QEP RESOURCES, INC.
1050 17th Street, Suite 800
Denver, Colorado 80265

October 12, 2017

VIA EDGAR

Ethan Horowitz
Accounting Branch Chief
Office of Natural Resources
Division of Corporation Finance
Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549

Re: QEP Resources, Inc.
Form 10-K for the Fiscal Year Ended December 31, 2016
Filed February 22, 2017
File No. 001-34778

Dear Mr. Horowitz:

Set forth below are the responses of QEP Resources, Inc. (the "Company" "we" or "us") to the comments of the staff (the "Staff") of the Division of Corporation Finance of the Securities and Exchange Commission, which were delivered in your letter dated September 13, 2017 (the "Comment Letter"), regarding the Company's Annual Report on Form 10-K for the year ended December 31, 2016, filed via EDGAR on February 22, 2017, ("Form 10-K"). For ease of reference, the text of each of the Staff's comments is reproduced in bold-face type below, followed by the Company's responses. The headings and numbered paragraphs in this letter correspond to the headings and numbered paragraphs in the Comment Letter. Capitalized terms used but not defined in this letter are intended to have the meanings ascribed to such terms in our Form 10-K.

Form 10-K for Fiscal Year Ended December 31, 2016
Items 1 and 2. Business and Properties, page 8
Reserves, page 12
Proved Undeveloped Reserves, page 13

1. Your response to prior comment 1 indicates that the majority of proved undeveloped reserves (PUDs) transferred to proved developed reserves in 2016 resulted from the installation of additional centralized compression in Pinedale. However, disclosure in your Form 10-K regarding the 18% conversion rate achieved in 2016 states that some of which was a result of installing additional compression at Pinedale. Revise to provide additional detail regarding the progress made during the year to convert PUDs, including as it relates to specific circumstances where you experienced lower than expected conversion rates. Refer to Item 1203(b) of Regulation S-K.

Company Response:

During the year ended December 31, 2016, a total of 45.5 MMboe, or 18%, of the Company’s reserves that were classified as proved undeveloped (PUD) at December 31, 2015, were transferred to proved developed. Out of the total 45.5 MMboe converted to proved developed, we converted 25.2 MMboe of PUD reserves in Pinedale, of which 16.4 MMboe were the result of additional centralized compression (the Pinedale Compression Project). The PUD reserves converted as a result of the Pinedale Compression Project represented 36% of the total PUD reserves transferred and 6.5% of our PUD reserves as of December 31, 2015. The reserves associated with the Pinedale Compression Project did not require drilling to be converted.

Our PUD conversions in Haynesville/Cotton Valley and the Uinta Basin were less than 20% due to (i) a reduction in capital expenditures and planned drilling activity in 2016 compared to 2015 as a result of significant and continued weakness in commodity prices in early 2016; (ii) the reallocation of our 2016 capital expenditure budget to the highest rate of return projects, which were our oil-weighted assets in the Permian and Williston basins; and (iii) our decision to test and validate new completion technologies, such as the Haynesville/Cotton Valley re-stimulation (refracturing) program. (See Response 2 and 3 below for additional information). At year-end 2015 and 2016 the Company planned to convert all PUD reserves to proved developed within their five-year life, or they were removed from proved reserves ahead of their five-year life expiration.

In the Williston Basin at December 31, 2015, we planned to convert 21.9 MMboe of PUD reserves to proved developed, however, during 2016 we converted 13.8 MMboe. The amount converted was less than planned in the Williston Basin as a result of (i) a reduction in capital expenditures and planned drilling rig activity in 2016 (we went from three operated drilling rigs at the end of 2015 to one rig in the second quarter of 2016), due to the weakness in oil prices in early 2016; and (ii) a dispute with a third-party midstream provider that purchases, gathers and processes associated gas on the Company's South Antelope acreage, which delayed the completion of 23 wells until the dispute was finally resolved in early November 2016. The Company converted 14 of the 23 delayed wells to proved developed in 2016, and the remaining nine wells were not converted to proved developed until 2017.

In our 2017 Annual Report on Form 10-K and in future annual filings, in addition to disclosing the number of PUD reserves converted to proved developed reserves during the year, we will provide additional detail regarding the progress made during the year to convert PUDs.

