved developed reserves:				
December 31, 2012	828	36	1	1,047
December 31, 2013	1,818	33	2	2,022
December 31, 2014	3,285	80	6	3,803
Proved undeveloped reserves:				
December 31, 2012	2,866	167	2	3,822
December 31, 2013	4,936	105	8	5,610
December 31, 2014	7,250	250	22	8,880

Significant items included in the categories of proved developed and undeveloped reserve changes for the years 2010, 2011, and 2012 in the above table include the following:

- 2012—Extensions, discoveries, and other additions during 2012 of 1,951 Bcfe were added through the drilling in the Marcellus and Utica Shales, including the addition of 709 Bcfe attributable to NGLs and oil. Downward price revisions resulted in a reduction of proved reserves of 102 Bcfe. Performance revisions increased proved reserves by 324 Bcfe. Sales of proved reserves of 2,174 Bcfe are the result of the sale of the Company's Arkoma and Piceance Basin properties.
- 2013—Extensions, discoveries, and other additions during 2013 of 3,682 Bcfe were added through exploratory and developmental drilling in the Marcellus and Utica Shales. Downward revisions of 788 Bcfe resulted from changing the underlying production assumption used to estimate reserves to ethane rejection at December 31, 2013 from ethane

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

recovery at December 31, 2012 as well as the reclassification of certain wells to the probable reserves category in 2013 because they are no longer expected to be drilled within five years of initial booking.

- 2014— Extensions, discoveries, and other additions during 2014 of 6,444 Bcfe were added through exploratory and developmental drilling in the Marcellus and Utica Shales. Purchases of 29 Bcfe relate to 5 horizontal producing wells acquired as part of our leasehold acquisition efforts. Upward performance revisions of 361 Bcfe relate to improved well performance from shorter stage length completions. Downward revisions of 1,417 Bcfe were due to the reclassification of 191 dry gas locations to the probable category because they are no longer expected to be drilled within five years of initial booking. Upward price revisions of 2 Bcfe were due to increases in the reference price for natural gas, partially offset by decreases in the reference prices for NGLs and oil.

The following table sets forth the standardized measure of the discounted future net cash flows attributable to the Company's proved reserves. Future cash inflows were computed by applying historical 12 month unweighted first day of the month average prices. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pretax net cash flows relating to the Company's proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of available net operating loss carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

(In millions)	Year ended December 31,		
	2012	2013	2014
Future cash inflows	\$ 12,151	\$ 30,113	\$ 63,632
Future production costs	(1,660)	(5,967)	(21,722)
Future development costs	(3,270)	(5,349)	(8,212)
Future net cash flows before income tax	7,221	18,797	33,698
Future income tax expense	(1,603)	(5,308)	(10,726)
Future net cash flows	5,618	13,489	22,972
10% annual discount for estimated timing of cash flows	(4,017)	(8,979)	(15,337)
Standardized measure of discounted future net cash flows	\$ 1,601	\$ 4,510	\$ 7,635

The 12 -month weighted average prices used to estimate the Company's total equivalent reserves were as follows (per Mcfe):

December 31, 2012	\$ 2.78
December 31, 2013	\$ 3.95
December 31, 2014	\$ 5.02

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

(f) *Changes in Standardized Measure of Discounted Future Net Cash Flow*

	Year ended December 31,		
	2012	2013	2014
Sales of oil and gas, net of production costs	\$ (147)	\$ (543)	\$ (1,158)
Net changes in prices and production costs	(1,631)	1,061	(184)
Development costs incurred during the period	296	384	564
Net changes in future development costs	(92)	(181)	(102)
Extensions, discoveries and other additions	813	3,441	5,759
Acquisitions	—	2	42
Divestitures	(1,277)	—	—
Revisions of previous quantity estimates	88	(270)	(828)
Accretion of discount	322	192	600
Net change in income taxes	653	(1,165)	(2,198)
Other changes	106	(12)	630
Net increase (decrease)	(869)	2,909	3,125
Beginning of year	2,470	1,601	4,510
End of year	\$ 1,601	\$ 4,510	\$ 7,635

**ANTERO RESOURCES CORPORATION
LONG-TERM INCENTIVE PLAN****RESTRICTED STOCK UNIT GRANT NOTICE**

Pursuant to the terms and conditions of the Antero Resources Corporation Long-Term Incentive Plan, as amended from time to time (the "Plan"), Antero Resources Corporation (the "Company") hereby grants to the individual listed below (" you " or the "Participant ") the number of Restricted Stock Units (the "RSUs ") set forth below. This award of RSUs (this "Award ") is subject to the terms and conditions set forth herein and in the Restricted Stock Unit Agreement attached hereto as Exhibit A (the "Agreement ") and the Plan, each of which is incorporated herein by reference. Capitalized terms used but not defined herein shall have the meanings set forth in the Plan.

Participant:	[_____]
Date of Grant:	_____, 20____
Total Number of Restricted Stock Units:	_____
Vesting Commencement Date:	_____, 20____
Vesting Schedule:	Subject to the Agreement, the Plan and the other terms and conditions set forth herein, 25% of the RSUs (rounded to the nearest whole number of RSUs, except in the case of the final vesting date) shall vest on each of the first, second, third and fourth anniversaries of the Vesting Commencement Date identified above so long as you remain continuously employed by the Company from the Date of Grant through each such anniversary date. Notwithstanding anything in the preceding sentence to the contrary, the RSUs granted hereunder shall immediately become fully vested if Employee's employment with the Company terminates by reason of Employee's disability (within the meaning of section 22(e)(3) of the Code) or death so long as Employee remains continuously employed by the Company from the Date of Grant through the date of such termination.

By your signature below, you agree to be bound by the terms and conditions of the Plan, the Agreement and this Restricted Stock Unit Grant Notice (this "Grant Notice"). You acknowledge that you have reviewed the Agreement, the Plan and this Grant Notice in their entirety and fully understand all provisions of the Agreement, the Plan and this Grant Notice. You hereby agree to accept as binding, conclusive and final all decisions or interpretations of the Committee regarding any questions or determinations arising under the Agreement, the Plan or this Grant Notice. This Grant Notice may be executed in one or more counterparts (including portable document format (.pdf) and facsimile counterparts), each of which shall be deemed to be an original, but all of which together shall constitute one and the same agreement.

[Remainder of Page Intentionally Blank;
Signature Page Follows]

IN WITNESS WHEREOF, the Company has caused this Grant Notice to be executed by an officer thereunto duly authorized, and the Participant has executed this Grant Notice, effective for all purposes as provided above.

ANTERO RESOURCES CORPORATION

By:

Alvyn A. Schopp

Chief Administrative Officer and Regional

Vice President

PARTICIPANT

[Name of Employee]

EXHIBIT A

RESTRICTED STOCK UNIT AGREEMENT

This Restricted Stock Unit Agreement (this "Agreement") is made as of the Date of Grant set forth in the Grant Notice to which this Agreement is attached by and between Antero Resources Corporation, a Delaware corporation (the "Company"), and [] ("Employee"). Capitalized terms used but not specifically defined herein shall have the meanings specified in the Plan or the Grant Notice.

1. **Award**. In consideration of Employee's past and/or continued employment with, or service to, the Company or a Subsidiary and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, effective as of the Date of Grant set forth in the Grant Notice (the "Date of Grant"), the Company hereby grants to Employee the number of RSUs set forth in the Grant Notice on the terms and conditions set forth in the Grant Notice, this Agreement and the Plan, which is incorporated herein by reference as a part of this Agreement. In the event of any inconsistency between the Plan and this Agreement, the terms of the Plan shall control. To the extent vested, each RSU represents the right to receive one share of Common Stock, subject to the terms and conditions set forth in the Grant Notice, this Agreement and the Plan. Unless and until the RSUs have become vested in the manner set forth in the Grant Notice, Employee will have no right to receive any Common Stock or other payments in respect of the RSUs. Prior to settlement of this Award, the RSUs and this Award represent an unsecured obligation of the Company, payable only from the general assets of the Company.

2. **Vesting of RSUs**. The RSUs shall vest in accordance with the vesting schedule set forth in the Grant Notice. Unless and until the RSUs have vested in accordance with such vesting schedule, Employee will have no right to receive any dividends or other distribution with respect to the RSUs. In the event of the termination of Employee's employment prior to the vesting of all of the RSUs (but after giving effect to any accelerated vesting pursuant to the Grant Notice), any unvested RSUs (and all rights arising from such RSUs and from being a holder thereof) will terminate automatically without any further action by the Company and will be forfeited without further notice and at no cost to the Company.

3. **Settlement of RSUs**. As soon as administratively practicable following the vesting of RSUs pursuant to Section 2, but in no event later than 30 days after such vesting date, the Company shall deliver to Employee (or Employee's permitted transferee, if applicable) a number of shares of Common Stock equal to the number of RSUs subject to this Award that become vested on the applicable vesting date and cash equal to any DERs credited with respect to such vested RSUs or, at the discretion of the Committee, shares of Common Stock having a Fair Market Value equal to such DERs as of the applicable vesting date. Any fractional RSU that becomes vested hereunder shall be rounded down at the time shares of Common Stock are issued in settlement of such RSU. No fractional shares of Common Stock, nor the cash value of any fractional shares of Common Stock, will be issuable or payable to Employee pursuant to this Agreement. All shares of Common Stock issued hereunder shall be delivered either by delivering one or more certificates for such shares to Employee or by entering such shares in book-entry form, as determined by the Committee in its sole discretion. The value of shares of Common Stock shall not bear any interest owing to the passage of time. Neither this Section 3 nor any action taken pursuant to or in accordance with this Agreement shall be construed to create a trust or a funded or secured obligation of any kind.

4. **Dividend Equivalent Rights**. Each RSU subject to this Award is hereby granted in tandem with a corresponding Dividend Equivalent ("DER"), which DER shall remain outstanding from the Date of Grant until the earlier of the settlement or forfeiture of the RSU to which it corresponds. Each vested DER shall entitle Employee to receive payments, subject to and in accordance with this Agreement, in an amount equal to any dividends paid by the Company in respect of the shares of Common Stock underlying the RSUs to which such DER relates. The Company shall establish, with respect to each RSU, a separate DER bookkeeping account for such RSU (a "DER Account"), which shall be credited (without interest) on the applicable dividend payment dates with an amount equal to any dividends paid during the period that such RSU remains outstanding with respect to the shares of Common Stock underlying the RSU to which such DER relates. Upon the vesting of an RSU, the DER (and the DER Account) with respect to such vested RSU shall also become vested. Similarly, upon the forfeiture of an RSU, the DER (and the DER Account) with respect to such forfeited RSU shall also be forfeited. DERs shall not entitle Employee to any payments relating to dividends paid after the earlier to occur of the applicable RSU settlement date or the forfeiture of the RSU underlying such DER.

5. **Rights as Stockholder**. Neither Employee nor any person claiming under or through Employee shall have any of the rights or privileges of a holder of shares of Common Stock in respect of any shares that may become deliverable hereunder unless and until certificates representing such shares have been issued or recorded in book entry form on the records of the Company or its transfer agents or registrars, and delivered in certificate or book entry form to Employee or any person claiming under or through Employee.

6. **Tax Withholding**. To the extent that the receipt or vesting of the RSUs results in compensation income or wages to Employee for federal, state, local or foreign tax purposes, Employee shall deliver to the Company or to any Affiliate nominated by the

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
TYLER	48	1	\$90.00
		2	\$90.00
		3	\$1.00
		4	\$90.00
		5	\$90.00
		8	\$80.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$90.00
UPSHUR	49	1	\$70.00
		2	\$70.00
		3	\$1.00
		4	\$70.00
		5	\$70.00
		8	\$70.00
		7	\$70.00
WAYNE	50	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$20.00
		10	\$20.00
		11	\$1.00
		12	\$20.00
WEBSTER	51	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$16.00
		5	\$16.00
		6	\$15.00
		7	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
ROANE	44	1	\$35.00
		2	\$38.00
		3	\$38.00
		4	\$38.00
		5	\$1.00
		8	\$38.00
		7	\$35.00
		8	\$1.00
		9	\$38.00
SUMMERS	45	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$10.00
		6	\$1.00
		7	\$1.00
TAYLOR	46	1	\$1.00
		2	\$1.00
		3	\$90.00
		4	\$90.00
		5	\$90.00
		6	\$90.00
		7	\$90.00
TUCKER	47	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$20.00
		10	\$1.00
		11	\$20.00
		12	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017

COUNTY	CO #	DISTRICT #	TY2017 \$/AC
RALEIGH	41	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$1.00
		7	\$20.00
		8	\$20.00
		9	\$20.00
		10	\$1.00
		11	\$20.00
		12	\$20.00
RANDOLPH	42	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$20.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$20.00
		11	\$20.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$20.00
		17	\$1.00
		18	\$1.00
RITCHIE	43	1	\$70.00
		2	\$1.00
		3	\$70.00
		4	\$1.00
		5	\$70.00
		6	\$1.00
		7	\$70.00
		8	\$1.00
		9	\$1.00
		10	\$70.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
PLEASANTS	37	1	\$48.00
		2	\$45.00
		3	\$45.00
		4	\$48.00
		5	\$48.00
		8	\$1.00
		7	\$48.00
		8	\$48.00
POCAHONTAS	38	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		8	\$1.00
		7	\$1.00
		8	\$1.00
PRESTON	39	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		8	\$30.00
		7	\$1.00
		8	\$30.00
		9	\$1.00
		10	\$30.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		18	\$1.00
		17	\$1.00
		18	\$1.00
		19	\$1.00
		20	\$1.00
PUTNAM	40	1	\$25.00
		2	\$25.00
		3	\$1.00
		4	\$25.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$25.00
		9	\$1.00
		10	\$25.00
		11	\$25.00
		12	\$25.00
		13	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
MONROE	32	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
MORGAN	33	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
NICHOLAS	34	1	\$1.00
		2	\$18.00
		3	\$18.00
		4	\$18.00
		5	\$1.00
		6	\$1.00
		7	\$18.00
		8	\$1.00
		9	\$1.00
OHIO	35	1	\$1.00
		2	\$1.00
		3	\$100.00
		4	\$100.00
		5	\$1.00
		6	\$100.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
PENOLETON	36	1	\$1.00
		2	\$10.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$10.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
MINERAL	29	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
MINGO	30	1	\$1.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
		7	\$20.00
		8	\$1.00
		9	\$20.00
		10	\$20.00
		11	\$20.00
		12	\$1.00
MONONGALIA	31	1	\$30.00
		2	\$1.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		6	\$1.00
		7	\$30.00
		8	\$30.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$30.00
		19	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
MASON	26	1	\$1.00
		2	\$25.00
		3	\$25.00
		4	\$25.00
		5	\$25.00
		6	\$25.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$25.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$25.00
		15	\$25.00
		16	\$25.00
		17	\$25.00
		18	\$25.00
MC DOWELL	27	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$1.00
		6	\$20.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$20.00
		12	\$1.00
		13	\$20.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$1.00
MERCER	28	1	\$1.00
		2	\$15.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$15.00
		7	\$1.00
		8	\$1.00
		9	\$15.00
		10	\$1.00
		11	\$15.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
LOGAN	23	1	\$15.00
		2	\$15.00
		3	\$15.00
		4	\$15.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$15.00
		9	\$1.00
MARION	24	1	\$1.00
		2	\$90.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$90.00
		10	\$1.00
		11	\$90.00
		12	\$90.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$90.00
		17	\$1.00
		18	\$80.00
		19	\$90.00
		20	\$1.00
		21	\$1.00
		22	\$1.00
MARSHALL	25	1	\$1.00
		2	\$1.00
		3	\$100.00
		4	\$100.00
		5	\$100.00
		6	\$1.00
		7	\$100.00
		8	\$1.00
		9	\$100.00
		10	\$1.00
		11	\$1.00
		12	\$100.00
		13	\$100.00
		14	\$100.00
		15	\$100.00
		16	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
KANAWHA	20	1	\$30.00
		2	\$1.00
		3	\$30.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$30.00
		16	\$30.00
		17	\$1.00
		18	\$1.00
		19	\$30.00
		20	\$1.00
		21	\$1.00
		22	\$1.00
		23	\$30.00
		24	\$30.00
		25	\$30.00
		26	\$1.00
		27	\$1.00
		28	\$30.00
		29	\$1.00
		30	\$1.00
		31	\$1.00
LEWIS	21	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$1.00
		6	\$35.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
LINCOLN	22	1	\$25.00
		2	\$25.00
		3	\$1.00
		4	\$25.00
		5	\$25.00
		6	\$25.00
		7	\$25.00
		8	\$25.00
		9	\$25.00
		10	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
HARDY	16	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
HARRISON	17	1	\$90.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$90.00
		6	\$1.00
		7	\$90.00
		8	\$1.00
		9	\$90.00
		10	\$1.00
		11	\$90.00
		12	\$90.00
		13	\$1.00
		14	\$90.00
		15	\$90.00
		16	\$1.00
		17	\$1.00
		18	\$90.00
		19	\$1.00
		20	\$90.00
		21	\$1.00
JACKSON	18	1	\$40.00
		2	\$40.00
		3	\$1.00
		4	\$40.00
		5	\$1.00
		6	\$40.00
		7	\$40.00
JEFFERSON	19	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
GILMER	11	1	\$25.00
		2	\$25.00
		3	\$25.00
		4	\$1.00
		5	\$1.00
		6	\$25.00
GRANT	12	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
GREENBRIER	13	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$1.00
HAMPSHIRE	14	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
HANCOCK	15	1	\$25.00
		2	\$1.00
		3	\$25.00
		4	\$25.00
		5	\$1.00
		6	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
CABELL	6	1	\$28.00
		2	\$1.00
		3	\$28.00
		4	\$28.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$28.00
		9	\$1.00
		10	\$28.00
CALHOUN	7	1	\$30.00
		2	\$1.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		6	\$30.00
CLAY	8	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
DODDRIDGE	9	1	\$90.00
		2	\$90.00
		3	\$90.00
		4	\$90.00
		5	\$90.00
		6	\$90.00
		7	\$90.00
		8	\$90.00
		9	\$1.00
FAYETTE	10	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
BARBOUR	1	1	\$80.00
		2	\$1.00
		3	\$80.00
		4	\$80.00
		5	\$80.00
		6	\$1.00
		7	\$80.00
		8	\$80.00
		9	\$80.00
		10	\$60.00
		11	\$80.00
BERKELEY	2	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
BOONE	3	1	\$20.00
		2	\$1.00
		3	\$1.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
		7	\$1.00
		8	\$20.00
		9	\$1.00
BRAXTON	4	1	\$20.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$20.00
		7	\$20.00
		8	\$1.00
BROOKE	5	1	\$1.00
		2	\$1.00
		3	\$100.00
		4	\$100.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00

Home Use Only Wells:

Appraised at \$500 per well

Industrial Use Only Wells:*

MCF usage X \$ 2.62/MCF

BBL usage X \$48.66/BBL

*(Also includes Department of Environmental Protection reported wells.)

Non-Filer Valuations

Working Interest = 150% of previous year's appraisal

Royalty Interest = 90% of previous year's appraisal

Valuation

The previously discussed variables are used to establish a future income stream converted to present worth through application of a capitalization rate. The sum of the discounted future net income per year represents a reasonable estimate of market value.

Lease Rate/Term Survey and Results

The non-producing property value for each county is determined by multiplying the average delay rental by a factor, which represents the average lease term under present economic conditions.

As a result of higher lease terms being inversely proportional to the value of oil and gas (thus counties with little leasing or production activities reflect inflated values) and with the volatile nature of county activity, necessary adjustments in the review have been made.

A compilation of lease terms produced a statewide average of 5 years. This term (5 years) was applied to all county lease rates and compared to the appraisal rates derived from calculations using individual county data as well as regional data. The resulting calculations were reviewed and considered in the assignment of an appraisal rate per acre.

The appraisal rate/acre amounts shown on the next page are preliminary figures, which may change if additional lease data is received. These rates have been applied to all county magisterial districts with either producing wells, lease activity within the past 5 years or both. Tax districts void of activity within the past 5 years have been assigned the minimum value per acre.

Industry Operating Expense Survey and Results

This component was determined through a review of responses to a survey distributed by the State Tax Department to producers of all oil and natural gas wells producing in West Virginia and through use of other market data.

GAS

- % Working Interest Expenses
for Typical Producing Well = 30%
- Maximum Operating Expenses = \$5,000
- Coal Bed Methane, Vertical Wells
Expenses = \$9,000

OIL

- % Working Interest Expenses
for Typical Producing Well = 35%
- Maximum Operating Expenses = \$5,750
- Maximum Enhanced Operating
Expenses = \$9,000

MARCELLUS/UTICA

- % Working Interest Expenses
for Vertical Producing Well = 30%
- Maximum Operating Expenses = \$30,000

- % Working Interest Expenses
for Horizontal Producing Well = 20%
- Maximum Operating Expenses = \$150,000

HORIZONTAL WELLS (OTHER THAN MARCELLUS/UTICA AND COAL BED METHANE)

- % Working Interest Expenses
for Horizontal Producing Well = 30%
- Maximum Operating Expenses = \$20,000

Minimum Working Interest Appraisal = \$500 per well

Flat Rate Royalty Multiplier = 5.75

Decline Rates for Natural Gas and Oil Formations: West

West: Jackson, Mason, Putnam

Code	Formation	Year 1	Year 2	Year 3 +
1	Oriskany	-0.40	-0.40	-0.29
2	Huron, Rhinestreet	-0.13	-0.12	-0.03
3	Devonian Shale	-0.31	-0.15	-0.04
4	Huron	-0.29	-0.14	-0.05
5	Huron, Shales above Huron	-0.38	-0.15	-0.06
6	Huron, Berea	-0.29	-0.08	-0.08
7	Berea, Devonian Shale	-0.08	-0.08	-0.08
8	Berea	-0.38	-0.18	-0.16
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.28	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.35	-0.20	-0.09
110	Marcellus *	-0.35	-0.20	-0.09
111	Utica*	-0.35	-0.20	-0.09
9	Exception (Median)	-0.35	-0.20	-0.09
10	Non-Filer	-0.08	-0.08	-0.03

Decline Rates for Natural Gas and Oil Formations: West Central

West Central: Calhoun, Roane, Wirt

Code	Formation	Year 1	Year 2	Year 3 +
2	Huron, Rhinestreet	-0.49	-0.11	-0.06
4	Huron	-0.33	-0.22	-0.14
27	Huron, Shales above Huron	-0.42	-0.23	-0.12
44	Rhinestreet, Huron, Shallow Shale	-0.51	-0.14	-0.11
45	Devonian Shale, Pocono	-0.25	-0.17	-0.12
46	Pocono	-0.29	-0.25	-0.12
84	Blg Injun, Oil	-0.41	-0.41	-0.11
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.28	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.42	-0.24	-0.10
110	Marcellus *	-0.42	-0.24	-0.10
111	Utica*	-0.42	-0.24	-0.10
9	Exception (Median)	-0.42	-0.24	-0.10
10	Non-Filer	-0.25	-0.11	-0.06

Decline Rates for Natural Gas and Oil Formations: South West

South West: Cabell, Lincoln, Logan, Mingo, Wayne

Code	Formation	Year 1	Year 2	Year 3 +
3	Devonian Shale	-0.31	-0.15	-0.04
8	Berea	-0.36	-0.11	-0.11
18	Big Injun	-0.38	-0.22	-0.04
22	Big Lime	-0.19	-0.19	-0.19
43	Berea, Big Lime	-0.18	-0.18	-0.18
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.38	-0.22	-0.10
110	Marcellus *	-0.38	-0.22	-0.10
111	Utica*	-0.38	-0.22	-0.10
9	Exception (Median)	-0.38	-0.22	-0.10
10	Non-Filer	-0.18	-0.11	-0.04

Decline Rates for Natural Gas and Oil Formations: South Central

South Central: Boone, Kanawha

Code	Formation	Year 1	Year 2	Year 3 +
3	Devonian Shale	-0.23	-0.08	-0.05
4	Huron	-0.31	-0.15	-0.04
8	Berea	-0.23	-0.14	-0.09
18	Big Injun	-0.29	-0.25	-0.12
27	Huron, Shales above Huron	-0.21	-0.08	-0.05
28	Weir	-0.30	-0.21	-0.14
29	Weir +	-0.31	-0.25	-0.09
31	Devonian Shales +	-0.27	-0.07	-0.05
86	Big Injun-Oil	-0.19	-0.18	-0.10
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.33	-0.19	-0.08
110	Marcellus *	-0.33	-0.19	-0.08
111	Utica*	-0.33	-0.19	-0.08
9	Exception (Median)	-0.33	-0.19	-0.08
10	Non-Filer	-0.19	-0.07	-0.04

Decline Rates for Natural Gas and Oil Formations: South

South: McDowell, Mercer, Raleigh, Wyoming

Code	Formation	Year 1	Year 2	Year 3 +
8	Berea	-0.34	-0.15	-0.15
22	Big Lime	-0.31	-0.19	-0.07
23	Big Lime, Maxton	-0.31	-0.19	-0.07
24	Big Lime, Ravencloff	-0.29	-0.29	-0.17
25	Berea +	-0.37	-0.12	-0.08
26	Ravencloff	-0.40	-0.08	-0.07
28	Weir	-0.44	-0.20	-0.10
29	Weir +	-0.28	-0.21	-0.08
30	Weir, Big Lime	-0.37	-0.19	-0.13
42	Maxton, Ravencloff	-0.40	-0.08	-0.07
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.27	-0.13	-0.09
97	Coalbed Methane (Vertical)	0.03	0.10	-0.05
98	Coalbed Methane (Horizontal)	-0.05	-0.05	-0.32
110	Marcellus *	-0.36	-0.19	-0.09
111	Utica*	-0.36	-0.19	-0.09
9	Exception (Median)	-0.36	-0.19	-0.09
10	Non-Filer	-0.23	-0.08	-0.05

Decline Rates for Natural Gas and Oil Formations: North West				
North West: Pleasants, Ritchie, Wood				
Code	Formation	Year 1	Year 2	Year 3 +
2	Huron, Rhinestreet	-0.41	-0.26	-0.07
4	Huron	-0.42	-0.24	-0.14
5	Huron, Shales above Huron	-0.39	-0.25	-0.14
8	Berea	-0.31	-0.15	-0.15
11	Gordon	-0.38	-0.10	-0.10
12	Alexander, Benson (No Riley)	-0.34	-0.23	-0.10
13	Alexander, Benson, Riley	-0.32	-0.20	-0.10
14	Benson	-0.19	-0.19	-0.10
44	Rhinestreet, Huron, Shallow Shale	-0.43	-0.28	-0.11
47	Alexander, Riley, (No Benson)	-0.41	-0.05	-0.05
48	Rhinestreet, Alexander, Benson, Riley	-0.31	-0.24	-0.10
49	Weir, Squaw, Big Injun	-0.27	-0.17	-0.07
50	Rhinestreet	-0.40	-0.27	-0.27
51	Rhinestreet +	-0.38	-0.21	-0.10
52	All Upper Devonian (Undiv)	-0.48	-0.33	-0.19
53	Huron, Chemung	-0.35	-0.11	-0.09
54	Huron, Hampshire, Pocono	-0.12	-0.12	-0.11
55	Upper Devonian (Above Huron)	-0.48	-0.33	-0.23
56	Chemung Sands= Riley, Bradford, Balltown, Speechley, Warren (No Benson or Alexander)	-0.28	-0.18	-0.10
83	Huron Oil	-0.74	-0.44	-0.40
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
9B	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.39	-0.23	-0.13
110	Marcellus	-0.46	-0.29	-0.23
111	Utica**	-0.46	-0.29	-0.23
9	Exception (Median)	-0.39	-0.23	-0.13
10	Non-Filler	-0.12	-0.05	-0.05

Decline Rates for Natural Gas and Oil Formations: North Central				
North Central: Barbour, Doddridge, Gilmer, Harrison, Lewis, Marion, Monongalia, Taylor, Upshur				
Code	Formation	Year 1	Year 2	Year 3 +
11	Gordon	-0.41	-0.14	-0.12
12	Alexander, Benson	-0.37	-0.19	-0.11
13	Alexander, Benson, Riley	-0.40	-0.28	-0.05
14	Benson	-0.31	-0.17	-0.12
15	Benson, Riley	-0.34	-0.17	-0.14
18	Big Injun	-0.38	-0.18	-0.13
21	Benson, Fifth	-0.31	-0.20	-0.14
28	Weir	-0.34	-0.34	-0.07
29	Weir +	-0.28	-0.28	-0.23
33	Elk, Benson	-0.34	-0.18	-0.11
34	Elk, Benson, Riley	-0.42	-0.27	-0.08
37	Elk, Alexander, Benson	-0.49	-0.23	-0.08
38	Elk, Alexander, Benson +	-0.38	-0.20	-0.12
40	Fox, Heverty	-0.46	-0.18	-0.08
50	Rhinestreet	-0.28	-0.03	-0.03
57	Alexander, Benson, Balltown	-0.39	-0.28	-0.08
58	Alexander	-0.35	-0.20	-0.10
59	Alexander +	-0.39	-0.22	-0.10
60	Alexander, Benson, Riley +	-0.39	-0.35	-0.12
61	Balltown	-0.35	-0.20	-0.10
62	Balltown, Speechley	-0.28	-0.22	-0.10
63	Balltown, Speechley +	-0.30	-0.13	-0.10
64	Benson, Balltown, Speechley	-0.28	-0.22	-0.09
65	Benson, Bradford	-0.37	-0.20	-0.10
68	Benson, Balltown	-0.29	-0.23	-0.11
67	Benson, Riley +	-0.38	-0.14	-0.10
68	Benson, Speechley	-0.30	-0.22	-0.14
69	Brellier, Elk	-0.42	-0.20	-0.13
70	Brallier	-0.40	-0.22	-0.15
71	Deeper/Onondaga or Oriskany/Helderberg	-0.24	-0.24	-0.03
72	Elk, Alexander	-0.42	-0.22	-0.09
73	Elk, Benson +	-0.38	-0.20	-0.12
74	Elk	-0.43	-0.12	-0.10
75	Elk, Riley	-0.60	-0.35	-0.17
78	Fox +	-0.46	-0.18	-0.09
77	Haverty, Elk, Benson (No Alexander)	-0.35	-0.16	-0.16
78	Haverty	-0.45	-0.15	-0.15
79	Riley	-0.44	-0.22	-0.10
80	Speechley	-0.30	-0.18	-0.09
81	Alexander, Benson, Speechley	-0.39	-0.24	-0.10
82	Haverty, Elk, Alexander	-0.47	-0.14	-0.14
85	Fifth, Oil	-0.45	-0.25	-0.22
87	Bayard All	-0.30	-0.20	-0.05
88	Fifth	-0.29	-0.18	-0.12
89	Fifth +	-0.25	-0.15	-0.13
90	Gordon, Injun All	-0.41	-0.23	-0.23
91	Squaw	-0.37	-0.31	-0.06
92	Injun +	-0.34	-0.22	-0.22
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
97	Coalbed Methane (Vertical)	-0.23	-0.08	-0.05
98	Coalbed Methane (Horizontal)	-0.05	-0.05	-0.32
109	Trenton/Deeper *	-0.38	-0.21	-0.11
110	Marcellus	-0.59	-0.29	-0.23
111	Utica**	-0.59	-0.29	-0.23
9	Exception (Median)	-0.38	-0.21	-0.11
10	Non-Filer	-0.23	-0.03	-0.03

Decline Rates for Natural Gas and Oil Formations: North

North: Brooke, Hancock, Marshall, Ohio, Tyler, Wetzel

Code	Formation	Year 1	Year 2	Year 3 +
11	Gordon	-0.47	-0.31	-0.09
13	Alexander, Benson, Riley	-0.26	-0.16	-0.15
15	Benson, Riley	-0.18	-0.18	-0.08
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
97	Coalbed Methane (Vertical)	-0.23	-0.08	-0.05
110	Marcellus	-0.52	-0.23	-0.18
111	Utica*	-0.52	-0.23	-0.18
9	Exception (Median)	-0.39	-0.23	-0.08
10	Non-Filer	-0.18	-0.16	-0.06

Decline Rates for Natural Gas and Oil Formations: East

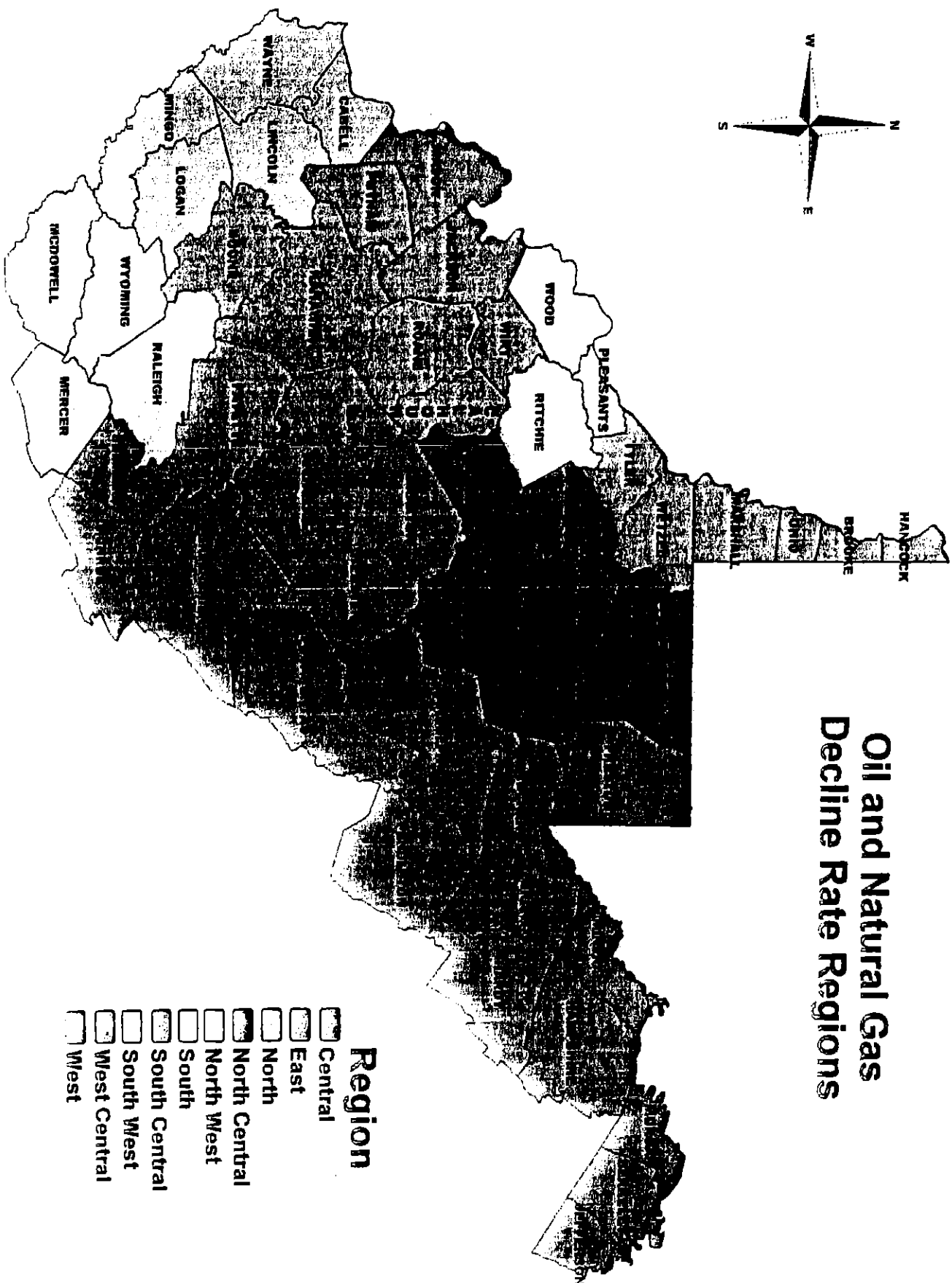
**East: Berkeley, Grant, Greenbrier, Hampshire, Hardy, Jefferson, Mineral,
Monroe, Morgan, Pendleton, Pocahontas, Preston, Randolph, Summers,
Tucker**

Code	Formation	Year 1	Year 2	Year 3 +
1	Oriskany	-0.30	-0.30	-0.19
14	Benson	-0.31	-0.17	-0.12
20	Benson +	-0.44	-0.20	-0.06
21	Benson, Fifth	-0.29	-0.26	-0.09
32	Brallier +	-0.48	-0.20	-0.05
33	Elk, Benson	-0.39	-0.21	-0.06
34	Elk, Benson, Riley	-0.53	-0.19	-0.05
35	Elk, Benson, Riley +	-0.36	-0.19	-0.11
36	Elk, Benson, Baitown	-0.34	-0.18	-0.11
37	Elk, Alexander, Benson	-0.50	-0.07	-0.07
38	Elk, Alexander, Benson +	-0.40	-0.16	-0.16
39	Huntermville	-0.31	-0.31	-0.14
40	Fox, Haverty	-0.36	-0.21	-0.15
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
110	Marcellus	-0.59	-0.22	-0.17
111	Utica*	-0.59	-0.22	-0.17
9	Exception (Median)	-0.41	-0.22	-0.10
10	Non-Filer	-0.29	-0.07	-0.05

Decline Rates for Natural Gas and Oil Formations: Central

Central: Braxton, Clay, Fayette, Nicholas, Webster

Code	Formation	Year 1	Year 2	Year 3 +
12	Alexander, Benson	-0.31	-0.20	-0.10
14	Benson	-0.48	-0.08	-0.08
16	Benson, Balltown+	-0.45	-0.16	-0.12
17	Gordon +	-0.30	-0.07	-0.07
18	Big Injun	-0.34	-0.13	-0.13
19	Big Injun, Big Lime	-0.36	-0.13	-0.13
22	Big Lime	-0.34	-0.34	-0.13
26	Ravencloft	-0.40	-0.40	-0.25
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.41	-0.22	-0.09
110	Marcellus *	-0.41	-0.22	-0.09
111	Utica*	-0.41	-0.22	-0.09
9	Exception (Median)	-0.41	-0.22	-0.09
10	Non-Filer	-0.30	-0.07	-0.07



Region

Capitalization Rate

Since the valuation of oil and gas property is predicated on a three year production, the capitalization rate will be considered in a similar manner.

	2015	2014	2013
Inflation Rate	-0.730%	-0.780%	-1.500%
Safe Rate	0.053%	0.033%	0.058%
Composite Risk Rate	15.188%	14.389%	14.834%
Non Liquidity Rate	0.269%	0.088%	0.074%
Management Rate	0.500%	0.500%	0.500%
Property Tax Rate	1.314%	1.314%	1.314%
Total	18.582%	15.584%	15.080%
	50.000%	33.333%	18.687%
	8.298%	5.188%	2.513%
			15.897%

Capitalization Rate Rounded to:

18.00%

MULTIPLIERS FOR 16.0% MID-YEAR LIFE (ANNUALLY)

YEAR		YEAR	
1	0.928477	21	0.047710
2	0.800411	22	0.041128
3	0.690009	23	0.036468
4	0.594838	24	0.030588
5	0.512789	25	0.028350
6	0.442080	26	0.022715
7	0.381088	27	0.018582
8	0.328522	28	0.016881
9	0.283208	29	0.014853
10	0.244148	30	0.012546
11	0.210470	31	0.010818
12	0.181440	32	0.008323
13	0.158414	33	0.008037
14	0.134840	34	0.008929
15	0.116241	35	0.005973
16	0.100208	36	0.005148
17	0.088388	37	0.004438
18	0.074471	38	0.003827
19	0.064189	39	0.003289
20	0.055344	40	0.002844

OIL AND GAS

TY 2017

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for producing oil and gas properties. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 1J.

Safe Rate (3-Month Constant Maturity Interest Rates)

January December 2015

0.053%

Risk Rate (Interest differential between Loan Rate and 3-Month Constant Maturity Interest Rates)Loan Rate*Risk Rate

2015 5.280%

5.207%

*Prime plus 2%

Equity (Differential between Equity Rates and 3-Month Constant Maturity Interest Rates)Equity Rate**Risk Rate2015 $[12.25\%/(1-.37)]-0.053\%$

19.381%

** Value Line Investment Survey Analysis

Composite Risk Rate

Loan and Equity Rates weighted by industry estimated capital structure.

Equity RateDebt RateComposite Risk

2015 12.8042%

1.822%

15.188%

Note: Debt equity Ratio

Debt

35%

Equity

65%

*** Effective severance tax adjustment

0.95

Non Liquidity Rate

Interest differential between 3-month Constant Maturity Interest Rates and a 1 year Constant Maturity Interest Rates which reflects a reasonable time necessary to sell active property.

January December 2015

1yr T Bill
0.322%90 day T Bill
0.053%Non Liquidity Rate
0.288%Management Rate

Charges for the management of investment portfolios.

Fixed Rate (by Rule)

0.500%

Property Tax Rate

Sixty percent (60%) of State average Class III property tax rate.

2015

60% of 2.19

1.314%

Inflation Rate

January December 2015

0.730%

OIL AND GAS PROPERTIES ANALYSIS

Tax Year 2017

June 30, 2016
Mark W. Matkovich
State Tax Commissioner
Department of Revenue



STATE OF WEST VIRGINIA

**Department of Revenue
State Tax Department**

**Earl Ray Tomblin
Governor**

**Mark W. Matkovich
State Tax Commissioner**

June 30, 2016

The Honorable Natalie Tennant
Secretary of State
Building 1, Suite 157-K
State Capitol
Charleston, West Virginia 25305

Dear Secretary Tennant:

Attached are tentative natural resource property valuation variables for the 2017 Tax Year that have been developed by the State Tax Department for use in appraising coal, oil, natural gas, managed timberland and other natural resource properties for ad valorem tax purposes.

The State Tax Department will accept written public comments on all variables until August 1, 2016. Final valuation variables will be filed on or before September 1, 2016.

Public comments concerning the attached variables should be forwarded to the following address:

West Virginia State Tax Department
Property Tax Division
Attention: Jeff Amburgey
P. O. Box 2389
Charleston, West Virginia 25328-2389

Sincerely,

A handwritten signature in black ink, appearing to be 'M. Matkovich', written over a horizontal line.

**Mark W. Matkovich
State Tax Commissioner**

MWM/ja/j

Attachment

OTHER MINED MINERALS

ROYALTY RATE SURVEY

The determination of royalty rates for other mined minerals within the state of West Virginia is dependent upon the availability of leasehold information. Since this information is limited, the Department has chosen to review data for the most recent thirty year period. A summary only of this review is shown below in order to protect the confidentiality of parties involved.

RESOURCE	DATA SOURCES	AVERAGE ROYALTY	MEDIAN ROYALTY	TY2018 RATE
LIMESTONE	15	\$0.22	\$0.20	\$0.22
SANDSTONE	8	\$0.31	\$0.25	\$0.30
CLAY/SHALE	34	\$0.12	\$0.10	\$0.11
SAND/GRAVEL	10	\$0.35	\$0.40	\$0.40
SALT BRINE	1	N/A	N/A	\$0.10

RESERVE VALUES

	number of sales	\$/AC
LIMESTONE	5	\$3,000.00
SANDSTONE	8	\$2,300.00
CLAY/SHALE	16	\$850.00
SAND/GRAVEL	6	\$4,000.00
SALT	2	\$1,140.00

OTHER MINED MINERALS CAPITALIZATION RATE

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for active coal. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 1k.

