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May 14, 2015

Via EDGAR

Mr. Brad Skinner
Senior Assistant Chief Accountant
Division of Corporation Finance
United States Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549

Re: Penn Virginia Corporation
Form 10-K for Fiscal Year Ended December 31, 2014
Filed February 25, 2015
Response dated March 6, 2015
File No. 001-13283

Dear Mr. Skinner:

On April 24, 2015, the Staff of the Securities and Exchange Commission (the "Staff") issued a comment letter to Penn Virginia Corporation (the "Company") regarding the Company's Annual Reports on Form 10-K for the fiscal years ended December 31, 2013 and December 31, 2014. The responses provided below are numbered to correspond to the Staff's comments, which have been reproduced here for ease of reference.

Form 10-K for the Fiscal Year Ended December 31, 2013

Properties, page 17

Summary of Oil and Gas Reserves, page 18

Proved Undeveloped Reserves, page 19

1. **We have considered the material provided in response to comments number one, three, four and five from our letter dated February 6, 2015, and note the following items:**
   - **Development activity related to PUD volumes, as a percentage of total opening PUD volumes, was very low during the years ended December 31, 2011, December 31, 2012 and December 31, 2013. This has been particularly true for the older "layers" of PUD volumes in each of those years.**
   - **Your actual drilling has consistently failed to follow schedules developed as part of your PUD determination. For example, you drilled during 2013 only nine out**

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of fifty locations identified for drilling during that year as part of your December 31, 2012 PUD determination. Similarly, during 2011, 2012 and 2014, you only drilled half of the PUD locations identified for drilling during those years as part of the PUD determinations as of the end of the prior year. For PUD locations scheduled to be 2011, 2012 and 2013, one third were never drilled and were eventually written off.

- **For the oldest "layers" in your PUD determinations as of December 31, 2012 and December 31, 2013, drilling had not proceeded according to the initial drilling schedule for the significant majority of PUD locations. For example, of the 109 locations in your 2013 reserve report attributable to 2009, 2010, 2011 and 2012, 47 have been written off as a result of the five year limitation, while only 16 have been drilled and 24 remain scheduled to be drilled in future years. Only 7 wells were drilled or remain scheduled to be drilled according their initial drilling schedules.**
- **During the years ended December 31, 2012, December 31, 2013 and December 31, 2014, you have written off material PUD volumes due to an inability to comply with the five year limitation.**

In view of the consistent variation between the drilling plans underlying your PUD determinations and your actual drilling activities, together with the recurring failure to develop PUD locations within 5 years of initial booking, explain to us your basis for concluding that you have met the reasonable certainty criteria as it relates to proved undeveloped reserves. See the definitions in Rule 4-10(a) paragraphs 22, 24 and 31 of Regulation S-X. Also, see Compliance and Disclosure Interpretation 131.04.

Response: The Company believes the reasonable certainty criteria requires the Company to have a development plan that, at the time of finalization of such development plan, will result in proved developed reserves ("PUDs") being drilled within five years. The Company believes that its development plans consistently met that criterion.

Background

While the Company agrees that there has been considerable variation between the drilling plans underlying its year-to-year PUD determinations and its actual drilling activities, it is important to note the significant factors responsible for this variation. First, the past seven years have been among the most volatile years for the oil and gas industry, beginning in 2008 with the global and financial market collapse and the resulting precipitous decline in natural gas prices. This initial shock was followed by unusually high and continuing volatility in commodity prices until most recently when the price of crude oil plummeted in the latter portion of 2014. Second, and most importantly, the Company was in a uniquely vulnerable position during these years.