2. From your response to prior comments 1 and 3, we note that you converted 4% of your PUDs and only drilled 8.0 of the 17.0 wells scheduled for 2016 in the Uinta Basin in 2016. We also note that none of your PUDs in the Haynesville/Cotton Valley area were converted in 2016 and that none of the 5.9 wells scheduled for 2016 there were drilled during the year. In light of these relatively low PUD conversion rates and the revisions to your planned activities, explain how you concluded that you have adopted a development plan and made a final investment decision with regard to these PUDs. Include details specifying the steps you have taken to demonstrate more than the mere intent to develop these PUDs. Refer to Rule 4-10(a)(31)(ii) of Regulation S-X along with Question 131.04 of the Compliance and Disclosure Interpretations regarding Oil and Gas Rules.

Company Response:

We acknowledge the Staff's comment and respectfully submit that we have historically recorded PUD reserves when all the requirements of Rule 4-10 of Regulation S-X have been met.

At the end of each year, management develops a five-year capital expenditure plan based on the best available data at the time the plan is developed. Our capital expenditure plan includes a development plan for converting PUD reserves. Our development plan includes only PUD reserves that we are reasonably certain will be drilled within five years of booking based upon qualitative and quantitative factors in existence at the time, including estimated risk-based returns, estimated well density, current commodity pricing and cost forecasts, recent drilling and re-stimulated well results, availability of services, equipment and personnel, seasonal weather and changes in drilling and completion techniques and technology. This process is intended to ensure that PUD reserves are only claimed for locations where a final investment decision has been made by the Company. Our five-year development plan generally does not contemplate a uniform (i.e. 20% per year) conversion of PUD reserves in all of our producing regions. We strive to maintain a balanced portfolio of oil and gas assets and production, which in part drives capital allocation decisions across our asset base, resulting in different PUD conversion rates by producing regions.

QEP maintains a Reserves Committee that is comprised of members of QEP's management team and our Director of Corporate Reserves. The Reserves Committee meets on a semi-annual basis, including prior to the filing of reserves estimates with the SEC or any public disclosure of reserve estimates. The Reserves Committee reviews data that is submitted by our Director of Corporate Reserves to the independent petroleum engineering firm we have engaged to prepare our reserve estimates, including cost and pricing assumptions and reserve reconciliations from the previous reserve determinations. The independent petroleum engineering firm prepares the estimate of proved reserves based on the definitions and disclosure guidelines of the Securities and Exchange Commission. The Director of Corporate Reserves' Annual Reserve Summary Report and the Reserve Committee's Certification are provided to QEP's Audit Committee annually and the Audit Committee also meets annually with the third-party independent petroleum engineering firm to review the reserves estimation reporting process and disclosure.

Executive management and QEP's Board of Directors ("the Board") review the Company's five-year capital expenditure plan, and the capital budget for the first year of the development plan is approved and established by the Board annually. Management reviews and revises the development plan throughout the year, and may modify the development plan for a variety of reasons, including (i) operating and drilling results; (ii) advances in technology; (iii) current and expected future commodity prices; (iv) service and supply costs; (v) acquisition and divestiture activity; and (vi) our current and projected financial condition and liquidity. Changes in our development plan are reviewed with the Audit Committee and the Board quarterly.

Changes in our development plan are also reviewed by management, the Director of Corporate Reserves and the Reserves Committee when reserves are estimated at year-end. If there are changes that result in certain PUD reserves no longer being scheduled for development within five years from the date of initial booking, we reclassify those PUD reserves to non-proved reserve categories. In addition, our asset portfolio has changed significantly over the past five years. As a result of multiple asset divestitures and acquisitions and associated changes in the priority of development within our portfolio of assets, PUD locations and reserves have also been removed from the development plan ahead of their five-year life expiration. For example, if in year two after booking PUD reserves we change our drilling plans and determine that we will not convert such PUD reserves in the next three years, we will reclassify those PUD reserves to non-proved reserve categories.