<u>Safe Rate</u>	90 day Treasury Bills			<u>Safe Rate</u>
	January	December	2014	0.033%
	January	December	2013	0.058%
	January	December	2012	0.088%

<u>Risk Rate</u>	Interest differential between Loan Rate and 90 day Treasury Bills			<u>Debt Risk Rate</u>
	<u>Loan Rate*</u>			
	2014	5.25%		3.217%
	2013	5.25%		3.192%
	2012	5.25%		3.164%
	*Prime plus 2%			

<u>Equity</u>	Differential between Equity Rates and 90 day Treasury Bills		<u>Equity Risk Rate</u>
	<u>Equity Rate**</u>		
	2014	$(11.75\%/(1-.30))-0.033$	16.753%
	2013	$(11.75\%/(1-.30))-0.058$	16.728%
	2012	$(11.75\%/(1-.30))-0.088$	16.700%
- Value Line Investment Survey Analysis			

<u>Composite Risk Rate</u>	Loan and Equity Rates weighted by industry estimated capital structure.			
	<u>Equity Rate</u>	<u>Debt Rate</u>	<u>Composite Risk</u>	
	2014	10.052%	2.087%	12.138%
	2013	10.037%	2.077%	12.114%
	2012	10.020%	2.068%	12.088%
	Note: Debt/Equity Ratio		Debt 40%	Equity 60%

Non Liquidity Rate Interest differential between 90 day Treasury Bills and a 1 year Treasury Bill which reflects a reasonable time necessary to sell active property.

			<u>1yr T Bill</u>	<u>90 d T Bill</u>	<u>Non Liquidity Rate</u>
January	December	2014	0.121%	0.033%	0.088%
January	December	2013	0.132%	0.058%	0.074%
January	December	2012	0.175%	0.088%	0.088%

Management Rate Charges for the management of investment portfolios.
Fixed Rate (by Rule) 0.500%

<u>Inflation Rate</u>			
January	December	2014	0.780%
January	December	2013	1.500%
January	December	2012	1.700%

<u>Property Tax Rate</u>	Sixty percent (60%) of State average Class III property tax rate.		
January	December	2014	80% of 2.190 = 1.314%
January	December	2013	60% of 2.190 = 1.314%
January	December	2012	60% of 2.210 = 1.326%

Capitalization Rate Since the valuation of other mined mineral property is predicated on a three year production average, the capitalization rate is considered in a similar manner.

	<u>2014</u>	<u>2013</u>	<u>2012</u>
Inflation Rate	-0.780%	-1.500%	-1.700%
Safe Rate	0.033%	0.088%	0.088%
Composite Risk Rate	12.139%	12.114%	12.088%
Non Liquidity Rate	0.088%	0.074%	0.088%
Management Rate	0.500%	0.500%	0.500%
Property Tax Rate	1.314%	1.314%	1.326%
<u>Total</u>	13.314%	12.580%	12.387%

Three Yr Average: 12.754% Rounded to: **12.80%**

CAPITALIZATION RATE - 12.80%

MULTIPLIERS:		%	%
1YR	0.942	9YR	5.491
2YR	1.776	10YR	5.809
3YR	2.516	11YR	6.092
4YR	3.172	12YR	6.342
5YR	3.754	13YR	6.564
6YR	4.289	14YR	6.761
7YR	4.727	15YR	6.935
8YR	5.132		

**OTHER MINED MINERAL
PROPERTY ANALYSIS**

Tax Year 2016

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

Title 110, Series 11
Valuation of Active and Reserve Coal Property for Ad Valorem Property Tax Purposes

The above Legislative Rule was modified during the 2005 Legislative Session requiring biennial (every other year) updating of the geostatistical basis for several valuation factors used in the Reserve Coal Valuation Model. To satisfy that requirement, maps and data files concerning the Market Interest Factor, the Market Mineability Factor, the Use Conflict Factor and the Environmental Factor have been revised for Tax Year 2015. Preliminary research has been conducted to determine the effects of the factors on coal valuation. The results are as follows:

Market Interest Factor

This is the relationship between transactions (sales, leases, prospects, permit applications, etc.) and mining as it relates to properties and locations. Trans_Ct is the number of transactions counted within the radius.

Radius = 5 miles

If Trans_Ct >= 20 Then TransFactor = 20

If Trans_Ct < 20 And Trans_Ct >= 10 Then TransFactor = 40

Else TransFactor = 80

Market Mineability Factor

This is the relationship between property location and mining, through time. Determining feature is count of mines within the radius.

Radius = 2.5 miles

Surface Mines: Smine

Deep Mines: Dmine

Boom Mines: Bmine

Historic Mines: Omine

Current Mines: Cmine

To assign MineFactor:

If Cmine > 0 Then MineFactor = 20

If Cmine = 0 And (Omine > 0 Or Bmine > 0) Then MineFactor = 40

Else MineFactor = 80

Use Conflict Factor

This is the relationship between oil & gas well drilling and mining as it relates to property location. Well density is in wells per square mile.

WellDensity < 5 Then WellFactor = 0

WellDensity >= 5 And WellDensity < 10 Then WellFactor = 20

WellDensity >= 10 And WellDensity < 20 Then WellFactor = 40

WellDensity > 20 Then WellFactor = 80

Environmental Factor

This is the relationship of known environmental hazards and impediments to the likelihood of mining occurring at this location. The rates are compiled from maps and represent densities of problems mapped.

Envrate <= 10 and Null Then EnvFactor = 0

Envrate > 10 and Envrate <= 30 Then EnvFactor = 20

Envrate > 30 and Envrate < 80 Then EnvFactor = 40

Envrate >= 80 Then EnvFactor = 80

Explanation of Reserve Coal Valuation

The RCVM consists of a computer model, which utilizes a database consisting of coal beds and characteristics, property locations, mine locations, sales, transportation, etc., for the entire state. An extensive algorithm calculates in-place tonnage, expected time of mining and present value for all the mineable coal on every property.

There are, therefore, no set "rates" available on reserve coal under the Rule. The RCVM values on each property will not be available until all data has been entered, after October 15 of each year. Please refer to the State Register, Legislative Rules, Title 110, Series 11 for details of the process.

COAL

Price and Royalty Rate Analysis

The development of royalty rates for the various categories of mines and markets involves information collection and review from a variety of sources. Coal lease rates have been derived from transaction information provided by county assessors, tax auditors, producers, and by individual lessors/lessees involved in the specific transaction. The prices for mined coal, as per 110-CSR-11, have been calculated from information provided by the WV Public Service Commission and U.S. Energy Information Administration concerning power plant fuel purchases. Prices provided by producers as part of tax filing and from data obtained from market summaries are included for comparison. Because a large portion of the data used in this analysis is, by law, considered confidential, only a summary of the results are published.

COAL SALE PRICES CY2014 FOR TY2018 APPLICATION

GRAND SUMMARY ALL SOURCES 2014	STEAM SPOT	STEAM TERM	MET
PSC	\$93.58	\$58.88	
FERC	\$58.77	\$82.88	
Coal Market Publication		\$57.81 (Platts-CAPP-CSX)	
Active Return Summary		\$58.35 52.7 MM tons	\$103.35 7.8 MM Tons

STATE STEAM PRICE (SPOT Market)	\$80.35 FERC & PSC, 3 YR AVE
STATE MET PRICE	\$103.35 Active Return

2014 WVPSC Tons reported in millions	Spot Sales	Term Sales	Total
	2,170,351	15,503,654	17,674,205

COAL TY2018 ROYALTY RATES	2014 1YR		2013 2YR		2012 3YR		2011 4YR		2010 5YR	
	%S	%D	%S	%D	%S	%D	%S	%D	%S	%D
TOTAL RECORDS	1,447	905	1,354	598	1,908	2,788	1,877	2,241	2,449	3,187
SUM of PERCENT	8,888.07	4,898.25	8,087.34	3,313.93	11,881.88	14,883.03	8,824.28	11,181.05	14,408.71	16,405.78
STRAIGHT AVERAGE	6.13	5.18	5.87	5.53	6.23	5.32	5.32	4.88	5.88	5.13
MEDIAN	6.00	5.00	5.00	5.00	6.00	5.13	5.00	5.00	5.22	5.00
WEIGHTED AVERAGE (by Mines)	6.84	5.48	6.58	5.84	6.45	6.28	6.27	5.72	6.24	5.88

TENTATIVE RATE DEEP (%)	5.80
TENTATIVE RATE SURFACE (%)	6.30

ROYALTY RATE CALCULATIONS

Steam Coal/ Deep Mine	\$80.35	per ton X	5.80%	=	\$3.50	per ton
Metallurgical Coal/ Deep Mine	\$103.35	per ton X	5.80%	=	\$5.89	per ton
Steam Coal/ Surface Mine	\$80.35	per ton X	6.50%	=	\$5.22	per ton
Metallurgical Coal/ Surface Mine	\$103.35	per ton X	6.50%	=	\$6.71	per ton

COAL CAPITALIZATION RATE

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for active coal. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 11.

<u>Safe Rate</u>	90 day Treasury Bills	<u>Safe Rate</u>
January	December 2014	0.033%
January	December 2013	0.058%
January	December 2012	0.088%

<u>Risk Rate</u>	Interest differential between Loan Rate and 90 day Treasury Bills		<u>Debt Risk Rate</u>
<u>Loan Rate*</u>			
2014	5.25%		5.217%
2013	5.25%		5.192%
2012	5.25%		5.164%
*Prime plus 2%			

<u>Equity</u>	Differential between Equity Rates and 90 day Treasury Bills		<u>Equity Risk Rate</u>
<u>Equity Rate**</u>			
2014	[15.60%/(1-.30)]-0.033		22.110%
2013	[13.25%/(1-.30)]-0.088		18.871%
2012	[13.25%/(1-.30)]-0.088		18.843%
** Value Line Investment Survey Analysis			

<u>Composite Risk Rate</u>	Loan and Equity Rates weighted by industry estimated capital structure		
<u>Equity Rate</u>	<u>Debt Rate</u>	<u>Composite Risk</u>	
2014	15.477%	1.565%	17.042%
2013	11.322%	2.077%	13.399%
2012	11.308%	2.088%	13.372%
Note: Debt Equity Ratio Debt 30% Equity 70%			

<u>Non Liquidity Rate</u>	Interest differential between a 90 day Treasury Bill and a 1 year Treasury Bill which reflects a reasonable time necessary to sell active property.		<u>1yr T Bill</u>	<u>90 d T Bill</u>	<u>Non Liquidity Rate</u>
January	December	2014	0.121%	0.033%	0.088%
January	December	2013	0.132%	0.058%	0.074%
January	December	2012	0.175%	0.088%	0.088%

<u>Management Rate</u>	Charges for the management of investment portfolios.	
<u>Fixed Rate (by Rule)</u>	0.500%	

<u>Inflation Rate</u>	January	December	
	2014		0.760%
	2013		1.500%
	2012		1.700%

Capitalization Rate Since the valuation of active coal property is predicated on a three year production average, the capitalization rate is considered in a similar manner.

	2014	2013	2012
Inflation Rate	-0.760%	-1.500%	-1.700%
Safe Rate	0.033%	0.058%	0.088%
Composite Risk Rate	17.042%	13.399%	13.372%
Non Liquidity Rate	0.088%	0.074%	0.088%
Management Rate	0.500%	0.500%	0.500%
Total	18.903%	12.531%	12.347%

Three Yr Average: 13.927 Rounded to: **13.90%**

CAPITALIZATION RATE - 13.9%			
MULTIPLIERS:		%	
1YR	0.937	9YR	5.298
2YR	1.760	10YR	5.588
3YR	2.482	11YR	5.844
4YR	3.118	12YR	6.087
5YR	3.673	13YR	6.284
6YR	4.162	14YR	6.437
7YR	4.581	15YR	6.588
8YR	4.967		

COAL PROPERTIES ANALYSIS

Tax Year 2016

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

REGION 4 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	5,020.80	303.89	33.33%	101.30
2013	12,820.20	211.47	28.87%	58.39
2012	4,808.73	183.47	20.00%	38.89
2011	15,517.51	178.40	13.33%	23.79
2010	24,125.85	187.02	6.67%	11.13
	62,293.19			231.30

REGION 4 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	7,785.20	8.18	33.33%	2.72
2013	15,468.80	8.32	28.87%	2.22
2012	7,382.20	9.81	20.00%	1.92
2011	21,074.10	8.84	13.33%	1.18
2010	28,223.70	5.93	6.67%	0.40
	77,933.80			8.41

REGION 5 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	21,681.40	288.98	33.33%	88.88
2013	31,659.00	198.20	28.87%	52.89
2012	10,887.05	138.83	20.00%	27.73
2011	24,780.43	122.43	13.33%	18.32
2010	58,803.00	143.15	6.67%	9.54
	145,770.88			195.10

REGION 5 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	10,191.40	8.19	33.33%	2.08
2013	18,282.80	7.13	28.87%	1.80
2012	8,298.30	8.93	20.00%	1.39
2011	8,432.30	8.28	13.33%	0.83
2010	19,223.30	4.08	6.67%	0.27
	62,435.90			6.48

West Virginia Wgt/Avg Managed Timberland Stumpage Prices

REGION 1 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	12,162.06	176.34	33.33%	56.76
2013	19,017.77	177.45	26.67%	47.32
2012	12,626.16	166.56	20.00%	37.31
2011	11,195.24	144.69	13.33%	19.32
2010	15,157.56	173.52	6.67%	11.57
	70,160.80			174.30

REGION 1 - Pulpwood *

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	464.40	5.40	33.33%	1.80
2013	6,102.20	2.96	26.67%	0.79
2012	45,367.00	8.42	20.00%	1.26
2011	46.10	9.67	13.33%	1.29
2010	1,859.30	6.90	6.67%	0.46
	53,661.00			5.62

REGION 2 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	22,001.80	162.47	33.33%	60.82
2013	25,696.66	177.79	26.67%	47.41
2012	25,640.98	149.01	20.00%	29.80
2011	12,639.41	166.26	13.33%	20.63
2010	56,576.40	163.96	6.67%	10.93
	142,754.44			169.80

REGION 2 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	2,166.10	5.04	33.33%	1.66
2013	119,279.40	12.63	26.67%	3.42
2012	22,647.40	2.66	20.00%	0.67
2011	5,235.20	6.76	13.33%	0.90
2010	23,291.90	4.15	6.67%	0.26
	172,622.00			6.86

REGION 3 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2014	91,467.44	280.52	33.33%	93.51
2013	161,397.70	275.83	26.67%	73.50
2012	111,920.60	201.57	20.00%	40.31
2011	102,216.30	201.45	13.33%	26.66
2010	145,592.20	211.21	6.67%	14.06
	612,596.24			246.26

REGION 3 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2014	170,736.30	3.57	33.33%	1.19
2013	153,197.40	7.76	26.67%	2.07
2012	183,132.60	6.39	20.00%	1.26
2011	159,040.70	7.34	13.33%	0.96
2010	123,856.50	9.34	6.67%	0.62
	789,965.50			6.14

Stumpage Prices:

	<u>Sawtimber</u>	<u>Pulpwood</u>
Stumpage Price Adjustment Factor	0.00%	1.66%

SAWTIMBER	Region	Current \$/MBF	1.0000	1.0000	1.0000	1.0000
			\$/MBF at age 35	\$/MBF at age 48	\$/MBF at age 55	\$/MBF at age 80
	Region 1	174.30	174.30	174.30	174.30	174.30
	Region 2	169.80	169.80	169.80	169.80	169.80
	Region 3	248.26	248.26	248.26	248.26	248.26
	Region 4	231.30	231.30	231.30	231.30	231.30
	Region 8	195.10	195.10	195.10	195.10	195.10

PULPWOOD:	Region	\$/Cord	1.9080	2.2917	2.7555	4.3881
			\$/cd at age 35	\$/cd at age 48	\$/cd at age 55	\$/cd at age 80
	Region 1	5.62	10.72	12.69	15.49	24.68
	Region 2	6.85	13.08	15.71	18.89	29.94
	Region 3	6.14	11.71	14.06	16.93	26.84
	Region 4	8.41	18.03	19.27	23.17	36.73
	Region 5	6.48	12.31	14.80	17.79	26.20

Management Costs:

Region	\$/acre (1)
1	3.17
2	3.17
3	3.17
4	3.17
5	3.17
State	

Tax Rates:

Effective Federal Income Tax Rate	35.00%
Effective WV State Income Tax Rate (8.5% * (1-.35))	4.23%
Effective WV Severance Tax Rate (2.76% * (1-.35))	1.81%

Yield (Volumes) (80 year rotation)

Timberland		Yield - MBF	Yield - Cords
Productivity Grades	Site Index		
Grade I	75 or more	14.6	10.5
Grade II	65-74	9.7	14.9
Grade III	less than 65	4.6	16.6

Managed Timberland Statistics

Estimation of Required Rate of Return: Class III & IV Blended Rates

A. Safe Rate of Return (5 Year T-Bill Rate)

Year	Rate	W/A %	W/A Rate
2014	1.6410	26.67%	0.4377
2013	1.1725	13.33%	0.1563
2012	0.7606	6.67%	0.0507
2011	1.5225	20.00%	0.3045
2010	1.9275	33.33%	0.6424

1.592 %

B. Nonliquidity Rate

(12 Month T-Bills vs. 3 Month T-Bills)

Year	Rate	W/A %	W/A Rate
2014	0.0863	33.33%	0.0294
2013	0.0733	26.67%	0.0195
2012	0.1292	20.00%	0.0256
2011	0.1617	13.33%	0.0242
2010	0.3200	6.67%	0.0213

0.120 %

C. Risk Rate (30 yr T-bills vs 5 yr T-bills)

Year	Rate	W/A %	W/A Rate
2014	1.8992	33.33%	0.5663
2013	2.2756	26.67%	0.6070
2012	2.1600	20.00%	0.4320
2011	2.3663	13.33%	0.3184
2010	2.3233	6.67%	0.1550

2.079 %

D. Management Factor of 0.5%

0.500 %

E. Property Tax Component

(80% of Blended III&IV Rates)

Year	Rate	W/A %	W/A Rate
2014	1.314	33.33%	0.4360
2013	1.314	26.67%	0.3504
2012	1.326	20.00%	0.2652
2011	1.326	13.33%	0.1766
2010	1.314	6.67%	0.0676

1.316 %

F. Inflation Rate:

(Bureau of Labor Statistics)

Year	Rate	W/A %	W/A Rate
2014	0.760	33.33%	0.2533
2013	1.500	26.67%	0.4001
2012	1.700	13.33%	0.2266
2011	3.000	6.67%	0.2001
2010	1.500	20.00%	0.3000

(1.360) %

TOTAL REQUIRED RATE OF RETURN (REAL)

4.228 %

LESS: PROPERTY TAX COMPONENT

(1.316)

TOTAL DISCOUNT COMPONENT

2.911 %

Stumpage Prices:

	<u>Sawtimber</u>	<u>Pulpwood</u>
Stumpage Price Adjustment Factor	0.00%	1.86%

		1.0000	1.0000	1.0000	1.0000
<u>SAWTIMBER</u>	Current	\$/MBF at age	\$/MBF at age	\$/MBF at age	\$/MBF at age
Region	\$/MBF	35	45	55	80
Region 1	174.30	174.30	174.30	174.30	174.30
Region 2	169.80	169.80	169.80	169.80	169.80
Region 3	248.28	248.28	248.28	248.28	248.28
Region 4	231.30	231.30	231.30	231.30	231.30
Region 8	195.10	195.10	195.10	195.10	195.10

		1.9060	2.2917	2.7555	4.3881
<u>PULPWOOD:</u>		\$/cd at age	\$/cd at age	\$/cd at age	\$/cd at age
Region	\$/Cord	35	45	55	80
Region 1	5.62	10.72	12.89	15.49	24.58
Region 2	8.85	13.08	15.71	18.89	29.94
Region 3	8.14	11.71	14.08	18.93	28.84
Region 4	8.41	16.03	19.27	23.17	38.73
Region 5	8.48	12.31	14.80	17.78	28.20

Management Costs:

Region	\$/acre (1)
1	3.17
2	3.17
3	3.17
4	3.17
5	3.17
State	

Tax Rates:

Effective Federal Income Tax Rate	35.00%
Effective WV State Income Tax Rate (6.5% * (1-.35))	4.23%
Effective WV Severance Tax Rate (2.78% * (1-.35))	1.81%

Yield (Volumes) (80 year rotation)

Productivity Grades	Site Index	Yield - MBF	Yield - Cords
Grade I	78 or more	14.5	10.5
Grade II	65-74	9.7	14.9
Grade III	less than 65	4.5	18.6

Managed Timberland Statistics

Estimation of Required Rate of Return: Class II Rates

A. Safe Rate of Return (5 Year T-Bill Rate)

Year	Rate	W/A %	W/A Rate
2014	1.8410	28.67%	0.4377
2013	1.1725	13.33%	0.1563
2012	0.7808	6.67%	0.0507
2011	1.5225	20.00%	0.3046
2010	1.9275	33.33%	0.6424

1.592 %

B. Nonliquidity Rate

(12 Month T-Bills vs. 3 Month T-Bills)

Year	Rate	W/A %	W/A Rate
2014	0.0863	33.33%	0.0294
2013	0.0733	28.67%	0.0195
2012	0.1282	20.00%	0.0258
2011	0.1817	13.33%	0.0242
2010	0.3200	6.67%	0.0213

0.120 %

C. Risk Rate (30 yr T-bills vs 5 yr T-bills)

Year	Rate	W/A %	W/A Rate
2014	1.8982	33.33%	0.5963
2013	2.2758	28.67%	0.6070
2012	2.1800	20.00%	0.4320
2011	2.3883	13.33%	0.3184
2010	2.3233	6.67%	0.1550

2.079 %

D. Management Factor of 0.5%

0.500 %

E. Property Tax Component

(50% of Class II Rate)

Year	Rate	W/A %	W/A Rate
2014	0.714	33.33%	0.2380
2013	0.708	28.67%	0.1888
2012	0.714	20.00%	0.1428
2011	0.708	13.33%	0.0944
2010	0.708	6.67%	0.0472

0.711 %

F. Inflation Rate:

(Bureau of Labor Statistics)

Year	Rate	W/A %	W/A Rate
2014	0.780	33.33%	0.2533
2013	1.500	28.67%	0.4001
2012	1.700	13.33%	0.2288
2011	3.000	6.67%	0.2001
2010	1.500	20.00%	0.3000

(1.380) %

TOTAL REQUIRED RATE OF RETURN (REAL)

3.622 %

LESS: PROPERTY TAX COMPONENT

(0.711)

TOTAL DISCOUNT COMPONENT

2.911 %

MANAGED TIMBERLAND APPRAISAL RATES

TAX YEAR 2016

(based on market 2010-2014)

Rates Per Acre

Class II Parcels

	<u>Grade 1</u>	<u>Grade 2</u>	<u>Grade 3</u>
Region 1	\$200	\$140	\$50
Region 2	\$200	\$140	\$50
Region 3	\$280	\$185	\$50
Region 4	\$265	\$180	\$55
Region 5	\$210	\$140	\$60

Class III/IV Parcels

	<u>Grade 1</u>	<u>Grade 2</u>	<u>Grade 3</u>
Region 1	\$225	\$150	\$75
Region 2	\$225	\$160	\$75
Region 3	\$250	\$165	\$75
Region 4	\$235	\$160	\$75
Region 5	\$225	\$150	\$75

- Region 1 = Brooke, Cabell, Hancock, Jackson, Marshall, Mason, Ohio, Pleasants, Putnam, Tyler, Wetzel, and Wood Counties
- Region 2 = Braxton, Calhoun, Clay, Doddridge, Gilmer, Harrison, Lewis, Marion, Monongalia, Ritchie, Roane, Taylor, and Wirt Counties
- Region 3 = Barbour, Greenbrier, Monroe, Nicholas, Pendleton, Pocahontas, Preston, Randolph, Tucker, Upshur, and Webster Counties
- Region 4 = Berkeley, Grant, Hampshire, Hardy, Jefferson, Mineral and Morgan Counties
- Region 5 = Boone, Fayette, Kanawha, Lincoln, Logan, McDowell, Mercer, Mingo, Raleigh, Summers, Wayne, and Wyoming Counties

Harvest Volumes per Acre

Harvest Interval Grades

	<u>35 yrs.</u>	<u>45 yrs.</u>	<u>55 yrs.</u>	<u>80 yrs.</u>	<u>Total</u>
1 - Site Index 75 or more	4.6 cords 1.5 Mbf	-- --	2.6 cords 4.4 Mbf	3.3 cords 8.6 Mbf	10.5 cords 14.5 Mbf
2 - Site Index 65 - 75	3.3 cords 1.0 Mbf	-- --	7.0 cords 3.2 Mbf	4.6 cords 5.5 Mbf	14.9 cords 9.7 Mbf
3 - Site Index less than 65	-- --	3.1 cords 0.8 Mbf	-- --	15.4 cords 3.7 Mbf	18.5 cords 4.5 Mbf

**MANAGED TIMBER
PROPERTY ANALYSIS**

Tax Year 2016

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

OIL & GAS RESERVE RATES FOR TY 2018			
COUNTY	CO #	DISTRICT #	TY2018 \$/AC
WETZEL	52	1	\$58.00
		2	\$58.00
		3	\$58.00
		4	\$58.00
		5	\$58.00
		6	\$1.00
		7	\$1.00
		8	\$58.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$55.00
		13	\$1.00
WIRT	53	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$1.00
		5	\$30.00
		6	\$30.00
		7	\$30.00
		8	\$30.00
WOOD	54	1	\$38.00
		2	\$38.00
		3	\$38.00
		4	\$38.00
		5	\$1.00
		6	\$38.00
		7	\$38.00
		8	\$38.00
		9	\$38.00
		10	\$1.00
		11	\$38.00
		12	\$38.00
		13	\$1.00
		14	\$1.00
WYOMING	55	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$1.00
		7	\$20.00
		8	\$1.00
		9	\$1.00
		10	\$20.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
TYLER	48	1	\$55.00
		2	\$55.00
		3	\$1.00
		4	\$55.00
		5	\$55.00
		6	\$55.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$55.00
UPSHUR	49	1	\$50.00
		2	\$50.00
		3	\$1.00
		4	\$50.00
		5	\$50.00
		6	\$50.00
		7	\$50.00
WAYNE	50	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$20.00
		10	\$20.00
		11	\$1.00
		12	\$20.00
WEBSTER	51	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$15.00
		5	\$15.00
		6	\$15.00
		7	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
ROANE	44	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		6	\$30.00
		7	\$30.00
		8	\$1.00
		9	\$30.00
SUMMERS	45	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$10.00
		6	\$1.00
		7	\$1.00
TAYLOR	46	1	\$1.00
		2	\$1.00
		3	\$55.00
		4	\$55.00
		5	\$55.00
		6	\$55.00
		7	\$55.00
TUCKER	47	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$20.00
		10	\$1.00
		11	\$20.00
		12	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
RALEIGH	41	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$1.00
		7	\$20.00
		8	\$20.00
		9	\$20.00
		10	\$1.00
		11	\$20.00
		12	\$20.00
RANOLPH	42	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$20.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$20.00
		11	\$20.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$20.00
		17	\$1.00
		18	\$1.00
RITCHIE	43	1	\$40.00
		2	\$1.00
		3	\$40.00
		4	\$1.00
		5	\$40.00
		6	\$1.00
		7	\$40.00
		8	\$1.00
		9	\$1.00
		10	\$40.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
PLEASANTS	37	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$35.00
		6	\$1.00
		7	\$35.00
		8	\$35.00
POCAHONTAS	38	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$10.00
		8	\$1.00
PRESTON	39	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$35.00
		6	\$35.00
		7	\$35.00
		8	\$35.00
		9	\$1.00
		10	\$35.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$1.00
		19	\$1.00
		20	\$1.00
PUTNAM	40	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$20.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$1.00
		10	\$20.00
		11	\$20.00
		12	\$20.00
		13	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
MONROE	32	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$10.00
		5	\$10.00
		6	\$1.00
		7	\$10.00
		8	\$1.00
		9	\$10.00
MORGAN	33	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
NICHOLAS	34	1	\$15.00
		2	\$15.00
		3	\$15.00
		4	\$15.00
		5	\$15.00
		6	\$1.00
		7	\$15.00
		8	\$1.00
		9	\$15.00
OHIO	35	1	\$1.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$35.00
		6	\$35.00
		7	\$1.00
		8	\$35.00
		9	\$35.00
		10	\$35.00
PENDLETON	36	1	\$1.00
		2	\$10.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$10.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
MINERAL	29	1	\$10.00
		2	\$1.00
		3	\$1.00
		4	\$10.00
		5	\$1.00
		6	\$10.00
		7	\$1.00
		8	\$10.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
MINGO	30	1	\$1.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
		7	\$20.00
		8	\$1.00
		9	\$20.00
		10	\$20.00
		11	\$20.00
		12	\$1.00
MONONGALIA	31	1	\$25.00
		2	\$1.00
		3	\$25.00
		4	\$25.00
		5	\$25.00
		6	\$1.00
		7	\$25.00
		8	\$25.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$25.00
		19	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
MASON	26	1	\$25.00
		2	\$25.00
		3	\$25.00
		4	\$25.00
		5	\$25.00
		6	\$25.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$25.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$25.00
		15	\$25.00
		16	\$25.00
MC DOWELL	27	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$1.00
		6	\$20.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$20.00
		12	\$1.00
		13	\$20.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
MERCER	28	1	\$1.00
		2	\$15.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$15.00
		7	\$1.00
		8	\$1.00
		9	\$15.00
		10	\$1.00
		11	\$15.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
LOGAN	23	1	\$15.00
		2	\$15.00
		3	\$15.00
		4	\$15.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$15.00
		9	\$1.00
MARION	24	1	\$55.00
		2	\$55.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$55.00
		10	\$1.00
		11	\$55.00
		12	\$55.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$55.00
		17	\$1.00
		18	\$55.00
		19	\$55.00
		20	\$1.00
		21	\$1.00
		22	\$1.00
MARSHALL	25	1	\$50.00
		2	\$1.00
		3	\$50.00
		4	\$50.00
		5	\$50.00
		6	\$1.00
		7	\$50.00
		8	\$1.00
		9	\$50.00
		10	\$1.00
		11	\$1.00
		12	\$50.00
		13	\$50.00
		14	\$50.00
		15	\$50.00
		16	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
KANAWHA	20	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$30.00
		16	\$30.00
		17	\$1.00
		18	\$1.00
		19	\$30.00
		20	\$1.00
		21	\$1.00
		22	\$1.00
		23	\$30.00
		24	\$30.00
		25	\$30.00
		26	\$1.00
		27	\$1.00
		28	\$30.00
		29	\$1.00
		30	\$1.00
		31	\$1.00
LEWIS	21	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$30.00
		5	\$1.00
		6	\$30.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
LINCOLN	22	1	\$15.00
		2	\$15.00
		3	\$1.00
		4	\$15.00
		5	\$15.00
		6	\$15.00
		7	\$15.00
		8	\$15.00
		9	\$15.00
		10	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
HARCOY	16	1	\$1.00
		2	\$10.00
		3	\$10.00
		4	\$10.00
		5	\$10.00
		6	\$1.00
HARRISON	17	1	\$80.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$60.00
		6	\$1.00
		7	\$60.00
		8	\$1.00
		9	\$80.00
		10	\$1.00
		11	\$80.00
		12	\$80.00
		13	\$1.00
		14	\$80.00
		15	\$80.00
		16	\$1.00
		17	\$1.00
		18	\$60.00
		19	\$1.00
		20	\$80.00
		21	\$1.00
JACKSON	18	1	\$38.00
		2	\$38.00
		3	\$1.00
		4	\$38.00
		5	\$1.00
		6	\$38.00
		7	\$35.00
JEFFERSON	19	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
GILMER	11	1	\$25.00
		2	\$25.00
		3	\$25.00
		4	\$1.00
		5	\$1.00
		6	\$25.00
GRANT	12	1	\$1.00
		2	\$1.00
		3	\$10.00
		4	\$1.00
		5	\$10.00
GREENBRIER	13	1	\$1.00
		2	\$1.00
		3	\$10.00
		4	\$10.00
		5	\$1.00
		6	\$10.00
		7	\$10.00
		8	\$10.00
		9	\$10.00
		10	\$1.00
		11	\$10.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$10.00
		17	\$1.00
		18	\$10.00
HAMPSHIRE	14	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$5.00
		6	\$1.00
		7	\$5.00
		8	\$1.00
		9	\$5.00
		10	\$1.00
HANCOCK	15	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$1.00
		6	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
CABELL	8	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		6	\$1.00
		8	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$1.00
		10	\$20.00
CALHOUN	7	1	\$30.00
		2	\$1.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		6	\$30.00
CLAY	6	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
DODDRIDGE	9	1	\$60.00
		2	\$60.00
		3	\$60.00
		4	\$60.00
		5	\$60.00
		6	\$60.00
		7	\$60.00
		8	\$60.00
		9	\$1.00
FAYETTE	10	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00

OIL & GAS RESERVE RATES FOR TY 2016			
COUNTY	CO #	DISTRICT #	TY2016 \$/AC
BARBOUR	1	1	\$60.00
		2	\$1.00
		3	\$50.00
		4	\$60.00
		5	\$50.00
		6	\$1.00
		7	\$50.00
		8	\$50.00
		9	\$60.00
		10	\$50.00
		11	\$50.00
BERKELEY	2	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
BOONE	3	1	\$20.00
		2	\$1.00
		3	\$1.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
		7	\$1.00
		8	\$20.00
		9	\$1.00
BRAXTON	4	1	\$20.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$20.00
		7	\$20.00
		8	\$1.00
BROOKE	5	1	\$1.00
		2	\$1.00
		3	\$25.00
		4	\$25.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00

Home Use Only Wells:

Appraised at \$500 per well

Industrial Use Only Wells:*

MCF usage X \$ 4.39/MCF
BBL usage X \$93.26/BBL

*(Also includes Department of Environmental Protection reported wells.)

Non-Filer Valuations

Working Interest	=	150% of previous year's appraisal
Royalty Interest	=	90% of previous year's appraisal

Valuation

The previously discussed variables are used to establish a future income stream converted to present worth through application of a capitalization rate. The sum of the discounted future net income per year represents a reasonable estimate of market value.

Lease Rate/Term Survey and Results

The non-producing property value for each county is determined by multiplying the average delay rental by a factor, which represents the average lease term under present economic conditions.

As a result of higher lease terms being inversely proportional to the value of oil and gas (thus counties with little leasing or production activities reflect inflated values) and with the volatile nature of county activity, necessary adjustments in the review have been made.

A compilation of lease terms produced a statewide average of 5 years. This term (5 years) was applied to all county lease rates and compared to the appraisal rates derived from calculations using individual county data. The two resulting calculations were reviewed and considered in the assignment of an appraisal rate per acre.

The appraisal rate/acre amounts shown on the next page are preliminary figures, which may change if additional lease data is received. These rates have been applied to all county magisterial districts with either producing wells, lease activity within the past 5 years or both. Tax districts void of activity within the past 5 years have been assigned the minimum value per acre.

Industry Operating Expense Survey and Results

This component was determined through a review of responses to a survey distributed by the State Tax Department to producers of all oil and natural gas wells producing in West Virginia and through use of other market data.

GAS

- % Working Interest Expenses for Typical Producing Well	=	30%
- Maximum Operating Expenses	=	\$5,000
- Coal Bed Methane, Vertical Wells Expenses	=	\$9,000

OIL

- % Working Interest Expenses for Typical Producing Well	=	35%
- Maximum Operating Expenses	=	\$5,750
- Maximum Enhanced Operating Expenses	=	\$9,000

MARCELLUS

- % Working Interest Expenses for Vertical Producing Well	=	30%
- Maximum Operating Expenses	=	\$30,000
- % Working Interest Expenses for Horizontal Producing Well	=	20%
- Maximum Operating Expenses	=	\$150,000

HORIZONTAL WELLS (OTHER THAN MARCELLUS)

- % Working Interest Expenses for Horizontal Producing Well	=	30%
- Maximum Operating Expenses	=	\$20,000

Minimum Working Interest Appraisal = \$500 per well

Flat Rate Royalty Multiplier = 5.75

Decline Rates for Natural Gas and Oil Formations: West Central

West Central: Calhoun, Roane, Wirt

Code	Formation	Year 1	Year 2	Year 3 +
2	Huron, Rhinestreet	-0.49	-0.11	-0.06
4	Huron	-0.33	-0.22	-0.14
27	Huron, Shales above Huron	-0.42	-0.23	-0.12
44	Rhinestreet, Huron, Shallow Shale	-0.51	-0.14	-0.11
45	Devonian Shale, Pocono	-0.25	-0.17	-0.12
46	Pocono	-0.29	-0.25	-0.12
84	Blg Injun, Oil	-0.41	-0.41	-0.11
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.06
109	Trenton/Deeper *	-0.42	-0.24	-0.10
110	Marcellus *	-0.42	-0.24	-0.10
9	Exception (Median)	-0.42	-0.24	-0.10
10	Non-Filer	-0.25	-0.11	-0.06

Decline Rates for Natural Gas and Oil Formations: West

West: Jackson, Mason, Putnam

Code	Formation	Year 1	Year 2	Year 3 +
1	Oriskany	-0.40	-0.40	-0.29
2	Huron, Rhinestreet	-0.13	-0.12	-0.03
3	Devonian Shale	-0.31	-0.15	-0.04
4	Huron	-0.29	-0.14	-0.05
5	Huron, Shales above Huron	-0.38	-0.15	-0.06
6	Huron, Berea	-0.29	-0.08	-0.08
7	Berea, Devonian Shale	-0.08	-0.08	-0.08
8	Berea	-0.38	-0.16	-0.16
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.35	-0.20	-0.09
110	Marcellus *	-0.35	-0.20	-0.09
9	Exception (Median)	-0.35	-0.20	-0.09
10	Non-Filer	-0.08	-0.08	-0.03

Decline Rates for Natural Gas and Oil Formations: South West

South West: Cabell, Lincoln, Logan, Mingo, Wayne

Code	Formation	Year 1	Year 2	Year 3 +
3	Devonian Shale	-0.31	-0.15	-0.04
8	Berea	-0.38	-0.11	-0.11
18	Big Injun	-0.38	-0.22	-0.04
22	Big Lime	-0.19	-0.19	-0.19
43	Berea, Big Lime	-0.18	-0.18	-0.18
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.28	-0.07
95	Injun/Weir	-0.51	-0.28	-0.09
98	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.38	-0.22	-0.10
110	Marcellus *	-0.38	-0.22	-0.10
9	Exception (Median)	-0.38	-0.22	-0.10
10	Non-Filer	-0.18	-0.11	-0.04

Decline Rates for Natural Gas and Oil Formations: South Central

South Central: Boone, Kanawha

Code	Formation	Year 1	Year 2	Year 3 +
3	Devonian Shale	-0.23	-0.08	-0.05
4	Huron	-0.31	-0.15	-0.04
8	Berea	-0.23	-0.14	-0.09
18	Big Injun	-0.29	-0.25	-0.12
27	Huron, Shales above Huron	-0.21	-0.08	-0.05
28	Weir	-0.30	-0.21	-0.14
29	Weir +	-0.31	-0.25	-0.09
31	Devonian Shales +	-0.27	-0.07	-0.05
88	Big Injun-Oil	-0.19	-0.18	-0.10
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.28	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.33	-0.19	-0.08
110	Marcellus *	-0.33	-0.19	-0.08
9	Exception (Median)	-0.33	-0.19	-0.08
10	Non-Filer	-0.19	-0.07	-0.04

Decline Rates for Natural Gas and Oil Formations: South

South: McDowell, Mercer, Raleigh, Wyoming

Code	Formation	Year 1	Year 2	Year 3 +
8	Berea	-0.34	-0.15	-0.15
22	Big Lime	-0.31	-0.19	-0.07
23	Big Lime, Maxton	-0.31	-0.19	-0.07
24	Big Lime, Ravencloff	-0.29	-0.29	-0.17
25	Berea +	-0.37	-0.12	-0.08
26	Ravencloff	-0.40	-0.08	-0.07
28	Weir	-0.44	-0.20	-0.10
29	Weir +	-0.28	-0.21	-0.08
30	Weir, Big Lime	-0.37	-0.19	-0.13
42	Maxton, Ravencloff	-0.40	-0.08	-0.07
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.28	-0.09
98	Maxton	-0.27	-0.13	-0.09
97	Coalbed Methane (Vertical)	0.03	0.10	-0.05
98	Coalbed Methane (Horizontal)	-0.05	-0.05	-0.32
110	Marcellus *	-0.36	-0.19	-0.09
9	Exception (Median)	-0.36	-0.19	-0.09
10	Non-Filer	-0.23	-0.08	-0.05

Decline Rates for Natural Gas and Oil Formations: North West

North West: Pleasants, Ritchie, Wood

Code	Formation	Year 1	Year 2	Year 3 +
2	Huron, Rhinestreet	-0.41	-0.26	-0.07
4	Huron	-0.42	-0.24	-0.14
5	Huron, Shales above Huron	-0.39	-0.25	-0.14
8	Beree	-0.31	-0.15	-0.15
11	Gordon	-0.38	-0.10	-0.10
12	Alexander, Benson (No Riley)	-0.34	-0.23	-0.10
13	Alexander, Benson, Riley	-0.32	-0.20	-0.10
14	Benson	-0.19	-0.19	-0.10
44	Rhinestreet, Huron, Shallow Shale	-0.43	-0.28	-0.11
47	Alexander, Riley, (No Benson)	-0.41	-0.05	-0.05
48	Rhinestreet, Alexander, Benson, Riley	-0.31	-0.24	-0.10
49	Weir, Squaw, Big Injun	-0.27	-0.17	-0.07
50	Rhinestreet	-0.40	-0.27	-0.27
51	Rhinestreet +	-0.36	-0.21	-0.10
52	All Upper Devonian (Undiv)	-0.48	-0.33	-0.19
53	Huron, Chemung	-0.35	-0.11	-0.09
54	Huron, Hampshire, Pocono	-0.12	-0.12	-0.11
55	Upper Devonian (Above Huron)	-0.46	-0.33	-0.23
58	Chemung Sands= Riley, Bradford, Baitown, Speechley, Warren (No Benson or Alexander)	-0.28	-0.18	-0.10
83	Huron Oil	-0.74	-0.44	-0.40
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.39	-0.23	-0.13
110	Marcellus	-0.46	-0.29	-0.13
9	Exception (Medlan)	-0.39	-0.23	-0.13
10	Maxton			

