Gulfport ENERGY
14313 North May Avenue, Suite 100
Oklahoma City, OK 73134

August 19, 2016

United States Securities and Exchange Commission
The Division of Corporate Finance
100 F Street, N.E.
Washington, D.C. 20549-3561
Attn: Karl Hiller, Branch Chief, Office of Natural Resources
Ron Winfrey

Re: Gulfport Energy Corporation
Form 10-K for the Fiscal Year Ended December 31, 2015
Filed February 19, 2016
Comment letter dated August 1, 2016
File No. 0-19514

Dear Messrs. Hiller and Winfrey:

Set forth below are the responses of Gulfport Energy Corporation, a Delaware corporation (the "***Company***"), to the comment letter of the staff (the "***Staff***") of the Securities and Exchange Commission (the "***Commission***") dated August 1, 2016 with respect to Form 10-K for the fiscal year ended December 31, 2015 filed February 19, 2016 (the "***Form 10-K***").

For your convenience, we have set forth below each Staff comment followed by the Company's response. Caption references and page numbers refer to the captions and pages contained in the Form 10-K, unless otherwise indicated.

<u>Form 10-K for the Fiscal Year Ended December 31, 2015</u>

<u>Properties, page 44</u>

<u>Proved Undeveloped Reserves (PUDs), page 47</u>

1. **You disclose the 2015 conversion of 81 BCFE of 14 available PUDs to proved developed status with capital expenditures of $112 million for an incurred unit development cost of $1.38/MCFE. In 2014 you converted 38 BCFE with capex of $68 million for a unit cost of $1.79/MCFE. It appears that you have projected, over the next five years, future PUD conversions of 938 BCFE for development costs of $837 million or $.89/MCFE.**

Please explain the basis for your lower projected development cost and identify any of the 14 PUDs locations referenced above that were developed at such lower development/conversion costs in 2015.

Response: On page 47 of the Form 10-K, the disclosure states that costs incurred relating to the development of PUDs were approximately $112.1 million in 2015. The $112.1 million incurred includes the 14 PUDs converted into proved developed reserves disclosed on page 47, as well as the four PUDs waiting on completion and pipeline connection at December 31, 2015 noted also on page 47. The costs incurred related only to the 14 converted PUDs were $97.2 million, or a unit development cost of $1.20/MCFE.

The 14 PUDs included six dry gas wells, four condensate wells and four wet gas wells. Our experience in developing the Utica Shale has shown that the dry gas wells are less costly to develop than the wet gas and condensate wells. For example, the six dry gas wells have a unit development cost of $0.97/MCFE, as compared to the total development cost of $1.20/MCFE. In addition, due to the decline we experienced in service costs in late 2014 and 2015, as well as operational efficiencies gained, our AFE costs trended down from 2014 to 2015. As such, the AFE costs used in our December 31, 2015 reserve report reflected such cost reductions and were lower than the future development costs used in our December 31, 2014 reserve report. As our future development plans are focused primarily on development of the dry gas window, and given the decrease in service costs, we believe the development rate of $0.89/MCFE is reasonable.

Production, Prices and Production Costs, page 48

2. We note that you report unit production costs of $.35/MCFE in your tabulation on page 48, and that midstream costs using the information on page F-4 appear to be $.69/MCFE [=$138.6 million/200.1 BCFE]. However, the projected unit production cost implicit in your presentation of the standardized measure on page F-50 is $.55/MCFE.

Please describe the portion of midstream costs (gathering, transportation, and processing) that are incurred prior to the transfer of custody, tell us how these costs are represented in the standardized measure, and explain your rationale.

Please also furnish to us a line item list of the components of and figures for your production costs incurred during each of the last three fiscal years.

Response: The production costs of $0.35/MCFE in 2015 cover similar expenses to the projected unit production cost implicit in the presentation of the standardized measure on page F-50 of $0.55/MCFE. The increase in per unit future projected costs relates to the expected increase in per unit costs per well over time as production from the wells decreases during the projected 35 to 40 year life per well whereas costs are not expected to decrease at the same rate.

Prior to the transfer of custody, we incur midstream costs for gathering, compression, processing and fractionation. In 2015, these midstream costs were $0.69/MCFE and are included as an expense line item in our consolidated statements of operations. These midstream costs are included as a deduction from prices in our reserve report, or a reduction to revenue, and are therefore netted from future cash flows in the standardized measure. This method of capturing midstream costs is common within the industry when reserves are forecasted. As a result, we believe this is the proper presentation of these costs in the standardized measure.

In response to the Staff's request, we are providing to the Staff supplementally Schedule A presenting a line item list of the components of and associated figures for our production costs incurred in each of the last three fiscal years.

Productive Wells and Acreage, page 49

3. You disclose that leases for 24% of your undeveloped Utica acreage will expire in 2016. Please tell us the extent to which your proved undeveloped reserves are attributed to acreage having expiration dates that precede the scheduled date for initial development, and explain how you expect to forestall the expiry of such acreage.

Response: The Staff has correctly noted our disclosure on page 49 of the Form 10-K that leases for 24% of our total Utica Shale acreage is subject to expiration during 2016. However, our disclosure on page 49 also states that our Utica Shale leases generally grant us the right to extend these leases for an additional five-year period. All of our PUD locations identified as of December 31, 2015 on our Utica Shale acreage are on leases that either will not expire prior to their scheduled development date or are subject to our right to extend for an additional five-year period. This extension right is conditioned only to our payment of an agreed fee. As stated in the Form 10-K and updated in our Form 10-Q for the quarter ended June 30, 2016, we have included in our 2016 capital expenditure budget $40.0 million to $50.0 million to be spent on leasehold expenses, primarily the extension of leases in the Utica Shale. Our planned capital budget for leases extensions is adequate to cover any lease extensions associated with our expiring PUD locations, and we have sufficient liquidity through our cash on hand ($396.4 million at June 30, 2016) and other sources to fund these lease extension payments, including our revolving credit agreement which had $494.2 million of available borrowing capacity at June 30, 2016.