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At the time of the 2008 economic collapse and subsequent downturn of natural gas prices, unlike many other exploration and production companies, the Company's reserves and production consisted of virtually all natural gas. The Company was very small and capital constrained as compared to most others in the industry. In light of these vulnerabilities, Company management felt that it was unwise to risk the future entirely on natural gas, and over the course of the next several years it carried out its strategic decision to take steps to refocus operations on higher margin return reserves, principally on oil. However, given the magnitude of the Company's natural gas reserves, the fact that the Company's oil drilling was to date then exploratory in nature and its belief that natural gas prices would recover over time, the Company continued its pursuit of natural gas development while simultaneously directing focus on higher return reserves. Ultimately, however, the Company decided to significantly change its drilling focus after it acquired $400 million of Eagle Ford Shale assets (primarily oil) (the "EF Acquisition") and began to concentrate its limited capital on the more profitable oil drilling. While the Company was optimistic about the possibilities for the EF Acquisition, there were limited proved reserves on the properties, and there were no guarantees that the EF Acquisition would ultimately be successful. Consequently, the Company retained a commitment to further natural gas drilling as natural gas prices recovered in the event its crude oil efforts were not fruitful. The Company's strategy and operational focus were described in its annual and quarterly reports for all periods involved.

This strategic transformation resulted in several reserve acquisitions, including the EF Acquisition, dispositions and resulting changes in the locations of the Company's operations. In 2008, 89% of the Company's production and 82% of its proved reserves were natural gas, and it had a geographically diverse asset base with operations in East Texas, Mid-Continent, Appalachia, Mississippi and the Gulf Coast. Today, the Company is almost exclusively an Eagle Ford Shale producer, with 73% of production and 77% of proved reserves coming from oil and natural gas liquids (NGLs).

The transformation described above evolved over some of the most dynamic years in the history of the oil and gas industry. That volatility, together with the Company's small size and capital constraints, made it essential that to survive and succeed, the Company remain nimble and able to react quickly to changing markets. As a consequence, the Company's development plans changed to a greater degree and more often than those in the industry with less leverage and greater diversity. It is in light of these facts that the Company respectfully addresses the Staff's noted items below.

<u>Specific Explanations for Low Development Rate and Failure to Follow Original Drilling Schedule</u>

We respectfully submit that the Company's drilling schedule used to develop year-end PUD reserves represents the Company's then-best commitment to future drilling activity based on the information known at that time. However, as noted above, the Company operates in a volatile and dynamic environment and, given its size and capital constraints, is particularly sensitive to market conditions, including commodity prices and available capital resources. Set forth below are some of the specific factors arising after the start of each year that resulted in changes and adjustments to the Company's development plan:

- Substantial decreases in natural gas prices in 2009 and again in 2012 compelled the Company to change its prior year-end plan of development to defer or eliminate the scheduled drilling of natural gas PUDs.

- Asset acquisitions and joint ventures, including the substantial EF Acquisition in April 2013 and a joint venture in the Eagle Ford Shale during 2012, caused the Company to revise its plan of development to re-allocate capital to integrate the acquired properties. The joint venture in the Eagle Ford dictated that we drill a mandatory number of wells within a contractual period of time in order to earn our interest in the acreage.
- Asset sales in 2011, 2012 and 2014 eliminated PUDs originally scheduled to be drilled. It should be noted, however, that the economic value of those foregone PUDs was recouped through the sale proceeds.
- The operators of the Company's non-operated PUDs failed to drill PUDs as originally planned, causing the development of some of the Company's PUD locations to be deferred or eliminated.
- Operating issues arising in the course of developing the Company's properties, such as changes in well spacing and the configuration of units in the Eagle Ford Shale, caused the Company's plan of development to change, resulting, in some instances, in the elimination of PUDs as the Company determined that the reserves associated with such PUDs would be captured by existing developed wells or other PUDs. It should be noted that the elimination of PUDs under these circumstances does not lower the ultimate volume of proved reserves.

Set forth below is a detailed explanation for each of the years 2011 through 2014 of the reasons for the deviations from the originally proposed drilling schedules.