Decline Rates for Natural Gas and Oil Formations: North Central				
North Central: Barbour, Doddridge, Gilmer, Harrison, Lewis, Marlon, Monongalia, Taylor, Upshur				
Code	Formation	Year 1	Year 2	Year 3 +
11	Gordon	-0.41	-0.14	-0.12
12	Alexander, Benson	-0.37	-0.19	-0.11
13	Alexander, Benson, Riley	-0.40	-0.28	-0.05
14	Benson	-0.31	-0.17	-0.12
15	Benson, Riley	-0.34	-0.17	-0.14
18	Big Injun	-0.38	-0.18	-0.13
21	Benson, Fifth	-0.31	-0.20	-0.14
28	Weir	-0.34	-0.34	-0.07
29	Weir +	-0.28	-0.28	-0.23
33	Elk, Benson	-0.34	-0.18	-0.11
34	Elk, Benson, Riley	-0.42	-0.27	-0.08
37	Elk, Alexander, Benson	-0.49	-0.23	-0.08
38	Elk, Alexander, Benson +	-0.38	-0.20	-0.12
40	Fox, Haverty	-0.48	-0.18	-0.08
50	Rhinestreet	-0.28	-0.03	-0.03
57	Alexander, Benson, Balltown	-0.39	-0.28	-0.08
58	Alexander	-0.35	-0.20	-0.10
59	Alexander +	-0.39	-0.22	-0.10
60	Alexander, Benson, Riley +	-0.39	-0.35	-0.12
61	Balltown	-0.35	-0.20	-0.10
62	Balltown, Speechley	-0.28	-0.22	-0.10
63	Balltown, Speechley +	-0.30	-0.13	-0.10
64	Benson, Balltown, Speechley	-0.28	-0.22	-0.09
65	Benson, Bradford	-0.37	-0.20	-0.10
68	Benson, Balltown	-0.29	-0.23	-0.11
67	Benson, Riley +	-0.38	-0.14	-0.10
68	Benson, Speechley	-0.30	-0.22	-0.14
69	Brallier, Elk	-0.42	-0.20	-0.13
70	Brallier	-0.40	-0.22	-0.15
71	Deeper/Onondaga or Oriskany/Helderberg	-0.24	-0.24	-0.03
72	Elk, Alexander	-0.42	-0.22	-0.09
73	Elk, Benson +	-0.38	-0.20	-0.12
74	Elk	-0.43	-0.12	-0.10
75	Elk, Riley	-0.60	-0.35	-0.17
78	Fox +	-0.48	-0.18	-0.09
77	Haverty, Elk, Benson (No Alexander)	-0.35	-0.18	-0.16
78	Haverty	-0.45	-0.15	-0.15
79	Riley	-0.44	-0.22	-0.10
80	Speechley	-0.30	-0.18	-0.09
81	Alexander, Benson, Speechley	-0.39	-0.24	-0.10
82	Haverty, Elk, Alexander	-0.47	-0.14	-0.14
85	Fifth, Oil	-0.45	-0.25	-0.22
87	Bayard All	-0.30	-0.20	-0.05
88	Fifth	-0.29	-0.18	-0.12
89	Fifth +	-0.25	-0.15	-0.13
90	Gordon, Injun All	-0.41	-0.23	-0.23
91	Squaw	-0.37	-0.31	-0.08
92	Injun +	-0.34	-0.22	-0.22
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
97	Coalbed Methane (Vertical)	-0.23	-0.08	-0.05
98	Coalbed Methane (Horizontal)	-0.05	-0.05	-0.32
109	Trenton/Deeper *	-0.38	-0.21	-0.11
110	Marcellus	-0.59	-0.29	-0.23
9	Exception (Median)	-0.38	-0.21	-0.11

Decline Rates for Natural Gas and Oil Formations: North

North: Brooke, Hancock, Marshall, Ohio, Tyler, Wetzel

Code	Formation	Year 1	Year 2	Year 3 +
11	Gordon	-0.47	-0.31	-0.09
13	Alexander, Benson, Riley	-0.28	-0.18	-0.15
15	Benson, Riley	-0.18	-0.18	-0.06
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.28	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
97	Coalbed Methane (Vertical)	-0.23	-0.08	-0.05
110	Marcellus	-0.52	-0.23	-0.18
9	Exception (Median)	-0.39	-0.23	-0.08
10	Non-Filer	-0.18	-0.16	-0.06

Decline Rates for Natural Gas and Oil Formations: East

**East: Berkeley, Grant, Greenbrier, Hampshire, Hardy, Jefferson, Mineral,
Monroe, Morgan, Pendleton, Pocahontas, Preston, Randolph, Summers,
Tucker**

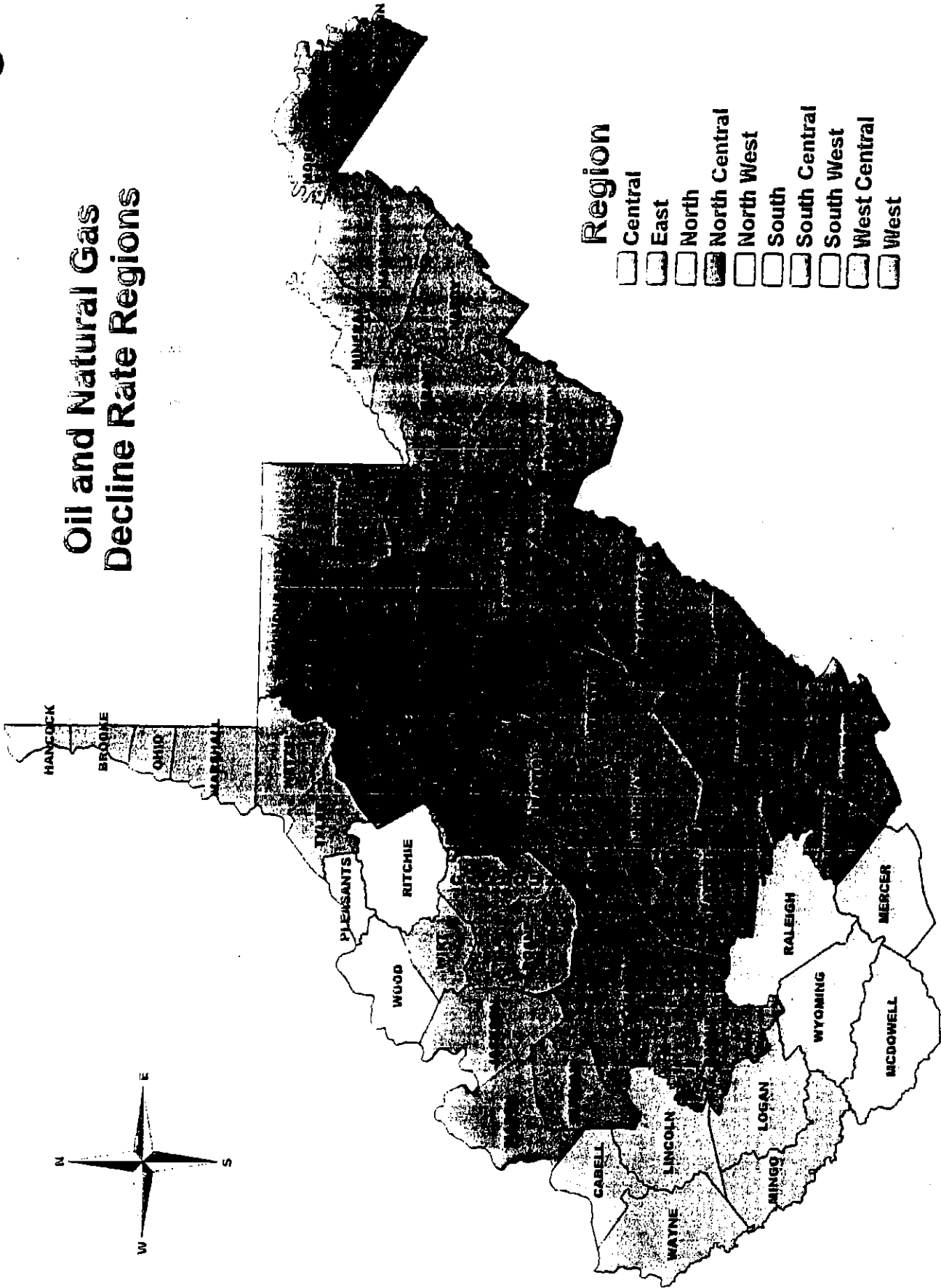
Code	Formation	Year 1	Year 2	Year 3 +
1	Oriskany	-0.30	-0.30	-0.19
14	Benson	-0.31	-0.17	-0.12
20	Benson +	-0.44	-0.20	-0.08
21	Benson, Fifth	-0.29	-0.28	-0.09
32	Brallier +	-0.48	-0.20	-0.05
33	Elk, Benson	-0.39	-0.21	-0.08
34	Elk, Benson, Riley	-0.53	-0.19	-0.05
35	Elk, Benson, Riley +	-0.36	-0.19	-0.11
36	Elk, Benson, Balltown	-0.34	-0.18	-0.11
37	Elk, Alexander, Benson	-0.50	-0.07	-0.07
38	Elk, Alexander, Benson +	-0.40	-0.16	-0.16
39	Huntermville	-0.31	-0.31	-0.14
40	Fox, Haverly	-0.36	-0.21	-0.15
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
110	Marcellus	-0.59	-0.22	-0.17
9	Exception (Median)	-0.41	-0.22	-0.10
10	Non-Filer	-0.29	-0.07	-0.05

Decline Rates for Natural Gas and Oil Formations: Central

Central: Braxton, Clay, Fayette, Nicholas, Webster

Code	Formation	Year 1	Year 2	Year 3 +
12	Alexander, Benson	-0.31	-0.20	-0.10
14	Benson	-0.48	-0.08	-0.08
16	Benson, Balltown+	-0.45	-0.16	-0.12
17	Gordon +	-0.30	-0.07	-0.07
18	Big Injun	-0.34	-0.13	-0.13
19	Big Injun, Big Lime	-0.36	-0.13	-0.13
22	Big Lime	-0.34	-0.34	-0.13
26	Ravenclyff	-0.40	-0.40	-0.25
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.41	-0.22	-0.09
110	Marcellus *	-0.41	-0.22	-0.09
9	Exception (Median)	-0.41	-0.22	-0.09
10	Non-Filer	-0.30	-0.07	-0.07

Oil and Natural Gas Decline Rate Regions



Capitalization Rate

Since the valuation of oil and gas property is predicated on a three year production, the capitalization rate will be considered in a similar manner.

	<u>2014</u>	<u>2013</u>	<u>2012</u>
Inflation Rate	-0.780%	-1.500%	-1.700%
Safe Rate	0.033%	0.058%	0.088%
Composite Risk Rate	14.388%	14.834%	14.805%
Non Liquidity Rate	0.088%	0.074%	0.088%
Management Rate	0.500%	0.500%	0.500%
Property Tax Rate	1.314%	1.314%	1.328%
Total	15.584%	15.080%	14.808%
	50.000%	33.333%	16.667%
	7.782%	5.027%	2.484%
			15.293%

Capitalization Rate Rounded to:

15.30%

MULTIPLIERS FOR 15.3% MID-YEAR LIFE (ANNUALLY)

<u>YEAR</u>		<u>YEAR</u>	
1	0.931291	21	0.054013
2	0.807711	22	0.046846
3	0.700530	23	0.040829
4	0.607572	24	0.035238
5	0.528948	25	0.030582
6	0.457024	26	0.026507
7	0.390376	27	0.022869
8	0.343780	28	0.019938
9	0.298181	29	0.017293
10	0.258596	30	0.014898
11	0.224281	31	0.013008
12	0.194519	32	0.011282
13	0.168707	33	0.009765
14	0.146320	34	0.008465
15	0.128904	35	0.007360
16	0.110084	36	0.006384
17	0.095459	37	0.005536
18	0.082792	38	0.004802
19	0.071808	39	0.004185
20	0.062277	40	0.003612

OIL AND GAS

TY 2016

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for producing oil and gas properties. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 1J.

<u>Safe Rate</u>	(3-Month Constant Maturity Interest Rates)		
	January	December	2014
			0.033%

<u>Risk Rate</u>	(Interest differential between Loan Rate and 3-Month Constant Maturity Interest Rates)		
	<u>Loan Rate*</u>		<u>Risk Rate</u>
	2014	5.250%	5.217%
		*Prime plus 2%	

<u>Equity</u>	(Differential between Equity Rates and 3-Month Constant Maturity Interest Rates)		
	<u>Equity Rate**</u>		<u>Risk Rate</u>
	2014	[11.5%/(1-.37)]-0.033%	18.221%
	** Value Line Investment Survey Analysis		

<u>Composite Risk Rate</u>	Loan and Equity Rates weighted by industry estimated capital structure.				
	<u>Equity Rate</u>		<u>Debt Rate</u>		<u>Composite Risk</u>
	2014	11.8438%		1.826%	14.389%
	Note: Debt equity Ratio		Debt	35%	Equity
	*** Effective severance tax adjustment			0.95	65%

<u>Non Liquidity Rate</u>	Interest differential between 3-month Constant Maturity Interest Rates and a 1 year Constant Maturity Interest Rates which reflects a reasonable time necessary to sell active property.				
				<u>1yr T Bill</u>	<u>90 day T Bill</u>
	January	December	2014	0.121%	0.033%
					Non Liquidity Rate
					0.088%

<u>Management Rate</u>	Charges for the management of investment portfolios.	
	Fixed Rate (by Rule)	0.500%

<u>Property Tax Rate</u>	Sixty percent (60%) of State average Class III property tax rate.		
	2014	60% of 2.19	1.314%

<u>Inflation Rate</u>	January	December	2014
			0.760%

OIL AND GAS PROPERTIES ANALYSIS

Tax Year 2016

August 27, 2015
Mark W. Matkovich
State Tax Commissioner
Department of Revenue



STATE OF WEST VIRGINIA
Department of Revenue
State Tax Department

Earl Ray Tomblin
Governor

Mark W. Matkovich
State Tax Commissioner

August 27, 2015

The Honorable Natalie Tennant
Secretary of State
Building 1, Suite 157-K
State Capitol
Charleston, West Virginia 25305

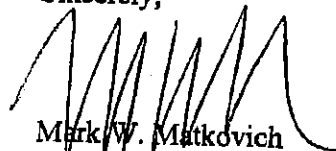
Dear Secretary Tennant:

Attached are final natural resource property valuation variables for the 2016 Tax Year that have been developed by the State Tax Department for use in appraising oil and gas, managed timberland, coal and other natural resource properties for ad valorem tax purposes.

In accordance with requirements of §§ 110 CSR 1-I, 1-J, and 1-K, tentative variables were made available for public comments on June 30, 2014. The Department received six comments on the tentative variables. Three comments related to the valuation of coal and three comments related to the valuation of producing oil and gas wells. The information supplied in the coal comments resulted in an increase in the capitalization rate for coal properties. One of the oil and gas commenters supplied data supporting an increase in the decline rate for Marcellus gas wells in the North West region.

The final valuation variables are being filed for inclusion in the State Register.

Sincerely,


Mark W. Matkovich
State Tax Commissioner

MWM/jaj

Attachment

cc: All County Assessors



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ITEM NO 414

14

[illegible]

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[illegible]

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Fair Market Value Assessment - Antero Resources Corp.

Fair Value Conclusion

Valuation as of July 1, 2015

DEIN

Income Approach Summary

County	Well Count ^[1]	Fair Market Value ^[2]
Ritchie	24	59,031,397
Total	24	\$ 59,031,397

198,900

Notes to Exhibit

[1] As provided by management. See Exhibit 3.

[2] See Exhibit 3.

ALTUS GROUP US INC.
Fair Market Value Assessment - Antero Resources Corp.
 Discount Rate Derivation
 Valuation as of July 1, 2015

Index	Company	(1) [1]	(2) [2]	(3) [3]	(4) [4]	(5) [5]	(6) [6]
AR	Antero Resources Corporation	United States	12,237	1.99	30.9%	28.0%	196,430
CHK	Chesapeake Energy Corporation	United States	16,048	1.47	114.1%	53.3%	196,430
CON	CONSOL Energy Inc.	United States	6,988	1.39	53.7%	36.4%	(1,505,000)
COG	Cabot Oil & Gas Corporation	United States	3,357	0.86	13.9%	12.2%	58,656
CEZ	Cardinal Oil & Gas Inc.	United States	3,454	1.93	71.9%	41.7%	(144,650)
ECR	Equipe Resources Corporation	United States	1,238	2.44	71.2%	41.5%	(103,023)
EQT	EQT Corporation	United States	16,498	0.94	28.7%	22.3%	(37,915)
NBL	Noble Energy, Inc.	United States	23,477	1.28	31.4%	23.9%	(52,492)
ARC	Range Resources Corporation	United States	9,974	1.01	32.6%	24.6%	76,000
SEV	Sunoco Energy Corp.	United States	1,487	1.68	100.3%	50.1%	(472,594)
							(45,581)

Maximum	2.64	114.1%	53.3%	\$ 76,000	\$ 196,430	53.5%	1.80	2.29
Upper Quartile	1.63	71.4%	41.7%	21,213	(177,375)	30.8%	1.04	1.32
Average	1.43	56.0%	33.4%	(226,564)	(1,953,797)	36.0%	1.04	1.31
Median	1.34	48.0%	32.2%	(49,137)	(1,043,049)	37.0%	0.94	1.19
Lower Quartile	1.03	31.7%	24.1%	(134,093)	(1,677,090)	32.2%	0.85	1.07
Minimum	0.86	13.9%	12.2%	(1,585,000)	(11,061,000)	17.2%	0.79	1.00
Selected		47.1%	32.0%	\$ (49,137)	\$ (1,043,049)	43.0%	0.94	1.19

Notes to Exhibit
 Unlevered Equity Beta = Levered Equity Beta / [1 + (1 - Tax Rate) x Debt-to-Equity]
 Based on median value 5 year average debt to capital for the guideline companies
 Based on blended federal and WY state tax rates
 Levered Equity Beta = Unlevered Equity Beta x [1 + (1 - Tax Rate) x Debt-to-Equity]
 Source: S&P Capital IQ
 Source: Duff & Phelps 2015 Valuation Handbook, Long horizon expected equity risk premium (supply side)
 Based on the median value of guideline companies
 Cost of Equity Capital = Risk Free Rate + [Equity Beta x Equity Risk Premium]
 Based on the blended yield to maturity for similarly rated energy company bonds as provided by S&P.

Based on the median value of the guideline companies
 WACC = [(Debt-to-Capital x Cost of Debt) + (Equity-to-Capital x Cost of Equity Capital)]

Selected Input	0.94
Unlevered Beta	47.1%
Debt to Equity	43.0%
Tax Rate	1.19
Levered Equity Beta	1.8%
Risk-Free Rate	7.0%
Equity Risk Premium	1.19
Cost of Equity Capital	10.1%
Pre-Tax Cost of Debt Capital	9.5%
Tax Rate	43.0%
After-Tax Cost of Debt	5.4%
Debt to Capital	32.0%
Equity to Capital	68.0%
Weighted Average Cost of Capital	8.62%
Plus Property Tax Rate	0.5%
Plus Oil & Gas Risk Premium	3.00%
After-Tax Discount Rate	12.4%
Implied Pre-tax Weighted Average Cost of Capital	15.1%
Plus Ad Valorem Tax Rate	1.3%
Plus Oil & Gas Risk Premium	3.00%
Pre-tax Discount Rate	20.0%

Notes to Exhibit
 [1] Source: S&P Capital IQ, Units in \$US millions
 [2] Summation of total book value of debt, total book value of preferred equity and market cap.
 [3] 5-year monthly historic beta as provided by S&P Capital IQ adjusted for Marshall Blume Formula (Adjusted Beta = 0.67 * Historical Beta + 0.33).
 [4] Represents 5-year average capital structure data.
 [5] Additional risk premium to account for one-well diversification risk, rapid decline rates, single completion risk, and limited production history.

ALTUS GROUP US INC.
Fair Market Value Assessment - Antero Resources Corp.

FMV Comparison - Antero Resources Corp.
 Valuation as of July 1, 2015

HEA

Fair Market Value Summary

Well Name	NDA #	County	Well Type	Target Interval	Main		West Virginia	
					FMV	% of Total	State Estimate	% of Total
Anna Unit 2H	0320159963	Ritchie	Horizontal	Marcellus	\$ 1,068,241	1.8%	\$ 6,766,223	3.5%
Belle Unit 1H	0320160027	Ritchie	Horizontal	Marcellus	1,798,192	3.0%	8,857,185	4.6%
Belle Unit 2H	0320160028	Ritchie	Horizontal	Marcellus	1,376,824	2.3%	5,953,786	3.1%
Belle Unit 3H	0320160029	Ritchie	Horizontal	Marcellus	1,724,759	2.9%	8,427,646	4.3%
Blanche Unit 1H	0320150036	Ritchie	Horizontal	Marcellus	1,792,097	3.0%	11,801,733	6.1%
0320160060		Ritchie	Horizontal	Marcellus	1,615,630	2.7%	8,731,251	4.5%
Hendershot Unit 2H	0320160088	Ritchie	Horizontal	Marcellus	1,730,185	2.9%	9,880,555	5.1%
Homers Unit 1H	0320160062	Ritchie	Horizontal	Marcellus	1,944,504	3.3%	10,589,234	5.4%
Homers Unit 2H	0320160063	Ritchie	Horizontal	Marcellus	1,672,593	2.8%	8,263,514	4.3%
Allstate Unit 2H	1020160017	Ritchie	Horizontal	Marcellus	1,568,916	2.7%	6,577,125	3.4%
Consable Unit 1H	1020150023	Ritchie	Horizontal	Marcellus	2,394,709	4.1%	15,652,042	8.1%
Delany Unit 1H	1020169999	Ritchie	Horizontal	Marcellus	1,853,443	3.1%	8,563,011	4.4%
Ireland Unit 1H	1020160005	Ritchie	Horizontal	Marcellus	1,849,367	3.1%	9,811,251	5.0%
Kuhn Unit 1H	1020150002	Ritchie	Horizontal	Marcellus	4,195,337	7.1%	4,594,637	2.4%
Langford Unit 2H	1020160045	Ritchie	Horizontal	Marcellus	2,274,936	3.9%	7,715,025	4.0%
McCabe Unit 3H	1020160019	Ritchie	Horizontal	Marcellus	1,975,103	3.3%	8,769,950	4.5%
Nicholson Unit 1H	1020159961	Ritchie	Horizontal	Marcellus	3,860,613	6.5%	4,433,217	2.3%
Nicholson Unit 2H	1020149960	Ritchie	Horizontal	Marcellus	5,552,627	9.4%	6,013,991	3.5%
O'Neil Unit 1H	1020159964	Ritchie	Horizontal	Marcellus	5,618,603	9.5%	6,688,592	3.4%
O'Neil Unit 2H	1020159966	Ritchie	Horizontal	Marcellus	4,751,293	8.0%	5,772,729	3.0%
Prunty Unit 1H	1020159970	Ritchie	Horizontal	Marcellus	2,227,910	3.8%	13,938,228	7.2%
Pullman Unit 2H	1020159978	Ritchie	Horizontal	Marcellus	3,011,483	5.1%	3,263,358	1.7%
Rufus Unit 1H	1020160046	Ritchie	Horizontal	Marcellus	2,201,226	3.7%	0,093,655	0.4%
Snodgrass Unit 2H	1020169996	Ritchie	Horizontal	Marcellus	972,805	1.6%	4,503,041	2.3%
					\$ 39,031,397	100.0%	\$ 194,400,979	100.0%

Notes to Exhibit

[1] Individual well data provided by Client.

[2] For further detail on the development of the FMV for each individual well, please refer to Exhibit 3.

ALTUS GROUP US INC.

Fair Market Value Assessment - Antero Resources Corp.

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Valuation as of July 1, 2015

HEIN

Reference #	Exhibit Description
Exhibit 1	FMV Conclusion
Exhibit 2	FMV Detail
Exhibit 3	FMV Comparison
Exhibit 4	Discount Rate Derivation

ALTUS GROUP US INC.

FMV Assessment of Ritchie County, WV Gas Wells
Held by Antero Resources Corporation

As of July 1, 2015

HEIN
APPRAISAL | TAX | ADVISORY

Specialty Services Group

EXHIBIT

11

2014 Calendar Year Revenue and Expenses for Horizontal Marcellus wells
From Operating Expenses Tab

		Gas	NGL	Gas	Gas	Sum of	Gas	NGL
Production Start Year	Count of API #	Sum of Total Gas Receipts	Sum of Total NGL Receipts	Sum of LOE Expenses	Gathering and Compression Expenses	Sum of Transportation Expenses	Sum of Processing Expenses (Note 2)	Sum of Total Operating Expenses
2013	103	453,900,512	106,853,867	8,247,489	64,953,924	24,741,804	33,389,202	131,332,419
2012	61	191,332,741	4,460,156	2,681,891	23,502,429	16,582,208	1,595,577	44,362,105
2011	38	86,508,451	-	1,295,059	10,445,664	7,826,988	-	19,567,711
2010	17	28,437,649	-	584,966	3,240,138	2,255,830	-	6,080,934
2009	4	4,799,270	-	120,080	584,768	453,609	-	1,158,457
Grand Total	223	764,978,624	111,314,023	12,929,485	102,726,923	51,860,439	34,984,778	202,501,626

Operating Expenses as a % of Revenue for 2014 Calendar Year

Production Start Year	OpEx as % of Revenue (Gas)	OpEx as % of Revenue (NGLs)	OpEx as % of Revenue (Total)
2013	22%	31%	23%
2012	22%	36%	23%
2011	23%		23%
2010	21%		21%
2009	24%		24%
Grand Total	22%	31%	23%

Non-Weighted Average

From Operating Expenses Tab

Production Start Year	Average of OpEx as % of Revenue	Average of OpEx as % of Revenue2	Average of OpEx as % of Revenue3
2013	22%	35%	24%
2012	22%	37%	23%
2011	23%		23%
2010	21%		21%
2009	26%		26%
Grand Total	22%	35%	23%

Article 2 - Antero associates all processing (set with the NGL) for reporting purposes, but the processing is also necessary in order for the natural gas to meet the quality and measurement standards of the Transportation that is required for sale.

Well Code	NRA Account #	API #	Production Start Year	2014 Calendar Year		2015 Calendar Year		2016 Calendar Year		2017 Calendar Year		2018 Calendar Year		2019 Calendar Year		Total	Unit Type
				Total Gas Reserves	Total Oil Reserves	Total Reported Reserves	LOE Expenses	Comprehensive Expenditures	Gas	Oil	Transposition Expenditures	Preemptive Expenditures	Total Operations Expenditures	Oil as % of Revenue	Oil as % of Revenue		
41037	17-2020155448	41-037-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41038	17-2020155449	41-038-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41039	17-2020155450	41-039-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41040	17-2020155451	41-040-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41041	17-2020155452	41-041-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41042	17-2020155453	41-042-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41043	17-2020155454	41-043-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41044	17-2020155455	41-044-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41045	17-2020155456	41-045-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41046	17-2020155457	41-046-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41047	17-2020155458	41-047-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41048	17-2020155459	41-048-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41049	17-2020155460	41-049-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41050	17-2020155461	41-050-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41051	17-2020155462	41-051-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41052	17-2020155463	41-052-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41053	17-2020155464	41-053-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41054	17-2020155465	41-054-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41055	17-2020155466	41-055-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41056	17-2020155467	41-056-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41057	17-2020155468	41-057-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41058	17-2020155469	41-058-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41059	17-2020155470	41-059-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41060	17-2020155471	41-060-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41061	17-2020155472	41-061-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41062	17-2020155473	41-062-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41063	17-2020155474	41-063-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41064	17-2020155475	41-064-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41065	17-2020155476	41-065-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41066	17-2020155477	41-066-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41067	17-2020155478	41-067-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41068	17-2020155479	41-068-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41069	17-2020155480	41-069-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41070	17-2020155481	41-070-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41071	17-2020155482	41-071-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41072	17-2020155483	41-072-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41073	17-2020155484	41-073-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41074	17-2020155485	41-074-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41075	17-2020155486	41-075-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41076	17-2020155487	41-076-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41077	17-2020155488	41-077-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41078	17-2020155489	41-078-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41079	17-2020155490	41-079-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41080	17-2020155491	41-080-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41081	17-2020155492	41-081-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41082	17-2020155493	41-082-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41083	17-2020155494	41-083-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41084	17-2020155495	41-084-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41085	17-2020155496	41-085-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41086	17-2020155497	41-086-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41087	17-2020155498	41-087-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41088	17-2020155499	41-088-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41089	17-2020155500	41-089-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41090	17-2020155501	41-090-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41091	17-2020155502	41-091-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41092	17-2020155503	41-092-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41093	17-2020155504	41-093-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41094	17-2020155505	41-094-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41095	17-2020155506	41-095-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41096	17-2020155507	41-096-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41097	17-2020155508	41-097-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41098	17-2020155509	41-098-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
41099	17-2020155510	41-099-00000	2013	5,183,024	-	5,183,024	21,437	620,355	430,048	1,112,703	72%	72%	22%	22%	22%	22%	Marcellus, Horizontal
4110																	

Operating expense	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	2079	2080	2081	2082	2083	2084	2085	2086	2087	2088	2089	2090	2091	2092	2093	2094	2095	2096	2097	2098	2099	2100	2101	2102	2103	2104	2105	2106	2107	2108	2109	2110	2111	2112	2113	2114	2115	2116	2117	2118	2119	2120	2121	2122	2123	2124	2125	2126	2127	2128	2129	2130	2131	2132	2133	2134	2135	2136	2137	2138	2139	2140	2141	2142	2143	2144	2145	2146	2147	2148	2149	2150	2151	2152	2153	2154	2155	2156	2157	2158	2159	2160	2161	2162	2163	2164	2165	2166	2167	2168	2169	2170	2171	2172	2173	2174	2175	2176	2177	2178	2179	2180	2181	2182	2183	2184	2185	2186	2187	2188	2189	2190	2191	2192	2193	2194	2195	2196	2197	2198	2199	2200	2201	2202	2203	2204	2205	2206	2207	2208	2209	2210	2211	2212	2213	2214	2215	2216	2217	2218	2219	2220	2221	2222	2223	2224	2225	2226	2227	2228	2229	2230	2231	2232	2233	2234	2235	2236	2237	2238	2239	2240	2241	2242	2243	2244	2245	2246	2247	2248	2249	2250	2251	2252	2253	2254	2255	2256	2257	2258	2259	2260	2261	2262	2263	2264	2265	2266	2267	2268	2269	2270	2271	2272	2273	2274	2275	2276	2277	2278	2279	2280	2281	2282	2283	2284	2285	2286	2287	2288	2289	2290	2291	2292	2293	2294	2295	2296	2297	2298	2299	2300	2301	2302	2303	2304	2305	2306	2307	2308	2309	2310	2311	2312	2313	2314	2315	2316	2317	2318	2319	2320	2321	2322	2323	2324	2325	2326	2327	2328	2329	2330	2331	2332	2333	2334	2335	2336	2337	2338	2339	2340	2341	2342	2343	2344	2345	2346	2347	2348	2349	2350	2351	2352	2353	2354	2355	2356	2357	2358	2359	2360	2361	2362	2363	2364	2365	2366	2367	2368	2369	2370	2371	2372	2373	2374	2375	2376	2377	2378	2379	2380	2381	2382	2383	2384	2385	2386	2387	2388	2389	2390	2391	2392	2393	2394	2395	2396	2397	2398	2399	2400	2401	2402	2403	2404

Well Code	NRA Account #	AP#	Production Start Year	2018 Calendar Year		2019 Calendar Year		2020 Calendar Year		2021 Calendar Year		Well Type
				Gas	Oil	Gas	Oil	Gas	Oil			
41018	17-1400175118	47-031-057151	2011	3,323,616	-	49,553	393,411	375,147	713,819	49,553	713,819	Marcellus, Horizontal
41019	17-1400175119	47-031-057152	2011	2,457,720	-	49,612	297,265	311,111	558,643	49,612	558,643	Marcellus, Horizontal
41020	17-1400175120	47-031-057153	2011	3,583,901	-	5,080,015	3,500,024	784,443	1,744,443	5,080,015	1,744,443	Marcellus, Horizontal
41021	17-1400175121	47-031-057154	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41022	17-1400175122	47-031-057155	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41023	17-1400175123	47-031-057156	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41024	17-1400175124	47-031-057157	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41025	17-1400175125	47-031-057158	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41026	17-1400175126	47-031-057159	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41027	17-1400175127	47-031-057160	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41028	17-1400175128	47-031-057161	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41029	17-1400175129	47-031-057162	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41030	17-1400175130	47-031-057163	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41031	17-1400175131	47-031-057164	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41032	17-1400175132	47-031-057165	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41033	17-1400175133	47-031-057166	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41034	17-1400175134	47-031-057167	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41035	17-1400175135	47-031-057168	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41036	17-1400175136	47-031-057169	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41037	17-1400175137	47-031-057170	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41038	17-1400175138	47-031-057171	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41039	17-1400175139	47-031-057172	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41040	17-1400175140	47-031-057173	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41041	17-1400175141	47-031-057174	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41042	17-1400175142	47-031-057175	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41043	17-1400175143	47-031-057176	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41044	17-1400175144	47-031-057177	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41045	17-1400175145	47-031-057178	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41046	17-1400175146	47-031-057179	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41047	17-1400175147	47-031-057180	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41048	17-1400175148	47-031-057181	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41049	17-1400175149	47-031-057182	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41050	17-1400175150	47-031-057183	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41051	17-1400175151	47-031-057184	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41052	17-1400175152	47-031-057185	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41053	17-1400175153	47-031-057186	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41054	17-1400175154	47-031-057187	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41055	17-1400175155	47-031-057188	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41056	17-1400175156	47-031-057189	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41057	17-1400175157	47-031-057190	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41058	17-1400175158	47-031-057191	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41059	17-1400175159	47-031-057192	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41060	17-1400175160	47-031-057193	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41061	17-1400175161	47-031-057194	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41062	17-1400175162	47-031-057195	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41063	17-1400175163	47-031-057196	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41064	17-1400175164	47-031-057197	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41065	17-1400175165	47-031-057198	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41066	17-1400175166	47-031-057199	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41067	17-1400175167	47-031-057200	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41068	17-1400175168	47-031-057201	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41069	17-1400175169	47-031-057202	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41070	17-1400175170	47-031-057203	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41071	17-1400175171	47-031-057204	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41072	17-1400175172	47-031-057205	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41073	17-1400175173	47-031-057206	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41074	17-1400175174	47-031-057207	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41075	17-1400175175	47-031-057208	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41076	17-1400175176	47-031-057209	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41077	17-1400175177	47-031-057210	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41078	17-1400175178	47-031-057211	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41079	17-1400175179	47-031-057212	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41080	17-1400175180	47-031-057213	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41081	17-1400175181	47-031-057214	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41082	17-1400175182	47-031-057215	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41083	17-1400175183	47-031-057216	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41084	17-1400175184	47-031-057217	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41085	17-1400175185	47-031-057218	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41086	17-1400175186	47-031-057219	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41087	17-1400175187	47-031-057220	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41088	17-1400175188	47-031-057221	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41089	17-1400175189	47-031-057222	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41090	17-1400175190	47-031-057223	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41091	17-1400175191	47-031-057224	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41092	17-1400175192	47-031-057225	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41093	17-1400175193	47-031-057226	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41094	17-1400175194	47-031-057227	2011	2,838,176	-	15,846	336,021	228,788	655,691	15,846	655,691	Marcellus, Horizontal
41095	17-1400175195	47-031-057228	2									

Well Code	NRA Account #	API #	Production Start Date	2014 Calendar Year			2014 Calendar Year Example Item 1 Wells Adjusted to Actual Expenses for Full 12 Months (Item 1)			Net Type								
				Gas	Oil	Water	Gas	Oil	Water									
40031	09-0020166011	41-017-06133	2014	130,584	49,849	2,526,624	3,126	1,848,833	133,777	51,124	567,931	39%	39%	39%	3,052,817	743,264	Macrophil, Horizontal	
40032	09-0020166012	41-017-06134	2014	1,081,281	527,164	5,055,352	31,640	1,814,778	1,258,874	109,013	7,486,021	28%	28%	28%	3,571,297	882,386	Macrophil, Horizontal	
40033	09-0020166013	41-017-06135	2014	2,662,548	844,187	8,292,964	56,290	1,684,246	3,238,728	239,233	17,921,313	17%	17%	17%	3,444,676	841,166	Macrophil, Horizontal	
40034	09-0020166014	41-017-06136	2014	1,455,796	546,548	4,085,796	114,590	860,008	374,672	618,415	2,723,219	27%	27%	27%	3,403,346	702,695	Macrophil, Horizontal	
40035	09-0020166015	41-017-06137	2014	1,545,612	513,621	4,085,796	114,590	860,008	374,672	618,415	2,723,219	27%	27%	27%	3,403,346	702,695	Macrophil, Horizontal	
40036	09-0020166016	41-017-06138	2014	1,545,612	513,621	4,085,796	114,590	860,008	374,672	618,415	2,723,219	27%	27%	27%	3,403,346	702,695	Macrophil, Horizontal	
40037	09-0020166017	41-017-06139	2014	1,545,612	513,621	4,085,796	114,590	860,008	374,672	618,415	2,723,219	27%	27%	27%	3,403,346	702,695	Macrophil, Horizontal	
40038	09-0020166018	41-017-06140	2014	1,545,612	513,621	4,085,796	114,590	860,008	374,672	618,415	2,723,219	27%	27%	27%	3,403,346	702,695	Macrophil, Horizontal	
40039	17-0020165011	41-033-05133	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40040	17-0020165012	41-033-05134	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40041	17-0020165013	41-033-05135	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40042	17-0020165014	41-033-05136	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40043	17-0020165015	41-033-05137	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40044	17-0020165016	41-033-05138	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40045	17-0020165017	41-033-05139	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40046	17-0020165018	41-033-05140	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40047	17-0020165019	41-033-05141	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40048	17-0020165020	41-033-05142	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40049	17-0020165021	41-033-05143	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40050	17-0020165022	41-033-05144	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40051	17-0020165023	41-033-05145	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40052	17-0020165024	41-033-05146	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40053	17-0020165025	41-033-05147	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40054	17-0020165026	41-033-05148	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40055	17-0020165027	41-033-05149	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40056	17-0020165028	41-033-05150	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40057	17-0020165029	41-033-05151	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40058	17-0020165030	41-033-05152	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40059	17-0020165031	41-033-05153	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40060	17-0020165032	41-033-05154	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40061	17-0020165033	41-033-05155	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40062	17-0020165034	41-033-05156	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40063	17-0020165035	41-033-05157	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40064	17-0020165036	41-033-05158	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40065	17-0020165037	41-033-05159	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40066	17-0020165038	41-033-05160	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40067	17-0020165039	41-033-05161	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40068	17-0020165040	41-033-05162	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40069	17-0020165041	41-033-05163	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40070	17-0020165042	41-033-05164	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40071	17-0020165043	41-033-05165	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40072	17-0020165044	41-033-05166	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40073	17-0020165045	41-033-05167	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40074	17-0020165046	41-033-05168	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40075	17-0020165047	41-033-05169	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40076	17-0020165048	41-033-05170	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40077	17-0020165049	41-033-05171	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	Macrophil, Horizontal
40078	17-0020165050	41-033-05172	2010	1,508,778	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,012	3,325,				

Well Costs	NRA Account #	API #	Production Start Year	2014 Calendar Year				2014 Calendar Year Except Year 1 Wells Adjusted to Annual Expenses for First 3 Months (Post 3)												Held Type																																																																																																																																																																																																																																																																																																																																																																																																																																																																						
				Total Gas Receipts	Total Oil Receipts	Total Reported Receipts	LOE Expenses	Casing and Completion Expenses	Transportation Expenses	Processing Expenses (Gels)	Total Operating Expenses	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas		NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total	Gas	NGLs	Total	Culls	Total

[illegible]

Craig Griffith

From: Nancy Sitton <nancy.sitton@altusgroup.com>
Sent: Tuesday, June 14, 2016 4:33 PM
To: 'Hoover, Cindi R'
Cc: 'Jan Mudrinich (mudrinichj@yahoo.com)'; Craig Griffith; Kirsten Evans; Elizabeth Burg
Subject: Antero Operating Expenses
Attachments: Antero Resource Company Operating Expenses 2014 - June 2016.xlsx

Cindi,

Attached please find the requested revenue and operating expense breakdown by well for the appealed wells (see first tab). Natural gas and NGL revenue for the 2014 calendar year has been provided in columns E and F. The NGL revenue reflects the full value of the NGLs based on the MarkWest settlement statements reviewed at our last meeting. Half of the appealed wells do not have NGL revenue (those are mostly located in Harrison County). The gathering, processing, and transportation expenses have been provided in columns J-L. The processing expense reflects the MarkWest fees that are not related to gathering and compression. Although Antero assigns all processing fees to the NGLs for reporting purposes, the processing at the Sherwood facility is necessary in order for the natural gas to meet the quality and measurement standards of the transporters that is required for sale.

Operating expenses as a percentage of revenue are provided in tab 2. For wells with 2+ years of production, operating expenses as a percentage of revenue is consistently 22% when comparing LOE, gathering, and transportation expenses (excluding processing) to gas revenue (excluding NGLs). This is consistent with the State's operating expense variable (20% of revenue) if the cap of \$150,000 were not applied.

The wells should be valued based on their future income stream. While future income related to natural gas can be reasonably estimated, this is not the case for NGLs because profitability fluctuates dramatically from year to year due to the volatility in NGL product prices. NGL revenue for the 2014 calendar year was \$263M, which was reported to be compliant with the State's filing instructions. However, in 2015, the NGLs were not profitable overall due to changes in product prices. Accordingly, we do not think it is appropriate to include the NGL revenue in the State's valuation template. Also, the combination of reporting NGLs (increasing revenue) and applying an operating cap further skews and understates the amount of operating expenses applied.

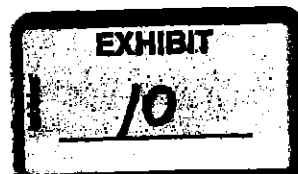
As previously discussed, there are many flaws in the State's discounted cash flow template that cause the current value to not fair market value, including:

- The operating expense cap understates actual operating expenses, especially in first few years of production. Operating expense per the State's variables was \$55M (compared to actual operating expenses of \$385M), or 3% of revenue.
- NGLs should not be included in reported revenue because profitability in the current year is not an indicator of future income stream and it results in further operating expenses being further understated, as noted above.
- The amount of operating expense calculated is assumed for the remainder of the well's life. This does not take into account that certain expenses are variable and will decrease as production decreases.

Antero's appealed value reflects actual operating expenses (including processing), of which 75% of expenses have been declined consistently with the revenue (which includes NGLs). Please note that applying an operating expense variable of 22% of revenue excluding NGLs (with no cap) in the State's existing template would get to a comparable answer.

Please let us know when you have availability to discuss further. We are available Thurs. 6/16, Mon. 6/20 (before 2:30), Wed. 6/22, and Thurs. 6/23.

