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

July 20, 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 July 10, 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. We note that you converted 18% and 23% of your proved undeveloped reserves ("PUDs") to proved developed reserves in the years ended December 31, 2016 and 2015, respectively. However, from 2015 to 2016 the costs incurred to continue the development of your PUDs decreased from $490.4 million to $258.1 million and the number of productive net development wells drilled decreased from 177.8 to 96.3. Tell us in reasonable detail how you were able to achieve a conversion rate of 18% for 2016 despite having significantly lowered the amount of capital expenditures and the number of wells drilled compared to 2015. With your response, provide us with quantitative information regarding the resource plays where development activity occurred during 2015 and 2016.

Company Response:
As discussed in our Business and Properties section (on page 13 of our Form 10-K), our 2016 PUD reserve conversion rate was 18% despite fewer net well completions and lower PUD development costs. A significant portion of the PUD reserve conversion rate was the result of a pilot program in 2015 and the subsequent installation of additional centralized compression in Pinedale, which lowered field-wide wellhead pressures, resulting in incremental production and increased proved developed reserves. The compression project in Pinedale resulted in conversion of 16.4 Mboe of PUD reserves to proved developed reserves. We did not incur any associated development costs for the compression project as the third-party gas gathering company installed the additional compression in exchange for an increased compression fee, which is reflected in our estimated future operating costs.

Our PUD development costs decreased by 47% from $490.4 million in 2015 to $258.1 million in 2016, and the number of our net well completions decreased by 46% from 177.8 in 2015 to 96.3 in 2016. Our conversion rate decreased from 23% in 2015 to 18% in 2016. The table below sets forth 2015 and 2016 PUD reserve conversion rates by resource play. Please note the PUD reserve conversion rate for Pinedale of 50% in 2016, which was driven by the compression project.

	PUD Reserves Converted to Proved Developed	PUD Reserves as of Year End	PUD Reserve Conversion Rate	PUD Reserves Converted to Proved Developed	PUD Reserves as of Year End	PUD Reserve Conversion Rate
	2016	2015	2016	2015	2014	2015
Northern Region	(MMboe)			(MMboe)		
Williston Basin	13.8	71.0	19%	30.1	57.7	52%
Pinedale	25.2	50.7	50%	26.4	98.9	27%
Uinta Basin	2.3	51.5	4%	4.3	49.3	9%
Other Northern	—	—	—	—	—	—
Southern Region						
Permian Basin	4.2	41.1	10%	1.5	36.1	4%
Haynesville/Cotton Valley	—	37.5	—	4.0	47.0	9%
Other Southern	—	—	—	—	—	—
	45.5	251.8	18%	66.3	289.0	23%

	PUD Development Costs Incurred		Net Wells Completed	
	2016	2015	2016	2015
Northern Region	(in millions)			
Williston Basin	$ 167.4	$ 269.4	39.5	59.7
Pinedale	37.2	142.6	24.4	68.1
Uinta Basin	8.7	16.5	8.0	11.2
Other Northern	—	—	3.0	3.0
Southern Region				
Permian Basin	44.8	35.2	18.8	32.5
Haynesville/Cotton Valley	—	26.7	2.6	3.2
Other Southern	—	—	—	0.1
	$ 258.1	$ 490.4	96.3	177.8

We recognize that in 2015 and 2016 we have relatively low PUD reserve conversion rates in our other natural gas assets (Uinta Basin and Haynesville/Cotton Valley) because we reallocated capital as a result of reduced corporate cash flows. In addition, we experienced a relatively low PUD reserve conversion rate in the Permian Basin as we allocated capital to the conversion of probable and possible reserves because we targeted multiple formations in a field that is in the early stages of development. However, all of our PUDs at December 31, 2016, based on future commodity prices at year end, were scheduled within five years. For further details of our future development plans please see our response to Comment 2.