2011 Explanation. The Company scheduled 33 PUDs to be drilled in 2011 in the prior year-end reserve report, all of which were natural gas. Of these, 17 were drilled in 2011. The ultimate disposition of the remaining 16 PUDs was as follows:

- Five natural gas PUDs were drilled in 2012. The drilling of these five PUDs was delayed by one year because (i) three non-operated substitute natural gas PUDs scheduled to be drilled in later years were drilled in 2011 due to a change in the drilling schedule by the operator, pushing the PUDs originally scheduled for 2011 back one year and (ii) two natural gas PUDs scheduled for 2011 were delayed when drilling was slowed down due to low natural gas prices.
- Two natural gas PUDs in Appalachia were dropped in 2011 when the Company elected to defer drilling wells in anticipation of selling those assets. That sale occurred in 2012.
- Two natural gas PUDs were dropped in 2012 when those locations were sold.

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- Two natural gas PUDs were eliminated (one in each of 2011 and 2012) when the plan of development changed such that reserves associated with the PUDs would be captured by existing wells or other PUDs.
- Five natural gas PUDs were dropped in 2014 when the Company elected to defer drilling natural gas assets in lieu of oil drilling.

2012 Explanation. The Company scheduled 34 PUDs to be drilled in 2012 in the prior year-end reserve report, 11 of which were natural gas and 23 of which were oil. Of these, three natural gas PUDs and 14 oil PUDs were drilled in 2012. The ultimate disposition of the remaining 17 PUDs was as follows:

- Natural gas prices dropped precipitously again in 2012, and the Company was forced to re-evaluate the profitability of natural gas drilling under the then-current economic climate. This caused the Company to delay the drilling of four natural gas PUDs pending a rebound in natural gas prices. One was drilled in 2013 and three were dropped as PUDs in 2013 when the Company's proposed development plan did not allow for them to be drilled within five years of initial booking.
- Three natural gas PUDs were dropped in 2012 because they no longer qualified as PUDs because they no longer were economically producible under then-current prices.
- One natural gas PUD was eliminated in 2013 when the plan of development changed such that the PUDs would be captured by existing wells or other PUDs.
- In late 2011, after the year end reserve report was substantially complete, the Company entered into a joint venture agreement that required the Company to drill wells on new acreage subject to the joint venture. This new obligation caused the Company to defer drilling some of the oil PUDs originally scheduled to be drilled in 2013 into subsequent years. Two oil PUDs were drilled in 2013 and two oil PUDs were drilled in 2014.
- One oil PUD was dropped in 2014 because it was no longer economically producible under then-current prices.
- One oil PUD was eliminated in 2013 and three oil PUDs were eliminated in 2014 when the plan of development changed such that reserves associated with the PUDs would be captured by existing wells or other PUDs.

2013 Explanation. The Company scheduled 50 PUDs to be drilled in 2013 in the prior year-end reserve report, nine of which were natural gas and 41 of which were oil. Of these, one natural gas PUD and nine oil PUDs were drilled in 2013. The ultimate disposition of the remaining 40 PUDs was as follows:

- Two natural gas PUDs in Pennsylvania were dropped in 2013 when the Company made a strategic decision to de-emphasize and ultimately exit the Marcellus Shale play.
- Three natural gas PUDs in Mississippi were not drilled when the Company made a strategic decision to sell its Mississippi assets. The sale of these assets occurred in 2014.

- The Company subsequently elected to non-consent one natural gas PUD proposed by another operator in Oklahoma in 2013 as a result of low natural gas prices impacting the well's economics.
- One natural gas PUD in Oklahoma was eliminated in 2013 when the plan of development changed such that reserves associated with the PUD would be captured by existing wells or other PUDs.
- One natural gas PUD was dropped in 2013 when its planned drilling was postponed due to low natural gas prices.
- In 2013, the Company completed the EF Acquisition (primarily oil). As a result of the EF Acquisition, the Company significantly altered its then-existing Eagle Ford Shale plan of development in order to incorporate the newly acquired assets and to maximize its capital resources and operational capabilities. As a result, many oil PUDs originally scheduled to be drilled in 2013 were deferred to later years. Fourteen oil PUDs were drilled in 2014 and 10 oil PUDs remained at year-end 2014 and are scheduled to be drilled in later years.
- Eight oil PUDs were eliminated when the plan of development changed such that reserves associated with the PUDs would be captured by existing wells or other PUDs.

