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CLAYTON WILLIAMS ENERGY, INC.

Michael L. POLLARD
SENIOR VICE PRESIDENT — FINANCE
AND CHIEF FINANCIAL OFFICER

October 23, 2015

H. Roger Schwall
Assistant Director
United States Securities and Exchange Commission
Division of Corporation Finance
100 F Street, N.E.
Washington, D.C. 20549-3561

Re: Clayton Williams Energy, Inc.
Form 10-K for the Fiscal Year Ended December 31, 2014
Filed February 27, 2015
Form 10-Q for the Quarterly Period Ended June 30, 2015
File No. 1-10924

Ladies and Gentlemen:

Set forth below are the responses of Clayton Williams Energy, Inc. (the "***Company***", "***we***," "***us***" or "***our***"), to comments received from the staff of the Division of Corporation Finance (the "***Staff***") of the Securities and Exchange Commission (the "***Commission***") by letter dated September 16, 2015, with respect to Form 10-K for the Fiscal Year Ended December 31, 2014 and Form 10-Q for the Quarterly Period Ended June 30, 2015, File No. 1-10924, filed with the Commission on February 27, 2015 and August 7, 2015, respectively.

For your convenience, each response is prefaced by the exact text of the Staff's corresponding comment in bold, italicized text. All references to page numbers and captions correspond to our Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2014 (our "***2014 10-K***") unless otherwise specified.

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

**Risk Factors, page 20**

***1. Please expand your risk factor disclosure to provide more specific information that focuses on actual risks that you are facing in light of the current market conditions and predicted volatility. In this regard, we note that as a result of the recent downturn in oil prices, you have temporarily suspended drilling activity, amended your credit facility and made significant cuts in overhead and capital expenditures.***

RESPONSE: At the time of the filing of our 2014 10-K, the dramatic downturn in oil and gas prices was only a few months old. Our disclosed reactions to the then short-lived pricing

downturn (suspending our drilling activities, reducing overhead and capital expenditures and seeking covenant modifications under our bank credit facility) were considered prudent and consistent with actions taken in other pricing downturns experienced by the Company. We did not, however, believe that we were in a position to fully evaluate potential outcomes given such short-term timing. Accordingly, we believe our risk factors included in our 2014 10-K were adequate to address the material risks of inevitable pricing downturns, including the most recent one, given the information available to the Company at the time. Since the filing of the 2014 10-K, however, we recognize that this current pricing downturn has proven to be more sustained with the potential for greater specific impacts on the Company. Accordingly, to address the Staff's concerns, we are proposing to include in our Quarterly Report on Form 10-Q for the quarter ended September 30, 2015 updated risk factors concerning the more specific impacts of the recent downturn in oil and natural gas prices.

**Properties**

**Reserves, page 30**

***2. Disclosure in your filings indicates that there has been significant variance in recent years between planned and actual conversion of proved undeveloped reserves, in terms of both costs and volumes converted. For example, disclosure in your Form 10-K for the year ended December 31, 2013, indicates that you expected to develop approximately 37.5% of your proved undeveloped reserves in 2014 at a cost of approximately $221.2 million. However, during 2014 you actually converted approximately 6.7% of your proved undeveloped reserves at a cost of approximately $46.9 million. Actual results for the years ended December 31, 2012 and 2013 varied in a similar fashion as compared to estimates from prior years. For each of these years, describe for us, in reasonable detail, the specific facts and circumstances that caused your actual conversion expenditures and volumes to be significantly different than the estimates from the prior years.***

RESPONSE: Following is a discussion of the specific facts and circumstances that caused actual conversion volumes and expenditures to vary from the scheduled amounts from the prior years.

**Overview**:

We have historically viewed our commitment to develop booked proved undeveloped reserves, or PUDs, as a commitment to develop within the five-year development horizon from the date of first booking. The actual year-to-year drilling schedule for drilling proved undeveloped reserves is determined each year in connection with our year-end reserve reports based upon information available at the time. In determining our estimated capital spending for each year, we consider all factors known to us as of each date of determination, including our expectations for commodity prices, cash flows from operations, adequacy of liquidity and financial resources, pre-drill well economics, lease expirations, and production growth. We also allow for capital spending that may be required to participate in any non-operated well proposals presented to us by the operator during the year. Based on these considerations, we develop an



operated-well drilling schedule (generally looking forward six months to one year) based on the number of rigs expected to be deployed. As information becomes available, specific wells are scheduled for drilling based on prioritization factors such as field delineation, lease expirations, pre-drill title work, regulatory permitting, and site preparation, among others.