<u>Management's Discussion and Analysis, page 55</u>

<u>2015 and 2016 Year to Date Highlights, page 56</u>

4. **We note your statement, "Of our 49 [46 net] new wells spud during 2015, ten were completed as producing wells and, at year end, 36 were in various stages of completion and three were drilling." You disclose the YE2015 total proved reserves increase due to extensions/discoveries to be about 1044 BCFE [page F-48] and the YE2015 PUD reserves increase due to extensions/discoveries to be about 626 BCFE [page 47]. This leaves 418 BCFE [=1044-626 BCFE] for the increase in proved developed reserves attributed to the ten wells completed as producers, and indicates an Estimated Ultimate Recovery of about 42 BCFE/well. Please explain the reasons for any difference between the increase in proved developed reserves indicated for each of the ten completed producers and the average for the 46 wells.**

   Please note that FASB ASC Section 932-235-20 (Glossary) states "Proved developed oil and gas reserves are proved reserves that can be expected to be recovered:

   a. **Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well."**

   As horizontal well completion costs are typically a significant portion of total well costs, please clarify the extent to which the incremental proved developed reserves are attributable to horizontal wells that require additional completion before production may commence.

   Please submit a schedule showing how the incremental proved developed reserves due to extensions/discoveries correlate with the various horizontal wells referenced in your disclosure, and for each well as of December 31, 2015, indicate the actual cumulative completion costs and estimated total completion costs.

   For any significant components, tell us how you assessed the remaining completion costs as "relatively minor compared with the cost of a new well" in deciding to classify the associated proved reserves as developed.

   Response: We note that the Staff arrived at the 418 BCFE increase in proved developed reserves by subtracting the 626 BCFE attributable to PUD reserve extensions/discoveries from the 1,044 BCFE of total proved reserve extensions/discoveries. The Staff then divided the 418 BCFE by ten wells to calculate an estimated ultimate recovery, or EUR, of approximately 42 BCFE per well. Please note, however, that only five of these ten wells contributed reserves to the 418 BCFE of proved developed reserves at December 31, 2015 since the other five wells were booked PUDs at December 31, 2014. Also contributing to these proved developed reserves were 36 gross (33 net) operated wells spud in 2014 but which did not commence sales until 2015, 39 gross (five net) non-operated wells, and 13 gross (7 net) operated wells spud in 2015 and two gross (one net) wells spud in 2014 but, in each case, only waiting on hookup at December 31, 2015. Since no proved developed reserves were assigned to the wells we spud in 2015 other than the ten gross wells completed as producing wells and the 13 gross wells awaiting hookup at year end 2015, there is no basis for comparison between these wells and the wells spud but not completed or waiting on hookup at December 31, 2015.

Please note also that we do not classify our reserves as proved developed reserves until the applicable well has commenced production or there are no material incremental completion capital expenditures associated with such proved developed reserves. In response to the Staff's request, we are providing to the Staff's supplementally Schedule B, which illustrates costs for our 41 gross operated wells turned to sales during 2015 that were not booked PUD locations at December 31, 2014 and our 15 gross operated wells waiting on hookup at December 31, 2015. Schedule B shows that 97.6% of the net completion costs for these wells had been incurred as of December 31, 2015. This demonstrates that the remaining completions costs as of that date were relatively minor compared with the cost of a new well.

Exhibit 99.1 Third Party Petroleum Engineering Report

5. **We note the description of procedures performed in Exhibit 99.1 indicates that per-well overhead expenses have been excluded for the operated properties, while noting this as an exception to the SEC and FASB requirements. Your standardized measure should reflect the producing well overhead that corresponds to the level and cost of field, region and headquarters supervision assigned in your organization. You should also consider the following guidance from FASB ASC paragraph 932-235-50-26,**

> **"…some expenses incurred at an entity's central administrative office may not be general corporate expenses, but rather may be operating expenses of oil- and gas-producing activities, and therefore shall be reported as such. The nature of an expense rather than the location of its incurrence shall determine whether it is an operating expense. Only those expenses identified by their nature as operating expenses shall be allocated as operating expenses in computing the results of operations for oil and gas-producing activities."**

Tell us the reasons you have not adhered to this guidance in the preparation of your reserve disclosures and the extent to which this information would need to change to properly reflect the attribution of all applicable overhead expenses.

Response: We acknowledge that overhead expenses were excluded from production costs in our reserve report and, as a result, were excluded from our standardized measure.

If such expenses were included, they would not have had a material impact on our reserve disclosures. The effect of including the overhead expense would result in a 1.7% reduction in our estimated total proved reserves as of December 31, 2015, as well as an approximately $1.1 million reduction to future production costs included in our standardized measure. We will include overhead expenses for operated properties in our standardized measure in our future filings with the Commission.

The Company acknowledges that:

- the Company is responsible for the adequacy and accuracy of the disclosure in the 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 you have any questions with respect to the foregoing, please do not hesitate to call me at (405) 242-4885 or Seth Molay of Akin Gump Strauss Hauer & Feld LLP at (214) 969-4780.

Sincerely,

/s/ Keri Crowell

Keri Crowell

cc: Seth R. Molay, P.C.