2014 Explanation. The Company scheduled 100 PUDs to be drilled in 2014 in the prior year-end reserve report, eight of which were natural gas and 92 of which were oil. Of these, 68 oil PUDs were drilled in 2014. The ultimate disposition of the remaining 32 PUDs was as follows:

- Continued low natural gas prices resulted in one natural gas PUD not being able to compete economically with the Company's more profitable South Texas oil wells.
- Seven natural gas PUDs were non-operated locations where the operator had indicated an intent to drill them in 2014, but ultimately chose not to do so, electing instead to drill other locations on which the Company had no working interest. The Company dropped them in its year-end 2014 reserve report when the rescheduled drilling dates were beyond five years.
- The Company's Eagle Ford Shale development plan was significantly affected by the dramatic drop in oil prices in the second half of 2014. As the Company continued to develop and become more knowledgeable about its Eagle Ford Shale acreage up to and through 2014, it concentrated its limited capital on what it was discovering to be its highest economic return locations. Consequently, the Company changed its plan of development of the field to optimize economic returns, resulting in the deferral of planned PUD locations. Sixteen oil PUDs remain at year-end 2014 and are scheduled to be drilled in later years, and four oil PUDs were dropped in 2014 when changes in the plan of development moved their scheduled development dates beyond five years.
- Four oil PUDs were eliminated in 2014 when the plan of development changed such that reserves associated with the PUDs would be captured by existing wells or other PUDs.

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Reason for Failing to Drill Older PUDs

In the Company's year-end 2013 reserve report, 109 PUDs were originally booked in 2009 through 2012. Of these, 65 were natural gas PUDs and 44 were oil PUDs.

Natural Gas. Of the 65 natural gas PUDs, 50 were booked in 2009 and 2010. As noted above, these PUDs were booked following a period of substantial natural gas drilling. Also, as noted above, starting in 2011, the Company refocused its drilling efforts on crude oil and NGL locations. Accordingly, only 11 additional natural gas PUDs were added in 2011 and only four natural gas PUDs were added in 2012. The following discusses the ultimate disposition of the 65 natural gas PUDs:

- 20 natural gas PUDs booked in 2010 and 2011 were not initially scheduled to be drilled until 2014 and 2015. They were never drilled because they were all sold in 2014.
- 13 natural gas PUDs initially booked in 2010 were not initially scheduled to be drilled until 2013. In 2012, they were deferred until 2015, and they were dropped in 2014 in accordance with the five-year rule.
- 20 natural gas PUDs initially booked in 2010 were not initially scheduled to be drilled until 2014. In 2012, they were deferred until 2015, and they too were dropped in 2014 in accordance with the five-year rule.
- 8 natural gas PUDs were initially booked in 2009. As noted above, seven of these eight natural gas PUDs were non-operated locations where the operator had planned to drill them. They were rescheduled when the operator changed its development plans. They were dropped in 2014 when it became clear to the Company that they would not be drilled with five years.
- 4 natural gas PUDs initially booked in 2012 were not initially scheduled to be drilled until 2017. The Company still intends to drill these PUDs.

Oil. Of the 44 oil PUDs, four were booked in 2011 and 40 were booked in 2012. The following discusses ultimate disposition of the 44 oil PUDs:

- 1 oil PUD booked in 2011 was drilled in 2014.
- 1 oil PUD booked in 2011 was eliminated in 2014 when it was determined that the reserves associated with the PUD would be captured by existing wells or other PUDs.
- 1 oil PUD booked in 2011 was dropped in 2014 in accordance with the five-year rule.
- 1 oil PUD booked in 2011 remains in the Company's plan of development.
- 14 oil PUDs booked in 2012 were drilled in 2014.
- 5 oil PUDs booked in 2012 were dropped in 2014 in accordance with the five-year rule.
- 3 oil PUDs booked in 2012 were eliminated in 2014 when it was determined that the reserves associated with the PUDs would be captured by existing wells or other PUDs.
- 18 oil PUDs booked in 2012 remain in the Company's plan of development.