2. We note that budgeted costs to develop your PUDs are expected to increase from $503.0 million in 2017 to $717.3 million in 2018 and $781.3 million in 2019. Quantify the PUDs you expect to convert in each of these years by resource play and provide appropriate context describing your planned activities. As part of your response, address your planned operations in areas where you appear to have reduced or suspended drilling activity. Refer to Rule 4-10(a)(31)(ii) of Regulation S-X.

Company Response:
Over the past five years, our annual PUD reserve conversion rate has averaged 19% through drilling programs that targeted both oil and gas assets across multiple resource plays as well as other production enhancement projects such as the Pinedale compression project. Historically, in addition to drilling locations with PUD reserves, the Company has allocated capital expenditures for development of probable and possible reserves, especially in projects that are early in their development cycle such as the Permian Basin. Over 2017, 2018 and 2019 our drilling schedule is expected to convert approximately 60% of the Company's December 31, 2016 PUD reserves to proved developed.

To assist the Staff in understanding our forecast development activities, we are supplementally providing the Staff with a schedule (Exhibit A) that sets forth both the number of net PUD well locations we planned to drill and complete and the PUD reserve conversion rate during the period from 2017 to 2019.

3. We note your statement regarding your efforts to reduce drilling and completion activities in 2016. Identify the locations and quantities of any PUDs that were scheduled for 2016 as of December 31, 2015, but were not drilled during the year and explain why drilling did not occur.

Company Response:
The following table presents the locations and quantities of net operated PUD well locations as of December 31, 2015, that were scheduled for drilling and completion and conversion of associated reserves from PUD to PDP during 2016.

	PUD wells scheduled as of December 31, 2015 for drilling and completion and conversion to proved developed	Actual wells drilled and completed and converted to proved developed in 2016	Difference
		(net well counts)	
Northern Region			
Williston Basin[1]	35.3	31.6	(3.7)
Pinedale	8.5	16.1	7.6
Uinta Basin[2]	17.0	8.0	(9.0)
Other Northern	—	3.0	3.0
Southern Region			
Permian Basin	9.0	16.8	7.8
Haynesville/Cotton Valley[3]	5.9	—	(5.9)
Other Southern	—	—	—
Total	75.7	75.5	(0.2)

(1) In 2016, we drilled and completed a total of 31.6 net PUD well locations in the Williston Basin, 3.7 net fewer completions than we had scheduled at December 31, 2015. However, 3.7 net PUD locations were drilled as of December 31, 2016 but waiting on completion . As discussed in Items 1 and 2. Business and Properties, Drilling Activities (page 22 of our Form 10-K), the Company sometimes suspends completion activities due to adverse weather conditions, operational factors or other macroeconomic circumstances, such as low commodity prices. The locations that remained as PUDs at December 31, 2016, were within their five year life and pursuant to our development plan, were planned to be converted to proved developed reserves within that period.

(2) In 2016, we drilled and completed a total of eight net PUD well locations in the Uinta Basin, nine fewer than we had scheduled at December 31, 2015. The capital scheduled to drill and complete these additional nine net wells was allocated to other resource plays within the Company's portfolio of assets as the Company chose to monitor performance of the eight new well completions, and allocated capital to other projects, rather than drilling the Uinta Basin scheduled PUDs. The locations that remained as PUDs at December 31, 2016, were within their five year life and pursuant to our development plan, were planned to be converted to proved developed reserves within that period.

(3) In 2016, we did not drill and complete any PUD well locations in Haynesville/Cotton Valley but had scheduled 5.9 net locations for 2016 at December 31, 2015. These 5.9 net PUD well locations in Haynesville/Cotton Valley were not drilled and completed as a result of our decision to restimulate 10 wells as a part of our refracturing program which added proved reserves, that are reflected as revisions to previous estimates in our reserve table. The development plan and rig schedule at December 31, 2015 added a drilling rig in 2016 but was revised in 2016 based on the returns of the refractured wells compared to cost of drilling and completing new wells. However, the refracturing program has allowed us to evaluate advancements in completion technology which we believe are directly applicable to future development of our PUD inventory. The locations that remained as PUDs at December 31, 2016, were within their five year life and pursuant to our development plan, were planned to be converted to proved developed reserves within that period.