Throughout 2016, the Company maintained development activities in Haynesville/Cotton Valley. At December 31, 2015, we planned to add one rig in Haynesville/Cotton Valley, however, the scheduled PUD development in 2016 was delayed while we evaluated the success of the re-stimulation (refracturing) program we initiated in the first half of 2016, with the anticipation that we would be able to apply advancements in completion technologies to the future development of our PUD locations in the field. The refracturing program was designed to test reservoir response to increased proppant concentrations and staging in the existing Haynesville Shale horizontal wellbores that would be directly applicable to new wells drilled in the area. During 2016, our production from Haynesville/Cotton Valley was essentially flat compared to 2015 as our refracturing program offset natural decline in the field, demonstrating our ongoing commitment to develop the asset. Based on the positive results from the refracturing program in 2016, and as contemplated in our 2017 development plan, we continued our successful refracturing program and have moved a drilling rig into Haynesville/Cotton Valley in the third quarter of 2017.

In the Uinta Basin, during each year from 2012 to 2016, we had ongoing development activities, including a drilling program focused on improving drilling techniques, reducing well costs, increasing per-well recoverable reserves and obtaining a better understanding of the complex reservoir. In 2013, we began drilling horizontal wells to determine the optimum combination of vertical and horizontal wells that would generate the highest rates of return and reserve recovery for that region. At December 31, 2015, our development plan included the conversion of 54 Bcfe of PUD reserves to PDP during 2016 utilizing one drilling rig throughout the year; however, due to the significant decline in commodity prices and subsequent reduction in drilling activity, only 14 Bcfe were converted. The forecasted conversion rate for the Uinta Basin was weighted to the later years of the five-year development schedule as of December 31, 2015. All of the 309.2 Bcfe of PUD reserves in the Uinta Basin as of December 31, 2015, were scheduled to be converted to PDP within five years from the date of initial booking. During 2016, in response to the low commodity price environment, we reduced our drilling and completion activity in the Uinta Basin from what was planned at year-end 2015 in order to maintain our drilling activity in Pinedale. Despite the reduction in activity in the Uinta Basin and Haynesville/Cotton Valley, QEP, in aggregate, still converted 273 Bcfe of the 293 Bcfe of PUD reserves scheduled for conversion in 2016. In addition, at year-end 2015 and 2016 the Company still planned to convert all PUD reserves to proved developed within their five-year life, or they were removed from proved reserves ahead of their five-year life expiration.

To assist the Staff in understanding our forecasted development activities as of December 31, 2015, we are supplementally providing the Staff with a schedule (Schedule 1) that sets forth our Projected Capital Expenditures to Convert PUD Locations to PDP and our Projected PUD to PDP Reserve Conversions by Year, in each case as of December 31, 2015, by producing region for the years 2016 through 2020.

3. Describe the steps routinely taken to evaluate interim and annual changes in your development schedule to determine whether your PUDs continue to meet the requirements for disclosure. In addition, tell us about any instances in the last five fiscal years where drilling activity was deferred from the original drilling schedule and PUDs were not converted to proved developed reserves within their five year life.

Company Response:

Please see our response to Comment No. 2 above for the steps we take to evaluate interim and annual changes to our development schedule to determine if our PUD reserves continue to meet the requirements of Rule 4-10 of Regulation S-X for disclosure.

We have revised our development plans over the past five fiscal years to defer drilling and have removed associated PUD locations and reserves that were not converted to proved developed within their five-year life as follows:

Year End	Net PUD Reserves Removed (MMboe)	Gross PUD Locations Removed	Producing Region
2012	0.3	1	Pinedale
2013	8.2	44	Pinedale(1)
2014	1.0	4	Pinedale
2015	6.2	20	Williston Basin(2)
2015	4.2	14	Pinedale(2)
2016	1.4	1	Haynesville
2016	0.4	1	Williston Basin
2016	1.4	3	Uinta Basin

(1) Removed PUD reserves due to a decrease in drilling activity in response to lower commodity prices and removal of certain lower rate of return PUD locations that were still economic but did not meet the Company's return threshold at then current commodity prices.

(2) Removed PUD reserves as a result of the significant decline in crude oil and natural gas prices and subsequent reduction in drilling activity. The Williston Basin rig count decreased from six active rigs at December 31, 2014, to three rigs at December 31, 2015, while the Pinedale rig count decreased from four to three rigs over the same period.