As noted above, when the Company completed the EF Acquisition, it completely changed the Company and, as a result, the Company changed its plan of development to integrate and develop the acquired properties. Consequently, many of the original PUDs booked in 2012 and scheduled to be drilled in 2013 and 2014 were deferred but still remain in the Company's plan of development.

Discussion of PUD Write Offs

The Company did, in fact, write off material PUD volumes during the years ended December 31, 2012, 2013 and 2014. However, the Company believes that these write offs support, rather than undercut, the Company's PUD reserve practices.

As noted above, most of the PUDs written off in those years were natural gas PUDs originally booked in 2008, 2009 and 2010, prior to the collapse of natural gas prices and the Company's refocus on crude oil and NGL development. As outlined above, the Company underwent a rigorous process each year of evaluating its PUDs. As the Company determined that portions of its natural gas PUDs locations would not be developed as a result of then-current development plans, the Company wrote off those locations via downward revisions of its reserves.

As of December 31, 2014, as a culmination of the Company's strategic shift to oil and NGLs, the Company has consolidated its operations in the Eagle Ford Shale. The Company's year-end 2014 reserve report contains 405 oil PUDs in South Texas. There are only four natural gas PUDs in East Texas and one natural gas PUD in the Mid-Continent.

Materiality of Natural Gas PUDs

The Company's PUDs are used to determine certain components of the Company's depreciation, depletion and amortization (DD&A) expense. The Company analyzed the effects on DD&A expense of writing off, instead of maintaining, the Company's natural gas PUDs in 2012, 2013 and 2014.

For the year ended December 31, 2012, a full write off of the Company's natural gas PUDs would have added no more than $6 million of DD&A expense, or 3 percent of reported DD&A expense. Alternatively, write offs of 50 percent and 25 percent of natural gas PUDs would have resulted in DD&A expense increases of approximately $2 million, or less than one percent of reported DD&A expense, and less than $1 million, or less than one-half of one percent of reported DD&A expense, respectively. For the subsequent years, the DD&A expense effects of the Company's PUDs decline significantly because of the write offs in 2013 and 2014 of additional natural gas PUDs.

On an after-tax basis, the financial statement effects of the Company's natural gas PUDs on net income and earnings per share is insignificant. Accordingly, the Company has determined that the financial statement impact of its natural gas PUDs is not material to its financial position or results of operations.

Preparation of Reserve Estimates and Internal Controls, page 19

2. **The information provided in response to prior comment number five from our letter dated February 6, 2015 indicates that the drilling schedules for a significant majority of the PUD locations included in your 2012 and 2013 reserves were changed at least once, and up to four times, over the time periods for which they were reported as reserves.**

   Describe for us the role that your senior management and board of directors have in the review and approval of the annual reserve estimates used for SEC reporting purposes. As part of your response, clarify the extent to which your senior management and Board of Directors, when considering annual reserve estimates and the underlying development plans, are fully apprised or aware of all changes to previously adopted development plans, including all previous deferrals, associated with locations for which PUD reserves continue to be claimed. Additionally, describe the factors that are considered in decisions to continue to defer rather than remove previously approved PUD locations that were not drilled according to previously approved development plans.

Response: The following summarizes the Company's processes with respect to the determination and reporting of proved reserves.

Annual Reserve Report

The Company's independent third party reserve engineers (the "Independent Engineers") prepare the Company's year-end reserve reports (the "Year-End Reports") through an iterative process, working chiefly with the Company's Vice President, Operations and Engineering (the "VPOE"). That process generally evolves as follows:

In the fall of each year, the Company's Executive Vice President and Chief Operating Officer (the "COO") and VPOE review with the Company's Vice President, Exploration; Manager, Exploitation; Vice President, Land; Vice President, Oil and Gas Marketing; Director, Operations; and Completions Manager the Company's anticipated drilling schedule by time and location, rig count, well costs, capital expenditure levels, leasehold status and third party obligations, such as minimum drilling obligations and minimum volumes required to be delivered to third parties who gather and transport the Company's crude oil and natural gas. This information, along with commodity prices, estimated ultimate reserves (EURs), type and decline curves and other assumptions (the "Assumptions"), and any additional information requested, is passed on to the Independent Engineers. Over the course of several weeks, the Independent Engineers prepare a draft of the Year-End Report, which is thoroughly discussed among members of senior management, including the Company's President and Chief Executive Officer (the "CEO") and the COO, the VPOE and the Independent Engineers. Any necessary changes are made and updated drafts are distributed back and forth and discussed.