4. We note the increase in planned capital expenditures to convert your PUDs in 2017, 2018, and 2019. Revise your disclosure of liquidity and capital resources to describe the expected sources of capital and the implications if adequate financing is not available. Refer to Items 303(a)(1) and (2) of Regulation S-K.

Company Response:
We acknowledge the Staff's comment and respectfully refer the Staff to Items 1 and 2. Business and Properties, Reserves (page 13 of our Form 10-K), where we discuss our belief that cash flow from operations, cash on hand and, if needed, availability under our revolving credit facility will be sufficient to cover these estimated future development costs. We also respectfully refer the Staff to Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources (MD&A Section) (page 60 of our Form 10-K), where we discuss our belief that these sources of cash will be sufficient to fund our operations and capital expenditures during the next 12 months and the foreseeable future. In addition, we state that to provide additional liquidity, QEP also periodically accesses debt and equity markets and sells non-core properties. Our net cash provided by operating activities was $663.7 million for the year ended December 31, 2016, and our cash on hand was $443.8 million at December 31, 2016. As of December 31, 2016, we had availability of $1.0 billion and no borrowings under our revolving credit facility, which is scheduled to mature in December 2019.

We also respectfully refer the staff to the discussion earlier in our MD&A Section under "Factors Affecting Results of Operations" where we state that declines in oil and gas prices resulted in QEP reducing drilling and completion activity and planned capital expenditures in 2016 (on page 52 of our Form 10-K) and that future declines in oil and gas prices could adversely affect QEP's expenditures on development of our oil and gas reserves and the price of QEP's common stock (on page 51 of our From 10-K).

Finally, we respectfully refer the staff to the following Item 1A – Risk Factors (beginning on page 28 of our Form 10-K), which are cross referenced at the front of our MD&A Section:

- *"QEP is dependent on its revolving credit facility and continued access to capital markets to successfully execute its operating strategies,"*
- *"QEP's debt and other financial commitments may limit its financial and operating flexibility,"*
- *"A downgrade in QEP's credit rating could negatively impact QEP's cost of and access to capital," and*
- *"Failure to fund continued capital expenditures could adversely affect QEP's properties."*

In these risk factors, we further discuss the implications for the Company if adequate financing is not available, including curtailing our operations relating to exploration and development, which could cause reductions in our oil or gas production, reserves and revenues, and negatively impact our results of operations.

We respectfully believe that our discussion of our liquidity and capital resources and factors that impact our results of operations in the MD&A Section, as well as our risk factors, provide sufficient information to investors regarding our ability to fund our development program and the implications for the Company if financing is unavailable.

5. Explain your statement that $258.1 million was incurred "to continue the development" of your PUDs in 2016 and tell us whether this is the amount of capital expenditures incurred in 2016 to convert 45.5 MMBoe of your PUD reserves pursuant to Item 1203(c) of Regulation S-K.

Company Response:
The $258.1 million was incurred in 2016 to convert 45.5 MMboe of PUD reserves to proved developed. The statement "to continue the development" of PUD reserves is meant to address the fact that while reserves are converted from proved undeveloped to proved developed in a given year, certain costs, such as location costs and sometimes drilling costs, are incurred in years prior to the year in which actual conversions are booked.

<u>Production, Prices and Production Costs, page 15</u>
<u>Expiring Leaseholds, page 20</u>

6. It appears that the leases for approximately 12% of your undeveloped acreage will expire over the next three years. Describe and quantify the PUDs associated with this acreage and tell us whether any of your PUDs are scheduled for drilling after lease expiration.

Company Response:

The Company does not have any PUD locations affected by any of the leaseholds listed as expiring over the next three years in our Form 10-K. In addition, the Company does not have any PUD locations scheduled to convert to proved developed reserves after lease expiration.