Thank you,
Nancy



Corporation Name	Account	Account Name	Tran Date	Acct Date	Svc Date	Value	Ref	Invoice #	Description
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	3/10/2015	1/1/2015	12/31/2014	(2,208,339)	Dec. 2014	02-GI-253	02-GI-253 CLEAR MOUNTAINEER INVOICE - DECEMBER 14 SHERWOOD
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	3/10/2015	2/1/2015	12/31/2014	10,887,211	Dec. 2014	02-GI-253	02-GI-153 CLEAR MARKWEST INVOICE - DECEMBER 2014 SHERWOOD
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	3/10/2015	2/1/2015	11/31/2014	35,088	Dec. 2014	02-GI-153	02-GI-253 DECEMBER 2014 FEES PAID TO MARKWEST & MOUNTAINEER
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	3/10/2015	1/1/2015	12/31/2014	(943,862)	Dec. 2014	02-GI-253	02-GI-253 DECEMBER 2014 MIDPOINT & NEW MILTON COMP STMT
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	3/10/2015	1/1/2015	12/31/2014	(40,619)	Dec. 2014	02-GI-253	02-GI-253 DECEMBER 2014 NGL INCOME NOT DISTRIBUTED TO
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	3/10/2015	2/1/2015	12/31/2014	(1,096,387)	Dec. 2014	02-GI-253	02-GI-153 DECEMBER 2014 SHERWOOD, PENNINGTON & VICTORIA
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	3/10/2015	2/1/2015	12/31/2014	(6,183,781)	Dec. 2014	02-GI-253	02-GI-153 DECEMBER 2014 WHITE OAK, WEST UNION COMP
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	3/10/2015	1/1/2015	11/31/2014	(448,816)	Dec. 2014	02-GI-253	02-GI-153 DECEMBER 2014 ZINNIA, BANNER, MORGAN, PERKINS
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	4/6/2015	3/1/2015	1/31/2015	(2,496,073)	Jan. 2015	03-GI-221	03-GI-221 CLEAR MOUNTAINEER INVOICE - JANUARY 2015 SHERWOOD
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	4/6/2015	3/1/2015	1/31/2015	6,398,270	Jan. 2015	03-GI-221	03-GI-221 CLEAR MARKWEST INVOICE - JANUARY 2015 SHERWOOD
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	4/6/2015	3/1/2015	1/31/2015	35,191	Jan. 2015	03-GI-221	03-GI-221 JANUARY 2015 FEES PAID TO MARKWEST & MOUNTAINEER
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	4/6/2015	3/1/2015	1/31/2015	(319,847)	Jan. 2015	03-GI-221	03-GI-221 JANUARY 2015 MIDPOINT & NEW MILTON COMP STMT
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	4/6/2015	3/1/2015	1/31/2015	(16,331)	Jan. 2015	03-GI-221	03-GI-221 JANUARY 2015 NGL INCOME NOT DISTRIBUTED TO
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	4/6/2015	3/1/2015	1/31/2015	(155,475)	Jan. 2015	03-GI-221	03-GI-221 JANUARY 2015 SHERWOOD, PENNINGTON & VICTORIA
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	4/6/2015	3/1/2015	1/31/2015	(4,353,502)	Jan. 2015	03-GI-221	03-GI-221 JANUARY 2015 WHITE OAK, WEST UNION COMP
Antero Resources Corporation	223.015	PLANT CLEARING ACCT	4/6/2015	3/1/2015	1/31/2015	987,768	Jan. 2015	03-GI-221	03-GI-221 JANUARY 2015 ZINNIA, BANNER, MORGAN, PERKINS

Dec. 2014 NGL Value less Total Fees (8,677,672)

Jan. 2015 NGL Value less Total Fees (3,902,197) Note > See adjustment on bottom of page 1 of PUF attachment

information. Any unauthorized disclosure is strictly prohibited. If you have received this message in error, please notify us immediately so that we may correct our internal records. Please then delete the original message. Thank you.

From: Nancy Sitton

Sent: Thursday, March 03, 2016 4:47 PM

To: 'Hoover, Cindi R'

Cc: Jan Mudrinich (mudrinich@yahoo.com); 'Craig Griffith'; Kirsten Evans; Elizabeth Burg

Subject: Antero WV Operating Expenses

Hi Cindi,

Attached please find the information listed below related to Antero's WV operating expenses, which was requested during our last discussion:

1. Sampling of amounts paid by Antero Resources to third parties for gathering, compression, and transportation – We have provided copies of 18 invoices (totaling \$42.8M) and the corresponding detail from Antero's revenue clearing account. All 3rd party gathering and transportation invoices are entered into the revenue clearing account. The expenses are allocated to the wells based on production and compressor station (this is done outside of the software due to size of calculation). The expenses are then entered into the software at a well level via a journal entry (and the clearing account is offset).
2. Sampling of amounts paid by Antero MidStream to third parties - We have provided a sampling of the gathering and compression operating expense detail, which includes invoice #, vendor name, and invoice description. Due to the immateriality of these expenses compared to the third party gathering and compression, copies of actual invoices were not pulled.
3. Proof of point of sale – We have provided 4 transaction confirmations from 3 different purchasing companies and a summary of the terms in Excel. All have Antero Resources as the seller and the delivery point is at third party sales meter locations. All operating expenses provided are related to activities that occur prior to this point of sale.

We still owe you support for the processing expenses (MarkWest) and plan to provide that in the next week or two. Once we send this over, we would like to schedule a time to discuss the information provided.

Also, it was confirmed that Antero's wells in Ritchie and Tyler Counties are not serviced by third party gatherers (only Antero Midstream). This is consistent with your observation that no third party gatherers filed returns to those counties.

Please let me know if you have any questions.

Thank you,
Nancy

Nancy Sitton, CPA

Manager, State & Local Tax and Advisory, Altus Group US Inc.

D: 410.568.0771 T: 410.568.0800 ext 3771 M: 703.999.3780 F: 410.568.0801

910 Ridgebrook Road, Suite 200, Sparks, Maryland, 21152 USA



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MTN G&C	\$2.2M
Total Fees	\$17.2M

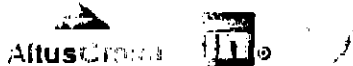
The amount booked to Antero's revenue clearing account was based on the NGL value less total fees (net), which is shown by compressor in rows 4-9 of the attached excel file (-\$8.6M). This amount was offset by clearing the \$2.2M MTN invoice and the \$10.8M MW payment (rows 2-3), and the gross NGL revenue (\$25.9M) and total fees (\$17.9M) were then entered into the software at a well level via a journal entry (this is done outside of the software due to size of calculation). The NGL revenue reported to the State reflects the full NGL value per the Sherwood settlement statements. The processing expenses reported to the State also reflect the total fees per the Sherwood settlement statements.

Craig Griffith will be in contact to schedule a meeting with the group to discuss the information provided.

Please let me know if you have any questions.

Thank you,
Nancy

Nancy Sitton, CPA
Manager, State & Local Tax and Advisory, Altus Group US Inc.
D: 410.568.0771 T: 410.568.0800 ext 3771 M: 703.999.3780 F: 410.568.0801
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From: Nancy Sitton
Sent: Thursday, March 03, 2016 4:54 PM
To: 'Hoover, Cindi R'
Cc: Jan Mudrinich (mudrinichj@yahoo.com); Craig Griffith; Kirsten Evans; Elizabeth Burg
Subject: FW: Antero WV Operating Expenses

Cindi,
I just received notification that the email below was not delivered to you. That may be due to the zip file I attached.

I have attached the excel files and transaction confirmation PDFs mentioned below and will send the third party invoices in a separate email.

Thanks,
Nancy

Nancy Sitton, CPA
Manager, State & Local Tax and Advisory, Altus Group US Inc.
D: 410.568.0771 T: 410.568.0800 ext 3771 M: 703.999.3780 F: 410.568.0801
910 Ridgebrook Road, Suite 200, Sparks, Maryland, 21152 USA



This message, and the documents attached hereto, are intended only for the addressee and may contain privileged or confidential

Craig Griffith

From: Nancy Sitton <nancy.sitton@altusgroup.com>
Sent: Thursday, April 21, 2016 8:27 PM
To: 'Hoover, Cindi R'
Cc: Jan Mudrinich (mudrinichj@yahoo.com); Craig Griffith; Kirsten Evans; Elizabeth Burg
Subject: RE: Antero WV Operating Expenses
Attachments: January 2015 Sherwood Settlement Statements.pdf

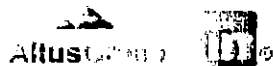
2 of 2 - Jan. 2015 file attached

Nancy Sitton, CPA

Manager, State & Local Tax and Advisory, Altus Group US Inc.

D: 410.568.0771 T: 410.568.0800 ext 3771 M: 703.999.3780 F: 410.568.0801

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From: Nancy Sitton
Sent: Thursday, April 21, 2016 8:26 PM
To: 'Hoover, Cindi R'
Cc: 'Jan Mudrinich (mudrinichj@yahoo.com)'; 'Craig Griffith'; Kirsten Evans; Elizabeth Burg
Subject: FW: Antero WV Operating Expenses

Cindi,

Sorry for the delay in getting you the support for Antero's processing expenses.

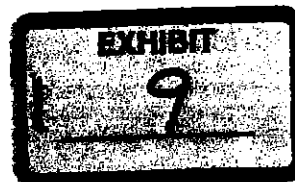
Attached please find the settlement statements from MarkWest (MW) related to the Sherwood, WV processing facility for Dec 2014. I will send a file for Jan. 2015 in a separate email due to size. The settlement statements show the amount paid by MW to Antero, which is based on the value of the NGLs less the processing expenses. Below is a summary of the Dec. 2014 settlement.

December 2014

MW paid Antero \$10.8M for the NGLs (\$25.9M NGL value less \$15M fees). Additionally Mountaineer (MTN) invoiced Antero \$2.2M for gathering and compression, so the NGL value less total fees was \$8.6M and total fees were \$17.2M (see fee breakdown below, from page 20 of attached):

MW Fees:

Compression	\$194K
Electric Fee	\$2.1M
Fractionation	\$2.4M
Pipeline fee	\$1.3M
Loading	\$307k
Processing	\$8.4M
Fractionation fuel fee	\$187k
Min. Comp. Fee	\$24k
Condensate facility	\$35k
Total MW	\$15M



Antero Resources Corporation
Summary of Point of Sale Contracts Sampled for WV

Confirmation Reference #	Buyer	Seller	Beginning Date	Termination Date	Commodity	Daily Quantity	Delivery Point
1	NextEra Energy Power Marketing, LLC	Antero Resources Appalachian Corporation	11/1/2013	10/31/2016	Natural Gas	100,000 Dth/Day	Dominion Meter EB 360 (ETC Northeast Pipeline)
2	EDF Trading North America, LLC	Antero Resources Appalachian Corporation	1/1/2014	12/31/2016	Natural Gas	30,000 MMBtu/Day	M2-30 Pool
3	South Jersey Gas Company	Antero Resources Appalachian Corporation	1/1/2014	1/31/2014	Natural Gas	50,000 MMBtu/Day	TCO
4	South Jersey Gas Company	Antero Resources Appalachian Corporation	1/1/2014	12/31/2014	Natural Gas	50,000 MMBtu/Day	EB095 or EB360

[illegible]

100% WASHED
27.7% WASHED

Craig Griffith

From: Nancy Sitton <nancy.sitton@altusgroup.com>
Sent: Thursday, March 03, 2016 4:47 PM
To: Hoover, Cindi R
Cc: Jan Mudrinich (mudrinichj@yahoo.com); Craig Griffith; Kirsten Evans; Elizabeth Burg
Subject: Antero WV Operating Expenses
Attachments: Antero Resources Op Exp Support 3.3.16.zip

Hi Cindi,

Attached please find the information listed below related to Antero's WV operating expenses, which was requested during our last discussion:

1. Sampling of amounts paid by Antero Resources to third parties for gathering, compression, and transportation – We have provided copies of 18 invoices (totaling \$42.8M) and the corresponding detail from Antero's revenue clearing account. All 3rd party gathering and transportation invoices are entered into the revenue clearing account. The expenses are allocated to the wells based on production and compressor station (this is done outside of the software due to size of calculation). The expenses are then entered into the software at a well level via a journal entry (and the clearing account is offset).
2. Sampling of amounts paid by Antero MidStream to third parties - We have provided a sampling of the gathering and compression operating expense detail, which includes invoice #, vendor name, and invoice description. Due to the immateriality of these expenses compared to the third party gathering and compression, copies of actual invoices were not pulled.
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Also, it was confirmed that Antero's wells in Ritchie and Tyler Counties are not serviced by third party gatherers (only Antero Midstream). This is consistent with your observation that no third party gatherers filed returns to those counties.

Please let me know if you have any questions.

Thank you,
Nancy

Nancy Sitton, CPA
Manager, State & Local Tax and Advisory, Altus Group US Inc.

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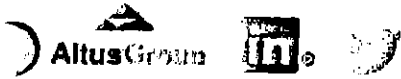


Note: The wells below are horizontal Marcellus wells but the values reflect the State's operating expense calculation for vertical Marcellus wells. We are requesting that the values be updated to reflect the State's variables for horizontal Marcellus wells.

PRODUCER	CY	ACCOUNT	RTN FIL	WELLS	API	GWIVPTD	OWIVPTD	TOTAL	OPERATOR
ANTERO RESOURCES CORPORATION	9	320156255	Y	1	6255	4,483,139	20,071	4,503,210	CONNIE UNIT 1H 40443
ANTERO RESOURCES CORPORATION	17	720115222	Y	1	5222	2,572,425	-	2,572,425	MORRISON
ANTERO RESOURCES CORPORATION	17	1820135389	Y	1	5389	3,307,985	-	3,307,985	TETRICK UNIT 2H
ANTERO RESOURCES CORPORATION	17	1820135392	Y	1	5392	3,880,335	-	3,880,335	TETRICK UNIT 1H
ANTERO RESOURCES CORPORATION	17	1820135437	Y	1	5437	4,356,173	-	4,356,173	SOUTH RICE O 1H UNIT
ANTERO RESOURCES CORPORATION	17	720135450	Y	1	5450	3,692,834	-	3,692,834	REYNOLDS 2 H UNIT
ANTERO RESOURCES CORPORATION	17	720135451	Y	1	5451	4,430,561	-	4,430,561	REYNOLDS 1H UNIT
ANTERO RESOURCES CORPORATION	17	2020135465	Y	1	5465	3,065,453	-	3,065,453	WAGNER 1H UNIT
ANTERO RESOURCES CORPORATION	17	2020135466	Y	1	5466	3,261,444	-	3,261,444	WAGNER 2H UNIT
ANTERO RESOURCES CORPORATION	17	2020135467	Y	1	5467	3,287,549	-	3,287,549	WAGNER 3H UNIT
ANTERO RESOURCES CORPORATION	17	2020135484	Y	1	5484	3,151,213	-	3,151,213	YATES 1H UNIT
ANTERO RESOURCES CORPORATION	17	2020135485	Y	1	5485	2,280,985	-	2,280,985	YATES 2H UNIT
ANTERO RESOURCES CORPORATION	17	2020135486	Y	1	5486	3,658,730	-	3,658,730	YATES 3H UNIT
ANTERO RESOURCES CORPORATION	17	2020135491	Y	1	5491	2,425,403	-	2,425,403	POST 1H UNIT
ANTERO RESOURCES CORPORATION	17	2020135492	Y	1	5492	2,032,794	-	2,032,794	POST 2H UNIT
ANTERO RESOURCES CORPORATION	17	2020135493	Y	1	5493	1,866,843	-	1,866,843	POST 3H UNIT
ANTERO RESOURCES CORPORATION	17	2020135502	Y	1	5502	4,866,371	-	4,866,371	SCOTT 2H UNIT
ANTERO RESOURCES CORPORATION	17	2020135503	Y	1	5503	3,600,927	-	3,600,927	SCOTT UNIT 3H
ANTERO RESOURCES CORPORATION	17	1820135507	Y	1	5507	4,828,328	-	4,828,328	POSEY 1H UNIT
ANTERO RESOURCES CORPORATION	17	1820135533	Y	1	5533	4,091,389	-	4,091,389	RICE NORTH 1H
ANTERO RESOURCES CORPORATION	17	2020155631	Y	1	5631	8,365,317	-	8,365,317	GEORGE UKNIT 1H (40330)

Manager, State & Local Tax and Advisory, Altus Group US Inc.

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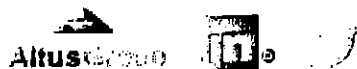
Craig Griffith

From: Kirsten Evans <kirsten.evans@altusgroup.com>
Sent: Friday, September 23, 2016 3:05 PM
To: Nancy Sitton; Craig Griffith
Subject: FW: Antero Resources Corporation 2016 TY Tentative Values
Attachments: Antero Resources Tentative Value Response 12.14.15.xlsx

12/14/15 email

Kirsten Evans

Director, State & Local Tax and Advisory, Altus Group US Inc.
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From: Nancy Sitton
Sent: Monday, December 14, 2015 10:51 AM
To: Hoover, Cindi R
Cc: Kirsten Evans; jeff.a.amburgey@wv.gov
Subject: Antero Resources Corporation 2016 TY Tentative Values

Cindi,

This email serves as a response to the 2016 tax year tentative values for Antero Resources Corporation's gas and oil wells. After review of the file received, we have the following concerns with the values:

\$30k Operating Expense Cap Applied to Certain Horizontal Marcellus Wells:

The values for certain horizontal Marcellus wells (21) do not reflect the State's operating expense variables for this type of well, and instead reflect the State's variables for vertical Marcellus wells (see attached listing). Most of these wells began production before the State began applying different variables for vertical vs. horizontal Marcellus wells. We are requesting that the values be updated to reflect the State's variables for horizontal Marcellus wells.

Operating Expenses:

The tentative values issued for the horizontal Marcellus wells do not reflect the actual operating expenses provided with the 2016 tax year West Virginia Oil and Gas Producer/ operator return. Per Kirsten's voicemail from earlier this morning, we would like to discuss your review of the data that we provided as a follow-up to the November 23rd meeting and application of actual operating expenses to the wells. We are willing to discuss applying actual expenses to a smaller population of wells.

Please let me know if you have any questions or need additional information.

Thank you,
Nancy



			2014 Calendar Year			2014 Calendar Year Except Year 1 Wells Adjusted to Actual Expenses for First 12 Months (Note 1)				
Well Code	NRA Account #	API #	LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	Fixed Portion of Operating Expenses (25%)	Well Type
40401	43-1020169999	47-085-09999	7,680	1,884,861	1,892,541	104,347	3,349,348	3,453,695	863,424	Marcellus, Horizontal
40581	48-0120162064	47-095-02064	65,591	-	65,591	66,375	-	66,375	16,594	Marcellus, Horizontal
40567	48-0220162126	47-095-02126	115,534	-	115,534	127,522	919,245	1,046,768	261,692	Marcellus, Horizontal
40289	48-0520142038	47-095-02038	44,551	776,347	820,898	44,551	776,347	820,898	205,224	Marcellus, Horizontal
40272	48-0520142038	47-095-02039	49,489	1,177,366	1,226,855	49,489	1,177,366	1,226,855	306,714	Marcellus, Horizontal
40378	48-0520152067	47-095-02067	42,801	1,002,972	1,045,773	42,801	1,002,972	1,045,773	261,443	Marcellus, Horizontal
40377	48-0520152068	47-095-02068	50,160	1,410,345	1,460,505	50,160	1,410,345	1,460,505	365,126	Marcellus, Horizontal
40391	48-0520152078	47-095-02078	49,367	1,193,514	1,242,881	49,367	1,193,514	1,242,881	310,720	Marcellus, Horizontal
40390	48-0520152079	47-095-02079	43,102	1,108,560	1,151,662	43,102	1,108,560	1,151,662	287,916	Marcellus, Horizontal
40708	48-0620162127	47-095-02127	740	788,666	789,406	36,745	2,334,695	2,371,441	592,860	Marcellus, Horizontal
	Total Marcellus, Horizontal		17,354,430	365,720,263	383,074,694	25,015,917	505,333,001	530,349,917	132,582,229	

Well Code	NRA Account #	API #	2014 Calendar Year			2014 Calendar Year Except Year 1 Wells Adjusted to Actual Expenses for First 12 Months (Note 1)			Well Type
			LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	Fixed Portion of Operating Expenses (25%)
40957	17-2020155691	47-033-05691	185,684	1,004,452	1,190,136	185,684	1,004,452	1,190,136	297,534
40956	17-2020155693	47-033-05693	202,015	1,094,091	1,296,106	202,015	1,094,091	1,296,106	324,027
40997	17-2020165624	47-033-05624	67,361	1,023,236	1,090,597	87,310	1,338,068	1,425,378	356,344
40998	17-2020165630	47-033-05630	44,004	896,648	940,652	61,023	1,180,348	1,241,371	310,343
40999	17-2020165643	47-033-05643	40,185	1,460,234	1,500,419	56,888	1,899,189	1,956,077	489,019
40994	17-2020165654	47-033-05654	50,211	973,224	1,023,435	69,791	1,367,199	1,436,990	359,247
40442	17-2020165679	47-033-05679	35,128	1,343,047	1,378,175	62,464	2,155,413	2,217,877	554,469
40441	17-2020165680	47-033-05680	43,950	1,488,362	1,532,313	76,607	2,453,999	2,530,606	632,651
40967	17-2020165695	47-033-05695	72,052	1,360,158	1,432,210	86,958	1,824,391	1,911,349	477,837
40968	17-2020165696	47-033-05696	71,312	1,780,009	1,851,321	87,107	2,425,956	2,513,063	628,266
40990	17-2020165700	47-033-05700	95,356	1,778,020	1,873,376	110,072	2,494,401	2,604,773	651,118
40418	17-2020165704	47-033-05704	32,851	2,156,558	2,189,409	33,090	2,194,629	2,227,719	556,930
40419	17-2020165705	47-033-05705	15,462	2,262,339	2,277,801	15,541	2,331,009	2,346,549	586,637
40420	17-2020165708	47-033-05708	27,024	2,555,973	2,582,997	27,842	2,638,571	2,666,414	666,603
40421	17-2020165710	47-033-05710	28,387	3,143,527	3,171,914	29,969	3,300,947	3,330,916	832,729
40495	17-2020165724	47-033-05724	23,117	2,171,750	2,194,867	27,325	2,925,835	2,953,161	738,290
40993	43-0320150036	47-085-10036	86,480	1,969,602	2,056,081	86,480	1,969,602	2,056,081	514,020
40324	43-0320150027	47-085-09963	88,738	1,199,246	1,287,983	88,738	1,199,246	1,287,983	321,996
40644	43-0320160028	47-085-10028	5,452	1,156,904	1,162,356	117,654	3,388,142	3,505,796	876,449
40554	43-0320160029	47-085-10029	989	899,884	900,873	113,769	2,403,434	2,517,183	629,296
40642	43-0320160060	47-085-10060	(377)	1,486,428	1,486,051	60,129	3,222,316	3,282,445	820,611
45573	43-0320160062	47-085-10062	232	1,357,903	1,358,135	152,449	4,536,691	4,689,140	1,172,285
45568	43-0320160063	47-085-10063	7,638	711,750	719,388	181,972	3,732,776	3,914,748	978,687
40643	43-0320160088	47-085-10088	(5,107)	1,656,090	1,650,983	62,038	3,581,070	3,643,108	910,777
40308	43-1020149960	47-085-09960	90,681	1,089,871	1,180,552	90,681	1,089,871	1,180,552	295,138
40958	43-1020150002	47-085-10002	90,495	835,558	926,053	90,495	835,558	926,053	231,513
40431	43-1020150023	47-085-10023	244,393	2,471,277	2,715,671	244,393	2,471,277	2,715,671	678,918
40371	43-1020159961	47-085-09961	93,090	785,373	878,464	93,090	785,373	878,464	219,616
40379	43-1020159964	47-085-09964	112,294	1,149,777	1,262,031	112,254	1,149,777	1,262,031	315,508
40380	43-1020159966	47-085-09966	108,482	991,486	1,099,968	108,482	991,486	1,099,968	274,992
40393	43-1020159970	47-085-09970	142,363	2,238,442	2,380,806	142,363	2,238,442	2,380,806	595,201
40363	43-1020159978	47-085-09978	106,515	643,279	749,794	106,515	643,279	749,794	187,449
40972	43-1020160005	47-085-10005	10,919	2,153,699	2,164,618	123,164	3,725,598	3,848,762	962,191
40538	43-1020160017	47-085-10017	231,014	1,551,702	1,782,716	279,922	2,070,417	2,350,339	587,585
40537	43-1020160019	47-085-10019	83,452	1,847,122	1,930,574	134,004	2,584,269	2,718,273	679,568
40687	43-1020160045	47-085-10045	1,140	10,092	11,232	399,057	3,752,266	4,151,323	1,037,831
40510	43-1020160046	47-085-10046	371	137,807	138,178	369,606	3,751,282	4,120,888	1,030,222
40654	43-1020169996	47-085-09996	11,180	934,998	946,179	99,358	2,091,265	2,190,624	547,656

Well Code	NRA Account #	API #	2014 Calendar Year			2014 Calendar Year Except Year 1 Wells Adjusted to Actual Expenses for First 12 Months (Note 1)			Well Type
			LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	LOE Expenses	Gathering, Processing, and Transportation Expenses	Fixed Portion of Operating Expenses (25%)	
40294	17-2020145593	47-033-05593	24,644	581,488	606,132	24,644	581,488	606,132	Marcellus, Horizontal
40295	17-2020145594	47-033-05594	17,725	526,277	544,002	17,725	526,277	544,002	Marcellus, Horizontal
40315	17-2020145621	47-033-05621	33,809	1,136,974	1,170,782	33,809	1,136,974	1,170,782	Marcellus, Horizontal
40242	17-2020145629	47-033-05629	21,444	1,232,833	1,254,277	21,444	1,232,833	1,254,277	Marcellus, Horizontal
40280	17-2020145632	47-033-05632	106,023	801,337	907,360	106,023	801,337	907,360	Marcellus, Horizontal
40321	17-2020145638	47-033-05638	34,675	1,172,084	1,206,759	34,675	1,172,084	1,206,759	Marcellus, Horizontal
40309	17-2020155608	47-033-05608	28,715	627,336	656,051	28,715	627,336	656,051	Marcellus, Horizontal
40310	17-2020155609	47-033-05609	22,842	619,747	642,589	22,842	619,747	642,589	Marcellus, Horizontal
40316	17-2020155612	47-033-05612	79,338	911,909	991,248	79,338	911,909	991,248	Marcellus, Horizontal
40317	17-2020155615	47-033-05615	73,204	856,997	930,201	73,204	856,997	930,201	Marcellus, Horizontal
40301	17-2020155616	47-033-05616	25,132	1,313,954	1,339,086	25,132	1,313,954	1,339,086	Marcellus, Horizontal
40359	17-2020155617	47-033-05617	114,046	652,804	766,851	114,046	652,804	766,851	Marcellus, Horizontal
40279	17-2020155618	47-033-05618	99,905	579,551	679,456	99,905	579,551	679,456	Marcellus, Horizontal
40356	17-2020155622	47-033-05622	46,150	494,029	540,179	46,150	494,029	540,179	Marcellus, Horizontal
40326	17-2020155623	47-033-05623	47,929	527,049	574,978	47,929	527,049	574,978	Marcellus, Horizontal
40330	17-2020155631	47-033-05631	101,893	1,238,115	1,340,008	101,893	1,238,115	1,340,008	Marcellus, Horizontal
40323	17-2020155636	47-033-05636	75,467	1,041,614	1,117,080	75,467	1,041,614	1,117,080	Marcellus, Horizontal
40322	17-2020155637	47-033-05637	114,217	988,903	1,103,120	114,217	988,903	1,103,120	Marcellus, Horizontal
40351	17-2020155639	47-033-05639	28,823	576,613	605,436	28,823	576,613	605,436	Marcellus, Horizontal
40345	17-2020155640	47-033-05640	26,872	660,186	687,058	26,872	660,186	687,058	Marcellus, Horizontal
40346	17-2020155641	47-033-05641	27,236	633,684	660,920	27,236	633,684	660,920	Marcellus, Horizontal
40355	17-2020155646	47-033-05646	30,550	868,185	898,736	30,550	868,185	898,736	Marcellus, Horizontal
40364	17-2020155647	47-033-05647	30,073	678,164	708,237	30,073	678,164	708,237	Marcellus, Horizontal
40352	17-2020155648	47-033-05648	22,457	1,103,245	1,125,701	22,457	1,103,245	1,125,701	Marcellus, Horizontal
40353	17-2020155649	47-033-05649	39,338	1,127,206	1,166,544	39,338	1,127,206	1,166,544	Marcellus, Horizontal
40344	17-2020155651	47-033-05651	5,537	1,942,767	1,948,304	5,537	1,942,767	1,948,304	Marcellus, Horizontal
40989	17-2020155653	47-033-05653	44,534	1,150,994	1,195,528	44,534	1,150,994	1,195,528	Marcellus, Horizontal
40358	17-2020155659	47-033-05659	33,574	1,430,309	1,463,883	33,574	1,430,309	1,463,883	Marcellus, Horizontal
40987	17-2020155660	47-033-05660	40,650	1,411,839	1,452,489	40,650	1,411,839	1,452,489	Marcellus, Horizontal
40988	17-2020155661	47-033-05661	41,154	1,160,038	1,201,192	41,154	1,160,038	1,201,192	Marcellus, Horizontal
40365	17-2020155666	47-033-05666	29,620	722,017	751,637	29,620	722,017	751,637	Marcellus, Horizontal
40389	17-2020155667	47-033-05667	64,028	854,800	918,828	64,028	854,800	918,828	Marcellus, Horizontal
40381	17-2020155668	47-033-05668	63,667	757,641	821,308	63,667	757,641	821,308	Marcellus, Horizontal
40388	17-2020155670	47-033-05670	76,605	781,183	857,788	76,605	781,183	857,788	Marcellus, Horizontal
40974	17-2020155673	47-033-05673	81,285	1,041,155	1,122,440	81,285	1,041,155	1,122,440	Marcellus, Horizontal
40382	17-2020155676	47-033-05676	61,858	783,386	845,244	61,858	783,386	845,244	Marcellus, Horizontal
40372	17-2020155677	47-033-05677	31,242	869,198	900,439	31,242	869,198	900,439	Marcellus, Horizontal
40955	17-2020155678	47-033-05678	57,739	1,013,661	1,071,400	57,739	1,013,661	1,071,400	Marcellus, Horizontal
40959	17-2020155688	47-033-05688	197,454	780,295	977,749	197,454	780,295	977,749	Marcellus, Horizontal

Well Code	NRA Account #	API #	2014 Calendar Year			2014 Calendar Year Except Year 1 Wells Adjusted to Actual Expenses for First 12 Months (Note 1)			Well Type
			LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	
40176	17-1820155674	47-033-05674	32,879	645,491	678,370	32,879	645,491	678,370	Marcellus, Horizontal
40177	17-1820155675	47-033-05675	33,060	644,125	677,185	33,060	644,125	677,185	Marcellus, Horizontal
40979	17-1820155698	47-033-05698	51,626	2,474,391	2,526,017	51,626	2,474,391	2,526,017	Marcellus, Horizontal
40412	17-1820155730	47-033-05730	188,516	2,195,945	2,384,461	188,516	2,195,945	2,384,461	Marcellus, Horizontal
40413	17-1820155731	47-033-05731	190,746	2,197,828	2,388,574	190,746	2,197,828	2,388,574	Marcellus, Horizontal
40976	17-1820155686	47-033-05686	50,123	2,199,344	2,249,467	54,758	2,286,498	2,341,255	Marcellus, Horizontal
40977	17-1820155699	47-033-05699	54,005	2,145,183	2,199,188	54,105	2,181,080	2,235,186	Marcellus, Horizontal
40978	17-1820155701	47-033-05701	49,604	2,024,958	2,074,562	49,750	2,071,103	2,120,852	Marcellus, Horizontal
40470	17-1820155721	47-033-05721	3,160	1,291,287	1,294,446	108,641	2,138,789	2,247,430	Marcellus, Horizontal
40469	17-1820155722	47-033-05722	30,954	1,154,358	1,185,312	129,815	1,856,812	1,986,627	Marcellus, Horizontal
40467	17-1820155723	47-033-05723	46,424	1,980,944	2,027,368	55,505	2,422,361	2,477,866	Marcellus, Horizontal
40468	17-1820155738	47-033-05738	72,498	2,335,161	2,407,658	93,976	2,987,984	3,081,960	Marcellus, Horizontal
40101	17-2020115198	47-033-05199	35,681	69,687	105,368	35,681	69,687	105,368	Marcellus, Horizontal
40205	17-2020135465	47-033-05465	27,682	467,428	495,111	27,682	467,428	495,111	Marcellus, Horizontal
40206	17-2020135466	47-033-05466	26,895	540,910	567,805	26,895	540,910	567,805	Marcellus, Horizontal
40207	17-2020135467	47-033-05467	27,140	457,196	484,336	27,140	457,196	484,336	Marcellus, Horizontal
40208	17-2020135484	47-033-05484	27,771	483,947	511,718	27,771	483,947	511,718	Marcellus, Horizontal
40209	17-2020135485	47-033-05485	22,222	358,342	380,564	22,222	358,342	380,564	Marcellus, Horizontal
40210	17-2020135486	47-033-05486	21,804	542,074	563,878	21,804	542,074	563,878	Marcellus, Horizontal
40248	17-2020135491	47-033-05491	19,211	360,659	379,870	19,211	360,659	379,870	Marcellus, Horizontal
40225	17-2020135492	47-033-05492	15,512	312,003	327,514	15,512	312,003	327,514	Marcellus, Horizontal
40226	17-2020135493	47-033-05493	15,435	291,793	307,228	15,435	291,793	307,228	Marcellus, Horizontal
40227	17-2020135494	47-033-05494	25,924	612,517	638,441	25,924	612,517	638,441	Marcellus, Horizontal
40274	17-2020135494	47-033-05580	51,258	1,097,165	1,148,424	51,258	1,097,165	1,148,424	Marcellus, Horizontal
40217	17-2020135502	47-033-05502	10,735	644,581	655,316	10,735	644,581	655,316	Marcellus, Horizontal
40218	17-2020135503	47-033-05503	14,265	544,030	558,295	14,265	544,030	558,295	Marcellus, Horizontal
40240	17-2020135554	47-033-05584	36,215	707,092	743,308	36,215	707,092	743,308	Marcellus, Horizontal
40216	17-2020145501	47-033-05501	13,385	160,417	173,802	13,385	160,417	173,802	Marcellus, Horizontal
40259	17-2020145559	47-033-05560	26,735	1,111,241	1,137,976	26,735	1,111,241	1,137,976	Marcellus, Horizontal
40260	17-2020145576	47-033-05576	15,061	502,265	517,325	15,061	502,265	517,325	Marcellus, Horizontal
40261	17-2020145577	47-033-05577	15,046	496,689	511,735	15,046	496,689	511,735	Marcellus, Horizontal
40292	17-2020145582	47-033-05582	44,025	571,285	615,310	44,025	571,285	615,310	Marcellus, Horizontal
40293	17-2020145583	47-033-05583	43,923	614,958	658,881	43,923	614,958	658,881	Marcellus, Horizontal
40286	17-2020145584	47-033-05584	53,914	757,753	811,666	53,914	757,753	811,666	Marcellus, Horizontal
40285	17-2020145585	47-033-05585	41,665	819,883	861,548	41,665	819,883	861,548	Marcellus, Horizontal
40278	17-2020145586	47-033-05586	106,621	824,394	931,015	106,621	824,394	931,015	Marcellus, Horizontal
40291	17-2020145590	47-033-05590	99,662	535,580	635,243	99,662	535,580	635,243	Marcellus, Horizontal
40288	17-2020145591	47-033-05591	16,717	619,835	636,553	16,717	619,835	636,553	Marcellus, Horizontal
40262	17-2020145592	47-033-05592	43,096	754,555	797,651	43,096	754,555	797,651	Marcellus, Horizontal

Company at the time of such receipt or lapse, as the case may be, such amount of money or, if permitted by the Committee in its sole discretion, shares of Common Stock as the Company or any Affiliate nominated by the Company may require to meet its minimum obligation under applicable tax or social security laws or regulations, and if Employee fails to do so, the Company and its Affiliates are authorized to withhold, or cause to be withheld, from any cash or stock remuneration (including withholding any shares of Common Stock otherwise deliverable to Employee under this Agreement) then or thereafter payable to Employee in an amount equal to any tax or social security required to be withheld by reason of such resulting compensation income or wages, and to take such other action as may be necessary in the opinion of the Company to satisfy such withholding obligation. Employee acknowledges and agrees that none of the Board, the Committee, the Company or any of its Affiliates have made any representation or warranty as to the tax consequences to Employee as a result of the receipt of the RSUs, the vesting of the RSUs or the forfeiture of any of the RSUs. Employee represents that he is in no manner relying on the Board, the Committee, the Company or any of its Affiliates or any of their respective managers, directors, officers, employees or authorized representatives (including, without limitation, attorneys, accountants, consultants, bankers, lenders, prospective lenders and financial representatives) for tax advice or an assessment of such tax consequences. Employee represents that he has consulted with any tax consultants that Employee deems advisable in connection with the RSUs.

7. **Non-Transferability.** During the lifetime of Employee, the RSUs may not be sold, pledged, assigned or transferred in any manner other than by will or the laws of descent and distribution, unless and until the shares of Common Stock underlying the RSUs have been issued, and all restrictions applicable to such shares have lapsed. Neither the RSUs nor any interest or right therein shall be liable for the debts, contracts or engagements of Employee or his or her successors in interest or shall be subject to disposition by transfer, alienation, anticipation, pledge, encumbrance, assignment or any other means whether such disposition be voluntary or involuntary or by operation of law by judgment, levy, attachment, garnishment or any other legal or equitable proceedings (including bankruptcy), and any attempted disposition thereof shall be null and void and of no effect, except to the extent that such disposition is permitted by the preceding sentence.

8. **Compliance with Securities Law.** Notwithstanding any provision of this Agreement to the contrary, the issuance of shares of Common Stock hereunder will be subject to compliance with all applicable requirements of applicable law with respect to such securities and with the requirements of any stock exchange or market system upon which the Common Stock may then be listed. No shares of Common Stock will be issued hereunder if such issuance would constitute a violation of any applicable law or regulation or the requirements of any stock exchange or market system upon which the Common Stock may then be listed. In addition, shares of Common Stock will not be issued hereunder unless (a) a registration statement under the Securities Act is in effect at the time of such issuance with respect to the shares to be issued or (b) in the opinion of legal counsel to the Company, the shares to be issued are permitted to be issued in accordance with the terms of an applicable exemption from the registration requirements of the Securities Act. The inability of the Company to obtain from any regulatory body having jurisdiction the authority, if any, deemed by the Company's legal counsel to be necessary for the lawful issuance and sale of any shares of Common Stock hereunder will relieve the Company of any liability in respect of the failure to issue such shares as to which such requisite authority has not been obtained. As a condition to any issuance of Common Stock hereunder, the Company may require Employee to satisfy any requirements that may be necessary or appropriate to evidence compliance with any applicable law or regulation and to make any representation or warranty with respect to such compliance as may be requested by the Company.

9. **Legends.** If a stock certificate is issued with respect to shares of Common Stock delivered hereunder, such certificate shall bear such legend or legends as the Committee deems appropriate in order to reflect the restrictions set forth in this Agreement and to ensure compliance with the terms and provisions of this Agreement, the rules, regulations and other requirements of the Securities and Exchange Commission, any applicable laws or the requirements of any stock exchange on which the Common Stock is then listed. If the shares of Common Stock issued hereunder are held in book-entry form, then such entry will reflect that the shares are subject to the restrictions set forth in this Agreement.

10. **Execution of Receipts and Releases.** Any payment of cash or any issuance or transfer of shares of Common Stock or other property to Employee or Employee's legal representative, heir, legatee or distributee, in accordance with this Agreement shall be in full satisfaction of all claims of such person hereunder. As a condition precedent to such payment or issuance, the Company may require Employee or Employee's legal representative, heir, legatee or distributee to execute a release and receipt therefor in such form as it shall determine appropriate; provided, however, that any review period under such release will not modify the date of settlement with respect to vested RSUs.

11. **No Right to Continued Employment or Awards.**

(a) For purposes of this Agreement, Employee shall be considered to be employed by the Company as long as Employee remains an Employee, or an employee of a corporation or other entity (or a parent or subsidiary of such corporation or other entity) assuming or substituting a new award for this Award. Without limiting the scope of the preceding sentence, it is specifically provided that Employee shall be considered to have terminated employment with the Company at the time of the termination of the "Affiliate" status of the entity or other organization that employs Employee. Nothing in the adoption of the Plan, nor the award of the RSUs thereunder pursuant to the Grant Notice and this Agreement, shall confer upon Employee the right to continued employment by,

or a continued service relationship with, the Company or any such Affiliate, or any other entity, or affect in any way the right of the Company or any such Affiliate, or any other entity to terminate such employment at any time. Unless otherwise provided in a written employment agreement or by applicable law, Employee's employment by the Company, or any such Affiliate, or any other entity shall be on an at-will basis, and the employment relationship may be terminated at any time by either Employee or the Company, or any such Affiliate, or other entity for any reason whatsoever, with or without cause or notice. Any question as to whether and when there has been a termination of such employment, and the cause of such termination, shall be determined by the Committee or its delegate, and such determination shall be final, conclusive and binding for all purposes.

(b) The grant of the RSUs is a one-time benefit and does not create any contractual or other right to receive a grant of Awards or benefits in lieu of Awards in the future. Future plans will be at the sole discretion of the Company.

12. Notices. Any notices or other communications provided for in this Agreement shall be sufficient if in writing. In the case of Employee, such notices or communications shall be effectively delivered if hand delivered to Employee at Employee's principal place of employment or if sent by registered or certified mail to Employee at the last address Employee has filed with the Company. In the case of the Company, such notices or communications shall be effectively delivered if sent by registered or certified mail to the Company at its principal executive offices.

13. Agreement to Furnish Information. Employee agrees to furnish to the Company all information requested by the Company to enable it to comply with any reporting or other requirement imposed upon the Company by or under any applicable statute or regulation.

14. Entire Agreement; Amendment. This Agreement constitutes the entire agreement of the parties with regard to the subject matter hereof, and contains all the covenants, promises, representations, warranties and agreements between the parties with respect to the RSUs granted hereby; provided, however, that the terms of this Agreement shall not modify and shall be subject to the terms and conditions of any employment and/or severance agreement between the Company (or an Affiliate or other entity) and Employee in effect as of the date a determination is to be made under this Agreement. Without limiting the scope of the preceding sentence, except as provided therein, all prior understandings and agreements, if any, among the parties hereto relating to the subject matter hereof are hereby null and void and of no further force and effect. The Committee may, in its sole discretion, amend this Agreement from time to time in any manner that is not inconsistent with the Plan; provided, however, that except as otherwise provided in the Plan or this Agreement, any such amendment that materially reduces the rights of Employee shall be effective only if it is in writing and signed by both Employee and an authorized officer of the Company.

15. Governing Law. This Agreement shall be governed by, and construed in accordance with, the laws of the State of Delaware, without regard to conflicts of law principles thereof.

16. Successors and Assigns. The Company may assign any of its rights under this Agreement without Employee's consent. This Agreement will be binding upon and inure to the benefit of the successors and assigns of the Company. Subject to the restrictions on transfer set forth herein and in the Plan, this Agreement will be binding upon Employee and Employee's beneficiaries, executors, administrators and the person(s) to whom the RSUs may be transferred by will or the laws of descent or distribution.

17. Clawback. Notwithstanding any provision in this Agreement, the Grant Notice or the Plan to the contrary, to the extent required by (a) applicable law, including, without limitation, the requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, any Securities and Exchange Commission rule or any applicable securities exchange listing standards and/or (b) any policy that may be adopted or amended by the Board from time to time, all shares of Common Stock issued hereunder shall be subject to forfeiture, repurchase, recoupment and/or cancellation to the extent necessary to comply with such law(s) and/or policy.

18. Counterparts. The Grant Notice may be executed in one or more counterparts, each of which shall be deemed an original and all of which together shall constitute one instrument. Delivery of an executed counterpart of the Grant Notice by facsimile or pdf attachment to electronic mail shall be effective as delivery of a manually executed counterpart of the Grant Notice.