In practice, and we believe consistent with the practice of most oil and gas companies, our drilling plans during a given year will change due to the many factors that impact the timing of drilling a well. Thus, our annual drilling schedules are dynamic and are amended frequently throughout the year. Some of the scheduled wells will be PUD locations and others will be unproved locations. Shale resource plays in which we operate typically require many years to develop, so our PUD development plan often requires us to consider the full five-year development time frame in assessing a PUD location's reasonable certainty of being drilled. In making this determination, we consider the total estimated capital requirements of our PUD development plan within the five-year time frame and assess the reasonableness of our being able to commit sufficient capital to our PUD development plan over multiple years. With exceptions discussed below, we remain committed to develop our PUDs within the five-year development window.

To assist the Staff in understanding our management of our development activities, we are supplementally providing the Staff with background information concerning:

- the variances in PUD reserves estimated in year-end reserve reports for 2012, 2013 and 2014 that were scheduled for drilling in the first year following such reports and actual conversions of such PUD reserves to developed in such year, together with related estimated costs; and

- a summary of our PUD reserves estimates as of year-end 2012, 2013 and 2014 by area and by scheduled drilling year.

**Year-End 2012 compared to actual 2013**

Since 2010, we have been primarily involved in three new shale resource plays primarily in Texas: the Wolfberry play in the Midland Basin in Andrews County, Texas; the Eagle Ford play near Giddings, Texas; and the Wolfbone play in the Delaware Basin in Reeves County, Texas. As is typical for our industry, in the early stages of development of a new play, most of our drilling and completion capital has been allocated to drill unproved wells in order to hold acreage and delineate the extent of the reservoir.

In our year-end 2012 reserve reports, we scheduled 26 PUD locations to be drilled at a cost of $41.3 million (6.4% of our PUD reserves at December 31, 2012). This relatively low conversion schedule was largely the result of our decision to reduce estimated capital spending for 2013 to $225.6 million from $436.8 million in 2012 in an effort to reduce leverage and protect liquidity. Three primary events occurred subsequent to year-end 2012 that caused us to further modify our original plan for 2013. First, in April 2013, we monetized a substantial portion of our Andrews County Wolfberry assets for $215.2 million. This transaction significantly further reduced our leverage and improved our liquidity. Second, by mid-2013 we



determined that our economics in the Delaware Basin improved significantly by converting the play from vertical Wolfbone drilling to horizontal Wolfcamp drilling. Finally, in October 2013, we improved our liquidity significantly by issuing an additional $250 million in senior notes. As a result of these changes, we focused our drilling activities largely on locations that were not booked as proved as of the end of 2012 and ultimately increased capital spending 22% to $275.0 million for the year 2013.

We drilled 18 gross PUD locations in 2013, eight fewer than were scheduled for such year in the prior year-end reserve reports. A majority of the PUD locations scheduled for 2013 that were not drilled in that year were non-operated properties in which we own relatively low working interests.

**Year-end 2013 compared to actual 2014**

At year-end 2013, our liquidity was good and our confidence for economic successes in both of our core areas, the Delaware Basin and Eagle Ford in the Giddings area, was high. Based on those factors, we increased our initial estimate for 2014 capital spending to $376.2 million from $275.0 million in 2013. Similarly, in our year-end 2013 reserve reports, we scheduled 83 PUD locations to be drilled at a cost of $208.1 million (30.2% of our PUD reserves at December 31, 2013) versus only 26 scheduled PUD locations for 2013. We drilled only seven PUD locations in 2014, significantly fewer than scheduled. The following is a discussion of the facts and circumstances related to this variance, by principal area of operations:

**Giddings Area**: In 2014, we drilled a total of 25 wells in this area, 23 of which were unproved locations. Of the 18 specific PUD locations in this area initially scheduled for drilling in 2014 in the 2013 year-end reserve report, two were drilled in 2014; nine remained drillable PUD locations at year-end 2014, but the scheduled drill year was deferred within their five-year development window; six were reclassified to unproved in 2014 as we decided not to commit to drill these wells in 2015, the last year of their five-year development window: and 1 was dropped due to land issues. Since we were in the early stages of development in this area, we chose to allocate most of our available resources to drilling unproved locations in 2014 for the reasons cited above in “Overview.”