When the Year-End Report is substantially complete, the VPOE presents a detailed summary of the report to the Audit Committee of the Company's Board of Directors (the "Board") at its February meeting, to which all directors are invited and which substantially all have attended in each of the past five years. The summary includes information regarding the amounts and locations of PUDs broken out by play type, the breakdown of crude oil, NGL and natural gas PUDs by play type, the Assumptions used for each play type, any material revisions from prior reserve estimates and the reasons therefor and changes in development plans resulting from the year-end reserve process. The VPOE also discusses, when pertinent, the effects on reserves of decline curve methodology, down spacing and other factors, the treatment of which may affect reserves. The Audit Committee is then given the opportunity to ask questions of the VPOE and other members of senior management. The information in the final Year-End Report is disclosed in the Company's Annual Report Form 10-K, which is signed by the required officers and the members of the Board.

Development Plan

The Company's development plan is initially based on the drilling schedule prepared by the Company and used by the Independent Engineers to prepare the Year-End Report. However, as explained above, the Company operates in an industry that is extremely volatile, and the Company believes that it is necessary to review its development plan on an continual basis so that it is able to optimize its results by making changes necessitated by unanticipated external factors such as significant commodity price fluctuations, changes in drilling and completions costs, financial markets changes, changes affecting our working interest partners and regulatory changes, as well as certain internal factors such as unanticipated well results, newly acquired geological or technical information, acquisitions, dispositions or other factors that the Company decides would likely affect its results. It is important that we make these changes in order to optimize the return on invested capital. The COO, in consultation with the Company's Director, Operations and its Completions Manager, recommends development plan changes after discussing those changes and the reasons therefor with the CEO.

The Board does not approve changes to specific drilling locations, but management makes the Board aware of any material changes in the Company's general plan of development. The Board has five regularly scheduled meetings each year, as well as additional special meetings as needed. At each of the regularly scheduled meetings, management explains to the Board significant developments in the Company's operations, including material changes in the Company's development plan. For example, in 2014, the Company began exploring the Upper Eagle Ford as a separate reservoir, and the Board was made aware of and supported the redeployment of capital from Lower Eagle Ford PUDs to new Upper Eagle Ford locations. In addition, in connection with its review and approval of material acquisitions or dispositions, the Board considers the effect such acquisitions or dispositions will have on the Company's development plan. For example, in connection with the EF Acquisition, the Board was apprised of management's plans to change the plan of development to drill non-PUD locations on the newly acquired acreage.

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Mid-Year Reserve Report

In addition to the periodic changes to the Company's development plan, the VPOE prepares an internal mid-year reserve report (the "Mid-Year Report"). In preparing the Mid-Year Report, the VPOE undertakes substantially the same process as used by the Company and the Independent Engineers in preparing the Year-End Report. The Mid-Year Report serves as an update of the previous Year-End Report. The Mid-Year Report, like the Year-End Report, is used by the Company's commercial banks to determine the Company's borrowing base under its revolving credit facility with adjustments and pricing provided by the banks. Any PUDs no longer scheduled to be drilled within five years are removed in the Mid-Year Report. As is done with the Year-End Report, the VPOE presents a summary of the Mid-Year Report to the Audit Committee.