19. Severability. If a court of competent jurisdiction determines that any provision of this Agreement is invalid or unenforceable, then the invalidity or unenforceability of such provision shall not affect the validity or enforceability of any other provision of this Agreement, and all other provisions shall remain in full force and effect.

20. Code Section 409A. None of the RSUs, DERs or any amounts payable pursuant to this Agreement are intended to constitute or provide for a deferral of compensation that is subject to Section 409A of the Code and the Treasury regulations and other interpretive guidance issued thereunder (collectively, "Section 409A"). Nevertheless, to the extent that the Committee determines that the RSUs or DERs may not be exempt from Section 409A, then, if Employee is deemed to be a "specified employee" within the meaning of Section 409A, as determined by the Committee, at a time when Employee becomes eligible for settlement of the RSUs

upon his "separation from service" within the meaning of Section 409A , then to the extent necessary to prevent any accelerated or additional tax under Section 409A , such settlement will be delayed until the earlier of: (a) the date that is six months following Employee's separation from service and (b) Employee's death. Notwithstanding the foregoing, the Company makes no representations that the payments provided under this Agreement are exempt from or compliant with Section 409A and in no event shall the Company be liable for all or any portion of any taxes, penalties, interest or other expenses that may be incurred by Employee on account of non-compliance with Section 409A .

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ANTERO RESOURCES CORPORATION
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in thousands)

	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>
Pre-tax income (loss) from continuing operations	\$ 1,155	\$456,485	\$346,505	\$162,023	\$ 1,117,049
Fixed Charges	<u>56,736</u>	<u>74,743</u>	<u>97,877</u>	<u>137,343</u>	<u>163,458</u>
Total adjusted earnings available for payment of fixed charges	<u>\$ 57,891</u>	<u>\$531,228</u>	<u>\$444,382</u>	<u>\$299,366</u>	<u>\$ 1,280,507</u>
Fixed Charges					
Interest expense, including amortization of debt-related expenses	\$ 56,463	\$ 74,404	\$ 97,510	\$136,617	\$ 160,051
Rental expense representative of interest factor	<u>273</u>	<u>339</u>	<u>367</u>	<u>726</u>	<u>3,407</u>
Total fixed charges	<u>\$ 56,736</u>	<u>\$ 74,743</u>	<u>\$ 97,877</u>	<u>\$137,343</u>	<u>\$ 163,458</u>
Ratio of earnings to fixed charges	1.02 X	7.11 X	4.54 X	2.18 X	7.83 X

SUBSIDIARIES OF ANTERO RESOURCES CORPORATION

<u>Name of Subsidiary</u>	<u>Jurisdiction of Organization</u>
Antero Midstream Partners LP	Delaware
Antero Midstream LLC	Delaware
Antero Water LLC	Delaware
AR OHIO LLC	Delaware
Monroe Pipeline LLC	Delaware

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Antero Resources Corporation:

We consent to the incorporation by reference in the registration statement (No. 333-195879) on Form S-3 and registration statement (No. 333-191693) on Form S-8 of Antero Resources Corporation of our reports dated February 25, 2015, with respect to the consolidated balance sheets of Antero Resources Corporation as of December 31, 2013 and 2014, and the related consolidated statements of operations and comprehensive income (loss), equity, and cash flows for each of the years in the three-year period ended December 31, 2014, and the effectiveness of internal control over financial reporting as of December 31, 2014, which reports appear in the December 31, 2014 annual report on Form 10-K of Antero Resources Corporation.

/s/ KPMG LLP
Denver, Colorado

February 25, 2015

**DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244**

February 25, 2015

Board of Directors of Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202

Gentlemen:

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (File No. 333-195879) and the Registration Statement on Form S-8 (File No. 333-191693) of Antero Resources Corporation (the "Company") of information taken from our report dated January 19, 2015 with respect to the Company's estimated proved reserves as of December 31, 2014.

Very truly yours,

/s/ DeGOLYER and MacNAUGHTON
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Paul M. Rady, Chairman and Chief Executive Officer of Antero Resources Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2014 of Antero Resources Corporation (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2015

/s/ Paul M. Rady

Paul M. Rady

Chief Executive Officer

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Glen C. Warren, Jr., President and Chief Financial Officer of Antero Resources Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2014 of Antero Resources Corporation (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2015

/s/ Glen C. Warren, Jr.

Glen C. Warren, Jr.

Chief Financial Officer

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF ANTERO RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with this Annual Report on Form 10-K of Antero Resources Corporation for the year ended December 31, 2014, I, Paul M. Rady, Chief Executive Officer of Antero Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Annual Report on Form 10-K for the year ended December 31, 2014 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in this Annual Report on Form 10-K for the year ended December 31, 2014 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: February 25, 2015

/s/ Paul M. Rady

Paul M. Rady

Chief Executive Officer

**CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF ANTERO RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with this Annual Report on Form 10-K of Antero Resources Corporation for the year ended December 31, 2014, I, Glen C. Warren, Jr., Chief Financial Officer of Antero Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Annual Report on Form 10-K for the year ended December 31, 2014 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in this Annual Report on Form 10-K for the year ended December 31, 2014 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: February 25, 2015

/s/ Glen C. Warren, Jr.

Glen C. Warren, Jr.
Chief Financial Officer

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244
January 19, 2015

Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202

Ladies and Gentlemen:

Pursuant to your request, we have conducted an audit of the estimates of the net proved crude oil, condensate, natural gas liquids (NGL), and natural gas reserves and present worth, as of December 31, 2014, prepared by the engineering staff of Antero Resources Corporation (Antero) for working and royalty interests in Ohio, Pennsylvania, and West Virginia that Antero has represented it owns. This evaluation was completed on January 19, 2015. Antero has represented to us that these properties account for approximately 99.90 percent on a million cubic feet equivalent basis of Antero's net proved reserves as of December 31, 2014, and that the net proved reserves estimates have been prepared in accordance with the reserves definitions of Rule 4-10(a) (1)-(32) of Regulation S-X of the Securities and Exchange Commission (SEC) of the United States. We have reviewed information provided to us by Antero that it represents to be Antero's estimates of the net reserves, as of December 31, 2014, for the same properties as those which we evaluated. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S-K and is to be used for inclusion in certain SEC filings by Antero.

Reserves estimates included herein are expressed as net reserves as represented by Antero. Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2014. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Antero after deducting all interests owned by others. NGL have been estimated for certain properties and are based on the NGL yields provided by Antero.

Values included herein are expressed in terms of estimated present worth. Future gross revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production and ad valorem taxes, operating expenses, capital costs, and abandonment costs from the future gross revenue. Present worth is defined as future net revenue discounted at a specified arbitrary rate compounded monthly over the expected period of realization.

Estimates of oil, condensate, NGL, and natural gas reserves and associated revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this audit were obtained from reviews with Antero personnel, from Antero files, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by Antero with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geological and engineering methods that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history. These assumptions, data, methods, and procedures are considered appropriate for the purpose for which this report has been prepared.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

In certain cases, when the previously named methods could not be used, reserves were estimated by analogy with similar wells or reservoirs for which more complete data were available.

Petroleum reserves estimated by Antero and by us are classified as proved and are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment.

In the course of our audit of the estimates of net proved reserves prepared by Antero, we have participated in reviews and discussions with Antero involving Antero's methodologies and procedures and we are in concurrence with the methodologies and procedures used by Antero.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as that portion of the total gas to be delivered into a gas pipeline for sale after separation, processing, fuel use, and flare. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base of the state in which the interest is located. Condensate reserves estimated herein are those to be recovered by conventional lease separation. NGL reserves are those attributed to the leasehold interests according to processing agreements.

Definition of Reserves

Petroleum reserves estimated by Antero included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous

reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12 -month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

- (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
- (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are

scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4-10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

The extent to which probable and possible reserves ultimately may be reclassified as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. No probable or possible reserves have been evaluated for this report.

Primary Economic Assumptions

The following economic assumptions were used for estimating existing and future prices and costs:

Oil, Condensate, and NGL Prices

Antero has represented that the oil, condensate, and NGL prices were based on NYMEX Light Sweet Crude Oil pricing, calculated as the unweighted arithmetic average of the first - day-of-the-month price for each month within the 12 -month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The oil, condensate, and NGL prices were calculated using differentials furnished by Antero to the reference price of \$9 4.42 per barrel. The resulting volume-weighted average price for oil and condensate was \$81.48 per barrel. The resulting volume - weighted average price for NGL was \$45.89 per barrel.

Natural Gas Prices

Antero has represented that the natural gas prices were based on pricing from five different indexes, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period,

unless prices are defined by contractual arrangements. The gas prices were calculated for each property using differentials and heating value adjustments furnished by Antero to the aggregated price of \$4.07 per million British thermal units and held constant thereafter. The resulting volume-weighted average price was \$4.39 per thousand cubic feet. The indexes and prices, expressed in dollars per million British thermal units (\$MMBtu), are shown in the table below.

Index	Average Natural Gas Price (\$/MMBtu)
NYMEX	4.41
Columbia Gas Transmission Appalachia	4.37
Texas Eastern Transmission M-2	3.35
Chicago City Gates	4.76
Dominion Transmission Appalachia	3.28

Operating Expenses and Capital Costs

Operating expenses and capital costs, based on information provided by Antero, were used in estimating future costs required to operate the properties. In certain cases, future costs, either higher or lower than existing costs, may have been used because of anticipated changes in operating conditions. Abandonment costs were included for all properties. These costs were not escalated for inflation.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2014, estimated oil and gas reserves.

Antero has represented that estimated net proved reserves and present worth at 10 percent attributable to the reviewed properties are based on the definitions of proved reserves of the SEC. Antero has represented that its estimates of the net proved reserves and present worth attributable to these properties, which represent 99.90 percent of Antero's total proved reserves on a net equivalent basis, are as follows, expressed in

thousands of barrels (Mbbbl), millions of cubic feet (MMcf), millions of cubic feet equivalent (MMcfe), and thousands of dollars (M\$):

Estimated by Antero					
Net Proved Reserves and Present Worth at 10 Percent					
as of December 31, 2013					
Proved Reserves	Oil and Condensate (Mbbbl)	Natural Gas Liquids (Mbbbl)	Natural Gas (MMcf)	Gas Equivalent (MMcfe)	Present Worth at 10 Percent (M\$)
Marcellus and Upper Devonian					
Proved Developed					
Audited by DeGolyer and MacNaughton	3,658	66,139	2,932,393	3,351,174	4,787,424
Not Audited by DeGolyer and MacNaughton	0	56	7,681	8,014	7,662
Proved Undeveloped					
Audited by DeGolyer and MacNaughton	19,452	239,870	7,010,552	8,566,486	5,133,576
Not Audited by DeGolyer and MacNaughton	0	0	0	0	0
Total Marcellus and Upper Devonian	23,110	306,065	9,950,626	11,925,674	9,928,662
Utica					
Proved Developed					
Audited by DeGolyer and MacNaughton	2,359	14,097	344,558	443,293	1,032,782
Not Audited by DeGolyer and MacNaughton	2	13	297	388	913
Proved Undeveloped					
Audited by DeGolyer and MacNaughton	2,414	10,028	239,229	313,875	357,963
Not Audited by DeGolyer and MacNaughton	0	0	0	0	0
Total Utica	4,774	24,138	584,084	757,556	1,391,658

Notes:

1. Liquids are converted to gas equivalent using an energy equivalent factor of 1 barrel of liquids per 6,000 cubic feet of gas equivalent.
2. Numbers may not add due to rounding.
3. Future income taxes were not taken into account in the preparation of the estimates of present worth.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4-10(a) (1)-(32) of Regulation S-X and Rules 302(b), 1201, 1202(a) (1), (2), (3),

(4), (8), and 1203(a) of Regulation S-K of the Securities and Exchange Commission; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

In comparing the detailed net proved reserves estimates prepared by us and by Antero of the properties audited, we have found differences, both positive and negative, resulting in an aggregate difference of 1.2 percent for the Marcellus and Upper Devonian properties and an aggregate difference of 0.7 percent for the Utica properties when compared on the basis of net gas equivalent. It is our opinion that there is no material difference between the net proved reserves estimates prepared by Antero and those prepared by us for those properties we audited. In comparing the detailed present worth at 10 percent estimates prepared by us and by Antero of the properties audited, we have found differences, both positive and negative, resulting in an aggregate difference of 0.3 percent for the Marcellus and Upper Devonian properties and an aggregate difference of 4.6 percent for the Utica properties when compared on the basis of present worth at 10 percent. It is our opinion that there is no material difference between the present worth at 10 percent estimates prepared by Antero and those prepared by us for those properties we audited.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Antero. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Antero. DeGolyer and MacNaughton has used all data, assumptions, procedures, and methods that it considers necessary to prepare this report.

Very truly yours,

/s/ DeGOLYER and MacNAUGHTON

DeGOLYER and MacNAUGHTON

Texas Registered Engineering Firm F-716

/s/ Gregory K. Graves, P.E.

Senior Vice President

Gregory K. Graves, P.E.

DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Gregory K. Graves, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to Antero dated January 19 , 2015, and that I, as Senior Vice President, was responsible for the preparation of this letter report.
2. That I attended the University of Texas at Austin, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1984; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers ; and that I have in excess of 30 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Gregory K. Graves, P.E.

Gregory K. Graves, P.E.

Senior Vice President

DeGolyer and MacNaughton

Craig Griffith

From: Nancy Sitton <nancy.sitton@altusgroup.com>
Sent: Tuesday, November 24, 2015 3:25 PM
To: Craig Griffith
Subject: FW: Antero Operating Expenses
Attachments: Well Example Calculations.xlsx; Antero Resource Company Operating Expenses 2014.xlsx

I forgot to include you on this, sorry!

Nancy Sitton, CPA
Manager, State & Local Tax and Advisory, Altus Group US Inc.
D: 410.568.0771 T: 410.568.0800 ext 3771 M: 703.999.3780 F: 410.568.0801
910 Ridgebrook Road, Suite 200, Sparks, Maryland, 21152 USA

This message, and the documents attached hereto, are intended only for the addressee and may contain privileged or confidential information. Any unauthorized disclosure is strictly prohibited. If you have received this message in error, please notify us immediately so that we may correct our internal records. Please then delete the original message. Thank you.

From: Nancy Sitton
Sent: Tuesday, November 24, 2015 12:57 PM
To: Hoover, Cindi R; Estep, Yvonne H; jerf.a.amburgey@wy.gov
Cc: Kirsten Evans
Subject: Antero Operating Expenses

Jeff, Cindi, and Yvonne,

Thank you again for taking the time to meet with Kirsten and I yesterday to discuss Antero.

As requested, attached please find the electronic version of the value calculation where 75% of operating expenses were declined consistent with the revenue. I have also attached an updated listing of operating expenses by well; It includes only the horizontal Marcellus wells and I have added the fixed portion of expenses (25%) in column J.

Please let us know if you have any questions or if we can provide any additional information.

Have a wonderful Thanksgiving!

Thank you,
Nancy

Nancy Sitton, CPA
Manager, State & Local Tax and Advisory, Altus Group US Inc.

D: 410.568.0771 T: 410.568.0800 ext 3771 M: 703.999.3780 F: 410.568.0801
910 Ridgebrook Road, Suite 200, Sparks, Maryland, 21152 USA



<5>Actual Op Exp-75% Declined

NATURAL OIL/GAS DEMONSTRATION APPRAISAL.....FLUSH WELL (Year 1)										
DECLINE RATES		GAS INC		OIL INC		GAS CAP INC		OIL CAP INC		
YR 1	48%	WRK INT	\$ 5,510,381	\$ 1,293,339	YR1	\$ 2,176,600	\$ 510,888			
YR 2	29%	ROY INT				\$ -	\$ -			
YR3+	23%				YR2	\$ 1,810,684	\$ 378,043			
Operating Expense			\$ 2,350,338			\$ -	\$ -			
TY2016 WORKING INT										
YEAR	WRK INT INC	WRK COST	NET INC	% FCTR(15.3)	DIS INC	YEAR	ROY INT INC	% FCTR(15.3)	DIS INC	
1	\$ 2,667,466	\$ 1,283,873	\$ 1,403,597	0.931291	\$ 1,307,167	1	\$ -	0.931291	\$ -	
2	\$ 1,986,727	\$ 1,102,836	\$ 885,890	0.907711	\$ 715,543	2	\$ -	0.807711	\$ -	
3	\$ 1,531,320	\$ 984,330	\$ 546,990	0.700530	\$ 383,183	3	\$ -	0.700530	\$ -	
4	\$ 1,179,115	\$ 893,079	\$ 286,036	0.607572	\$ 173,789	4	\$ -	0.607572	\$ -	
5	\$ 907,920	\$ 822,615	\$ 85,305	0.526948	\$ 44,846	5	\$ -	0.526948	\$ -	
6	\$ 699,088	\$ 768,712	\$ -	0.457024	\$ -	6	\$ -	0.457024	\$ -	
7	\$ 538,308	\$ 727,053	\$ -	0.398378	\$ -	7	\$ -	0.398378	\$ -	
8	\$ 414,485	\$ 694,976	\$ -	0.343780	\$ -	8	\$ -	0.343780	\$ -	
9	\$ 319,161	\$ 670,275	\$ -	0.298191	\$ -	9	\$ -	0.298191	\$ -	
10	\$ 248,764	\$ 651,258	\$ -	0.256696	\$ -	10	\$ -	0.256696	\$ -	
11	\$ 189,231	\$ 636,812	\$ -	0.224281	\$ -	11	\$ -	0.224281	\$ -	
12	\$ 146,708	\$ 625,336	\$ -	0.194519	\$ -	12	\$ -	0.194519	\$ -	
13	\$ 112,195	\$ 618,883	\$ -	0.168707	\$ -	13	\$ -	0.168707	\$ -	
14	\$ 86,390	\$ 609,987	\$ -	0.148320	\$ -	14	\$ -	0.148320	\$ -	
15	\$ 68,620	\$ 604,819	\$ -	0.128904	\$ -	15	\$ -	0.128904	\$ -	
16	\$ 51,221	\$ 600,655	\$ -	0.110084	\$ -	16	\$ -	0.110084	\$ -	
17	\$ 39,440	\$ 597,803	\$ -	0.095459	\$ -	17	\$ -	0.095459	\$ -	
18	\$ 30,389	\$ 595,453	\$ -	0.082792	\$ -	18	\$ -	0.082792	\$ -	
19	\$ 23,384	\$ 593,843	\$ -	0.071608	\$ -	19	\$ -	0.071608	\$ -	
20	\$ 18,006	\$ 592,250	\$ -	0.062277	\$ -	20	\$ -	0.062277	\$ -	
21	\$ 13,664	\$ 591,177	\$ -	0.054013	\$ -	21	\$ -	0.054013	\$ -	
22	\$ 10,678	\$ 590,361	\$ -	0.046846	\$ -	22	\$ -	0.046846	\$ -	
23	\$ 8,220	\$ 589,714	\$ -	0.040829	\$ -	23	\$ -	0.040829	\$ -	
24	\$ 6,330	\$ 589,225	\$ -	0.035238	\$ -	24	\$ -	0.035238	\$ -	
25	\$ 4,874	\$ 588,847	\$ -	0.030592	\$ -	25	\$ -	0.030592	\$ -	
26	\$ 3,753	\$ 588,557	\$ -	0.026507	\$ -	26	\$ -	0.026507	\$ -	
27	\$ 2,890	\$ 588,333	\$ -	0.022999	\$ -	27	\$ -	0.022999	\$ -	
28	\$ 2,225	\$ 588,181	\$ -	0.019939	\$ -	28	\$ -	0.019939	\$ -	
29	\$ 1,713	\$ 588,029	\$ -	0.017293	\$ -	29	\$ -	0.017293	\$ -	
30	\$ 1,319	\$ 587,927	\$ -	0.014998	\$ -	30	\$ -	0.014998	\$ -	
31	\$ 1,016	\$ 587,846	\$ -	0.013008	\$ -	31	\$ -	0.013008	\$ -	
32	\$ 782	\$ 587,787	\$ -	0.011282	\$ -	32	\$ -	0.011282	\$ -	
33	\$ 602	\$ 587,741	\$ -	0.009785	\$ -	33	\$ -	0.009785	\$ -	
34	\$ 484	\$ 587,705	\$ -	0.008488	\$ -	34	\$ -	0.008488	\$ -	
35	\$ 357	\$ 587,677	\$ -	0.007360	\$ -	35	\$ -	0.007360	\$ -	
36	\$ 275	\$ 587,658	\$ -	0.006384	\$ -	36	\$ -	0.006384	\$ -	
37	\$ 212	\$ 587,640	\$ -	0.005539	\$ -	37	\$ -	0.005539	\$ -	
38	\$ 183	\$ 587,627	\$ -	0.004802	\$ -	38	\$ -	0.004802	\$ -	
39	\$ 128	\$ 587,617	\$ -	0.004185	\$ -	39	\$ -	0.004185	\$ -	
40	\$ 97	\$ 587,610	\$ -	0.003612	\$ -	40	\$ -	0.003612	\$ -	
WORKING INTEREST APPRAISAL				ROYALTY INTEREST APPRAISAL						
Assessment Ratio				60.00%	\$ 2,624,617					
					\$ 1,574,710					
Tax Estimate				0.022	\$ 34,896					

Well Code	NRA Account #	API #	2014 Calendar Year			2014 Calendar Year Except Year 1 Wells Adjusted to Actual Expenses for First 12 Months (Note 1)			Well Type
			LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	
40307	09-0120146079	47-017-06079	43,900	1,385,002	1,428,901	43,900	1,385,002	1,428,901	Marcellus, Horizontal
40306	09-0120146083	47-017-06083	46,372	1,464,200	1,510,572	46,372	1,464,200	1,510,572	Marcellus, Horizontal
40400	09-0120156169	47-017-06169	171,177	1,822,217	1,993,393	171,177	1,822,217	1,993,393	Marcellus, Horizontal
40437	09-0120156170	47-017-06170	167,169	1,954,910	2,122,079	167,169	1,954,910	2,122,079	Marcellus, Horizontal
40414	09-0120156187	47-017-06187	49,670	1,563,122	1,612,792	49,670	1,563,122	1,612,792	Marcellus, Horizontal
40416	09-0120156188	47-017-06188	62,096	1,707,644	1,769,740	62,096	1,707,644	1,769,740	Marcellus, Horizontal
40415	09-0120156189	47-017-06189	51,259	1,631,653	1,682,912	51,259	1,631,653	1,682,912	Marcellus, Horizontal
40410	09-0120166141	47-017-06141	17,147	2,070,963	2,088,110	17,147	2,070,963	2,088,110	Marcellus, Horizontal
40409	09-0120166142	47-017-06142	26,987	1,880,555	1,907,542	26,987	1,880,555	1,907,542	Marcellus, Horizontal
40435	09-0120166190	47-017-06190	10,600	1,255,862	1,266,463	10,600	1,255,862	1,266,463	Marcellus, Horizontal
40499	09-0120166191	47-017-06191	16,755	1,044,192	1,060,948	16,755	1,044,192	1,060,948	Marcellus, Horizontal
40497	09-0120166192	47-017-06192	10,539	937,423	947,962	10,539	937,423	947,962	Marcellus, Horizontal
40498	09-0120166193	47-017-06193	981,449	356,144	1,337,593	981,449	356,144	1,337,593	Marcellus, Horizontal
40475	09-0120166201	47-017-06201	28,771	2,235,908	2,264,679	28,771	2,235,908	2,264,679	Marcellus, Horizontal
40438	09-0120166206	47-017-06206	5,382	650,663	656,046	5,382	650,663	656,046	Marcellus, Horizontal
40490	09-0120166207	47-017-06207	23,150	2,146,258	2,169,409	23,150	2,146,258	2,169,409	Marcellus, Horizontal
40581	09-0120166211	47-017-06211	99,173	3,144,354	3,243,528	99,173	3,144,354	3,243,528	Marcellus, Horizontal
40982	09-0120166212	47-017-06212	(59,781)	1,028,705	968,924	(59,781)	1,028,705	968,924	Marcellus, Horizontal
40980	09-0120166213	47-017-06213	358	997,362	997,720	358	997,362	997,720	Marcellus, Horizontal
40447	09-0120166266	47-017-06266	126	1,008,992	1,009,118	126	1,008,992	1,009,118	Marcellus, Horizontal
40448	09-0120166272	47-017-06272	75,667	2,954,918	3,030,585	75,667	2,954,918	3,030,585	Marcellus, Horizontal
40466	09-0120166275	47-017-06275	85,816	3,401,705	3,487,521	85,816	3,401,705	3,487,521	Marcellus, Horizontal
40550	09-0120166289	47-017-06289	338	546,412	546,750	338	546,412	546,750	Marcellus, Horizontal
40549	09-0120166292	47-017-06292	406	403,884	404,290	406	403,884	404,290	Marcellus, Horizontal
40551	09-0120166294	47-017-06294	338	511,200	511,538	338	511,200	511,538	Marcellus, Horizontal
40619	09-0120166359	47-017-06359	406	478,030	478,436	406	478,030	478,436	Marcellus, Horizontal
40620	09-0120166402	47-017-06402	303	862,274	862,577	303	862,274	862,577	Marcellus, Horizontal
40621	09-0120166430	47-017-06430	303	894,658	894,960	303	894,658	894,960	Marcellus, Horizontal
40622	09-0120166431	47-017-06431	145	167,191	167,336	145	167,191	167,336	Marcellus, Horizontal
40623	09-0120166432	47-017-06432	144	121,998	122,142	144	121,998	122,142	Marcellus, Horizontal
40303	09-0320146080	47-017-06080	56,892	598,166	655,058	56,892	598,166	655,058	Marcellus, Horizontal
40312	09-0320146085	47-017-06085	67,180	916,495	983,675	67,180	916,495	983,675	Marcellus, Horizontal
40305	09-0320156084	47-017-06084	56,189	395,282	451,471	56,189	395,282	451,471	Marcellus, Horizontal
40361	09-0320156128	47-017-06128	73,144	615,331	688,475	73,144	615,331	688,475	Marcellus, Horizontal
40362	09-0320156129	47-017-06129	52,852	1,316,362	1,369,214	52,852	1,316,362	1,369,214	Marcellus, Horizontal
40387	09-0320156163	47-017-06163	59,405	1,262,500	1,321,905	59,405	1,262,500	1,321,905	Marcellus, Horizontal
40386	09-0320156166	47-017-06166	49,017	1,043,003	1,092,020	49,017	1,043,003	1,092,020	Marcellus, Horizontal
			56,673	992,362	1,049,034	56,673	992,362	1,049,034	Marcellus, Horizontal

Well Code	NRA Account #	API #	2014 Calendar Year			2014 Calendar Year Except Year 1 Wells Adjusted to Actual Expenses for First 12 Months (Note 1)			Well Type
			LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	Fixed Portion of Operating Expenses (26%)
40440	09-0320156194	47-017-06194	140,715	2,724,765	2,865,479	140,715	2,724,765	2,865,479	716,370
40485	09-0320156204	47-017-06204	43,987	2,004,049	2,048,036	43,987	2,004,049	2,048,036	512,009
40486	09-0320156205	47-017-06205	108,566	2,180,201	2,288,767	108,566	2,180,201	2,288,767	572,192
40494	09-0320156221	47-017-06221	49,506	1,056,471	1,105,977	49,506	1,056,471	1,105,977	276,494
40443	09-0320156255	47-017-06255	52,980	807,705	860,685	52,980	807,705	860,685	215,171
40444	09-0320156256	47-017-06256	50,222	755,742	805,964	50,222	755,742	805,964	201,491
40479	09-0320156260	47-017-06260	154,760	2,293,778	2,448,538	154,760	2,293,778	2,448,538	612,134
40483	09-0320166202	47-017-06202	80,370	1,244,316	1,324,685	80,616	1,244,523	1,325,139	331,285
40439	09-0320166203	47-017-06203	73,881	1,230,533	1,304,415	75,169	1,244,547	1,319,715	329,929
40450	09-0320166220	47-017-06220	6,155	1,624,904	1,631,060	59,784	3,447,748	3,507,531	876,883
40513	09-0320166246	47-017-06246	[10,193]	1,597,909	1,587,717	40,447	3,255,178	3,295,625	823,906
40520	09-0320166247	47-017-06247	5,763	1,756,620	1,762,383	58,381	3,735,306	3,793,687	948,422
40519	09-0320166259	47-017-06259	5,703	947,859	953,562	58,752	2,003,679	2,062,431	515,608
40562	09-0320166262	47-017-06262	11,693	1,504,174	1,515,867	46,276	2,107,336	2,153,896	387,597
40560	09-0320166263	47-017-06263	12,718	1,560,803	1,573,521	46,560	2,107,336	2,153,896	538,474
40563	09-0320166264	47-017-06264	13,723	1,012,314	1,026,037	46,365	1,012,266	1,058,631	264,658
40516	09-0320166267	47-017-06267	10,473	1,761,147	1,771,619	38,473	2,572,917	2,611,390	652,848
40518	09-0320166268	47-017-06268	9,994	2,110,507	2,120,501	39,635	2,668,993	2,708,629	677,157
40517	09-0320166269	47-017-06269	10,743	1,658,672	1,669,415	37,362	2,381,986	2,419,348	604,837
40482	09-0320166281	47-017-06281	42,147	1,577,706	1,619,853	57,003	1,796,295	1,853,298	463,324
40501	09-0320166301	47-017-06301	48,029	2,909,979	2,958,007	64,563	3,232,015	3,296,578	824,144
40483	09-0320166302	47-017-06302	43,303	2,085,245	2,128,548	65,363	2,187,867	2,253,230	563,307
40566	09-0320166399	47-017-06399	213	3,799	4,012	166,041	2,739,563	2,905,604	726,401
40383	09-0420156143	47-017-06143	17,311	1,596,207	1,613,518	17,311	1,596,207	1,613,518	403,380
40408	09-0420156144	47-017-06144	33,747	1,074,359	1,108,106	33,747	1,074,359	1,108,106	277,027
40398	09-0420156158	47-017-06158	52,404	1,767,562	1,819,966	52,404	1,763,562	1,815,966	453,992
40399	09-0420156162	47-017-06162	42,705	1,677,648	1,719,353	42,705	1,672,648	1,715,353	428,838
40397	09-0420156164	47-017-06164	48,141	1,675,000	1,723,141	48,141	1,675,000	1,723,141	430,785
40417	09-0420156180	47-017-06180	31,361	1,482,961	1,514,321	31,361	1,482,961	1,514,321	378,580
40458	09-0420166138	47-017-06138	19,092	859,941	879,033	81,354	1,574,218	1,655,572	413,893
40457	09-0420166139	47-017-06139	28,178	1,081,345	1,109,523	91,934	1,924,008	2,015,943	503,986
40402	09-0420166140	47-017-06140	18,571	806,202	824,773	80,408	1,381,725	1,462,133	365,533
40445	09-0420166159	47-017-06159	1,147	125,554	126,701	89,283	1,869,727	1,959,010	489,752
40463	09-0420166160	47-017-06160	28,173	1,208,642	1,236,815	18,379	1,234,445	1,262,824	315,706
40403	09-0420166161	47-017-06161	44,088	1,648,452	1,692,539	44,176	1,661,021	1,705,197	426,299
40461	09-0420166167	47-017-06167	24,077	2,133,812	2,157,890	24,688	2,211,959	2,236,647	559,162
40608	09-0420166181	47-017-06181	[191]	203,503	203,312	70,290	1,798,195	1,868,485	467,121
40607	09-0420166182	47-017-06182	303	292,005	292,307	69,835	2,103,228	2,173,063	543,266
40455	09-0420166183	47-017-06183	15,987	1,978,258	1,994,245	29,359	2,401,536	2,430,895	607,724

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			LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	Fixed Portion of Operating Expenses (25%)
40592	09-0420166210	47-017-06210	76,932	1,166,500	1,243,432	125,288	1,737,895	1,863,183	465,796
40464	09-0420166219	47-017-06219	49,167	2,083,128	2,132,295	51,300	2,173,427	2,224,727	556,182
40512	09-0420166226	47-017-06226	50,382	1,496,090	1,546,472	103,186	2,205,539	2,308,724	577,181
40453	09-0420166227	47-017-06227	29,277	2,468,771	2,498,048	35,122	3,022,365	3,057,488	764,372
40454	09-0420166230	47-017-06230	25,972	2,300,434	2,326,406	35,572	2,814,923	2,850,494	712,624
40515	09-0420166245	47-017-06245	49,017	1,415,044	1,464,061	104,182	2,263,563	2,367,745	591,936
40543	09-0420166278	47-017-06278	20,217	1,633,393	1,653,610	54,337	2,525,754	2,580,091	645,023
40494	09-0420166279	47-017-06279	17,663	1,646,196	1,663,859	47,222	2,371,818	2,419,040	604,760
40544	09-0420166280	47-017-06280	15,351	1,468,062	1,483,413	40,754	2,264,077	2,304,831	576,208
40536	09-0420166369	47-017-06369	1,214	336,806	338,020	153,169	2,351,655	2,504,823	626,206
40540	09-0420166377	47-017-06377	49,074	1,309,179	1,358,254	97,202	2,393,005	2,490,208	622,552
40585	09-0420166422	47-017-06422	238	270,922	271,161	78,473	2,857,540	2,936,013	734,003
40598	09-0420166433	47-017-06433	232	372,169	372,400	79,621	2,262,266	2,341,887	585,472
40599	09-0420166434	47-017-06434	(2,249)	287,605	285,356	77,072	2,808,461	2,885,533	721,383
40586	09-0420166435	47-017-06435	239	399,734	399,972	72,947	2,556,324	2,629,271	657,318
40600	09-0420166450	47-017-06450	1,140	10,927	12,067	112,761	3,103,033	3,215,794	803,948
40257	09-0520145962	47-017-05962	77,584	519,878	597,462	77,584	519,878	597,462	149,366
40275	09-0520145962	47-017-06026	65,089	528,513	593,602	65,089	528,513	593,602	148,400
40277	09-0520146027	47-017-06027	49,228	708,379	758,607	49,228	709,379	758,607	189,652
40276	09-0520146028	47-017-06028	59,183	711,984	771,117	59,183	711,984	771,117	192,779
40269	09-0520146044	47-017-06044	61,469	475,889	537,359	61,469	475,889	537,359	134,340
40270	09-0520146045	47-017-06045	53,145	414,257	467,402	53,145	414,257	467,402	116,850
40271	09-0520146046	47-017-06046	38,966	521,392	560,358	38,966	521,392	560,358	140,090
40373	09-0520156117	47-017-06117	115,502	959,151	1,074,654	115,502	959,151	1,074,654	268,663
40376	09-0520156118	47-017-06118	94,416	761,600	856,017	94,416	761,600	856,017	214,004
40375	09-0520156120	47-017-06120	98,422	625,256	723,677	98,422	625,256	723,677	180,919
40374	09-0520156121	47-017-06121	97,634	689,711	787,346	97,634	689,711	787,346	196,836
40969	09-0520166119	47-017-06119	25,574	1,440,872	1,466,446	36,160	1,982,641	2,018,801	504,700
40970	09-0520166134	47-017-06134	32,543	1,351,750	1,384,293	41,245	1,807,988	1,849,233	462,308
40971	09-0520166148	47-017-06148	33,013	1,679,712	1,712,725	41,768	2,197,192	2,238,960	559,740
40341	09-0620146096	47-017-06096	84,226	1,009,155	1,093,381	84,226	1,009,155	1,093,381	273,345
40320	09-0620146099	47-017-06099	69,972	780,029	850,002	69,972	780,029	850,002	212,500
40313	09-0620156076	47-017-06076	85,438	1,140,971	1,226,409	85,438	1,140,971	1,226,409	306,602
40318	09-0620156081	47-017-06081	78,783	1,040,849	1,119,632	78,783	1,040,849	1,119,632	279,908
40319	09-0620156082	47-017-06082	79,080	1,318,343	1,397,424	79,080	1,318,343	1,397,424	349,356
40348	09-0620156094	47-017-06094	77,414	1,119,974	1,197,388	77,414	1,119,974	1,197,388	299,347
40328	09-0620156095	47-017-06095	70,619	794,489	865,109	70,619	794,489	865,109	216,277
40311	09-0620156097	47-017-06097	117,274	977,100	1,094,374	117,274	977,100	1,094,374	273,594
40343	09-0620156098	47-017-06098	108,723	1,106,401	1,215,124	108,723	1,106,401	1,215,124	303,781

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			LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	LOE Expenses	Gathering, Processing, and Transportation Expenses	Total Operating Expenses	Fixed Portion of Operating Expenses (25%)
40350	09-0620156100	47-017-06100	118,023	1,359,339	1,477,361	118,023	1,359,339	1,477,361	369,340
40327	09-0620156102	47-017-06102	252,915	1,503,028	1,755,943	252,915	1,503,028	1,755,943	438,986
40347	09-0620156103	47-017-06103	73,031	752,430	825,461	73,031	752,430	825,461	206,365
40349	09-0620156104	47-017-06104	130,707	1,423,025	1,553,732	130,707	1,423,025	1,553,732	388,433
40329	09-0620156126	47-017-06126	78,186	1,110,054	1,188,240	78,186	1,110,054	1,189,240	297,060
40953	09-0620156153	47-017-06153	89,518	2,028,063	2,117,582	89,518	2,028,063	2,117,582	529,395
40422	09-0620156156	47-017-06156	71,128	1,011,023	1,082,151	71,128	1,011,023	1,082,151	270,538
40426	09-0620156157	47-017-06157	89,655	2,310,323	2,399,977	89,655	2,310,323	2,399,977	599,994
40464	09-0620156173	47-017-06173	94,502	1,504,308	1,598,809	94,502	1,504,308	1,598,809	399,702
40428	09-0620166165	47-017-06165	155,392	2,514,994	2,670,386	159,392	2,588,814	2,748,207	687,052
40965	09-0620166174	47-017-06174	70,804	1,616,879	1,687,683	77,798	1,830,583	1,908,381	477,095
40473	09-0620166238	47-017-06238	16,040	1,345,395	1,361,436	59,005	2,013,248	2,072,253	518,063
40474	09-0620166240	47-017-06240	12,705	1,355,553	1,368,258	51,144	1,999,682	2,050,827	512,707
40471	09-0620166243	47-017-06243	13,386	1,376,734	1,390,119	46,417	2,252,498	2,298,915	574,729
40472	09-0620166244	47-017-06244	8,579	1,146,225	1,154,804	39,815	1,794,907	1,834,722	458,680
40493	09-0620166261	47-017-06261	18,180	1,465,725	1,483,904	50,924	2,211,083	2,262,008	565,502
40452	09-0620166265	47-017-06265	20,484	1,416,638	1,437,122	56,949	2,132,973	2,189,921	547,480
40531	09-0620166295	47-017-06295	22,086	1,585,877	1,607,964	55,235	2,444,147	2,499,382	617,345
40542	09-0620166296	47-017-06296	15,674	1,911,213	1,926,887	44,709	2,793,959	2,838,668	709,667
40546	09-0620166311	47-017-06311	385	267,439	267,824	93,462	1,862,155	1,955,617	488,904
40533	09-0620166313	47-017-06313	371	69,302	69,673	196,281	802,295	998,576	249,644
40611	09-0620166320	47-017-06320	371	101,835	102,206	189,888	994,815	1,184,703	296,176
40534	09-0620166321	47-017-06321	232	113,337	113,569	186,936	799,030	985,966	246,492
40545	09-0620166333	47-017-06333	303	430,274	430,576	89,214	2,134,293	2,223,507	555,877
40574	09-0620166334	47-017-06334	310	581,924	582,234	109,675	2,174,870	2,284,545	571,136
40532	09-0620166358	47-017-06358	78,053	1,566,197	1,644,250	90,000	1,772,669	1,862,670	465,667
40547	09-0620166362	47-017-06362	310	251,814	252,124	95,222	1,709,232	1,804,453	451,113
40548	09-0620166366	47-017-06366	310	474,448	474,758	88,112	1,921,968	2,010,080	502,520
40703	09-0620166404	47-017-06404	0	36,275	36,275	143,848	2,127,673	2,271,521	567,880
40564	09-0620166419	47-017-06419	158	30,061	30,219	81,286	1,746,152	1,827,438	456,859
40692	09-0620166429	47-017-06429	158	108,508	108,666	79,871	2,257,033	2,336,904	584,226
40591	09-0620166453	47-017-06453	310	507,622	507,931	93,418	2,959,399	3,052,817	763,204
40488	09-0820166223	47-017-06223	44,620	2,443,987	2,488,607	98,329	3,473,297	3,571,626	892,906
40487	09-0820166224	47-017-06224	42,608	2,260,203	2,302,811	98,494	3,346,182	3,444,676	861,169
40492	09-0820166258	47-017-06258	56,292	2,111,707	2,167,999	108,149	2,732,219	2,840,368	710,092
40489	09-0820166258	47-017-06258	(16,556)	1,657,602	1,641,045	43,441	2,358,995	2,402,435	600,609
40484	09-0820166312	47-017-06312	(3,197)	1,453,055	1,449,859	45,046	2,661,815	2,706,861	676,715
40552	09-0820166316	47-017-06316	16,759	1,779,404	1,796,163	53,766	2,835,715	2,889,481	722,370
40561	09-0820166317	47-017-06317	8,019	1,218,109	1,226,129	51,915	2,080,744	2,132,659	533,165