**Delaware Basin**: In 2014, we drilled a total of 15 wells in this area in 2014, of which 10 were unproved locations and two were PUD locations scheduled for drilling after 2014. Of the 20 specific PUD locations in this area scheduled for drilling for 2014 in the 2013 year-end reserve report, three were drilled; 15 remained drillable PUD locations at year-end 2014, but their scheduled drilling was deferred until a later year; and two were dropped due to land issues. As in the case of our Giddings Eagle Ford play, we were in the early stages of development in this area and chose to allocate most of our available resources to drilling unproved locations in 2014 for the reasons cited above in "Overview".

**Other Areas**: In our year-end reserve report for 2013, we had scheduled 45 PUD locations to be drilled in 2014 outside of our core resource plays. Although the locations represent more than half of our location count for 2014, they made up only 21% of our proved undeveloped reserves by volume and 18% of our scheduled capital costs for PUD development.



Of these 45 locations, 26 were operated by us and 19 were operated by third parties. Of the 26 operated locations, 14 were associated with PUD reserves that we disclosed in our 2013 Form 10-K had remained undrilled for more than five years. These properties were subject to a title dispute that was resolved in 2013, and we anticipated applying for the necessary state and federal drilling permits in 2014 and completing development in 2015. The downturn in commodity prices in 2014, however, caused us to indefinitely suspend that development plan, and the PUD reserves were reclassified to unproved in the year-end 2014 reserve report. Drilling plans for the remaining 12 operated locations were also suspended, of which nine locations were reclassified to probable at year-end 2014 due to a decision not to commit to drill such wells, and three locations were rescheduled for development within the five-year time frame. Of the 19 non-operated PUD locations scheduled for 2014, which made up only 1% of our total PUD reserves and less than 3% of the estimated total PUD development costs, two were drilled in 2014, 15 were rescheduled for development within the five-year development time frame, and two were dropped as uneconomic.

**Year-End 2014 compared to nine months 2015**

As a result of the significant downturn in commodity prices commencing in late 2014, we indefinitely suspended new drilling operations in both of our core resource plays in early 2015 until we could better evaluate profit margins and returns on capital through a combination of higher or stabilized oil prices and lower capital costs. At the time of filing our 2014 10-K, we did not know the extent or the duration of the pricing downturn, but we were optimistic that conditions would improve to a point which would enable us to resume drilling at a reduced level during 2015. In addition, we had several wells that were in varying stages of completion at the end of 2014 that we planned to complete in 2015.

In our year-end 2014 reserve reports, we scheduled 36 PUD locations to be drilled in 2015 (14.4% of our PUD reserves at December 31, 2014) at a total estimated development cost of $102.6 million versus 83 scheduled PUD locations for 2014. Through the first nine months in 2015, we drilled nine of those PUD locations. Following is a discussion of the facts and circumstances related to this variance, by principal area of operations:

**Giddings Area**: We drilled or completed a total of nine wells in this area in the first nine months of 2015, of which three were unproved locations. Of the 13 specific PUD locations in this area scheduled for drilling in 2015 in the year-end 2014 reserve report, six were drilled in the first nine months of 2015, and seven currently remain drillable PUD locations. Five of these seven were originally booked as PUD locations in 2010. Due to the extreme volatility in commodity prices thus far in 2015, it is unlikely that any of these five PUD locations will be drilled by the end of 2015, and if not drilled, PUD reserves totaling 1,076 MBOE will be reclassified to probable reserves in 2015 due to the five-year rule. The remaining two undrilled PUD locations scheduled for 2015 were originally booked as PUD locations in 2014 and will likely be re-scheduled for development within the five-year time frame.

**Delaware Basin**: We drilled or completed a total of five wells in this area in the first nine months of 2015, of which one was an unproved location. Of the five PUD locations scheduled for 2015 in the year-end 2014 reserve report, four were drilled in 2015, and one remains a drillable PUD location which, if not drilled during the remainder of 2015, will likely be re-scheduled for development within the five-year time frame.

**Other Areas**: In our year-end reserve report for 2014, we had scheduled 18 PUD locations to be drilled in 2015 outside of our core resource plays. Although the locations represent half of our location count for 2015, they made up only 14% of our scheduled PUD volumes and 8% of our scheduled capital costs. All 18 of these locations were non-operated, and six were originally booked as PUD locations in 2010. In light of the sustained downturn in pricing, it is likely that none of these six wells, estimated in our last year-end reserve report to total approximately 274 MBOE in PUD volumes will be drilled by the end of 2015 and, if not drilled, these locations will be reclassified to unproved at year end. The remaining 12 undrilled PUD locations scheduled for 2015 will likely be re-scheduled for development within the five-year time frame.