Form 10-K for the Fiscal Year Ended December 31, 2014

Management's Discussion and Analysis of Financial Condition and Results of Operations, page 29

Key Developments, page 30

Significant Decline in Commodity Prices and Addition of Crude Oil Hedge Contracts for Calendar Years 2015 and 2016

3. **Discussion on page 10 of your filing indicates that your projections and estimates are based on assumptions as to future prices of crude oil, NGLs and natural gas. Separately, discussion on page 12 indicates that, under your current 2015 business plan, you are projected to be operating near the limits of the leverage permitted by your credit revolver. Tell us whether the estimated prices underlying your 2015 business plan assume increases over current prices. If so, tell us how you evaluated whether the potential variation between your estimated and actual future prices represents a material trend or uncertainty that would require disclosure, including possible quantification in your MD&A. See Item 303(a) of Regulation S-K and Section III.B.3 of Securities and Exchange Commission Release No. 34-48960.**

Response: The commodity pricing assumed in the Company's 2015 business plan, which was approved by the Board on February 23, 2015, was based on NYMEX and Henry Hub strip prices and, as such, assumed increases over then-current commodity prices for crude oil and natural gas, in each case adjusted for location and quality differentials and the expected effects of the significant hedges that were in place with respect to 2015 production.

The Company believes that it has provided adequate disclosure of any potential variation between estimated budgeted commodity prices and actual future prices. See, for example, the following disclosures in the Company's Annual Report on Form 10-K for the year ended December 31, 2014 (the "2014 Form 10-K"): Item 1A — Risk Factors — "Crude oil, NGL and natural gas prices are volatile, and a substantial or extended decline in prices would hurt our profitability and financial condition" on page 10, Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity on page 40 – paragraph one, and Item 7A — Quantitative and Qualitative Disclosures About Market Risk on page 48.

Please also refer to disclosures regarding the Company's commodity hedging program included on page 5 of Part I and pages 30, 34, 38, 40, 48, 49, 61, 62 and 63 of Part II of the 2014 Form 10-K. The Company provides these disclosures in order to permit meaningful and comprehensive analysis of its exposure to the underlying price risk, such that a reader of the 2014 Form 10-K can objectively assess our potential liquidity under any number of commodity price assumptions for 2015.

Finally, although the Company's 2015 business plan projects that it will operate near the limits of the leverage permitted by its revolving credit facility, the Company believes that it has available to it various alternatives to ensure that it does not exceed those limits, including deferral of capital projects and waivers or amendments of its leverage covenants. In fact, on May 7, 2015, the Company's revolving credit facility was amended to relax the leverage covenant from 4.25 times through maturity to 4.75 times through March 31, 2016, 5.25 times through June 30, 2016 and 5.5 times through December 31, 2016. See Current Report on Form 8-K filed on May 11, 2015.

Critical Accounting Estimates, page 46

Oil and Gas Properties

4. **Under the description of your accounting estimates related to proved oil and gas properties, you indicate that "it is possible that impairment would not be appropriate for certain properties that failed the objective assessment based on consideration of other factors, including the timeliness of reserve assignment, among others. Likewise, impairment may be appropriate for other properties that otherwise passed the objective assessment based on the trending of prices, lease expirations and future development plans." Explain to us, in greater detail, how this accounting policy is applied. Address the following:**

   - **Clarify whether the phrase "objective assessment" refers to the comparison of carrying value to undiscounted estimated future cash flows;**
   - **The circumstances under which you determine, and the factors considered in reaching such a determination, that impairment is not appropriate for properties that fail the objective assessment; and**
   - **The circumstances under which you determine, and the factors considered in reaching such a determination, that impairment is appropriate for properties that do not fail the objective assessment.**

As part of your response, provide us detailed descriptions of specific instances where you applied this policy to avoid and record impairment charges. Also, provide reference to the specific authoritative literature that supports this policy.

Response: The use of the term "objective assessment" does, in fact, refer to the comparison of carrying value to undiscounted estimated future cash flows.

Circumstances under which the Company could determine that impairment is not appropriate for properties that fail the objective assessment would typically arise with respect to areas whose development programs are in their early stages. For example, in 2011 and the first half of 2012 the Company's Eagle Ford Shale program had just begun. Based on the initial results in the play, however, and estimates of future cash flows and future expenditures necessary to develop the field (as contemplated by ASC 360-10-35-34), no impairment was indicated. Further development of the field has, of course, shown this to be accurate.