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40553	09-0820166318	47-017-06518	7,855	1,055,720	1,063,575	40,022	1,633,138	1,673,159	Marcellus, Horizontal
40239	17-0120145553	47-033-05553	30,368	667,962	698,330	30,368	667,962	698,330	Marcellus, Horizontal
40120	17-0720115222	47-033-05222	16,849	418,049	434,898	16,849	418,049	434,898	Marcellus, Horizontal
40137	17-0720115305	47-033-05305	27,118	324,286	351,404	27,118	324,286	351,404	Marcellus, Horizontal
40139	17-0720125339	47-033-05339	27,251	377,438	404,689	27,251	377,438	404,689	Marcellus, Horizontal
40164	17-0720125357	47-033-05357	34,345	304,982	339,327	34,345	304,982	339,327	Marcellus, Horizontal
40140	17-0720125357	47-033-05358	31,896	229,800	261,697	31,896	229,800	261,697	Marcellus, Horizontal
40152	17-0720125363	47-033-05363	51,269	656,575	707,843	51,269	656,575	707,843	Marcellus, Horizontal
40185	17-0720135427	47-033-05427	17,854	380,946	398,800	17,854	380,946	398,800	Marcellus, Horizontal
40183	17-0720135428	47-033-05428	16,101	424,752	440,853	16,101	424,752	440,853	Marcellus, Horizontal
40147	17-0720135429	47-033-05429	19,233	310,782	330,015	19,233	310,782	330,015	Marcellus, Horizontal
40170	17-0720135430	47-033-05430	27,888	361,012	388,899	27,888	361,012	388,899	Marcellus, Horizontal
40151	17-0720135439	47-033-05439	28,679	503,893	532,572	28,679	503,893	532,572	Marcellus, Horizontal
40172	17-0720135440	47-033-05440	27,555	472,734	500,288	27,555	472,734	500,288	Marcellus, Horizontal
40191	17-0720135450	47-033-05450	48,794	558,567	607,360	48,794	558,567	607,360	Marcellus, Horizontal
40190	17-0720135451	47-033-05451	60,473	682,044	742,517	60,473	682,044	742,517	Marcellus, Horizontal
40199	17-0720135472	47-033-05472	50,958	774,495	825,453	50,958	774,495	825,453	Marcellus, Horizontal
40198	17-0720135473	47-033-05473	34,566	650,493	685,060	34,566	650,493	685,060	Marcellus, Horizontal
40220	17-0720135477	47-033-05477	28,747	514,483	543,230	28,747	514,483	543,230	Marcellus, Horizontal
40221	17-0720135499	47-033-05499	27,244	569,966	597,210	27,244	569,966	597,210	Marcellus, Horizontal
40236	17-0720135506	47-033-05506	54,504	463,860	518,364	54,504	463,860	518,364	Marcellus, Horizontal
40194	17-0720135550	47-033-05550	55,585	182,929	238,514	55,585	182,929	238,514	Marcellus, Horizontal
40143	17-0720145362	47-033-05362	56,997	492,776	549,774	56,997	492,776	549,774	Marcellus, Horizontal
40232	17-0720145470	47-033-05470	42,276	902,966	945,241	42,276	902,966	945,241	Marcellus, Horizontal
40230	17-0720145518	47-033-05518	26,513	602,290	628,803	26,513	602,290	628,803	Marcellus, Horizontal
40231	17-0720145519	47-033-05519	15,785	671,860	687,645	15,785	671,860	687,645	Marcellus, Horizontal
40249	17-0720145538	47-033-05538	35,315	705,685	741,001	35,315	705,685	741,001	Marcellus, Horizontal
40250	17-0720145538	47-033-05539	28,123	675,567	703,690	28,123	675,567	703,690	Marcellus, Horizontal
40160	17-0720145549	47-033-05549	40,712	1,076,237	1,116,949	40,712	1,076,237	1,116,949	Marcellus, Horizontal
40159	17-0720145549	47-033-05549	60,173	571,824	631,997	60,173	571,824	631,997	Marcellus, Horizontal
40157	17-0720145551	47-033-05551	60,783	689,605	750,388	60,783	689,605	750,388	Marcellus, Horizontal
40196	17-0720145558	47-033-05558	44,554	684,888	729,442	44,554	684,888	729,442	Marcellus, Horizontal
40219	17-0720145558	47-033-05561	47,790	835,749	883,539	47,790	835,749	883,539	Marcellus, Horizontal
40123	17-0720145595	47-033-05595	20,613	643,148	663,761	20,613	643,148	663,761	Marcellus, Horizontal
40195	17-0720145603	47-033-05603	31,952	528,712	560,664	31,952	528,712	560,664	Marcellus, Horizontal
40296	17-0720145604	47-033-05604	25,588	446,645	472,234	25,588	446,645	472,234	Marcellus, Horizontal
40181	17-0920135445	47-033-05445	36,711	438,114	474,825	36,711	438,114	474,825	Marcellus, Horizontal
40253	17-0920145520	47-033-05520	27,254	672,354	699,608	27,254	672,354	699,608	Marcellus, Horizontal
40254	17-0920145520	47-033-05546	23,498	605,814	629,312	23,498	605,814	629,312	Marcellus, Horizontal

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40251	17-0920145544	47-033-05544	28,673	484,596	513,269	28,673	484,596	513,269	128,317
40252	17-0920145544	47-033-05545	23,393	593,258	616,651	23,393	593,258	616,651	154,163
40268	17-0920145570	47-033-05570	67,086	722,588	789,674	67,086	722,588	789,674	197,419
40265	17-0920145570	47-033-05571	58,929	716,801	775,730	58,929	716,801	775,730	193,933
40144	17-1420125361	47-033-05361	64,610	346,488	411,098	64,610	346,488	411,098	102,774
40178	17-1420125361	47-033-05417	33,525	424,287	457,812	33,525	424,287	457,812	114,453
40166	17-1420125382	47-033-05382	46,125	513,558	559,683	46,125	513,558	559,683	139,921
40150	17-1420125386	47-033-05386	24,667	298,600	323,266	24,667	298,600	323,266	80,817
40146	17-1420125386	47-033-05393	34,433	424,011	458,443	34,433	424,011	458,443	114,611
40168	17-1420135387	47-033-05387	25,352	469,973	495,325	25,352	469,973	495,325	123,831
40169	17-1420135388	47-033-05388	21,071	413,359	434,430	21,071	413,359	434,430	108,607
40197	17-1420145475	47-033-05475	56,469	638,900	695,369	56,469	638,900	695,369	173,842
40193	17-1420145626	47-033-05626	39,862	701,474	741,336	39,862	701,474	741,336	185,334
40200	17-1420145627	47-033-05627	24,909	551,943	576,851	24,909	551,943	576,851	144,213
40951	17-1420145665	47-033-05665	28,851	555,676	584,526	28,851	555,676	584,526	146,132
40125	17-1820115236	47-033-05236	40,433	226,354	266,787	40,433	226,354	266,787	66,597
40184	17-1820125245	47-033-05243	44,825	378,768	423,593	44,825	378,768	423,593	105,898
40130	17-1820125245	47-033-05245	41,876	212,526	254,402	41,876	212,526	254,402	63,600
40173	17-1820125303	47-033-05303	32,969	273,406	306,375	32,969	273,406	306,375	76,594
40145	17-1820125303	47-033-05304	29,914	300,226	330,140	29,914	300,226	330,140	82,535
40138	17-1820125327	47-033-05327	36,813	353,084	389,897	36,813	353,084	389,897	97,474
41087	17-1820125375	47-033-05375	27,733	84,299	112,032	27,733	84,299	112,032	28,008
41130	17-1820125413	47-033-05413	6,584	82,242	88,826	6,584	82,242	88,826	22,207
41138	17-1820125448	47-033-05448	3,959	121,670	125,629	3,959	121,670	125,629	31,407
40127	17-1820135238	47-033-05238	47,279	222,941	270,220	47,279	222,941	270,220	67,555
40128	17-1820135239	47-033-05239	46,611	264,301	310,913	46,611	264,301	310,913	77,728
40154	17-1820135389	47-033-05389	45,786	453,225	499,010	45,786	453,225	499,010	124,753
40163	17-1820135391	47-033-05391	49,559	664,360	713,919	49,559	664,360	713,919	178,480
40153	17-1820135392	47-033-05392	49,612	508,851	558,463	49,612	508,851	558,463	139,616
40245	17-1820135437	47-033-05437	78,643	577,215	655,859	78,643	577,215	655,859	163,965
41139	17-1820135453	47-033-05453	15,846	156,021	171,866	15,846	156,021	171,866	42,967
40246	17-1820135507	47-033-05507	76,825	613,156	689,981	76,825	613,156	689,981	172,495
40222	17-1820135533	47-033-05533	68,356	500,540	568,896	68,356	500,540	568,896	142,224
40162	17-1820145390	47-033-05390	60,327	663,426	723,753	60,327	663,426	723,753	180,938
40215	17-1820145588	47-033-05588	46,526	778,166	824,692	46,526	778,166	824,692	206,173
40213	17-1820145596	47-033-05596	50,584	777,841	828,426	50,584	777,841	828,426	207,106
40214	17-1820145601	47-033-05601	46,180	890,630	936,810	46,180	890,630	936,810	234,203
40302	17-1820155602	47-033-05602	149,262	614,713	763,975	149,262	614,713	763,975	190,994
40366	17-1820155619	47-033-05619	117,341	755,644	872,985	117,341	755,644	872,985	218,246

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
WETZEL	52	1	\$90.00
		2	\$90.00
		3	\$90.00
		4	\$90.00
		5	\$90.00
		6	\$1.00
		7	\$1.00
		8	\$90.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$90.00
		13	\$1.00
MRT	53	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$1.00
		5	\$35.00
		6	\$35.00
		7	\$35.00
		8	\$35.00
WOOD	54	1	\$40.00
		2	\$40.00
		3	\$40.00
		4	\$40.00
		5	\$1.00
		6	\$40.00
		7	\$40.00
		8	\$40.00
		9	\$40.00
		10	\$1.00
		11	\$40.00
		12	\$40.00
		13	\$1.00
		14	\$1.00
WYOMING	55	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$1.00
		7	\$20.00
		8	\$1.00
		9	\$1.00
		10	\$20.00

**MANAGED TIMBER
PROPERTY ANALYSIS**

Tax Year 2017

June 30, 2016
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

MANAGED TIMBERLAND APPRAISAL RATES

TAX YEAR 2017

(based on market 2011-2015)

Rates Per Acre

Class II Parcels

	<u>Grade 1</u>	<u>Grade 2</u>	<u>Grade 3</u>
Region 1	\$205	\$140	\$50
Region 2	\$200	\$140	\$50
Region 3	\$265	\$175	\$50
Region 4	\$270	\$185	\$55
Region 5	\$205	\$140	\$50

Class III/IV Parcels

	<u>Grade 1</u>	<u>Grade 2</u>	<u>Grade 3</u>
Region 1	\$225	\$150	\$75
Region 2	\$225	\$150	\$75
Region 3	\$240	\$155	\$75
Region 4	\$245	\$165	\$75
Region 5	\$225	\$150	\$75

- Region 1 = Brooke, Cabell, Hancock, Jackson, Marshall, Mason, Ohio, Pleasants, Putnam, Tyler, Wetzel, and Wood Counties
- Region 2 = Braxton, Calhoun, Clay, Doddridge, Gilmer, Harrison, Lewis, Marion, Monongalia, Ritchie, Roane, Taylor, and Wirt Counties
- Region 3 = Barbour, Greenbrier, Monroe, Nicholas, Pendleton, Pocahontas, Preston, Randolph, Tucker, Upshur, and Webster Counties
- Region 4 = Berkeley, Grant, Hampshire, Hardy, Jefferson, Mineral and Morgan Counties
- Region 5 = Boone, Fayette, Kanawha, Lincoln, Logan, McDowell, Mercer, Mingo, Raleigh, Summers, Wayne, and Wyoming Counties

Harvest Volumee per Acre

Harvest Interval Grades

	<u>35 yrs.</u>	<u>45 yrs.</u>	<u>55 yrs.</u>	<u>80 yrs.</u>		<u>Total</u>
1 - Site Index 75 or more	4.6 cords 1.5 Mbf	-- --	2.6 cords 4.4 Mbf	3.3 cords 8.6 Mbf		10.5 cords 14.5 Mbf
2 - Site Index 65 - 75	3.3 cords 1.0 Mbf	-- --	7.0 cords 3.2 Mbf	4.6 cords 5.5 Mbf		14.9 cords 9.7 Mbf
3 - Site Index less than 65	-- --	3.1 cords 0.8 Mbf	-- --	15.4 cords 3.7 Mbf		16.5 cords 4.5 Mbf

Managed Timberland Statistics

Estimation of Required Rate of Return: Class II Rates

A. Safe Rate of Return (5 Year T-Bill Rate)

Year	Rate	W/A %	W/A Rate
2015	1.5292	26.67%	0.4076
2014	1.8410	33.33%	0.6469
2013	1.1725	13.33%	0.1583
2012	0.7608	6.67%	0.0507
2011	1.5225	20.00%	0.3045

1.465 %

B. Nonliquidity Rate

(12 Month T-Bills vs. 3 Month T-Bills)

Year	Rate	W/A %	W/A Rate
2015	0.2683	33.33%	0.0894
2014	0.0883	26.67%	0.0235
2013	0.0733	20.00%	0.0147
2012	0.1292	13.33%	0.0172
2011	0.1817	6.67%	0.0121

0.187 %

C. Risk Rate (30 yr T-bills vs 5 yr T-bills)

Year	Rate	W/A %	W/A Rate
2015	1.3117	13.33%	0.1746
2014	1.6982	26.67%	0.4532
2013	2.2766	20.00%	0.4552
2012	2.1800	33.33%	0.7198
2011	2.3683	6.67%	0.1593

1.962 %

D. Management Factor of 0.5%

0.500 %

E. Property Tax Component

(60% of Class II Rate)

Year	Rate	W/A %	W/A Rate
2015	0.714	33.33%	0.2380
2014	0.714	26.67%	0.1904
2013	0.708	20.00%	0.1416
2012	0.714	13.33%	0.0952
2011	0.708	6.67%	0.0472

0.712 %

F. Inflation Rate:

(Bureau of Labor Statistics)

Year	Rate	W/A %	W/A Rate
2015	0.730	33.33%	0.2433
2014	0.760	26.67%	0.2027
2013	1.500	20.00%	0.3000
2012	1.700	13.33%	0.2266
2011	3.000	6.67%	0.2001

(1.173) %

TOTAL REQUIRED RATE OF RETURN (REAL)

3.625 %

LESS: PROPERTY TAX COMPONENT

(0.712)

TOTAL DISCOUNT COMPONENT

2.913 %

Stumpage Prices:

	<u>Sawtimber</u>	<u>Pulpwood</u>
Stumpage Price Adjustment Factor	0.00%	1.85%

		1.0000	1.0000	1.0000	1.0000
<u>SAWTIMBER</u>	Current	\$/MBF at age	\$/MBF at age	\$/MBF at age	\$/MBF at age
Region	\$/MBF	35	45	55	80
Region 1	181.34	181.34	181.34	181.34	181.34
Region 2	172.92	172.92	172.92	172.92	172.92
Region 3	239.28	239.28	239.28	239.28	239.28
Region 4	235.49	235.49	235.49	235.49	235.49
Region 5	190.59	190.59	190.59	190.59	190.59

		1.8995	2.2818	2.7407	4.3339
<u>PULPWOOD:</u>		\$/cd at age	\$/cd at age	\$/cd at age	\$/cd at age
Region	\$/Cord	35	45	55	80
Region 1	8.54	18.23	19.49	23.41	37.02
Region 2	8.73	12.79	15.36	18.45	29.18
Region 3	5.13	9.78	11.71	14.07	22.24
Region 4	8.10	15.39	18.49	22.21	35.12
Region 5	5.77	10.98	13.18	15.81	25.00

Management Costs:

Region	\$/acre (1)
1	3.17
2	3.17
3	3.17
4	3.17
5	3.17
State	

Tax Rates:

Effective Federal Income Tax Rate	35.00%
Effective WV State Income Tax Rate (6.5% * (1-.35))	4.23%
Effective WV Severance Tax Rate (1.5% * (1-.35))	0.98%

Yield (Volumes) (80 year rotation)

Timberland	Site Index	Yield - MBF	Yield - Cords
Productivity Grades			
Grade I	75 or more	14.5	10.5
Grade II	65-74	9.7	14.9
Grade III	less than 65	4.5	18.5

Managed Timberland Statistics

Estimation of Required Rate of Return: Class III & IV Blended Rates

A. Safe Rate of Return (5 Year T-Bill Rate)

Year	Rate	W/A %	W/A Rate
2015	1.5292	28.67%	0.4078
2014	1.8410	33.33%	0.5489
2013	1.1725	13.33%	0.1563
2012	0.7808	6.87%	0.0507
2011	1.5225	20.00%	0.3046

1.486 %

B. Nonliquidity Rate

(12 Month T-Bills vs. 3 Month T-Bills)

Year	Rate	W/A %	W/A Rate
2015	0.2683	33.33%	0.0894
2014	0.0883	28.87%	0.0235
2013	0.0733	20.00%	0.0147
2012	0.1292	13.33%	0.0172
2011	0.1817	6.87%	0.0121

0.157 %

C. Risk Rate (30 yr T-bills vs 5 yr T-bills)

Year	Rate	W/A %	W/A Rate
2015	1.3117	13.33%	0.1748
2014	1.6892	28.87%	0.4532
2013	2.2758	20.00%	0.4652
2012	2.1600	33.33%	0.7199
2011	2.3883	6.87%	0.1593

1.982 %

D. Management Factor of 0.5%

0.500 %

E. Property Tax Component

(80% of Blended III&IV Rates)

Year	Rate	W/A %	W/A Rate
2015	1.314	33.33%	0.4380
2014	1.314	28.87%	0.3504
2013	1.314	20.00%	0.2628
2012	1.326	13.33%	0.1768
2011	1.328	6.87%	0.0884

1.316 %

F. Inflation Rate:

(Bureau of Labor Statistics)

Year	Rate	W/A %	W/A Rate
2015	0.730	33.33%	0.2433
2014	0.760	28.87%	0.2027
2013	1.500	20.00%	0.3000
2012	1.700	13.33%	0.2288
2011	3.000	6.87%	0.2001

(1.173) %

TOTAL REQUIRED RATE OF RETURN (REAL)

4.229 %

LESS: PROPERTY TAX COMPONENT

(1.318)

TOTAL DISCOUNT COMPONENT

2.913 %

Stumpage Prices:

	<u>Sawtimber</u>	<u>Pulpwood</u>
Stumpage Price Adjustment Factor	0.00%	1.85%

SAWTIMBER	Current \$/MBF	1.0000	1.0000	1.0000	1.0000
		\$/MBF at age 35	\$/MBF at age 45	\$/MBF at age 55	\$/MBF at age 80
Region 1	181.34	181.34	181.34	181.34	181.34
Region 2	172.92	172.92	172.92	172.92	172.92
Region 3	238.28	239.28	239.28	238.28	239.28
Region 4	238.49	235.48	235.48	235.49	235.48
Region 5	190.59	180.59	190.59	190.89	190.59

PULPWOOD:	\$/Cord	1.8985	2.2818	2.7407	4.3339
		\$/cd at age 35	\$/cd at age 45	\$/cd at age 55	\$/cd at age 80
Region 1	8.54	16.23	19.49	23.41	37.02
Region 2	6.73	12.79	15.38	18.45	29.18
Region 3	5.13	9.78	11.71	14.07	22.24
Region 4	8.10	15.39	18.49	22.21	35.12
Region 5	5.77	10.98	13.18	15.81	25.00

Management Costs:

Region	\$/acre (1)
1	3.17
2	3.17
3	3.17
4	3.17
5	3.17

State

Tax Rates:

Effective Federal Income Tax Rate	35.00%
Effective WV State income Tax Rate (8.5% * (1-.35))	4.23%
Effective WV Severance Tax Rate (1.5% * (1-.35))	0.98%

Yield (Volumes) (80 year rotation)

Timberland		Yield - MBF	Yield - Cords
Productivity Grades	Site Index		
Grade I	75 or more	14.5	10.5
Grade II	68-74	9.7	14.9
Grade III	less than 65	4.5	18.5

West Virginia Wgt/Avg Managed Timberland Stumpage Prices

REGION 1 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2015	12,581.60	192.85	33.33%	84.28
2014	12,162.08	178.34	26.67%	47.02
2013	19,017.77	177.45	20.00%	35.49
2012	12,628.15	166.66	13.33%	24.87
2011	11,195.24	144.69	6.67%	9.66
	67,565.02			181.34

REGION 1 - Pulpwood

Year	Volume	\$/CDRD	W/A%	\$/CORD
2015	7,216.90	15.03	33.33%	5.01
2014	484.40	5.40	26.67%	1.44
2013	6,102.20	2.96	20.00%	0.59
2012	45,367.00	6.42	13.33%	0.66
2011	46.10	9.67	6.67%	0.64
	59,220.60			8.54

REGION 2 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2015	26,487.65	175.25	33.33%	56.42
2014	22,001.60	162.47	26.67%	48.66
2013	25,698.65	177.79	20.00%	35.58
2012	25,640.98	149.01	13.33%	19.87
2011	12,639.41	156.26	6.67%	10.42
	112,668.69			172.92

REGION 2 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2015	42,683.30	5.97	33.33%	1.99
2014	2,188.10	5.04	26.67%	1.34
2013	119,279.40	12.63	20.00%	2.57
2012	22,647.40	2.66	13.33%	0.36
2011	5,235.20	6.78	6.67%	0.45
	192,193.40			6.73

REGION 3 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2015	135,967.80	207.12	33.33%	59.04
2014	91,467.44	260.62	26.67%	74.61
2013	161,397.70	276.63	20.00%	55.13
2012	111,920.60	201.57	13.33%	26.66
2011	102,216.30	201.45	6.67%	13.43
	502,971.84			239.26

REGION 3 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2015	184,907.30	3.85	33.33%	1.28
2014	170,736.30	3.57	26.67%	0.95
2013	153,197.40	7.78	20.00%	1.58
2012	183,132.60	6.39	13.33%	0.85
2011	159,040.70	7.34	6.67%	0.49
	851,014.30			5.13

REGION 4 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2015	6,644.42	223.42	33.33%	74.47
2014	5,020.90	303.69	26.67%	81.04
2013	12,820.20	211.47	20.00%	42.26
2012	4,808.73	193.47	13.33%	25.60
2011	15,517.51	178.40	6.67%	11.89
	44,811.78			235.49

REGION 4 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2015	5,137.40	7.22	33.33%	2.41
2014	7,785.20	8.16	26.67%	2.18
2013	15,486.80	8.32	20.00%	1.66
2012	7,382.20	9.61	13.33%	1.28
2011	21,074.10	8.84	6.67%	0.56
	57,847.50			8.10

REGION 5 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2015	37,714.40	150.15	33.33%	53.36
2014	21,661.40	265.65	26.67%	70.92
2013	31,656.00	198.20	20.00%	36.64
2012	10,667.05	138.63	13.33%	18.46
2011	24,780.43	122.43	6.67%	8.16
	126,662.28			190.56

REGION 5 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2015	2,889.50	4.05	33.33%	1.36
2014	10,161.40	8.19	26.67%	1.65
2013	18,292.50	7.13	20.00%	1.43
2012	6,296.30	5.63	13.33%	0.82
2011	6,432.30	8.26	6.67%	0.42
	48,102.10			5.77

COAL PROPERTIES ANALYSIS

Tax Year 2017

June 30, 2016
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

COAL CAPITALIZATION RATE

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bonds-of-Investment and Summation Technique approaches are utilized in establishing discount rates for active coal. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 11.

<u>Safe Rate</u>	90 day Treasury Bills	<u>Safe Rate</u>
January	December 2015	0.053%
January	December 2014	0.033%
January	December 2013	0.058%

<u>Risk Rate</u>	Interest differential between Loan Rate and 90 day Treasury Bills	<u>Debt Risk Rate</u>
<u>Loan Rate*</u>		
2015	5.25%	5.207%
2014	5.25%	5.217%
2013	5.25%	5.192%
	*Prime plus 2%	

<u>Equity</u>	Differential between Equity Rates and 90 day Treasury Bills	<u>Equity Risk Rate</u>
<u>Equity Rate**</u>		
2015	$(14.75\% / (1 - .30)) - 0.053$	21.038%
2014	$(15.50\% / (1 - .30)) - 0.033$	22.110%
2013	$(13.25\% / (1 - .30)) - 0.058$	18.871%
	** Value Line Investment Survey Analysis	

<u>Composite Risk Rate</u>	Loan and Equity Rates weighted by industry estimated capital structure
<u>Equity Rate</u>	<u>Debt Rate</u> <u>Composite Risk</u>
2015 13.875%	1.822% 15.497%
2014 15.477%	1.588% 17.042%
2013 11.322%	2.077% 13.388%
Note: Debt Equity Ratio	Debt 35% Equity 65%

Non Liquidity Rate Interest differential between a 90 day Treasury Bill and a 1 year Treasury Bill which reflects a reasonable time necessary to sell active property.

			<u>1yr T Bill</u>	<u>90 d T Bill</u>	<u>Non Liquidity Rate</u>
January	December	2015	0.322%	0.053%	0.269%
January	December	2014	0.121%	0.033%	0.088%
January	December	2013	0.132%	0.058%	0.074%

Management Rate Charges for the management of investment portfolios.
Fixed Rate (by Rule) 0.500%

<u>Inflation Rate</u>			
January	December	2015	0.730%
January	December	2014	0.780%
January	December	2013	1.500%

Capitalization Rate Since the valuation of active coal property is predicated on a three year production average, the capitalization rate is considered in a similar manner.

	2015	2014	2013
Inflation Rate	-0.730%	-0.780%	-1.500%
Safe Rate	0.053%	0.033%	0.058%
Composite Risk Rate	15.497%	17.042%	13.399%
Non Liquidity Rate	0.269%	0.088%	0.074%
Management Rate	0.500%	0.500%	0.500%
Total	15.586%	16.903%	12.531%

Three Yr Average: 15.008 Rounded to: **15.00%**

<u>CAPITALIZATION RATE - 15.0%</u>				
<u>MULTIPLIERS:</u>		<u>%</u>		
1YR	0.933	9YR	5.117	
2YR	1.743	10YR	5.382	
3YR	2.448	11YR	5.813	
4YR	3.082	12YR	5.813	
5YR	3.595	13YR	5.987	
6YR	4.058	14YR	6.139	
7YR	4.482	15YR	6.271	
8YR	4.812			

COAL

Price and Royalty Rate Analysis

The development of royalty rates for the various categories of mines and markets involves information collection and review from a variety of sources. Coal lease rates have been derived from transaction information provided by county producers, assessors, tax auditors, and by individual lessors/lessees involved in the specific transaction. The prices for mined coal, as per 110-CSR-11, have been calculated from information provided by the WV Public Service Commission and U.S. Energy Information Administration concerning power plant fuel purchases. Prices provided by producers as part of tax filing and from data obtained from market summaries are included for comparison. Because a large portion of the data used in this analysis is, by law, considered confidential, only a summary of the results are published.

* - WVPSC Fuel Purchases for 2015 was not available at the time of this publication

COAL SALE PRICES CY2015 FOR TY2017 APPLICATION

GRAND SUMMARY ALL SOURCES 2015	STEAM SPOT	STEAM TERM	MET
PSC	na	na	
FERC	\$51.10	\$60.81	
Active Return Summary		\$55.52 55.0 MM tons	\$67.85 9.1 MM Tons
Coal Market Publication (Platts)		\$46.09 CAPP (12/1,87) Berge	
		\$46.65 PGH - (13/3) Rail	
			\$67.54 Low Vol HCC

STATE STEAM PRICE (SPOT Market)	\$58.66 FERC & PSC, 3 YR AVE
STATE MET PRICE	\$67.85 Active Return, 1 YR

2015 WVPSC Tons reported in millions	Spot Sales na	Term Sales na	Total na

COAL TY2017 ROYALTY RATES	2015 1YR		2014 2YR		2013 3YR		2012 4YR		2011 5YR	
	%S	%D	%S	%D	%S	%D	%S	%D	%S	%D
TOTAL RECORDS	447	452	1,447	908	1,354	599	1,906	2,756	1,877	2,241
SUM of PERCENT	2904.68	2327.95	8,666.07	4,666.26	6,067.34	3,313.63	11,661.66	14,683.03	9,624.26	11,181.08
STRAIGHT AVERAGE	6.50	5.15	6.13	5.19	5.97	5.53	6.23	5.32	5.32	4.99
MEDIAN	6.00	5.00	6.00	5.00	5.00	5.00	6.00	5.13	5.00	5.00
WEIGHTED AVERAGE (by Mines)	6.60	5.10	6.94	5.49	6.56	5.64	6.46	6.26	6.27	5.72
TENTATIVE RATE DEEP (%)	5.69									
TENTATIVE RATE SURFACE (%)	6.81									
ROYALTY RATE CALCULATIONS										
Steam Coal/ Deep Mine	\$58.66	per ton X	5.69%	=	\$3.35	per ton				
Metallurgical Coal/ Deep Mine	\$67.65	per ton X	5.66%	=	\$4.98	per ton				
Steam Coal/ Surface Mine	\$58.66	per ton X	6.81%	=	\$3.89	per ton				
Metallurgical Coal/ Surface Mine	\$67.65	per ton X	6.81%	=	\$5.76	per ton				

Explanation of Reserve Coal Valuation

The RCVM consists of a computer model, which utilizes a database consisting of coal beds and characteristics, property locations, mine locations, sales, transportation, etc., for the entire state. An extensive algorithm calculates in-place tonnage, expected time of mining and present value for all the mineable coal on every property.

There are, therefore, no set "rates" available on reserve coal under the Rule. The RCVM values on each property will not be available until all data has been entered, after October 15 of each year. Please refer to the State Register, Legislative Rules, Title 110, Series 11 for details of the process.

Title 110, Series 11
Valuation of Active and Reserve Coal Property for Ad Valorem Property Tax Purposes

The above Legislative Rule was modified during the 2005 Legislative Session requiring biennial (every other year) updating of the geostatistical basis for several valuation factors used in the Reserve Coal Valuation Model. To satisfy that requirement, maps and data files concerning the Market Interest Factor, the Market Mineability Factor, the Use Conflict Factor and the Environmental Factor have been revised for Tax Year 2016. Preliminary research has been conducted to determine the effects of the factors on coal valuation. The results are as follows:

Market Interest Factor

This is the relationship between transactions (sales, leases, prospects, permit applications, etc.) and mining as it relates to properties and locations. Trans_Ct is the number of transactions counted within the radius.

Radius = 5 miles

If Trans_Ct >= 20 Then TransFactor = 20

If Trans_Ct < 20 And Trans_Ct >= 10 Then TransFactor = 40

Else TransFactor = 80

Market Mineability Factor

This is the relationship between property location and mining, through time. Determining feature is count of mines within the radius.

Radius = 2.5 miles

Surface Mines: Smine

Open Mines: Omine

Boom Mines: Bmine

Historic Mines: Hmine

Current Mines: Cmine

To assign MineFactor:

If Cmine > 0 Then MineFactor = 20

If Cmine = 0 And (Omine > 0 Or Bmine > 0) Then MineFactor = 40

Else MineFactor = 80

Use Conflict Factor

This is the relationship between oil & gas well drilling and mining as it relates to property location. Well density is in wells per square mile.

WellDensity < 5 Then WellFactor = 0

WellDensity >= 5 And WellDensity < 10 Then WellFactor = 20

WellDensity >= 10 And WellDensity < 20 Then WellFactor = 40

WellDensity > 20 Then WellFactor = 80

Environmental Factor

This is the relationship of known environmental hazards and impediments to the likelihood of mining occurring at this location. The rates are compiled from maps and represent densities of problems mapped.

Envrate <= 20 or Null Then EnvFactor = 0

Envrate > 20 and Envrate <= 40 Then EnvFactor = 20

Envrate > 40 and Envrate < 80 Then EnvFactor = 40

Envrate >= 80 Then EnvFactor = 80

**OTHER MINED MINERAL
PROPERTY ANALYSIS**

Tax Year 2017

June 30, 2016
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

OTHER MINED MINERALS CAPITALIZATION RATE

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bonds-of-Investment and Summation Technique approaches are utilized in establishing discount rates for active coal. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 1K.

<u>Safe Rate</u>	90 day Treasury Bill		<u>Safe Rate</u>
January	December	2015	0.053%
January	December	2014	0.033%
January	December	2013	0.058%

<u>Risk Rate</u>	Interest differential between Loan Rate and 90 day Treasury Bill			<u>Debt Risk Rate</u>
<u>Loan Rate*</u>				
2015	5.28%			5.207%
2014	5.25%			5.217%
2013	5.25%			5.182%
	*Prime plus 2%			

<u>Equity</u>	Differential between Equity Rates and 90 day Treasury Bill			<u>Equity Risk Rate</u>
<u>Equity Rate**</u>				
2015	(11.75%/(1-.30))-0.053			18.733%
2013	(11.75%/(1-.30))-0.033			18.753%
2012	(11.75%/(1-.30))-0.055			18.728%
	** Value Line Investment Survey Analysis			

<u>Composite Risk Rate</u>	Loan and Equity Rates weighted by industry estimated capital structure.		
	<u>Equity Rate</u>	<u>Debt Rate</u>	<u>Composite Risk</u>
2015	10.040%	2.083%	12.123%
2014	10.052%	2.087%	12.138%
2013	10.037%	2.077%	12.114%
Note: Debt Equity Ratio		Debt 40%	Equity 60%

<u>Non Liquidity Rate</u>			Interest differential between 90 day Treasury Bill and a 1 year Treasury Bill which reflects a reasonable time necessary to sell active property.		
			<u>1yr T. Bill</u>	<u>90 d T. Bill</u>	<u>Non Liquidity Rate</u>
January	December	2015	0.322%	0.053%	0.289%
January	December	2014	0.121%	0.033%	0.088%
January	December	2013	0.132%	0.058%	0.074%

<u>Management Rate</u>	Charges for the management of investment portfolios.	
Fixed Rate (by Rule)	0.500%	

<u>Inflation Rate</u>			
January	December	2015	0.730%
January	December	2014	0.780%
January	December	2013	1.500%

<u>Property Tax Rate</u>	Sixty percent (60%) of State average Class III property tax rate.		
January	December	2015	60% of 2.190 = 1.314%
January	December	2014	60% of 2.190 = 1.314%
January	December	2013	60% of 2.190 = 1.314%

<u>Capitalization Rate</u>	Since the valuation of other mined mineral property is predicated on a three year production average, the capitalization rate is considered in a similar manner.		
	<u>2015</u>	<u>2014</u>	<u>2013</u>
Inflation Rate	-0.730%	-0.780%	-1.500%
Safe Rate	0.053%	0.033%	0.058%
Composite Risk Rate	12.123%	12.138%	12.114%
Non Liquidity Rate	0.289%	0.088%	0.074%
Management Rate	0.500%	0.500%	0.500%
Property Tax Rate	1.314%	1.314%	1.314%
<u>Total</u>	<u>13.529%</u>	<u>13.314%</u>	<u>12.580%</u>

Three Yr Average: 13.134% Rounded to: **13.10%**

CAPITALIZATION RATE - 13.10%

MULTIPLIERS:	%	%
1YR	0.940	5.437
2YR	1.772	5.746
3YR	2.507	6.022
4YR	3.157	6.285
5YR	3.731	6.480
6YR	4.240	6.669
7YR	4.689	6.837
8YR	5.088	

OTHER MINED MINERALS

ROYALTY RATE SURVEY

The determination of royalty rates for other mined minerals within the state of West Virginia is dependent upon the availability of leasehold information. Since this information is limited, the Department has chosen to review data for the most recent thirty year period. A summary only of this review is shown below in order to protect the confidentiality of parties involved:

RESOURCE	DATA SOURCES	AVERAGE ROYALTY	MEDIAN ROYALTY	TY2017 RATE
LIMESTONE	15	\$0.22	\$0.20	\$0.22
SANDSTONE	8	\$0.31	\$0.25	\$0.30
CLAY/SHALE	34	\$0.12	\$0.10	\$0.11
SAND/GRAVEL	10	\$0.35	\$0.40	\$0.40
SALT BRINE	1	N/A	N/A	\$0.10

RESERVE VALUES

	number of sales	\$/AC
LIMESTONE	5	\$3,000.00
SANDSTONE	8	\$2,300.00
CLAY/SHALE	16	\$850.00
SAND/GRAVEL	6	\$4,000.00
SALT	2	\$1,140.00



STATE OF WEST VIRGINIA

Department of Revenue
State Tax Department

Earl Ray Tomblin
Governor

Mark W. Matkovich
State Tax Commissioner

September 1, 2016

The Honorable Natalie Tennant
Secretary of State
Building 1, Suite 157-K
State Capitol
Charleston, West Virginia 25305

Dear Secretary Tennant:

Attached are final natural resource property valuation variables for the 2017 Tax Year that have been developed by the State Tax Department for use in appraising oil and gas, managed timberland, coal and other natural resource properties for ad valorem tax purposes.

In accordance with requirements of §§ 110 CSR 1-I, 1-J, and 1-K, tentative variables were made available for public comments on June 30, 2016. The Department received nine comments on the tentative variables. One comment related to the valuation of coal and three comments related to reserve oil and gas values and 5 related to the expenses allowed in the valuation of producing oil and gas wells. The information supplied for coal and reserve oil and gas did not result in any change to the tentative variables. The oil and gas comments resulted in adjustments to the operating expenses allowed in the valuation of producing oil and gas wells. Additionally, the prices for Metallurgical and Steam coal were updated based upon information that was unavailable on June 30.

The final valuation variables are being filed for inclusion in the State Register.

Sincerely,

Mark W. Matkovich
State Tax Commissioner

MWM/jaj

Attachment

cc: All County Assessors

OIL AND GAS PROPERTIES ANALYSIS

Tax Year 2017

September 1, 2016
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

OIL AND GAS

TY 2017

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for producing oil and gas properties. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 1J.

Safe Rate (3-Month Constant Maturity Interest Rates)

January December 2015

0.053%

Risk Rate (Interest differential between Loan Rate and 3-Month Constant Maturity Interest Rates)Loan Rate*Risk Rate

2015 5.280%

5.207%

*Prime plus 2%

Equity (Differential between Equity Rates and 3-Month Constant Maturity Interest Rates)Equity Rate**Risk Rate

2015 [12.25%/(1-.37)]-0.053%

19.391%

** Value Line Investment Survey Analysis

Composite Risk Rate

Loan and Equity Rates weighted by industry estimated capital structure.

Equity RateDebt RateComposite Risk

2015 12.8042%

1.822%

15.186%

Note: Debt equity Ratio

Debt

35%

Equity

65%

*** Effective severance tax adjustment

0.95

Non Liquidity Rate

Interest differential between 3-month Constant Maturity Interest Rates and a 1 year Constant Maturity Interest Rates which reflects a reasonable time necessary to sell active property.

January

December

2015

1yr T.Bill

0.322%

90 day T.Bill

0.053%

Non Liquidity Rate

0.289%

Management Rate

Charges for the management of investment portfolios.

Fixed Rate (by Rule)

0.500%

Property Tax Rate

Sixty percent (60%) of State average Class III property tax rate.

2015

60% of 2.19

1.314%

Inflation Rate

January

December

2015

0.730%

Capitalization Rate

Since the valuation of oil and gas property is predicated on a three year production, the capitalization rate will be considered in a similar manner.