***3. We note that during the year ended December 31, 2014 you recorded a downward revision of PUD's to probable reserves of 4,911 MBOE as a result of the five year development rule. Regarding this revision tell us the following:***

- ***When the volumes were originally booked as PUDs;***
- ***The year they were scheduled for development at the time of initial booking;***
- ***Any subsequent revisions to the initial development date, along with reasons for any such subsequent revisions; and,***
- ***The specific facts and circumstances that led to your decision to reclassify these reserves to probable.***

RESPONSE: We have supplementally provided to the Staff a schedule which summarizes the downward revision of 4,911 MBOE of PUD reserves that were reclassified to unproved (probable) at year-end 2014. These PUD reserves are grouped by the year originally booked (strata), then by year first scheduled for development and showing subsequent revisions to the development date. The number of PUD locations for each group is also shown.

The 19 properties with a 2004 strata were associated with PUD reserves that we disclosed in our 2013 Form 10-K had remained undrilled for more than five years. These properties were subject to a title dispute that was resolved in 2013, and we had anticipated applying for the necessary state and federal drilling permits in 2014 and completing development in 2015. The downturn in commodity prices in 2014, however, caused us to indefinitely suspend that development plan, and the PUD reserves were reclassified to unproved in the year-end 2014 reserve report.

About 64% of the reclassified PUD reserves in the 2010 strata were associated with 24 locations in three non-core fields: War-Wink South (six), Amacker-Tippett (nine) and Austin Chalk Trend (nine). The War-Wink field is located in the Delaware Basin northeast of our core acreage block in Reeves County. The Amacker-Tippett field is located in the Midland Basin.



The Austin Chalk Trend is in our Giddings area where we have been actively drilling horizontal wells in the Eagle Ford Shale formation which lies beneath a significant portion of our legacy Austin Chalk production. The remaining 48 locations were attributable to seven other non-core fields located in the Permian Basin.

As discussed in our response to comment 2 under "Overview", we focus our commitment to drill PUDs within the five-year development time frame and make all reasonable effort to drill any PUD locations before the expiration of such period. Developments may occur that require that we assign a lower drilling priority to PUD locations than to unproved locations in any given year. This action may result in our revising the scheduled drilling year to a subsequent year. In the event any PUD locations cannot be drilled within the allotted five-year time frame, those proved undeveloped reserves will be reclassified to unproved, as was the case with the reserves associated with these 72 PUD locations.

At year-end 2014, all of the reclassified PUD reserves in the 2010 strata had one additional year of eligible development prior to the expiration of their five-year time frame. However, due to the downturn in commodity prices in

2014, and the resulting reduction in our expected capital spending for 2015, we determined that it was not likely that we would be able to allocate capital to drill each of those 72 locations. Based on that analysis, we reclassified 4.1 MBOE of PUD reserves, or 13% of our total PUD volumes at year-end 2013, to unproved (probable) at year-end 2014.

***4. For your reported proved reserve balances as of each of the years ending December 31, 2014, December 31, 2013 and December 31, 2012, provide us an aging and roll-forward that shows the year-end balance broken down by the year in which the volumes were originally booked, and the changes/revisions, also by year booked, that have been made to those volumes since being recorded as proved.***

RESPONSE: We have supplementally provided the Staff with a schedule that shows an aging and roll-forward of our proved reserves as of year-end 2012, broken down by the strata year, and the changes or revisions, also by strata year, that have been made to those volumes during 2013 and 2014.

***5. For the years ended December 31, 2014, December 31, 2013, December 31, 2012 and December 31, 2011, tell us the number of PUD locations scheduled to be drilled in the following year per the year end reserve report and the number of wells actually drilled. For example, tell us the number of PUD locations scheduled to be drilled during 2012 according to the development schedule underlying your December 31, 2011 reserve report and the number of PUD locations actually drilled during 2012.***

RESPONSE: We refer to our response to comment 2 for information about the number of PUD locations scheduled to be drilled in the following year as provided in each of the year-end reserve reports for 2012, 2013 and 2014 and the number of PUD locations actually drilled in such year. In our year-end reserve reports for 2011, we scheduled 80 PUD locations to be drilled in 2012, and drilled 40 PUD locations during 2012.