As a result of our success in refracturing existing wells with significantly larger proppant concentrations and higher fracture stage counts, combined with continued evolution of well designs in the Haynesville Shale portion of Haynesville/Cotton Valley, where several operators directly offsetting our acreage have successfully drilled and completed laterals up to 10,000 feet in length, we removed the majority of our previously booked PUD reserves associated with horizontal laterals approximately 4,800 feet in length that existed at December 31, 2015, and replaced them with horizontal laterals averaging approximately 7,500 feet in length at December 31, 2016. We revised our development plan accordingly. Based on the strong performance of our refractured wells, which demonstrated the uplift in recoverable reserves associated with increased proppant loading, and the strong performance of longer lateral length wells drilled by offset operators, which demonstrated the technical and operational viability of drilling and completing laterals up to 10,000 feet or longer in the Haynesville Shale, and pursuant to our development plan as of December 31, 2016, we commenced drilling in the third quarter of 2017. Our current plan is to develop our acreage utilizing approximately 10,000 foot laterals where possible, which will most likely necessitate further revision of our PUD bookings at year-end 2017, demonstrating that while our intention to develop our Haynesville/Cotton Valley asset has not changed, the specific well design has evolved and will likely continue to do so as we seek to maximize returns on invested capital and recovery of reserves on all of our assets.

4. Your response to prior comment 2 states that you expect to convert approximately 60% of your PUDs to proved developed reserves over 2017, 2018, and 2019. Tell us about the drilling that occurred through June 30, 2017 and the percentage of PUDs that will be converted during 2017 based on your experience to date.

Company Response:

We completed 85 gross wells across our asset portfolio through June 30, 2017, and had additional wells waiting on completion and drilling. As of June 30, 2017, 63 of our PUD locations (22.3 MMboe) that were scheduled at December 31, 2016, were converted to proved developed during 2017. In total, based on our experience through September 30, 2017, we expect that during 2017 we will convert approximately 95 gross locations that were scheduled as PUDs (38.3 MMboe) at December 31, 2016, which results in an expected conversion of 84% of the 45.4 MMboe PUD reserves that were scheduled to be completed in 2017. We anticipate that our PUD reserve conversion rate during 2017 will be less than planned due (i) unforeseen drilling delays, primarily in the Permian Basin, where we continued to refine our "tank style" development (which necessitates that we drill and complete all wells in a given "tank", typically 15 to 20 wells, before any individual well is turned to production); and (ii) changes in actual versus forecasted well spacing, i.e., increased well density, as we are drilling and completing wells that were classified as non-proved locations between PUD locations that were booked at December 31, 2016. We anticipate some changes in the schedule of development of our currently booked PUD locations in the Permian Basin at the end of 2017 due to these drilling delays and changes in actual versus originally assumed well density.

5. Your response to prior comment 3 indicates that 9.0 PUD wells in the Permian Basin were scheduled for drilling in 2016, but that 16.8 wells were drilled and completed. However, your response to prior comment 1 states that you experienced a relatively low conversion rate in the Permian Basin as capital was allocated to the conversion of probable and possible reserves. Tell us whether any of the wells you drilled in the Permian Basin were related to reserves that were not characterized as PUDs as of December 31, 2015 and, if so, the number of PUD wells drilled.

Company Response:

Of the 16.8 net wells that were completed in the Permian Basin during the year ended December 31, 2016, 9.0 net wells contained reserves that were classified as PUD reserves at December 31, 2015, and 7.8 net remaining wells were increased density locations that contained reserves that were not classified as PUD.

Because the Company continues to refine its development model for the various reservoirs in its Permian Basin asset, at December 31, 2015, not all locations scheduled to be drilled in 2016 were classified as PUD. Based on our experience, it is our belief that it will be less efficient to drill infill wells in years subsequent to the initial development of the various reservoirs. As such, during 2016, we drilled locations in pilot programs that were classified as PUD at December 31, 2015, and additional locations between each PUD location that were classified as non-proved to better understand ultimate well density/spacing in each reservoir. The results of these pilot programs will provide additional data to further refine our development program in the Permian Basin and could cause us to modify our future PUD booking methodology going forward to include higher well density/tighter spacing in certain reservoirs.

Notes Accompanying the Consolidated Financial Statements
Note 1 - Summary of Significant Accounting Policies, page 78
Impairment of Long-Lived Assets, page 81

6. Your response to prior comment 7 states that a deterioration in expected future prices for oil and NGLs caused you to perform an impairment analysis at June 30, 2017. Revise to provide additional disclosure discussing and analyzing the facts and circumstances surrounding known material trends and uncertainties related to future commodity prices and the implications to your financial statements. Refer to Item 303(a)(3) of Regulation S-K along with section III.B. of SEC Release No. 33-8350.