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

7. Future net cash flows used to calculate your standardized measure of discounted future net cash flows decreased from $10.5 billion as of December 31, 2014 to $4.1 billion as of December 31, 2016 primarily due to changes in sales prices and in production costs related to future production. As a result of this change, net capitalized costs relating to oil- and gas-producing activities exceed the amount of future net cash flows as of December 31, 2016. In addition, your stock price appears to have fallen since December 31, 2016 causing a significant decline in your market capitalization. Tell us whether these are circumstances indicating that a triggering event requiring impairment tests for a possible decline in the recoverability of your capitalized costs has occurred. Refer to FASB ASC 360-10-35-21.

Company Response:
The prices for oil, gas and NGLs used in the calculation of the standardized measure of discounted future cash flows are the average of the first day of the twelve months preceding the calculation date while the Company's impairment testing policy incorporates management’s expectation of future prices in determining fair value. The average realized prices for oil, gas and NGLs in the standardized measure at December 31, 2016 were; $38.59 per Bbl, $2.39 per Mcf, and $13.85 per Bbl, respectively, which were substantially lower than management's expectation of future prices. We acknowledge that subsequent to December 31, 2016, our market capitalization has declined, however, we believe a decline in market capitalization does not necessarily indicate a triggering event. Our triggering events 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, declines in oil, gas, and NGL prices or increases in future development or operating costs.

At December 31, 2016, we tested our capitalized costs relating to oil and gas producing properties in accordance with our annual impairment testing policy. At December 31, 2016, the carrying value of two successful effort fields within our Uinta Basin and Other Southern assets exceeded the sum of the estimated undiscounted future net cash flows for those assets, triggering an impairment analysis and resulting in our recognition of a proved property impairment expense of $4.8 million. At March 31, 2017, our review indicated a triggering event had not occurred. At June 30, 2017, our review determined that deterioration in expected future prices for oil and NGLs had created a triggering event. As such, we performed a detailed impairment analysis at June 30, 2017, which resulted in no impairment charge for the quarter ended June 30, 2017.

8. Disclosure on page 52 of your annual report states that the cash flow model you use to assess proved properties for impairment includes numerous assumptions such as the market outlook on forward commodity prices. Revise to more clearly describe your basis for estimating oil, gas and NGL prices used in your calculation of undiscounted future net cash flows and to explain how you assess the sensitivity of your capitalized costs to changes in estimated future prices. For additional guidance, refer to section V of SEC Release No. 33-8350.

Company Response:
We propose that in future filings, beginning with our second quarter 2017 Form 10-Q, we will revise our statement in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations, Potential for Future Asset Impairments, to read similar to the following (which is based on June 30, 2017 information and is presented for illustrative purposes with additions in bold and italics):

> The carrying values of the Company’s properties are sensitive to declines in oil, gas and NGL prices ***as well as increases in various development and operating costs and expenses and, therefore, are at risk of impairment***. The Company uses a cash flow model to assess its proved properties for impairment. The cash flow model includes numerous assumptions, including estimates of future oil, gas and NGL production; estimates of future prices for production ***that are based on the price forecast that management uses to make investment decisions, including estimates of basis differentials, future operating costs, transportation expenses, production taxes, and development costs that management believes are consistent with its price forecast;*** and discount rates. ***Management also considers a number of other factors, including the forward curve for future oil and gas prices, and developments in regional transportation infrastructure when developing its estimate of future prices for production***. All inputs for the cash flow model are evaluated at each date of estimate.

We base our fair value estimates on projected financial information that we believe to be reasonably likely to occur. An assessment of the sensitivity of our capitalized costs to changes in the assumptions in our cash flow calculations is not practicable, given the numerous assumptions (e.g., future oil, gas and NGL prices; production and reserves; pace and timing of development plans; timing of capital expenditures; operating costs; drilling and development costs; and inflation and discount rates) that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced oil, gas and NGL prices on future undiscounted cash flows would likely be offset by lower drilling and development costs and lower operating costs.

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.