**Alternative Pricing Cases, page 33**

***6. Disclosure accompanying the presentation under this heading indicates, in part, that "costs were adjusted to reflect expected reductions in capital costs and well operating costs consistent with the projected price environment". Tell us, and revise your disclosure to describe, in reasonable detail, the methodology used to determine costs, your basis for concluding that the methodology and resulting costs were reasonable, and how the resulting costs compared to corresponding costs used in preparing your estimates of proved reserves and standardize measure as of December 31, 2014.***

RESPONSE: For the Futures Pricing Case presented in our 2014 Form 10-K, development capital costs were reduced to 80% of the estimated capital costs presented in the SEC Case, and well operating costs were reduced to 90% of the SEC Case estimated operating costs. Following is a discussion of the methodology used to determine these cost reductions and our basis for concluding that the methodology and resulting factors were reasonable.

*Development Capital Costs.* We arrived at our estimated 20% reduction in drilling and completion costs by comparing historical Authority for Expenditures (AFE) in each of our core areas (Eagle Ford and Delaware Basin) with revised AFEs developed through direct bids provided by the key vendors that provide those services. As of mid-February, our revised model Eagle Ford AFE was down 27% to $4.3 million versus $5.8 million, and our revised model Delaware Basin AFE was down 24% to $7.1 million versus $9.3 million. Conservatively, we used a cost reduction factor of 20%.

*Well Operating Costs***.** We arrived at our estimated 10% reduction in well operating costs primarily by analogy to costs savings experienced in the first half of 2009 as a result of the 2008 financial crisis. We experienced a reduction in operating costs of approximately 13% from the fourth quarter of 2008 to the first quarter of 2009 which was due primarily to the lower cost of field services caused by a slowdown in activity. We analyzed each major component of well operating costs for 2008 compared to 2009 and assigned a cost reduction factor to each. By applying such cost reduction factors to the same cost incurred in 2014, we computed an annual reduction of 14%. Conservatively, we used a cost reduction factor of 10%.

Actual cost reductions experienced in 2015 to date have further confirmed the reasonableness and conservatism of the above-described estimated cost reductions. We respectfully submit that detailing the development of these estimated cost reductions is not material to the sensitivity analysis to warrant an amendment to the 2014 10-K.



**Acreage, page 38**

7. ***Tell us the extent to which you have assigned any proved undeveloped reserves to locations which are currently scheduled to be drilled after lease expiration. If your proved undeveloped reserves include any such locations, expand your disclosure here or in an appropriate section elsewhere to explain the steps which would be necessary to extend the time to the expiration of such leases.***

RESPONSE: Approximately 2,392 MBOE, or 7% of our year-end 2014 PUD reserves, are associated with locations scheduled to be drilled after lease expiration. In future 10-K filings, we propose to include disclosure to explain that we frequently engage in discussions with mineral interest owners to renew and extend leases in the ordinary course of business, and that it is our intention to drill all PUD locations prior to the expiration of the underlying leases or to renew and extend the leases to preserve the applicable drilling rights. Due to the availability of other locations that may be booked as PUD locations, the high likelihood of our ability to obtain lease extensions or renewals and the relatively immaterial volume of such PUD reserves subject to expiring leases, we respectfully submit that an amendment to our 2014 Form 10-K is unnecessary.

**Form 10-Q for the Quarter Ended June 30, 2015**

**Management's Discussion and Analysis of Financial Condition and Results of Operations, page 26**

**Revolving credit facility, page 42**

8. ***Update your discussion of the revised debt covenant to indicate your current level of compliance — that is, quantify your current consolidated indebtedness to consolidated EBITDAX.***

RESPONSE: As of June 30, 2015, our ratio of consolidated current assets to consolidated current liabilities was 5.5 to 1 versus the minimum ratio of 1 to 1; our ratio of consolidated senior debt to consolidated EBITDAX was 0.73 to 1 versus the maximum ratio of 2.5 to 1 and our ratio of consolidated interest expense to consolidated EBITDAX was 3.87 to 1 versus the minimum ratio of 1.5 to 1. We acknowledge the Staff's comment and respectfully propose that we comply with this comment on a prospective basis beginning with our Form 10-Q for the quarter ended September 30, 2015.

* * * * *



In connection with responding to the Staff's comments, we acknowledge 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.

Please direct any questions that you have with respect to the foregoing or if any additional supplemental information is required by the Staff, please contact Jim Prince of Vinson & Elkins L.L.P. at (713) 758-3710.

Very truly yours,

CLAYTON WILLIAMS ENERGY, INC.

By: /s/ Michael L. Pollard
Michael L. Pollard
Senior Vice President and Chief Financial Officer