Company Response:

We acknowledge the Staff's comment and respectively advise the Staff that we believe we have substantially complied with the provisions of Section III.B.3 of SEC Release No. 33-8350. Our 2016 Form 10-K and our quarterly reports on Form 10-Q filed during 2017 have included the following disclosures in MD&A under the caption "Factors Affecting Results of Operations – Supply, Demand, Market Risk and Their Impact on Oil and Gas Prices:"

> *Changes in the market prices for oil, gas and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, planned drilling and completion activity and related capital expenditures, liquidity, rate of growth, costs of goods and services required to drill, complete and cooperate wells, and the carrying value of its oil and gas properties…. If prices of oil, gas or NGL decline to early 2016 levels or further, our operations, financial condition, level of expenditures for the development of our oil and gas reserves and the price of our common stock may be materially and adversely affected.*

We continuously review the outlook of future prices and other qualitative and quantitative factors, including estimated risk-based returns, estimated well density, current commodity pricing and cost forecasts, recent drilling and refractured well results, availability of services, equipment and personnel, seasonal weather and changes in drilling and completions techniques and technology. We evaluate proved oil and gas properties on a field-by-field basis for potential impairment. Impairment is indicated when a triggering event occurs and/or the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset's carrying value. Triggering events could include, but are not limited to, a reduction of oil, gas and NGL reserves caused by mechanical problems, faster-than-expected decline of production, lease ownership issues and declines in future oil, gas and NGL prices. We recorded more than $2.0 billion of impairments during 2014 through 2016, largely as a result of the decline in future oil, gas and NGL prices.

At June 30, 2017, future projected commodity prices fell to levels below our last full impairment test that was performed at December 31, 2016, indicating that a triggering event had occurred, and we performed a full impairment analysis and test. The impairment analysis and test indicated no impairment. We did not provide additional qualitative disclosure in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, filed July 26, 2017, because, at the time of filing, we determined we would not have additional impairment if the current future commodity price trends and operational performances continued.We also had no indication of a triggering event due to mechanical problems, substantial declines in production, or ownership issues. Therefore, at June 30, 2017, we did not believe that substantial further impairment of our assets was reasonably likely to occur in the near future.

When future pricing trends may cause a material impairment, we have disclosed to our investors the anticipated impact from such trends. For example, when forward future prices in mid-February 2016 had declined subsequent to the test for impairment at December 31, 2015, we disclosed to investors in our Annual Report on Form 10-K for the year ended December 31, 2015, filed on February 24, 2016, in the MD&A discussion under the caption "Potential for Asset Impairments" the following:

> *If forward prices remain at mid February 2016 levels we have approximately $1.8 billion of proved property net book value, as of December 31, 2015, primarily associated with our Pinedale field, at risk for impairment. The actual amount of impairment incurred, if any, for these properties will depend on a variety of factors including, but not limited to, subsequent forward price curve changes, the additional risk-adjusted value of probable and possible reserves associated with the properties, weighted-average cost of capital, operating cost estimates and future capital expenditure estimates.*

In addition to the impairment impact that future commodity prices may have on our financial statements, we have generally addressed in our disclosures that future projected pricing trends could impact planned drilling and completion activity and related capital expenditures.We have not, however, specifically highlighted the potential impact of lower future projected pricing trends, reduced capital expenditures and changes in our drilling and completion activity on conversion of our PUD reserves. In future filings, in addition to highlighting the potential for asset impairment, we will specifically highlight any potential material impact of lower future pricing trends, reduced capital expenditures and/or changes in our in our drilling and completion activity on conversion of our PUD reserves.

Closing comment

The Company acknowledges that:

- the Company is responsible for the adequacy and accuracy of the disclosure in its filing;
- Staff comments or changes to disclosure in response to staff comments do not foreclose the Commission from taking any action with respect to the filing; 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.

If the Staff has any questions or comments concerning these responses, please contact the undersigned, at (303) 640-4242 or email at richard.doleshek@qepres.com.

Sincerely,

/s/ Richard J. Doleshek

Richard J. Doleshek
Executive Vice President and Chief Financial Officer
QEP Resources, Inc.