	<u>2015</u>	<u>2014</u>	<u>2013</u>
Inflation Rate	-0.730%	-0.780%	-1.500%
Safe Rate	0.053%	0.033%	0.058%
Composite Risk Rate	15.188%	14.389%	14.834%
Non Liquidity Rate	0.269%	0.088%	0.074%
Management Rate	0.500%	0.500%	0.500%
Property Tax Rate	1.314%	1.314%	1.314%
Total	16.592%	15.584%	15.080%
	50.000%	33.333%	18.897%
	8.298%	5.188%	2.513%
			15.997%

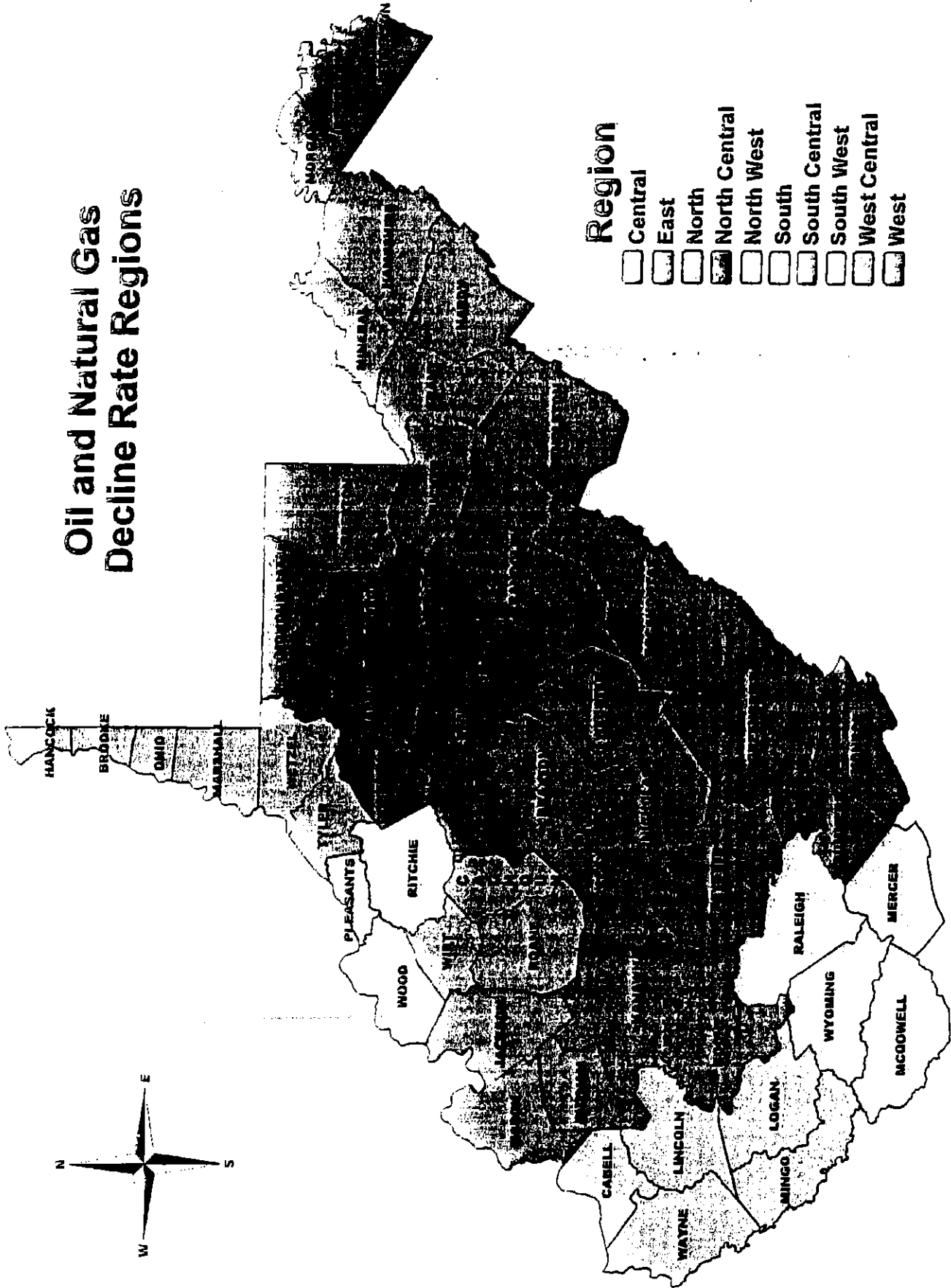
Capitalization Rate Rounded to:

18.00%

MULTIPLIERS FOR 18.0% MID-YEAR LIFE (ANNUALLY)

<u>YEAR</u>		<u>YEAR</u>	
1	0.928477	21	0.047710
2	0.800411	22	0.041128
3	0.690009	23	0.035455
4	0.594838	24	0.030586
5	0.512789	25	0.026350
6	0.442080	26	0.022715
7	0.381088	27	0.019582
8	0.328522	28	0.016861
9	0.283208	29	0.014583
10	0.244146	30	0.012548
11	0.210470	31	0.010815
12	0.181440	32	0.009323
13	0.156414	33	0.008037
14	0.134840	34	0.006929
15	0.116241	35	0.005973
16	0.100208	36	0.005148
17	0.086358	37	0.004439
18	0.074471	38	0.003827
19	0.064189	39	0.003299
20	0.055344	40	0.002844

Oil and Natural Gas Decline Rate Regions



Decline Rates for Natural Gas and Oil Formations: Central

Central: Braxton, Clay, Fayette, Nicholas, Webster

Code	Formation	Year 1	Year 2	Year 3 +
12	Alexander, Benson	-0.31	-0.20	-0.10
14	Benson	-0.48	-0.08	-0.08
16	Benson, Balltown+	-0.45	-0.16	-0.12
17	Gordon +	-0.30	-0.07	-0.07
18	Big Injun	-0.34	-0.13	-0.13
19	Big Injun, Big Lime	-0.36	-0.13	-0.13
22	Big Lime	-0.34	-0.34	-0.13
26	Ravenc Cliff	-0.40	-0.40	-0.25
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.41	-0.22	-0.09
110	Marcellus *	-0.41	-0.22	-0.09
9	Exception (Median)	-0.41	-0.22	-0.09
10	Non-Filer	-0.30	-0.07	-0.07

Decline Rates for Natural Gas and Oil Formations: East

**East: Berkeley, Grant, Greenbrier, Hampshire, Hardy, Jefferson, Mineral,
Monroe, Morgan, Pendleton, Pocahontas, Preston, Randolph, Summers,
Tucker**

Code	Formation	Year 1	Year 2	Year 3 +
1	Oriskany	-0.30	-0.30	-0.19
14	Benson	-0.31	-0.17	-0.12
20	Benson +	-0.44	-0.20	-0.08
21	Benson, Fifth	-0.29	-0.28	-0.09
32	Brallier +	-0.48	-0.20	-0.05
33	Elk, Benson	-0.39	-0.21	-0.08
34	Elk, Benson, Riley	-0.53	-0.19	-0.05
35	Elk, Benson, Riley +	-0.38	-0.19	-0.11
36	Elk, Benson, Balltown	-0.34	-0.18	-0.11
37	Elk, Alexander, Benson	-0.50	-0.07	-0.07
38	Elk, Alexander, Benson +	-0.40	-0.18	-0.18
39	Hunterville	-0.31	-0.31	-0.14
40	Fox, Haverly	-0.38	-0.21	-0.15
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.28	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
110	Marcellus	-0.59	-0.22	-0.17
111	Utica*	-0.59	-0.22	-0.17
9	Exception (Median)	-0.41	-0.22	-0.10
10	Non-Filer	-0.29	-0.07	-0.05

Decline Rates for Natural Gas and Oil Formations: North

North: Brooke, Hancock, Marshall, Ohio, Tyler, Wetzel

Code	Formation	Year 1	Year 2	Year 3 +
11	Gordon	-0.47	-0.31	-0.09
13	Alexander, Benson, Riley	-0.28	-0.16	-0.15
15	Benson, Riley	-0.18	-0.18	-0.08
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
97	Coalbed Methane (Vertical)	-0.23	-0.08	-0.05
110	Marcellus	-0.52	-0.23	-0.18
111	Utica*	-0.52	-0.23	-0.18
9	Exception (Median)	-0.39	-0.23	-0.08
10	Non-Filer	-0.18	-0.16	-0.08

Decline Rates for Natural Gas and Oil Formations: North Central				
North Central: Barbour, Doddridge, Gilmer, Harrison, Lewis, Marion, Monongalia, Taylor, Upshur				
Code	Formation	Year 1	Year 2	Year 3 +
11	Gordon	-0.41	-0.14	-0.12
12	Alexander, Benson	-0.37	-0.19	-0.11
13	Alexander, Benson, Riley	-0.40	-0.28	-0.06
14	Benson	-0.31	-0.17	-0.12
15	Benson, Riley	-0.34	-0.17	-0.14
18	Big Injun	-0.38	-0.16	-0.13
21	Benson, Fifth	-0.31	-0.20	-0.14
28	Weir	-0.34	-0.34	-0.07
29	Weir +	-0.28	-0.28	-0.23
33	Elk, Benson	-0.34	-0.16	-0.11
34	Elk, Benson, Riley	-0.42	-0.27	-0.08
37	Elk, Alexander, Benson	-0.49	-0.23	-0.08
38	Elk, Alexander, Benson +	-0.36	-0.20	-0.12
40	Fox, Haverly	-0.48	-0.18	-0.08
50	Rhinestreet	-0.28	-0.03	-0.03
57	Alexander, Benson, Balltown	-0.39	-0.28	-0.08
58	Alexander	-0.35	-0.20	-0.10
59	Alexander +	-0.39	-0.22	-0.10
60	Alexander, Benson, Riley +	-0.39	-0.35	-0.12
61	Balltown	-0.35	-0.20	-0.10
62	Balltown, Speechley	-0.26	-0.22	-0.10
63	Balltown, Speechley +	-0.30	-0.13	-0.10
64	Benson, Balltown, Speechley	-0.26	-0.22	-0.09
65	Benson, Bradford	-0.37	-0.20	-0.10
66	Benson, Balltown	-0.29	-0.23	-0.11
67	Benson, Riley +	-0.36	-0.14	-0.10
68	Benson, Speechley	-0.30	-0.22	-0.14
69	Brallier, Elk	-0.42	-0.20	-0.13
70	Brallier	-0.40	-0.22	-0.15
71	Deeper/Onondaga or Oriskany/Helderberg	-0.24	-0.24	-0.03
72	Elk, Alexander	-0.42	-0.22	-0.09
73	Elk, Benson +	-0.36	-0.20	-0.12
74	Elk	-0.43	-0.12	-0.10
75	Elk, Riley	-0.80	-0.35	-0.17
76	Fox +	-0.46	-0.16	-0.09
77	Haverly, Elk, Benson (No Alexander)	-0.35	-0.16	-0.16
78	Haverly	-0.45	-0.15	-0.15
79	Riley	-0.44	-0.22	-0.10
80	Speechley	-0.30	-0.18	-0.09
81	Alexander, Benson, Speechley	-0.39	-0.24	-0.10
82	Haverly, Elk, Alexander	-0.47	-0.14	-0.14
85	Fifth, Oil	-0.45	-0.25	-0.22
87	Bayard All	-0.30	-0.20	-0.05
88	Fifth	-0.29	-0.16	-0.12
89	Fifth +	-0.25	-0.15	-0.13
90	Gordon, Injun All	-0.41	-0.23	-0.23
91	Squaw	-0.37	-0.31	-0.06
92	Injun +	-0.34	-0.22	-0.22
93	4th Sand	-0.42	-0.32	-0.06
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Mexton	-0.70	-0.27	-0.08
97	Coalbed Methane (Vertical)	-0.23	-0.06	-0.05
98	Coalbed Methane (Horizontal)	-0.05	-0.05	-0.32
109	Trenton/Deeper *	-0.38	-0.21	-0.11
110	Marcellus	-0.59	-0.29	-0.23
111	Utica**	-0.59	-0.29	-0.23
9	Exception (Median)	-0.36	-0.21	-0.11
10	Non-Filer	-0.23	-0.03	-0.03

*New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: North West				
North West: Pleasants, Ritchie, Wood				
Code	Formation	Year 1	Year 2	Year 3+
2	Huron, Rhinestreet	-0.41	-0.28	-0.07
4	Huron	-0.42	-0.24	-0.14
5	Huron, Shales above Huron	-0.39	-0.25	-0.14
8	Berea	-0.31	-0.15	-0.15
11	Gordon	-0.38	-0.10	-0.10
12	Alexander, Benson (No Riley)	-0.34	-0.23	-0.10
13	Alexander, Benson, Riley	-0.32	-0.20	-0.10
14	Benson	-0.19	-0.19	-0.10
44	Rhinestreet, Huron, Shallow Shale	-0.43	-0.26	-0.11
47	Alexander, Riley, (No Benson)	-0.41	-0.05	-0.05
48	Rhinestreet, Alexander, Benson, Riley	-0.31	-0.24	-0.10
49	Weir, Squaw, Big Injun	-0.27	-0.17	-0.07
50	Rhinestreet	-0.40	-0.27	-0.27
51	Rhinestreet +	-0.38	-0.21	-0.10
52	All Upper Devonian (Undiv)	-0.48	-0.33	-0.19
53	Huron, Chemung	-0.35	-0.11	-0.09
54	Huron, Hampshire, Pocono	-0.12	-0.12	-0.11
55	Upper Devonian (Above Huron)	-0.46	-0.33	-0.23
58	Chemung Sands= Riley, Bradford, Belltown, Speechley, Warren (No Benson or Alexander)	-0.28	-0.18	-0.10
83	Huron Oil	-0.74	-0.44	-0.40
93	4th Sand	-0.42	-0.32	-0.06
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.39	-0.23	-0.13
110	Marcellus	-0.46	-0.29	-0.23
111	Utica**	-0.46	-0.29	-0.23
9	Exception (Median)	-0.39	-0.23	-0.13
10	Non-Filer	-0.12	-0.05	-0.05

*New Formation(s) involved in recent production. These will be valued with the Exception Rates until decline information is available.

Decline Rates for Natural Gas and Oil Formations: South

South: McDowell, Mercer, Raleigh, Wyoming

Code	Formation	Year 1	Year 2	Year 3 +
8	Berea	-0.34	-0.15	-0.15
22	Big Lime	-0.31	-0.19	-0.07
23	Big Lime, Maxton	-0.31	-0.19	-0.07
24	Big Lime, Ravencloff	-0.29	-0.29	-0.17
25	Berea +	-0.37	-0.12	-0.08
28	Ravencloff	-0.40	-0.08	-0.07
28	Weir	-0.44	-0.20	-0.10
29	Weir +	-0.28	-0.21	-0.08
30	Weir, Big Lime	-0.37	-0.19	-0.13
42	Maxton, Ravencloff	-0.40	-0.08	-0.07
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.28	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.27	-0.13	-0.09
97	Coalbed Methane (Vertical)	0.03	0.10	-0.05
98	Coalbed Methane (Horizontal)	-0.05	-0.05	-0.32
110	Marcellus *	-0.36	-0.19	-0.09
9	Exception (Median)	-0.36	-0.19	-0.09
10	Non-Filer	-0.23	-0.08	-0.05

Decline Rates for Natural Gas and Oil Formations: South Central

South Central: Boone, Kanawha

Code	Formation	Year 1	Year 2	Year 3 +
3	Devonian Shale	-0.23	-0.08	-0.05
4	Huron	-0.31	-0.15	-0.04
8	Berea	-0.23	-0.14	-0.09
18	Big Injun	-0.29	-0.25	-0.12
27	Huron, Shales above Huron	-0.21	-0.08	-0.05
28	Weir	-0.30	-0.21	-0.14
29	Weir +	-0.31	-0.25	-0.09
31	Devonian Shales +	-0.27	-0.07	-0.05
86	Big Injun-Oil	-0.19	-0.18	-0.10
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.33	-0.19	-0.08
110	Marcellus *	-0.33	-0.19	-0.08
9	Exception (Median)	-0.33	-0.19	-0.08
10	Non-Filer	-0.19	-0.07	-0.04

Decline Rates for Natural Gas and Oil Formations: South West

South West: Cabell, Lincoln, Logan, Mingo, Wayne

Code	Formation	Year 1	Year 2	Year 3 +
3	Devonian Shale	-0.31	-0.15	-0.04
8	Berea	-0.36	-0.11	-0.11
18	Big Injun	-0.38	-0.22	-0.04
22	Big Lime	-0.19	-0.19	-0.19
43	Berea, Big Lime	-0.18	-0.18	-0.18
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.28	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.38	-0.22	-0.10
110	Marcellus *	-0.38	-0.22	-0.10
9	Exception (Median)	-0.38	-0.22	-0.10
10	Non-Filer	-0.18	-0.11	-0.04

Decline Rates for Natural Gas and Oil Formations: West Central

West Central: Calhoun, Roane, Wirt

Code	Formation	Year 1	Year 2	Year 3 +
2	Huron, Rhinestreet	-0.49	-0.11	-0.06
4	Huron	-0.33	-0.22	-0.14
27	Huron, Shales above Huron	-0.42	-0.23	-0.12
44	Rhinestreet, Huron, Shallow Shale	-0.51	-0.14	-0.11
45	Devonian Shale, Pocono	-0.25	-0.17	-0.12
46	Pocono	-0.29	-0.25	-0.12
84	Big Injun, Oil	-0.41	-0.41	-0.11
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.28	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
98	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.42	-0.24	-0.10
110	Marcellus *	-0.42	-0.24	-0.10
9	Exception (Median)	-0.42	-0.24	-0.10
10	Non-Filer	-0.25	-0.11	-0.06

Decline Rates for Natural Gas and Oil Formations: West

West: Jackson, Mason, Putnam

Code	Formation	Year 1	Year 2	Year 3 +
1	Oriskany	-0.40	-0.40	-0.29
2	Huron, Rhinestreet	-0.13	-0.12	-0.03
3	Devonian Shale	-0.31	-0.15	-0.04
4	Huron	-0.29	-0.14	-0.05
5	Huron, Shales above Huron	-0.38	-0.15	-0.06
6	Huron, Berea	-0.29	-0.08	-0.08
7	Berea, Devonian Shale	-0.08	-0.08	-0.08
6	Berea	-0.38	-0.16	-0.18
93	4th Sand	-0.42	-0.32	-0.06
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.28	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.35	-0.20	-0.09
110	Marcellus *	-0.35	-0.20	-0.09
9	Exception (Median)	-0.35	-0.20	-0.09
10	Non-Filer	-0.08	-0.08	-0.03

Industry Operating Expense Survey and Results

This component was determined through a review of responses to a survey distributed by the State Tax Department to producers of all oil and natural gas wells producing in West Virginia and through use of other market data.

GAS

- % Working Interest Expenses for Typical Producing Well	=	45%
- Maximum Operating Expenses	=	\$5,000
- Coal Bed Methane, Vertical Wells Expenses	=	\$9,000

OIL

- % Working Interest Expenses for Typical Producing Well	=	35%
- Maximum Operating Expenses	=	\$5,750
- Maximum Enhanced Operating Expenses	=	\$9,000

MARCELLUS/UTICA

- % Working Interest Expenses for Vertical Producing Well	=	30%
- Maximum Operating Expenses	=	\$30,000
- % Working Interest Expenses for Horizontal Producing Well	=	20%
- Maximum Operating Expenses	=	\$175,000

HORIZONTAL WELLS (OTHER THAN MARCELLUS/UTICA AND COAL BED METHANE)

- % Working Interest Expenses for Horizontal Producing Well	=	30%
- Maximum Operating Expenses	=	\$20,000

Minimum Working Interest Appraisal = \$500 per well

Flat Rate Royalty Multiplier = 5.75

Home Use Only Wells: Appraised at \$500 per well

Industrial Use Only Wells:* MCF usage X \$ 2.62/MCF
BBL usage X \$48.66/BBL

*(Also includes Department of Environmental Protection reported wells.)

Non-Filer Valuations

Working Interest	=	150% of previous year's appraisal
Royalty Interest	=	90% of previous year's appraisal

Valuation

The previously discussed variables are used to establish a future income stream converted to present worth through application of a capitalization rate. The sum of the discounted future net income per year represents a reasonable estimate of market value.

Lease Rate/Term Survey and Results

The non-producing property value for each county is determined by multiplying the average delay rental by a factor, which represents the average lease term under present economic conditions.

As a result of higher lease terms being inversely proportional to the value of oil and gas (thus counties with little leasing or production activities reflect inflated values) and with the volatile nature of county activity, necessary adjustments in the review have been made.

A compilation of lease terms produced a statewide average of 5 years. This term (5 years) was applied to all county lease rates and compared to the appraisal rates derived from calculations using individual county data as well as regional data. The resulting calculations were reviewed and considered in the assignment of an appraisal rate per acre.

The appraisal rate/acre amounts shown on the next page are preliminary figures, which may change if additional lease data is received. These rates have been applied to all county magisterial districts with either producing wells, lease activity within the past 5 years or both. Tax districts void of activity within the past 5 years have been assigned the minimum value per acre.

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
BARBOUR	1	1.	\$80.00
		2	\$1.00
		3	\$80.00
		4	\$80.00
		5	\$60.00
		6	\$1.00
		7	\$80.00
		8	\$80.00
		9	\$80.00
		10	\$80.00
		11	\$80.00
BERKELEY	2	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
BOONE	3	1	\$20.00
		2	\$1.00
		3	\$1.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
		7	\$1.00
		8	\$20.00
		9	\$1.00
BRAXTON	4	1	\$20.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$20.00
		7	\$20.00
		8	\$1.00
BROOKE	5	1	\$1.00
		2	\$1.00
		3	\$100.00
		4	\$100.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AG
CABELL	8	1	\$25.00
		2	\$1.00
		3	\$25.00
		4	\$25.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$25.00
		9	\$1.00
		10	\$25.00
CALHOUN	7	1	\$30.00
		2	\$1.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		8	\$30.00
CLAY	8	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		8	\$20.00
DODDRIDGE	9	1	\$90.00
		2	\$90.00
		3	\$90.00
		4	\$90.00
		5	\$90.00
		8	\$90.00
		7	\$90.00
		8	\$90.00
		9	\$1.00
FAYETTE	10	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
GILMER	11	1	\$25.00
		2	\$25.00
		3	\$25.00
		4	\$1.00
		5	\$1.00
		6	\$25.00
GRANT	12	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
GREENBRIER	13	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$1.00
HAMPSHIRE	14	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
HANCOCK	15	1	\$25.00
		2	\$1.00
		3	\$25.00
		4	\$25.00
		5	\$1.00
		6	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
HARDY	16	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
HARRISON	17	1	\$90.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$90.00
		6	\$1.00
		7	\$90.00
		8	\$1.00
		9	\$90.00
		10	\$1.00
		11	\$90.00
		12	\$90.00
		13	\$1.00
		14	\$90.00
		15	\$90.00
		16	\$1.00
		17	\$1.00
		18	\$90.00
		19	\$1.00
		20	\$90.00
		21	\$1.00
JACKSON	18	1	\$40.00
		2	\$40.00
		3	\$1.00
		4	\$40.00
		5	\$1.00
		6	\$40.00
		7	\$40.00
JEFFERSON	19	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
KANAWHA	20	1	\$30.00
		2	\$1.00
		3	\$30.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$30.00
		16	\$30.00
		17	\$1.00
		18	\$1.00
		19	\$30.00
		20	\$1.00
		21	\$1.00
		22	\$1.00
		23	\$30.00
		24	\$30.00
		25	\$30.00
		26	\$1.00
		27	\$1.00
		28	\$30.00
		29	\$1.00
		30	\$1.00
		31	\$1.00
LEWIS	21	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$1.00
		6	\$35.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
LINCOLN	22	1	\$25.00
		2	\$25.00
		3	\$1.00
		4	\$25.00
		5	\$25.00
		6	\$25.00
		7	\$25.00
		8	\$25.00
		9	\$25.00
		10	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
LOGAN	23	1	\$15.00
		2	\$15.00
		3	\$15.00
		4	\$15.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$15.00
		9	\$1.00
MARION	24	1	\$1.00
		2	\$90.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$90.00
		10	\$1.00
		11	\$90.00
		12	\$90.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$90.00
		17	\$1.00
		18	\$90.00
		19	\$90.00
		20	\$1.00
		21	\$1.00
		22	\$1.00
MARSHALL	25	1	\$1.00
		2	\$1.00
		3	\$100.00
		4	\$100.00
		5	\$100.00
		6	\$1.00
		7	\$100.00
		8	\$1.00
		9	\$100.00
		10	\$1.00
		11	\$1.00
		12	\$100.00
		13	\$100.00
		14	\$100.00
		15	\$100.00
		16	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
MASON	26	1	\$1.00
		2	\$25.00
		3	\$25.00
		4	\$25.00
		5	\$25.00
		6	\$25.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$25.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$25.00
		15	\$25.00
		16	\$25.00
MC DOWELL	27	1	\$20.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$1.00
		6	\$20.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$20.00
		12	\$1.00
		13	\$20.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
MERCER	28	1	\$1.00
		2	\$15.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$15.00
		7	\$1.00
		8	\$1.00
		9	\$15.00
		10	\$1.00
		11	\$15.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
MINERAL	29	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
MINGO	30	1	\$1.00
		2	\$1.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		6	\$20.00
		7	\$20.00
		8	\$1.00
		9	\$20.00
		10	\$20.00
		11	\$20.00
		12	\$1.00
MONONGALIA	31	1	\$30.00
		2	\$1.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		6	\$1.00
		7	\$30.00
		8	\$30.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$30.00
		19	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
CDUNTY	CO #	DISTRICT #	TY2017 \$/AC
MONROE	32	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
MORGAN	33	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
NICHOLAS	34	1	\$1.00
		2	\$18.00
		3	\$18.00
		4	\$18.00
		5	\$1.00
		6	\$1.00
		7	\$18.00
		8	\$1.00
		9	\$1.00
OHIO	35	1	\$1.00
		2	\$1.00
		3	\$100.00
		4	\$100.00
		5	\$1.00
		6	\$100.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$1.00
PENDLETON	38	1	\$1.00
		2	\$10.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$10.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
PLEASANTS	37	1	\$48.00
		2	\$48.00
		3	\$48.00
		4	\$48.00
		5	\$48.00
		6	\$1.00
		7	\$48.00
		8	\$48.00
POCAHONTAS	38	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
PRESTON	39	1	\$30.00
		2	\$30.00
		3	\$30.00
		4	\$30.00
		5	\$30.00
		6	\$30.00
		7	\$1.00
		8	\$30.00
		9	\$1.00
		10	\$30.00
		11	\$1.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$1.00
		17	\$1.00
		18	\$1.00
		19	\$1.00
		20	\$1.00
PUTNAM	40	1	\$25.00
		2	\$25.00
		3	\$1.00
		4	\$25.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$25.00
		9	\$1.00
		10	\$25.00
		11	\$25.00
		12	\$25.00
		13	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
RALEIGH	41	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$1.00
		7	\$20.00
		8	\$20.00
		9	\$20.00
		10	\$1.00
		11	\$20.00
		12	\$20.00
RANDOLPH	42	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$20.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$20.00
		11	\$20.00
		12	\$1.00
		13	\$1.00
		14	\$1.00
		15	\$1.00
		16	\$20.00
		17	\$1.00
		18	\$1.00
RITCHIE	43	1	\$70.00
		2	\$1.00
		3	\$70.00
		4	\$1.00
		5	\$70.00
		6	\$1.00
		7	\$70.00
		8	\$1.00
		9	\$1.00
		10	\$70.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
ROANE	44	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$35.00
		5	\$1.00
		6	\$35.00
		7	\$35.00
		8	\$1.00
		9	\$35.00
SUMMERS	45	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$1.00
		5	\$10.00
		6	\$1.00
		7	\$1.00
TAYLOR	46	1	\$1.00
		2	\$1.00
		3	\$90.00
		4	\$90.00
		5	\$90.00
		6	\$90.00
		7	\$90.00
TUCKER	47	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$20.00
		6	\$1.00
		7	\$1.00
		8	\$1.00
		9	\$20.00
		10	\$1.00
		11	\$20.00
		12	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
TYLER	46	1	\$90.00
		2	\$90.00
		3	\$1.00
		4	\$90.00
		5	\$90.00
		6	\$90.00
		7	\$1.00
		8	\$1.00
		9	\$1.00
		10	\$80.00
UPSHUR	46	1	\$70.00
		2	\$70.00
		3	\$1.00
		4	\$70.00
		5	\$70.00
		6	\$70.00
		7	\$70.00
WAYNE	50	1	\$20.00
		2	\$20.00
		3	\$1.00
		4	\$1.00
		5	\$1.00
		6	\$1.00
		7	\$1.00
		8	\$20.00
		9	\$20.00
		10	\$20.00
		11	\$1.00
		12	\$20.00
WEBSTER	51	1	\$1.00
		2	\$1.00
		3	\$1.00
		4	\$15.00
		5	\$15.00
		6	\$15.00
		7	\$1.00

OIL & GAS RESERVE RATES FOR TY 2017			
COUNTY	CO #	DISTRICT #	TY2017 \$/AC
WETZEL	52	1	\$90.00
		2	\$90.00
		3	\$90.00
		4	\$90.00
		5	\$90.00
		8	\$1.00
		7	\$1.00
		8	\$90.00
		9	\$1.00
		10	\$1.00
		11	\$1.00
		12	\$90.00
		13	\$1.00
WIRT	53	1	\$35.00
		2	\$35.00
		3	\$35.00
		4	\$1.00
		5	\$35.00
		8	\$35.00
		7	\$35.00
		8	\$35.00
WOOD	54	1	\$40.00
		2	\$40.00
		3	\$40.00
		4	\$40.00
		8	\$1.00
		6	\$40.00
		7	\$40.00
		8	\$40.00
		9	\$40.00
		10	\$1.00
		11	\$40.00
		12	\$40.00
		13	\$1.00
		14	\$1.00
WYOMING	55	1	\$20.00
		2	\$20.00
		3	\$20.00
		4	\$20.00
		5	\$20.00
		8	\$1.00
		7	\$20.00
		8	\$1.00
		9	\$1.00
		10	\$20.00

**MANAGED TIMBER
PROPERTY ANALYSIS**

Tax Year 2017

September 1, 2016
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

MANAGED TIMBERLAND APPRAISAL RATES TAX YEAR 2017

(based on market 2011-2015)

Rates Per Acre

Class II Parcels

	<u>Grade 1</u>	<u>Grade 2</u>	<u>Grade 3</u>
Region 1	\$205	\$140	\$50
Region 2	\$200	\$140	\$50
Region 3	\$265	\$175	\$50
Region 4	\$270	\$185	\$55
Region 5	\$205	\$140	\$50

Class III/IV Parcels

	<u>Grade 1</u>	<u>Grade 2</u>	<u>Grade 3</u>
Region 1	\$225	\$150	\$75
Region 2	\$225	\$150	\$75
Region 3	\$240	\$155	\$75
Region 4	\$245	\$165	\$75
Region 5	\$225	\$150	\$75

- Region 1 = Brooks, Cabell, Hancock, Jackson, Marshall, Mason, Ohio, Pleasants, Putnam, Tyler, Wetzel, and Wood Counties
- Region 2 = Braxton, Calhoun, Clay, Doddridge, Gilmer, Harrison, Lewis, Marion, Monongelle, Ritchie, Roane, Taylor, and Wirt Counties
- Region 3 = Barbour, Greenbrier, Monroe, Nicholas, Pendleton, Pocahontas, Preeton, Randolph, Tucker, Upshur, and Webster Counties
- Region 4 = Berkeley, Grant, Hampshire, Hardy, Jefferson, Mineral and Morgan Counties
- Region 5 = Boone, Fayette, Kanawha, Lincoln, Logan, McDowell, Mercer, Mingo, Raleigh, Summers, Wayne, and Wyoming Counties

Harvest Volumes per Acre

Harvest Interval Grades

	<u>35 yrs.</u>	<u>45 yrs.</u>	<u>55 yrs.</u>	<u>80 yrs.</u>		<u>Total</u>
1 - Site Index 75 or more	4.8 cords	--	2.8 cords	3.3 cords		10.5 cords
	1.5 Mbf	--	4.4 Mbf	8.6 Mbf		14.5 Mbf
2 - Site Index 65 - 75	3.3 cords	--	7.0 cords	4.6 cords		14.9 cords
	1.0 Mbf	--	3.2 Mbf	5.5 Mbf		9.7 Mbf
3 - Site Index less than 65	--	3.1 cords	--	15.4 cords		18.5 cords
	--	0.8 Mbf	--	3.7 Mbf		4.5 Mbf

Managed Timberland Statistics

Estimation of Required Rate of Return: Class II Rates

A. Safe Rate of Return (5 Year T-Bill Rate)

Year	Rate	W/A %	W/A Rate
2015	1.5292	28.67%	0.4076
2014	1.6410	33.33%	0.8469
2013	1.1725	13.33%	0.1563
2012	0.7808	6.67%	0.0507
2011	1.5225	20.00%	0.3045

1.468 %

B. Nonliquidity Rate

(12 Month T-Bills vs. 3 Month T-Bills)

Year	Rate	W/A %	W/A Rate
2015	0.2663	33.33%	0.0894
2014	0.0663	26.67%	0.0235
2013	0.0733	20.00%	0.0147
2012	0.1292	13.33%	0.0172
2011	0.1817	6.67%	0.0121

0.187 %

C. Risk Rate (30 yr T-bills vs 5 yr T-bills)

Year	Rate	W/A %	W/A Rate
2015	1.3117	13.33%	0.1748
2014	1.6992	26.67%	0.4532
2013	2.2756	20.00%	0.4552
2012	2.1600	33.33%	0.7199
2011	2.3883	6.67%	0.1593

1.992 %

D. Management Factor of 0.5%

0.600 %

E. Property Tax Component

(80% of Class II Rate)

Year	Rate	W/A %	W/A Rate
2015	0.714	33.33%	0.2360
2014	0.714	26.67%	0.1904
2013	0.706	20.00%	0.1415
2012	0.714	13.33%	0.0952
2011	0.706	6.67%	0.0472

0.712 %

F. Inflation Rate:

(Bureau of Labor Statistics)

Year	Rate	W/A %	W/A Rate
2015	0.730	33.33%	0.2433
2014	0.760	26.67%	0.2027
2013	1.500	20.00%	0.3000
2012	1.700	13.33%	0.2266
2011	3.000	6.67%	0.2001

(1.173) %

TOTAL REQUIRED RATE OF RETURN (REAL)

3.625 %

LESS: PROPERTY TAX COMPONENT

(0.712)

TOTAL DISCOUNT COMPONENT

2.913 %

Stumpage Prices:

	<u>Sawtimber</u>	<u>Pulpwood</u>
Stumpage Price Adjustment Factor	0.00%	1.85%

		1.0000	1.0000	1.0000	1.0000
<u>SAWTIMBER</u>	Current	\$/MBF at age	\$/MBF at age	\$/MBF at age	\$/MBF at age
Region	\$/MBF	35	45	55	80
Region 1	181.34	181.34	181.34	181.34	181.34
Region 2	172.92	172.92	172.92	172.92	172.92
Region 3	239.28	239.28	239.28	239.28	239.28
Region 4	235.49	235.49	235.49	235.49	235.49
Region 5	190.59	190.59	190.59	190.59	190.59

		1.8995	2.2816	2.7407	4.3339
<u>PULPWOOD:</u>		\$/cd at age	\$/cd at age	\$/cd at age	\$/cd at age
Region	\$/Cord	35	45	55	80
Region 1	8.54	18.23	19.49	23.41	37.02
Region 2	8.73	12.79	15.38	18.45	29.15
Region 3	5.13	9.75	11.71	14.07	22.24
Region 4	8.10	15.39	18.49	22.21	35.12
Region 5	5.77	10.88	13.18	15.61	25.00

Management Costs:

Region	\$/acre (1)
1	3.17
2	3.17
3	3.17
4	3.17
5	3.17
State	

Tax Rates:

Effective Federal Income Tax Rate	35.00%
Effective WV State Income Tax Rate (6.5% * (1-.35))	4.23%
Effective WV Severance Tax Rate (1.5% * (1-.35))	0.98%

Yield (Volumes) (80 year rotation)

Timberland Productivity Grades	Site Index	Yield - MBF	Yield - Cords
Grade I	75 or more	14.5	10.5
Grade II	65-74	9.7	14.9
Grade III	less than 65	4.5	18.5

Managed Timberland Statistics

Estimation of Required Rate of Return: Class III & IV Blended Rates

A. Safe Rate of Return (5 Year T-Bill Rate)

Year	Rate	W/A %	W/A Rate
2015	1.5292	26.67%	0.4076
2014	1.8410	33.33%	0.5489
2013	1.1726	13.33%	0.1663
2012	0.7808	6.67%	0.0507
2011	1.5225	20.00%	0.3045

1.486 %

B. Nonliquidity Rate

(12 Month T-Bills vs. 3 Month T-Bills)

Year	Rate	W/A %	W/A Rate
2015	0.2663	33.33%	0.0894
2014	0.0663	26.67%	0.0236
2013	0.0733	20.00%	0.0147
2012	0.1292	13.33%	0.0172
2011	0.1617	6.67%	0.0121

0.157 %

C. Risk Rate (30 yr T-bills vs 5 yr T-bills)

Year	Rate	W/A %	W/A Rate
2015	1.3117	13.33%	0.1746
2014	1.6992	26.67%	0.4632
2013	2.2756	20.00%	0.4652
2012	2.1600	33.33%	0.7199
2011	2.3663	6.67%	0.1563

1.662 %

D. Management Factor of 0.5%

0.500 %

E. Property Tax Component

(80% of Blended III&IV Rates)

Year	Rate	W/A %	W/A Rate
2015	1.314	33.33%	0.4380
2014	1.314	26.67%	0.3504
2013	1.314	20.00%	0.2628
2012	1.326	13.33%	0.1766
2011	1.326	6.67%	0.0884

1.316 %

F. Inflation Rate:

(Bureau of Labor Statistics)

Year	Rate	W/A %	W/A Rate
2015	0.730	33.33%	0.2433
2014	0.760	26.67%	0.2027
2013	1.500	20.00%	0.3000
2012	1.700	13.33%	0.2266
2011	3.000	6.67%	0.2001

(1.173) %

TOTAL REQUIRED RATE OF RETURN (REAL)

4.229 %

LESS: PROPERTY TAX COMPONENT

(1.316)

TOTAL DISCOUNT COMPONENT

2.913 %

Stumpage Prices:

	<u>Sawtimber</u>	<u>Pulpwood</u>
Stumpage Price Adjustment Factor	0.00%	1.85%

		1.0000	1.0000	1.0000	1.0000
SAWTIMBER	Current	\$/MBF at age	\$/MBF at age	\$/MBF at age	\$/MBF at age
Region	\$/MBF	35	45	55	80
Region 1	181.34	181.34	181.34	181.34	181.34
Region 2	172.92	172.92	172.92	172.92	172.92
Region 3	239.25	239.25	239.28	239.28	239.28
Region 4	235.49	235.49	235.49	235.49	235.49
Region 5	190.59	180.59	190.59	190.59	190.59

		1.8895	2.2815	2.7407	4.3339
PULPWOOD:		\$/cd at age	\$/cd at age	\$/cd at age	\$/cd at age
Region	\$/Cord	35	45	55	80
Region 1	8.54	16.23	19.49	23.41	37.02
Region 2	8.73	12.78	15.35	18.45	29.18
Region 3	5.13	9.75	11.71	14.07	22.24
Region 4	8.10	15.39	18.49	22.21	35.12
Region 5	5.77	10.99	13.19	15.81	25.00

Management Costs:

Region	\$/acre (1)
1	3.17
2	3.17
3	3.17
4	3.17
5	3.17
State	

Tax Rates:

Effective Federal Income Tax Rate	35.00%
Effective WV State Income Tax Rate (8.5% * (1-.35))	4.23%
Effective WV Severance Tax Rate (1.5% * (1-.35))	0.98%

Yield (Volumes) (80 year rotation)

Productivity Grades	Site Index	Yield - MBF	Yield - Cords
Grade I	75 or more	14.5	10.5
Grade II	55-74	9.7	14.9
Grade III	less than 55	4.5	18.5

West Virginia Wgt/Avg Managed Timberland Stumpage Prices

REGION 1 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2015	12,581.80	192.65	33.33%	84.28
2014	12,182.08	178.34	28.87%	47.02
2013	19,017.77	177.48	20.00%	35.49
2012	12,828.18	185.58	13.33%	24.87
2011	11,195.24	144.89	8.87%	9.88
	67,585.02			181.34

REGION 1 - Pulpwood*

Year	Volume	\$/CORD	W/A%	\$/CORD
2015	7,218.90	15.03	33.33%	5.01
2014	484.40	5.40	28.87%	1.44
2013	8,102.20	2.98	20.00%	0.59
2012	45,387.00	6.42	13.33%	0.88
2011	48.10	9.87	8.87%	0.84
	59,220.80			8.54

REGION 2 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2015	28,487.85	175.25	33.33%	58.42
2014	22,001.80	182.47	28.87%	48.86
2013	25,896.85	177.79	20.00%	35.58
2012	25,840.98	149.01	13.33%	19.87
2011	12,839.41	155.28	8.87%	10.42
	112,865.89			172.92

REGION 2 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2015	42,883.30	5.97	33.33%	1.99
2014	2,168.10	8.04	28.87%	1.34
2013	119,279.40	12.83	20.00%	2.57
2012	22,847.40	2.88	13.33%	0.38
2011	5,235.20	8.78	8.87%	0.45
	192,193.40			8.73

REGION 3 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2015	135,987.80	207.12	33.33%	69.04
2014	91,487.44	280.52	28.87%	74.81
2013	181,397.70	275.83	20.00%	55.13
2012	111,920.80	201.57	13.33%	28.88
2011	102,218.30	201.48	8.87%	13.43
	602,971.84			239.28

REGION 3 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2015	184,907.30	3.85	33.33%	1.28
2014	170,738.30	3.67	28.87%	0.98
2013	153,197.40	7.78	20.00%	1.58
2012	183,132.80	8.39	13.33%	0.85
2011	159,040.70	7.34	8.87%	0.49
	851,014.30			5.13

REGION 4 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2015	8,644.42	223.42	33.33%	74.47
2014	6,020.90	303.89	26.67%	61.04
2013	12,820.20	211.47	20.00%	42.29
2012	4,808.73	193.47	13.33%	25.80
2011	18,517.51	178.40	8.67%	11.69
	44,811.78			235.49

REGION 4 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2015	8,137.40	7.22	33.33%	2.41
2014	7,785.20	8.16	26.67%	2.18
2013	15,466.80	8.32	20.00%	1.66
2012	7,382.20	9.61	13.33%	1.28
2011	21,074.10	6.64	8.67%	0.58
	57,847.50			8.10

REGION 5 - Sawtimber

Year	Volume	\$/MBF	W/A%	\$/MBF
2015	37,714.40	160.15	33.33%	53.36
2014	21,881.40	265.85	26.67%	70.92
2013	31,858.00	195.20	20.00%	39.64
2012	10,867.05	138.63	13.33%	18.46
2011	24,760.43	122.43	8.67%	8.16
	126,882.28			190.69

REGION 5 - Pulpwood

Year	Volume	\$/CORD	W/A%	\$/CORD
2015	2,889.50	4.05	33.33%	1.35
2014	10,181.40	6.19	26.67%	1.65
2013	16,282.60	7.13	20.00%	1.43
2012	8,295.30	6.93	13.33%	0.92
2011	6,432.30	8.26	8.67%	0.42
	48,102.10			5.77

COAL PROPERTIES ANALYSIS

Tax Year 2017

September 1, 2016
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

COAL CAPITALIZATION RATE

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for active coal. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 11.

<u>Safe Rate</u>	90 day Treasury Bill	<u>Safe Rate</u>
January	December 2016	0.053%
January	December 2014	0.033%
January	December 2013	0.056%

<u>Risk Rate</u>	Interest differential between Loan Rate and 90 day Treasury Bill		<u>Debt Risk Rate</u>
<u>Loan Rate*</u>			
2016	5.25%		5.207%
2014	5.25%		5.217%
2013	6.25%		5.192%
	*Prime plus 2%		

<u>Equity</u>	Differential between Equity Rates and 90 day Treasury Bill		<u>Equity Risk Rate</u>
<u>Equity Rate**</u>			
2016	(14.75%/(1-.30))-0.053		21.035%
2014	(15.50%/(1-.30))-0.033		22.110%
2013	(13.25%/(1-.30))-0.056		18.871%
	** Value Line Investment Survey Analysis		

<u>Composite Risk Rate</u>	Loan and Equity Rates weighted by industry estimated capital structure		
	<u>Equity Rate</u>	<u>Debt Rate</u>	<u>Composite Risk</u>
2016	13.575%	1.822%	15.497%
2014	15.477%	1.585%	17.042%
2013	11.322%	2.077%	13.389%
Note: Debt Equity Ratio		Debt 35%	Equity 65%

Non Liquidity Rate Interest differential between a 90 day Treasury Bill and a 1 year Treasury Bill which reflects a reasonable time necessary to sell active property.

			<u>1yr T Bill</u>	<u>90 d T Bill</u>	<u>Non Liquidity Rate</u>
January	December	2016	0.322%	0.053%	0.269%
January	December	2014	0.121%	0.033%	0.088%
January	December	2013	0.132%	0.056%	0.074%

Management Rate Charges for the management of investment portfolios.
Fixed Rate (by Rule) 0.500%

<u>Inflation Rate</u>			
January	December	2016	0.730%
January	December	2014	0.780%
January	December	2013	1.500%

Capitalization Rate Since the valuation of active coal property is predicated on a three year production average, the capitalization rate is considered in a similar manner.

	2016	2014	2013
Inflation Rate	-0.730%	-0.780%	-1.500%
Safe Rate	0.053%	0.033%	0.056%
Composite Risk Rate	15.497%	17.042%	13.389%
Non Liquidity Rate	0.269%	0.088%	0.074%
Management Rate	0.500%	0.500%	0.500%
Total	15.598%	16.903%	12.531%

Three Yr Average: 15.008 Rounded to: **15.00%**

<u>CAPITALIZATION RATE - 15.0%</u>			
<u>MULTIPLIERS:</u>			<u>%</u>
1YR	0.933	9YR	5.117
2YR	1.743	10YR	5.382
3YR	2.448	11YR	5.813
4YR	3.082	12YR	5.813
5YR	3.595	13YR	5.987
6YR	4.058	14YR	6.139
7YR	4.482	15YR	6.271
8YR	4.812		

COAL

Price and Royalty Rate Analysis

Development of royalty rates for the various categories of mines and markets involves information collection and review from a variety of sources. Coal lease rates have been derived from production information provided by county producers, assessors, tax auditors, and by individual lessors/lessees involved in the specific transaction. The prices for mined coal, as per 110-CSR 11, have been calculated from information provided by the WV Public Service Commission and U.S. Energy Information Administration concerning power plant fuel purchases. Prices provided by producers as part of tax filing and from data obtained from market summaries are included for comparison. Because a large portion of the data used in this analysis is, by law, considered confidential, only a summary of the results are published.

COAL SALE PRICES CY2015 FOR TY2017 APPLICATION

GRAND SUMMARY ALL SOURCES 201	STEAM SPOT	STEAM TERM	MET
PSC	\$54.62	\$54.03	
FERC	\$51.10	\$50.81	
Active Return Summary		\$52.05 52.1 MM tons	\$74.60 23.6 MM Tons
Coal Market Publication (Platts)		\$46.09 CAPP (12/1.67) Sarge	
		\$48.85 PGH - (13/3) Reil	
			\$57.54 Low Vol HCC

STATE STEAM PRICE (SPOT Market)	\$53.15 FERC & PSC, 3 YR AVE
STATE MET PRICE	\$74.60 Active Return, 1 YR

2016 WVPSC Tons reported in millions	Spot Sales 6,112,303	Term Sales 13,281,896	Total 19,404,199

COAL TY2017 ROYALTY RATES	2013 1YR		2014 2YR		2013 3YR		2012 4YR		2011 5YR	
	%S	%D	%S	%D	%S	%D	%S	%D	%S	%D
TOTAL RECORDS	447	452	1,447	908	1,354	599	1,909	2,756	1,877	2,241
SUM of PERCENT	2904.95	2327.98	9,993.07	4,686.25	8,067.34	3,313.93	11,981.89	14,863.03	8,924.25	11,181.05
STRAIGHT AVERAGE	6.50	5.15	6.13	5.19	5.97	5.53	6.23	5.32	5.32	4.99
MEDIAN	6.00	5.00	6.00	6.00	5.00	6.00	6.00	5.13	5.00	5.00
WEIGHTED AVERAGE (by Mines)	6.60	5.10	6.64	5.49	6.58	5.84	6.48	6.25	6.27	5.72
TENTATIVE RATE DEEP (%)	5.69									
TENTATIVE RATE SURFACE (%)	6.81									

ROYALTY RATE CALCULATIONS

Coal/ Deep Mine	\$58.15	per ton X	5.69%	=	\$3.31	per ton
Metallurgical Coal/ Deep Mine	\$74.60	per ton X	5.69%	=	\$4.24	per ton
Steam Coal/ Surface Mine	\$58.15	per ton X	6.81%	=	\$3.94	per ton
Metallurgical Coal/ Surface Mine	\$74.60	per ton X	6.81%	=	\$5.08	per ton

Explanation of Reserve Coal Valuation

The RCVM consists of a computer model, which utilizes a database consisting of coal beds and characteristics, property locations, mine locations, sales, transportation, etc., for the entire state. An extensive algorithm calculates in-place tonnage, expected time of mining and present value for all the mineable coal on every property.