The Company's practice is to place on a "watch list" any areas that have undiscounted estimated future cash flows in excess of their net carrying value by less than a 10% margin. Properties on the watch list, although they have technically not failed the impairment test, are more closely monitored in terms of economic conditions affecting their value. At December 31, 2011, for example, the Company's former coal bed methane properties in Appalachia had undiscounted estimated future cash flows in excess of net book value by only 7%. The decrease in the value of the properties was attributable to higher trending operating costs and basis differentials in addition to lower prices. Both of these changes had been considered in the year-end reserve evaluation, resulting in a 50% decrease in the value of the proved reserves in the field. Management reviewed the results and determined that an impairment had occurred. Accordingly, the value of the coal bed methane properties was written down to estimated net present value.

Consolidated Financial Statements, page 51

Notes to Consolidated Financial Statements, page 57

Note 16 - Impairments, page 76

5. **Regarding the impairment charge related to your East Texas, Granite Wash and Marcellus regions, tell us the following:**
   - **The factors and assumptions considered in determining the amount and timing of the charge;**
   - **The carrying values of the properties involved before and after the charge;**

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- **How you applied these factors and assumptions to your South Texas properties, and;**
- **Your basis for concluding that your south Texas properties were not impaired.**

Response: In the fourth quarter of 2014, the Company recognized an impairment of $667.8 million attributable to its oil and gas properties in the East Texas, Granite Wash and Marcellus regions. The following is a discussion of the factors and assumptions considered in the amount and timing of the charge.

Consistent with its internal policies and the processes described above with respect to *Critical Accounting Estimates – Oil and Gas Properties*, the Company began its fourth quarter 2014 impairment analysis with an objective recoverability assessment. The review is undertaken by comparing the net carrying value of the Company's oil and gas properties for each area to the value of undiscounted estimated future cash flows based on 5-year NYMEX strip prices consistent with those used for budgeting and forecasting purposes. The following table summarizes the objective assessment for impairment based on the carrying value of the Company's oil and gas properties as of December 31, 2014: (in thousands):

Region	Carrying Value Before	Undiscounted Estimated Future Cash Flows	Coverage Amount	Impairment Indicated
South Texas	$1,509,501	$18,961,090	$17,451,589	No
East Texas	649,226	171,347	(477,879)	Yes
Granite Wash	83,146	63,568	(19,578)	Yes
Marcellus	646	7	(639)	Yes
Totals	$2,242,519	$19,196,012	$16,953,493	

As indicated in the table above, the carrying value of the Company's oil and gas properties in the East Texas, Granite Wash and Marcellus regions exceeded the sum of their respective undiscounted estimated future cash flows. Accordingly, these properties were subject to impairment. Impairment charges were determined by comparing the carrying values of the properties to their fair values derived by reference to discounted estimated future cash flows. The following table summarizes the results of this comparison (in thousands):

Region	Carrying Value Before	Impairment Charge	Carrying Value After
East Texas	$649,226	$617,346	$31,880
Granite Wash	83,146	49,837	33,309
Marcellus	646	632	14
Totals	$733,018	$667,815	$65,203

Inasmuch as the value of the undiscounted estimated future cash flows attributable to the Company's South Texas properties of $18.9 billion was well in excess of the $1.5 billion net carrying value of the properties, these properties were not subject to impairment as of December 31, 2014.

In connection with this response letter, the Company acknowledges that:

- the Company is responsible for the adequacy and accuracy of the disclosure in its filings with the Commission;
- Staff comments or changes to disclosure in response to Staff comments do not foreclose the Commission from taking any action with respect to the Company's filings; and
- the Company may not assert Staff comments as a defense in any proceeding initiated by the Commission or any person under the federal securities laws of the United States.

Please contact me at (610) 687-8900 if you need additional information or would like to discuss any questions or comments.

Sincerely,

/s/ Steven A. Hartman
Steven A. Hartman
Senior Vice President and Chief Financial Officer

cc: Nancy M. Snyder
Jenifer Gallagher