There are, therefore, no set "rates" available on reserve coal under the Rule. The RCVM values on each property will not be available until all data has been entered, after October 15 of each year. Please refer to the State Register, Legislative Rules, Title 110, Series 11 for details of the process.

Title 110, Series 11
Valuation of Active and Reserve Coal Property for Ad Valorem Property Tax Purpose

The above Legislative Rule was modified during the 2005 Legislative Session requiring biennial (every other year) updating of the geostatistical base for several valuation factors used in the Reserve Coal Valuation Model. To satisfy that requirement, maps and data files concerning the Market Interest Factor, the Market Minesability Factor, the Use Conflict Factor and the Environmental Factor have been revised for Tax Year 2018. Preliminary research has been conducted to determine the affects of the factors on coal valuation. The results are as follows:

Market Interest Factor

This is the relationship between transactions (sales, leases, prospects, permit applications, etc.) and mining as it relates to properties and locations. Trans_Ct is the number of transactions counted within the radius.

Radius = 5 miles

If Trans_Ct >= 20 Then TransFactor = 20

If Trans_Ct < 20 And Trans_Ct >= 10 Then TransFactor = 40

Else TransFactor = 80

Market Minesability Factor

This is the relationship between property location and mining, through time. Determining feature is count of mines within the radius.

Radius = 2.5 miles

Surface Mines: Smine

Deep Mines: Dmine

Boom Mines: Bmine

Historic Mines: Omine

Current Mines: Cmine

To assign MineFactor:

If Cmine > 0 Then MineFactor = 20

If Cmine = 0 And (Omine > 0 Or Bmine > 0) Then MineFactor = 40

Else MineFactor = 80

Use Conflict Factor

This is the relationship between oil & gas well drilling and mining as it relates to property location. Well density is in wells per square mile.

WellDensity < 5 Then WellFactor = 0

WellDensity >= 5 And WellDensity < 10 Then WellFactor = 20

WellDensity >= 10 And WellDensity < 20 Then WellFactor = 40

WellDensity > 20 Then WellFactor = 80

Environmental Factor

This is the relationship of known environmental hazards and impediments to the likelihood of mining occurring at this location. The rates are compiled from maps and represent densities of problems mapped.

Envrate <= 20 or Null Then EnvFactor = 0

Envrate > 20 and Envrate <= 40 Then EnvFactor = 20

Envrate > 40 and Envrate < 80 Then EnvFactor = 40

Envrate >= 80 Then EnvFactor = 80

**OTHER MINED MINERAL
PROPERTY ANALYSIS**

Tax Year 2017

September 1, 2016
Mark W. Matkovich
State Tax Commissioner
Department of Revenue

OTHER MINED MINERALS CAPITALIZATION RATE

Capitalization Rate Analysis and Results:

In developing a capitalization rate for use in valuing specific income-producing properties consideration is given to the three approaches generally employed in estimating a discount rate. As a matter of practicality, the Bands-of-Investment and Summation Technique approaches are utilized in establishing discount rates for active coal. Data for analysis has been derived in accordance with current Legislative Rule Title 110, Series 1k.

<u>Safe Rate</u>	90 day Treasury Bill		<u>Safe Rate</u>
January	December	2015	0.053%
January	December	2014	0.033%
January	December	2013	0.058%

<u>Risk Rate</u>	Interest differential between Loan Rate and 90 day Treasury Bill		
<u>Loan Rate*</u>			<u>Debt Risk Rate</u>
2015	5.26%		5.207%
2014	5.25%		5.217%
2013	5.26%		5.192%
	*Prime plus 2%		

<u>Equity</u>	Differential between Equity Rates and 90 day Treasury Bills		
<u>Equity Rate**</u>			<u>Equity Risk Rate</u>
2015	{11.75%/(1-.30)}-0.053		16.733%
2013	{11.75%/(1-.30)}-0.033		16.753%
2012	{11.75%/(1-.30)}-0.058		16.726%
** Value Line Investment Survey Analysis			

<u>Composite Risk Rate</u>	Loan and Equity Rates weighted by industry estimated capital structure.		
	<u>Equity Rate</u>	<u>Debt Rate</u>	<u>Composite Risk</u>
2015	10.040%	2.083%	12.123%
2014	10.052%	2.087%	12.139%
2013	10.037%	2.077%	12.114%
Note: Debt/Equity Ratio Debt 40% Equity 60%			

<u>Non Liquidity Rate</u>			Interest differential between 90 day Treasury Bill and a 1 year Treasury Bill which reflects a reasonable time necessary to sell active property.		
			<u>1yr T.Bill</u>	<u>90 d T.Bill</u>	<u>Non Liquidity Rate</u>
January	December	2015	0.322%	0.053%	0.269%
January	December	2014	0.121%	0.033%	0.088%
January	December	2013	0.132%	0.058%	0.074%

<u>Management Rate</u>	Charges for the management of investment portfolios.	
Fixed Rate (by Rule)	0.500%	

<u>Inflation Rate</u>			
January	December	2015	0.730%
January	December	2014	0.760%
January	December	2013	1.500%

<u>Property Tax Rate</u>	Sixty percent (60%) of State average Class III property tax rate.		
January	December	2015	80% of 2.190 = 1.314%
January	December	2014	80% of 2.190 = 1.314%
January	December	2013	80% of 2.190 = 1.314%

Capitalization Rate Since the valuation of other mined mineral property is predicated on a three year production average, the capitalization rate is considered in a similar manner.

	2015	2014	2013
Inflation Rate	-0.730%	-0.760%	-1.500%
Safe Rate	0.053%	0.033%	0.058%
Composite Risk Rate	12.123%	12.139%	12.114%
Non Liquidity Rate	0.269%	0.088%	0.074%
Management Rate	0.500%	0.500%	0.500%
Property Tax Rate	1.314%	1.314%	1.314%
<u>Total</u>	13.529%	13.314%	12.560%

Three Yr Average: 13.134% Rounded to: **13.10%**

CAPITALIZATION RATE - 13.10%

MULTIPLIERS:	%	%
1YR	0.940	9YR 5.437
2YR	1.772	10YR 5.748
3YR	2.507	11YR 6.022
4YR	3.157	12YR 6.266
5YR	3.731	13YR 6.480
6YR	4.240	14YR 6.669
7YR	4.689	15YR 6.837
8YR	5.086	

OTHER MINED MINERALS

ROYALTY RATE SURVEY

The determination of royalty rates for other mined minerals within the state of West Virginia is dependent upon the availability of leasehold information. Since this information is limited, the Department has chosen to review data for the most recent thirty year period. A summary only of this review is shown below in order to protect the confidentiality of parties involved.

RESOURCE	DATA SOURCES	AVERAGE ROYALTY	MEDIAN ROYALTY	TY2017 RATE
LIMESTONE	15	\$0.22	\$0.20	\$0.22
SANDSTONE	8	\$0.31	\$0.25	\$0.30
CLAY/SHALE	34	\$0.12	\$0.10	\$0.11
SAND/GRAVEL	10	\$0.35	\$0.40	\$0.40
SALT BRINE	1	N/A	N/A	\$0.10

RESERVE VALUES

	number of sales	\$/AC
LIMESTONE	5	\$3,000.00
SANDSTONE	8	\$2,300.00
CLAY/SHALE	16	\$850.00
SAND/GRAVEL	8	\$4,000.00
SALT	2	\$1,140.00

August 1, 2016

West Virginia State Tax Department
Property Tax Division
Attention: Jeff Amburgey
P.O. Box 2389
Charleston, WV 25328-2389

Dear Mr. Amburgey,

The Independent Oil and Gas Association of West Virginia Inc. (IOGAWV) is hereby filing comments to the tentative natural resource property valuation variables for 2017 Tax Year.

West Virginia Code §11-3-1(a), as amended, states that: "All property, except public service businesses assessed pursuant to article six of this chapter, shall be assessed annually as of July 1 at sixty percent of its true and actual value; that is to say, at the price for which the property would sell if voluntarily offered for sale by the owner thereof, upon the terms as the property, the value of which is sought to be ascertained, is usually sold, and not the price which might be realized if the property were sold at a forced sale."

The Tax Commissioner has chosen the use of an "income approach" as the most appropriate method for the valuation of oil and natural gas properties as set forth in the Tax Commissioner's "Administrative Notice 2016-02, State Tax Commissioner's Statement Concerning Primary Reliance on the Income Approach to Value for Appraisals of Producing and Reserve Coal, Producing Oil and Gas, and Producing Other Mined Minerals Pursuant to §§ 110 CSR 11-4, 1J-4 and 1K-4". Administrative Notice 2016-02, states, in part, that, "The income approach to value is based upon the assumption that a property is worth the future income, discounted to present worth, that it will generate for a prospective buyer".

The use of the "income approach" to valuation requires the appraiser to consider realistic operating expenses to determine net cash flow as the basis for calculating "true and actual value". The method of calculating operating expenses for oil and gas wells as set forth in the State Tax Department's proposed valuation variables for Tax Year 2017 would result in grossly understated expenses, and further resulting in appraised values which would greatly exceed "true and actual value".

WV CSR §110-1J-4.1 of the Legislative Rule of the State Tax Department regarding Valuation of Producing and Reserve Oil and Natural Gas for Ad Valorem Property Tax Purposes, states that the value of oil and/or natural gas producing property shall be determined through the process of applying a yield capitalization model to the net receipts (gross receipts less royalties paid less operating expenses) for the working interest. Rule 4.1 would seem to require the deduction of actual operating expenses from the gross receipts. Rule 4.3 in that section does state that the Tax Commissioner shall every 5 years, determine the average industry operating expenses per well which will be deducted from working interest gross receipts.

The Tax Commissioner, in the last 10 years, has conducted surveys regarding operating expenses of all wells in 2007, 2009, 2013, and 2014. In addition, in 2013, a survey specifically for Marcellus wells was conducted and in 2014 a survey for Marcellus wells and horizontal wells other than Marcellus was conducted.

Although surveys have been used several times over the last 10 years, the State Tax Department continues its decades-old practice of basing annual operating expenses for conventional gas wells at



30% of gross revenues with a cap of \$5,000 and for oil wells at 35% with a cap of \$5,750. In the last 10 years natural gas and oil prices have been extremely volatile. That volatility resulted in the dramatic changes in allowable expenses under the current valuation procedures. Those allowable expenses are not reflective of actual operating expenses.

By way of demonstration, the following is a table of published index prices for Appalachian gas delivered to the two primary pipelines in West Virginia, Columbia Gas Transmission and Dominion Transmission, Inc., showing average annual gas prices and the allowable expense per mcf of produced gas utilizing the State Tax Department's proposed expense allowance:

Year	Columbia		Dominion *	
	Index \$/Mcf	Exp @ 30%	Index \$/Mcf	Exp @ 30%
2007	\$7.1242	\$2.1373	\$7.2200	\$2.1660
2008	\$9.3858	\$2.8158	\$9.5292	\$2.8588
2009	\$4.1758	\$1.2528	\$4.2692	\$1.2808
2010	\$4.5267	\$1.3580	\$4.5867	\$1.3760
2011	\$4.1367	\$1.2410	\$4.1983	\$1.2595
2012	\$2.7933	\$0.8380	\$2.7850	\$0.8355
2013	\$3.6525	\$1.0958	\$2.8867	\$0.8660
2014	\$4.3650	\$1.3095	\$2.7383	\$0.8215
2015	\$2.5533	\$0.7660	\$0.8842	\$0.2653

(* Note: The Dominion index prices for 2013, 2014 and 2015 reflect deductions for "Gateway Firm", which most producers delivering to Dominion are obligated to pay.)

In years of peak prices (2007, 2008) excessive expenses were not a factor, due to the \$5,000 expense cap. However, as prices have cratered, the 30% methodology does not reflect actual operating expense. Whenever expenses are understated, appraised and assessed values are overstated, resulting in unfair property tax assessments.

To further demonstrate that the 30% expensed methodology is not appropriate, suppose a producer has two very similar wells that each produce 10 mcf/day, with one well delivering gas to Columbia and the other well delivering gas to Dominion, subject to Gateway transportation expenses. Using the proposed methodology, allowable expenses would be determined as follows:

	Columbia	Dominion
Mcf/Day	10	10
Days/Year	<u>365</u>	<u>365</u>
Annual Mcf	3650	3650
Gas Price - 2015	<u>\$2.5533</u>	<u>\$0.8842</u>
Total Revenues	\$9,319.57	\$3,227.21
30% Expenses	\$2,795.90	\$968.18

It is simply impossible to operate any oil and gas well in West Virginia for \$968 per year (or \$80 per month). It would be extremely difficult to operate a well for \$2,795.90 per year (\$233 per month) unless the well produced no fluid and required very minimal maintenance. These expenses do not reflect real costs, and, therefore, cannot be used to determine "true and actual value" as required under West Virginia Code §11-3-1(a). The proposed methodology is flawed, and will result in inconsistent and incorrect calculations of expenses, and inaccurate appraised values.

Costs to operators for such things as wages, health insurance expenses, gasoline for trucks, etc., have dramatically increased since 2007. However, in 2007 and 2008 a well making 10 mcf/day would have

generated in excess of \$25,000 in gross revenues, and allowable expenses (\$7,500) would have been capped at \$5,000 for ad valorem tax calculation purposes. However, as demonstrated above, allowable expenses for that same well for Tax Year 2017 would be just \$2,795, if the well delivered gas on the Columbia system, and just \$963.16 if the well was connected to Dominion and subject to Gateway charges. This is not realistic.

The appropriate mechanism to provide for accurate deductions of well operating expenses is to allow the submission of actual operating expenses as Rule 4.1 seems to require. Rule 4.3 provides for a mechanism (an average based on survey results) that the Tax Department could use to estimate if and when a producer does not provide actual operating expenses in a suitable format to be used in a yield capitalization model.

The State Tax Department has issued Administrative Notices regarding the valuation variable of oil and gas operating expenses in 2014, 2015, and 2016. In 2014, the notice stated that if a producer's ordinary expenses exceeded the stated maximums, then the Tax Department would accept and review documentation on wells for the previous three years provided by the producer as long as submitted on or before August 1st. The 2015 Administrative Notice repeated that option for producer submission of three years of actual operating expenses. However, the 2016 Notice does not even mention that option and IOGAWV has been informed that the Tax Department will not consider or review actual expenses submitted due to lack of personnel to have that accomplished. Entering data from Producer/Operator returns into the State Tax Department's evaluation system is a significant task. It would appear that the average Producer/Operator return has at least 40 data items to enter. Some returns, with extensively fractured royalty ownership, have hundreds of data items (names, addresses, percentages, royalty revenue, etc.) Adding "operating expense" would add just one more data item (likely a four-digit integer), which would be insignificant when considered in the context of the entire data entry operation.

IOGAWV believes that the Tax Department is required by Rule 4.1 to deduct actual operating expenses if accurate verifiable data is provided by the producer. In the absence of such data, if expenses are to be based on a percentage of gross revenues, it would seem appropriate to have a "floor" on operating expenses recognizing that many legitimate operating costs are not in any way related to gross revenues. To ensure the most accurate appraisal possible, IOGAWV requests the Tax Commissioner to only use actual expenses whenever possible and to only use estimated operating expenses when actuals are not timely submitted.

IOGAWV gathered some samples of well revenue and operating expenses and it showed that the only solution for non-conventional wells is to be able to submit actual operating costs for fair property tax valuation. The current formula at 20% of revenue limited to \$150,000 per year for operating costs does not fit for any non-conventional wells.

Based on the sample wells IOGAWV finds the following recommendations to be appropriate:

- Non-conventional wells be allowed to submit actual operating costs for proper valuation in all cases,
- Conventional wells with flush production be allowed to submit actual operating costs but that would have to be done for all flush production wells submitted in that year,
- Other conventional wells will be part of the normal valuation formula with operating costs at 30% and a maximum of \$5,000 for natural gas but be allowed a minimum in that formula of \$2,500 per year operating costs.
- The minimum value for property tax purposes for a well will be \$500 which is the value assessed for home use wells.

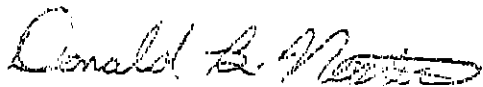
- Conventional Oil wells be allowed a minimum of \$7,500 per year operating costs and also be able to submit actual operating costs for flush production years.

The State Tax Department needs to recognize that during these times of historic low natural gas commodity prices (the lowest in history, when adjusted for inflation), many wells in the State will be operating at a loss until prices recover. Considering recent market conditions, it could be argued that such wells are a liability, not an income producing asset, and have no "true and actual value". Whenever it can be shown that actual allowable expenses exceed production revenues net of royalties, iOGAWV suggests that such wells should be valued at the Minimum Working Interest Appraisal Rate of \$500 (as stated in the 2017 valuation variables).

iOGAWV appreciates the opportunity to file comments on this important matter and looks forward to the response.

Respectfully,

iOGA OF WEST VIRGINIA



Donald B. Nestor, Member
Finance and Taxation Committee



SPILMAN THOMAS & BATTLE, LLC

ATTORNEYS AT LAW

Dale W. Steager

304.340.1692

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July 29, 2016

RECEIVED

Via Hand Delivery

West Virginia State Tax Department
Property Tax Division
Attention Jeff Amburgey, Director, Property Tax Division
1124 Smith Street
Charleston, WV 25301

JUL 29 2016

State Tax Department
Property Tax Division

Re: Tentative Natural Resource Property Valuation Variables for 2017 Tax Year

Dear Director Amburgey:

The West Virginia Oil and Natural Gas Association (WVONGA) appreciates the opportunity to comment on the Tentative Natural Resource Property Valuation Variables for the 2017 Tax Year dated June 30, 2016. Our comments are limited to the tentative variables affecting the oil and natural gas industry.

WVONGA is a trade association that serves West Virginia's extensive oil and gas industry. WVONGA members operate in virtually every county in West Virginia. Its members employ thousands of people across the state, having payrolls totaling hundreds of millions of dollars annually. Its members have a cumulative investment of nearly \$10 billion in West Virginia, own about 20,000 oil and gas wells, have more than 15,000 miles of pipeline crisscrossing the state, and provide oil and natural gas to roughly 300,000 West Virginia homes and businesses.

In response to the recently published variables, WVONGA surveyed its members as to their actual operating expenses incurred in West Virginia. Responses received cover 65% of the total gas production and approximately 11,000 of the over 40,000 active wells in West Virginia for the 2015 calendar year. WVONGA's primary concerns with the published variables relate to the Working Interest Expense Allowance and the Maximum Operating Expenses allowed for typically producing wells and horizontal Marcellus wells.

Based on a review of the State's published variables, these two variables have remained unchanged, with the exception of the introduction of Marcellus/Utica and Horizontal well categories, since before tax year 2010 (2008 calendar year production). Conversely, the price of natural gas has decreased 66% during that same time period which includes a 28% decline since 2012 when the Marcellus group was added to the 2013 tax year variables.

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Virginia

West Virginia State Tax Department
Property Tax Division
Attention Jeff Amburgey, Director, Property Tax Division
July 29, 2016
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While revenue has been declining for the industry's producers, operating expenses have not. By calculating an allowance for operating expense using the same variables as when gas was at a higher rate per MCF, the State is significantly understating actual operating expenses for the working interest portion of the tax calculation.

It also appears the State's maximum operating expense allowance fails to acknowledge all expenses needed to get natural gas to a salable state. Allowable expenses should not only include lease operating expenses, but also gathering, compression, processing, and transportation charges. The processing charges are especially prevalent for the Marcellus wells where wet gas needs to be processed before it can be sold for distribution, and are incurred, on average, at 17% of revenue. Compression can be upwards of 30% of revenue, depending on whether a company is vertically integrated or otherwise owns its own system.

The data collected from WVONGA members related to operating expense as a percentage of revenue, and average expenditure per well has been aggregated below for your consideration:

Well Type	State Working Interest Expense Allowance	Average WVONGA Participant Operating Expense as % of Revenue
Marcellus/Utica, Horizontal Wells	20%	38%
Typical Producing Wells	30%	41%

Well Type	Allowed Expense	WVONGA Average of Actual Expense
Marcellus/Utica, Horizontal Wells	\$150,000	\$720,000

In the State's calculation, the expense allowance and the maximum work together to determine the appropriate operating expense allowance to use in the discounted cash flow calculation. Unless the State addresses both of these variables, the values assigned to the gas wells for the 2017 tax year will be grossly overstated.

Additionally, WVONGA requests that the State revise the operating expense calculation for wells where both oil and gas are produced. When wells reach the maximum operating expense allowances for oil and gas, the State applies a weighted average approach to the maximum operating expense allowance.

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Property Tax Division
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July 29, 2016
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As seen in the example provided below, a well that produces oil and gas at a level that reaches the maximum allowances is actually afforded a lesser operating expense allowance than a well that just produces gas at the same level. We suggest that, instead of a weighted average maximum, the State use a combined maximum in these cases.

Example:

	Gas WI Revenue	Oil WI Revenue	State OpEx Allowance Prior to Maximums	State OpEx Maximum
Gas Only Well	900,000	0	180,000	150,000
Gas & Oil Well	900,000	100,000	275,000	135,575

As the above industry data indicates, the maximum allowances as a percentage of working interest revenue and fixed dollar caps being employed by the State in its valuations is inappropriate as neither adequately reflects actual expenses being incurred by the industry to get produced gas to its point of sale. Accordingly, we believe that both should be eliminated for purposes of property tax valuation.

WVONGA recognizes that under Article X, §1 of the Constitution, all property not exempt from taxation is subject to ad valorem property taxation that must be equal and uniform through the State and no one species of property from which a tax may be collected may be taxed higher than any other species of property of equal value, except as otherwise provided in the Constitution. This means that oil and natural gas property may not be subject to ad valorem property taxation policies and formulas that discriminate against, or in favor of, oil and natural gas real and personal property.

WVONGA is disappointed that the expense percentages and caps included in the 2017 tentative variable for oil and natural gas continue to be low when compared with actual expenses incurred by well operators. WVONGA realizes that the expense percentages and caps are determined by the State Tax Department from surveys of well operators conducted every five years and from other sources not known to WVONGA.

The last survey was made in 2014, and the next survey is scheduled to be made in 2019. This suggests that the survey made prior to the 2014 survey was made in 2009. The attached

West Virginia State Tax Department
Property Tax Division
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spreadsheet shows that the expense percentages and caps on expenses have, except in the case of horizontal wells, remained the same since tax year 2009. Beginning with tax year 2014, Marcellus and Utica horizontal wells have been treated differently than vertically drilled wells. However, even these numbers are unrealistically low.

WVONGA and its members believe that the allowable expenses and the caps on expenses set forth in the tentative 2017 natural resource variables for oil and natural gas properties are unrealistically low and, unless appropriately adjusted, will result in oil and gas wells being over valued for 2017 ad valorem property taxation in violation of the "Equal and Uniform" taxation clause in Article X, § 1 of the Constitution.

We appreciate the opportunity to comment on the tentative variables. This response is intended to work with the State toward a more reasonable mass appraisal of gas producing properties for property tax purposes, but should not deny Taxpayers from being afforded an opportunity to further work with the State based on their individual facts and circumstances. We respectfully request the right to seasonably supplement the response with other information that may be of benefit to the Department and would be happy to discuss the issues with you at your convenience. Please do not hesitate to contact me if you have any questions about these comments or wish to discuss them.

Respectfully submitted,

Spilman Thomas and Battle, PLLC



Dale W. Steager
Counsel for WVONGA

DWS/ljr
Enclosure

cc: Kevin Ellis, Chairman of WVONGA's Board of Directors

8678994 (19087.1)

OIL AND GAS VARIABLES FOR PROPERTY TAX PURPOSE

	Tentative 2017	Final 2016	Final 2015	Final 2014	Final 2013	Final 2012	Final 2011	Final 2010	Final 2009
CAPITALIZATION RATE	16.00%	15.30%	14.80%	14.70%	14.70%	15.90%	16.00%	16.70%	15.10%
GAS									
- % Working Interest Expenses									
- For Typical Producing Well	= 30%	30%	30%	30%	30%	30%	30%	30%	30%
- Maximum Operating Expenses	= \$5,000	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000
- Coal Bed Methane, Vertical Wells									
- Expenses	= \$9,000	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000
OIL									
- % Working Interest Expenses									
- For Typical Producing Well	= 35%	35%	35%	35%	35%	35%	35%	35%	35%
- Maximum Operating Expenses	= \$5,750	\$5,750	\$5,750	\$5,750	\$5,750	\$5,750	\$5,750	\$5,750	\$5,750
- Maximum Enhanced Operating									
- Expenses	= \$9,000	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000
MARCELLUS/UTICA									
- % Working Interest Expenses									
- for Vertical Producing Well	= 30%	30%	30%	30%	N/A	N/A	N/A	N/A	N/A
- Maximum Operating Expenses	= \$30,000	\$30,000	\$30,000	\$30,000	\$30,000	N/A	N/A	N/A	N/A
- % Working Interest Expenses									
- for Horizontal Producing Well	= 20%	20%	20%	20%	N/A	N/A	N/A	N/A	N/A
- Maximum Operating Expenses	= \$150,000	\$150,000	\$150,000	\$150,000	N/A	N/A	N/A	N/A	N/A
HORIZONTAL WELLS (OTHER THAN MARCELLUS/UTICA AND COAL BED METHANE)									
- % Working Interest Expenses									
- for Horizontal Producing Well	= 30%	30%	30%	N/A	N/A	N/A	N/A	N/A	N/A
- Maximum Operating Expenses	= \$20,000	\$20,000	\$20,000	N/A	N/A	N/A	N/A	N/A	N/A
Minimum Working Interest Appraisal	= \$500 per well	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500
Flat Rate Royalty Multiplier	= 5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75
Home Use Only Wells:									
Appraised at	\$500 per well	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500/well
Industrial Use Only Wells:									
Appraised at	MCF usage X \$2.62/MCF	X \$4.39/MCF	X \$3.73/MCF	X \$2.66/MCF	X \$3.95/MCF	X \$4.16/MCF	X \$3.71/MCF	X \$8.07/MCF	X \$6.39/MCF
	BBL usage X \$48.66/BBL	X \$93.26	X \$97.98	X \$94.05	X \$94.00	X \$79.48	X \$61.65/BBL	X \$99.57/BBL	X \$72.32/BBL
	*(Also includes Department of Environmental Protection reported wells.)								
Non-Filler Valuations									
Working Interest	= 150% of previous year's appraisal	Same	Same	Same	Same	Same	Same	Same	Same
Royalty Interest	= 90% of previous year's appraisal	Same	Same	Same	Same	Same	Same	Same	Same

Attachment to WVON/GA letter of July 2, 2016



U.S. Energy Information
Administration

NATURAL GAS

OVERVIEW | DATA | ANALYSIS & PROJECTIONS

GLOSSARY | FAQs

Referring Pages:

- [Natural Gas Wellhead Price](#)
- [U.S. Natural Gas Prices](#)
- [Natural Gas Wellhead Price](#)

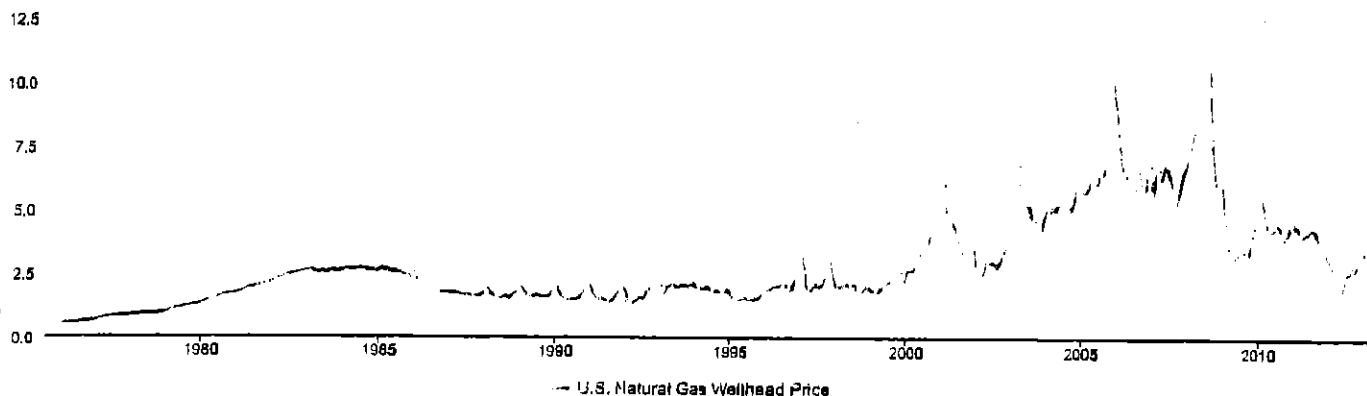
New History: ☒ Monthly ☐ Annual

[Download Data \(XLS File\)](#)

U.S. Natural Gas Wellhead Price

[DOWNLOAD](#)

Dollars per Thousand Cubic Feet



Source: U.S. Energy Information Administration

Chart Tools

no analysis applied

This series is available through the EIA open data API and can be downloaded to Excel or embedded as an interactive chart or map on your website.

U.S. Natural Gas Wellhead Price (Dollars per Thousand Cubic Feet)

Year	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
1973	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1974	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1975	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1976	0.54	0.54	0.54	0.55	0.55	0.58	0.58	0.60	0.60	0.62	0.63	0.64								
1977	0.67	0.71	0.75	0.77	0.77	0.82	0.83	0.82	0.83	0.84	0.83	0.84								
1978	0.87	0.88	0.89	0.88	0.91	0.91	0.89	0.91	0.92	0.92	0.93	0.96								
1979	1.02	1.05	1.10	1.11	1.15	1.17	1.20	1.24	1.24	1.28	1.29	1.31								
1980	1.37	1.42	1.46	1.51	1.56	1.57	1.64	1.64	1.69	1.71	1.76	1.74								
1981	1.77	1.81	1.86	1.93	1.95	1.95	2.01	2.02	2.08	2.11	2.15	2.16								
1982	2.23	2.30	2.35	2.40	2.45	2.45	2.47	2.53	2.56	2.60	2.62	2.62								
1983	2.66	2.66	2.58	2.53	2.53	2.59	2.52	2.58	2.67	2.58	2.60	2.61								
1984	2.67	2.71	2.67	2.64	2.67	2.70	2.68	2.69	2.62	2.63	2.61	2.57								
1985	2.64	2.71	2.62	2.64	2.53	2.58	2.51	2.47	2.42	2.37	2.36	2.28								
1986	2.28	2.26	2.16	2.10	1.96	1.85	1.80	1.77	1.78	1.73	1.77	1.76								
1987	1.74	1.73	1.73	1.69	1.65	1.65	1.66	1.63	1.56	1.57	1.64	1.70								
1988	1.96	1.84	1.70	1.59	1.52	1.53	1.56	1.62	1.53	1.68	1.76	1.89								
1989	1.99	1.81	1.69	1.56	1.61	1.65	1.65	1.61	1.55	1.58	1.66	1.92								
1990	2.23	1.85	1.55	1.49	1.47	1.48	1.49	1.51	1.56	1.76	1.94	2.04								
1991	1.96	1.62	1.49	1.50	1.48	1.43	1.34	1.43	1.59	1.82	1.89	2.00								
1992	1.74	1.26	1.35	1.42	1.51	1.62	1.55	1.84	1.92	2.38	2.13	2.07								



9/27/2016

U.S. Natural Gas Wellhead Price (Dollars per Thousand Cubic Feet)

1993	2.03	1.76	2.00	2.06	2.18	1.98	1.99	2.04	2.09	2.02	2.03	2.15
1994	1.93	1.88	1.93	1.91	2.00	1.80	1.81	1.83	1.78	1.70	1.75	1.88
1995	1.62	1.48	1.47	1.52	1.55	1.58	1.43	1.43	1.52	1.54	1.61	1.84
1996	2.05	1.89	1.95	2.08	2.01	2.08	2.25	2.10	1.85	1.94	2.50	3.26
1997	3.40	2.49	1.79	1.81	2.00	2.08	2.00	2.08	2.33	2.68	2.92	2.28
1998	1.96	1.96	2.06	2.16	2.04	1.91	2.09	1.82	1.70	1.86	1.94	1.95
1999	1.85	1.77	1.70	1.90	2.17	2.14	2.20	2.51	2.62	2.52	2.68	2.24
2000	2.60	2.73	2.66	2.86	3.04	3.77	3.84	3.73	4.26	4.58	4.40	5.77
2001	6.82	5.08	4.37	4.52	4.36	3.79	3.35	3.33	2.93	2.78	3.41	3.42
2002	2.50	2.19	2.40	2.94	2.94	2.96	2.92	2.76	2.97	3.24	3.59	1.96
2003	4.43	5.05	6.96	4.47	4.77	5.41	5.08	4.46	4.59	4.32	4.26	4.76
2004	5.21	5.02	5.12	5.03	5.40	5.82	5.62	5.52	5.06	5.43	6.21	6.01
2005	5.80	5.73	5.95	6.57	6.25	6.09	6.71	6.48	8.95	10.33	9.89	9.08
2006	8.01	6.85	6.43	6.37	6.23	5.77	5.91	6.55	6.06	5.09	6.71	6.76
2007	5.70	6.80	6.65	6.26	6.75	6.62	6.21	5.76	5.30	5.78	6.46	6.87
2008	7.38	8.02	8.63	8.87	9.96	10.36	10.79	8.21	6.71	5.64	5.23	5.94
2009	4.60	3.70	3.38	3.18	3.23	3.38	3.45	3.37	2.98	3.83	4.20	4.66
2010	5.69	5.30	4.70	4.10	4.34	4.27	4.44	4.38	3.83	4.05	4.12	4.68
2011	4.37	4.34	3.95	4.05	4.12	4.20	4.27	4.20	3.82	3.62	3.35	3.14
2012	2.89	2.46	2.25	1.89	1.94	2.54	2.59	2.86	2.71	3.03	3.35	3.35
2013	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2014	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016	NA	NA	NA	NA	NA	NA						

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

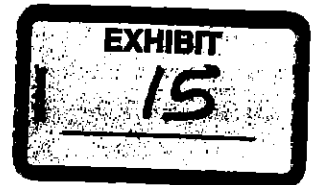
Release Date: 8/31/2016

Next Release Date: 9/30/2016

Referring Pages:

- [Natural Gas Wellhead Price](#)
- [U.S. Natural Gas Prices](#)
- [Natural Gas Wellhead Price](#)

Antero Resources Corporation Tax Year 2016 West Virginia Ad Valorem Value Comparison						
Account #	API #	Property Description	State Appraised Value	Taxpayer Appraised Value	Taxpayer Appealed Value	Value Removing Operating Expense Cap of \$150k Max
1020149960	085-09960	NICHOLSON UNIT 2H	6,813,991	5,552,627	4,432,767	4,387,411
1020159961	085-09961	NICHOLSON UNIT 1H 40371	4,433,217	3,860,613	2,841,770	2,983,875
0320159963	085-09963	ANNA UNIT 2H 40324	6,766,223	1,068,241	4,251,817	4,669,980
1020159964	085-09964	O'NEIL UNIT 1H 40379	6,688,592	5,618,603	4,124,290	4,333,703
1020159966	085-09966	O'NEIL UNIT 2H 40380	5,772,729	4,751,293	3,617,974	3,780,907
1020159970	085-09970	PRUNTY UNIT 1H 40393	13,938,228	2,227,910	8,454,652	8,637,772
1020159978	085-09978	PULLMAN UNIT 2H 40363	3,263,358	3,011,483	2,058,974	2,374,184
1020169996	085-09996	SNODGRASS UNIT 2H (40654)	4,503,041	972,805	1,168,596	3,133,144
1020169999	085-09999	DEBERRY UNIT 1H (40401)	8,563,011	1,853,443	2,647,385	5,443,225
1020150002	085-10002	KUHN UNIT 1H 40958	4,594,637	4,195,337	2,913,904	3,136,097
1020160005	085-10005	IRELAND UNIT 1H (40972)	9,811,251	1,849,367	3,116,278	6,248,291
1020160017	085-10017	ALLSTATE UNIT 2H (40538)	6,577,125	1,568,916	2,624,517	4,220,616
1020160019	085-10019	MCCA8E UNIT 3H (40537)	8,709,950	1,975,103	3,933,798	5,539,669
1020150023	085-10023	CONSTABLE UNIT 1H 40431	15,652,042	2,394,709	9,314,567	9,695,739
0320160027	085-10027	BELLE UNIT 1H (40459)	8,857,185	1,798,192	2,859,069	5,798,070
0320160028	085-10028	BELLE UNIT 2H (40644)	5,953,786	1,376,824	1,925,322	4,116,735
0320160029	085-10029	BELLE UNIT 3H (40554)	8,427,646	1,724,759	3,131,376	5,551,551
0320150036	085-10036	BLANCHE UNIT 1H 40993	11,801,733	1,792,097	7,243,384	7,638,754
1020160045	085-10045	LANGFORD UNIT 2H (40687)	7,715,025	2,274,936	1,118,151	4,999,363
1020160046	085-10046	RUFUS UNIT 1H (40510)	8,093,655	2,201,226	1,443,198	5,305,885
0320160060	085-10060	HENDERSHOT UNIT 1H (40642)	8,731,251	1,615,630	3,100,938	5,753,002
0320160062	085-10062	HORNET UNIT 1H (45573)	10,589,234	1,944,504	2,616,106	6,963,450
0320160063	085-10063	HORNET UNIT 2H (45568)	8,263,514	1,672,593	1,842,182	5,554,881
0320160088	085-10088	HENDERSHOT UNIT 2H (40643)	9,880,555	1,730,185	3,536,193	6,473,217
			194,400,979	59,031,397	84,317,207	126,739,524



DEP Production Report
2014 Calendar Year Production
Horizontal Wells Only

YEAR	2014				
Horizontal Well Indicator	Horizontal				
COUNTY	(All)				
Row Labels	Count of API	Sum of GAS_PRODUCTION_T TOTAL	Average Production per API	% of Marcellus Production	Average Operating Expense Per Well
ANTERO RESOURCES	263	345,873,516	1315.333	40%	648,000
EQT PRODUCTION COMPANY	551	145,652,455	264,342		
CHESAPEAKE APPALACHIA, L.L.C.	277	114,600,768	413,721		
NOBLE ENERGY, INC.	85	45,979,201	517,402		
STONE ENERGY CORPORATION	101	42,090,185	416,734		
CONSOL/CNX ENTITIES	59	30,040,501	509,181	3%	537,000
JAY-BEE OIL & GAS	35	27,616,160	789,055		
HG ENERGY, LLC	29	27,172,252	938,974		
GASTAR EXPLORATION USA, INC.	69	20,248,091	293,451		
POC MOUNTAINEER LLC	29	19,242,703	663,541		
ATO ENERGY, INC.	36	15,776,145	438,226		
TRIAD HUNTER, LLC	38	13,294,052	349,843		
STATOIL USA ONSHORE PROPERTIES, INC.	14	11,058,763	789,912		
TRIANA ENERGY, LLC	11	3,522,600	320,236		
CHEVRON APPALACHIA, LLC	18	3,411,110	189,506		
MOUNTAINEER ENTITIES	2	1,957,889	968,945		
NORTHEAST NATURAL ENERGY LLC	1	1,877,875	1,877,875		
WACO OIL & GAS CO INC	10	1,666,892	166,689		
HARO ROCK EXPLORATION, INC.	53	1,284,524	24,235		
MOUNTAIN V OIL & GAS, INC.	5	658,991	131,798		
TENASKA RESOURCES, LLC	5	423,229	84,646		
ENERPLUS RESOURCES (USA) CORPORATION	3	387,460	129,155		
ENERGY CORPORATION OF AMERICA	17	290,581	17,092		
EXCO RESOURCES (PA), LLC	12	204,097	17,008		
NYTIS EXPLORATION COMPANY, LLC	11	196,932	17,903		
CABOT OIL & GAS CORPORATION	18	109,228	6,068		
VIKING INTERNATIONAL RESOURCES CO. INC	3	84,367	28,122		
NORTHSTAR ENERGY CORPORATION	2	27,380	13,690		
BUCKEYE OIL PRODUCING CO	2	21,420	10,710		
HORIZON ENERGY CORPORATION	2	13,742	6,871		
HAUGHT ENERGY CORPORATION	3	12,503	4,301		
RESERVE OIL & GAS, INC.	2	9,440	4,720		
ALLIANCE PETROLEUM CORPORATION	11	8,581	780		
DURST OIL & GAS CO., INC.	1	8,528	8,528		
TEXAS KEYSTONE INC	1	5,006	5,008		
STALWAKER ENERGY CORPORATION	2	4,507	2,254		
TAPO ENERGY, INC.	1	4,446	4,446		
ABARTA OIL & GAS COMPANY	1	4,201	4,201		
ENERVEST OPERATING L L C.	6	4,123	687		
YOST HERITAGE INC.	1	3,797	3,797		
CUNNINGHAM ENERGY, LLC	1	3,780	1,260		
QUALITY NATURAL GAS, LLC	1	3,729	3,729		
TEAM ENERGY CORP.	1	2,652	2,652		
UPPISAN PETROLEUM, INC.	2	1,971	986		
P & C OIL & GAS, INC.	1	1,686	1,686		
BRC OPERATING COMPANY, LLC	7				
BASE PETROLEUM, INC.	1				
DIVERSIFIED RESOURCES, INC.	1				
EXCO RESOURCES (WV), INC.	3				
Grand Total	1,910	870,849,037			

[illegible]

**IN RE: RULING CONCERNING ANTERO RESOURCES CORPORATION'S PROTEST OF ASSESSMENT OF
WELL PROPERTY FROM OCTOBER 20, 2016 BOARD OF APPEALS**

Upon motion by Stephen C. Worden, seconded by Samuel C. Rogers, the County Commission voted this day to deny Antero Resources Corporation request to adjust the property tax assessment, for the tax year 2016, for the wells listed in the attached spreadsheet.

Motion carried with unanimous vote.

EXHIBIT
B



The County Commission of Ritchie County

RITCHIE COUNTY COURT HOUSE
115 East Main Street, Room 201
Harrisville, West Virginia
Phone (304) 643-2164
Fax (304) 643-2906

MEMBERS:
SAMUEL C. ROGERS
STEPHEN C. WORDEN
FLOYD M. HODGE, SR.

FRACIE D. McDONALD
CLERK

December 8th, 2016

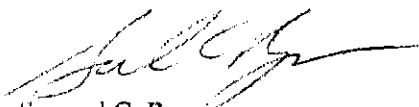
Craig A. Griffith
Legal Counsel for Antero Resources Corporation
PO Box 1588 Charleston WV 25326-1588

RE: Antero Resources Corporation

Dear Mr. Griffith:

The Ritchie County Commission met on November 10th, 2016, and made a motion to deny the request from Antero Resources Corporation to adjust the property tax assessment, for the tax year 2016. I have enclosed a certified copy of the minutes.

Respectfully,


Samuel C. Rogers
Commission President

Enclosures

