MEMORANDUM

TO: Kathleen Sgamma, VP of Government & Public Affairs, Western Energy Alliance
FROM: John Dunham, Managing Partner
DATE: October 28, 2015
RE: Business Impact of Revised Completion Regulations

On May 11, 2012, the Bureau of Land Management (BLM) first proposed extensive new rules for companies completing wells for the extraction of petroleum products on federal and Indian lands. When John Dunham & Associates (JDA) reviewed the initial proposal it was estimated that the annual implementation cost would be nearly $1.3 billion. On May 24, 2013, BLM issued a revised proposed rule, removing some of the original proposal's most expensive provisions. JDA estimated that, under the revised version of the proposed rule, the annual costs the rule would impose on the oil and gas industry would be approximately $345.6 million, or $96,913 per well.

On March 26, 2015, BLM published a final rule.[1] Changes BLM made between the proposed rule issued in May 2013 and the final rule led to an increase of $57.7 million, in JDA's estimated annual costs. JDA now estimates the final rule will impose costs of $403.271 million per year. This equates to $113,088 per well, a $16,175 increase over the last proposed rule. Table 1 below outlines the estimated costs by source. The additional costs in our estimate stem from a more thorough review of the new administrative burdens and the requirement that tanks be used exclusively to hold fluids during the completion process.

Table 1
Revised Cost Calculations

Cost Component	Final Rule	May 2013 Revision	Initial Cost Estimate
Initial Delay Costs	$18,024,272	$5,632,585	$56,404,007
Pre Completion Delay Costs	$0	$0	$38,326,948
Administrative Costs	$31,744,152	$1,765,170	$2,503,710
Enhanced Casing Costs	$310,063,700	$310,063,700	$439,793,100
Cement Log Costs for "Type Wells"	$0	$2,603,465	$736,773,570
Mechanical Integrity Tests	$26,778,983	$0	$10,116,000
Cement Log Delay Costs	$0	$5,914,436	$0
Cost of Tanks over Pits	$16,660,196	$19,613,000	$0
Total	$403,271,304	$345,592,356	$1,283,917,335

Changes in Final Rule:

Analysis of the final rule shows that some costly provisions that were part of the proposed rule were removed while others were added. These changes include:

- The elimination of requirements that companies perform an additional cement log (CEL) for specific "type wells." Under the final rule, CELs are not required when cement is

[1] *Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands*, Department of Interior, Bureau of Land Management, 43 CFR Part 3160, Final Rule, Federal Register, March 26, 2015, at: http://www.gpo.gov/fdsys/pkg/FR-2015-03-26/pdf/2015-06658.pdf

returned to the surface. The final rule requires CELs on every well, not just "type wells," on all intermediate or production casing where cement is not returned to the surface.[2] BLM estimates that the cost of complying with this requirement would be $112,000 per well, but concedes that the agency does not have reliable data regarding how frequently this requirement will differ from current practices.[3] JDA has not incorporated any cost in its estimates associated with this requirement, suggesting that the final cost estimates are likely understated.

- A new requirement that operators conduct a mechanical integrity test on all casing and fracturing strings – including the horizontal portion of any well – that will be subjected to pressure during hydraulic fracturing operations.
- Substantial changes in the administrative reporting and permitting burden placed on operators by the proposed rule.
- A new requirement that fluids recovered be stored in above-ground tanks before permanent disposal, rather than in either tanks or lined pits. While there are instances where the BLM may approve a lined pit in lieu of a tank, BLM asserts that these "exceptions should be limited and rarely granted." [4] Based on BLM's guidance, this analysis assumes that all recovered fluid will be stored in tanks.

As a result of these changes, there are substantial differences in the calculation of the cost attributable to the final rule from those calculated before the publication of the final rule. These are outlined below.

Number of Impacted Wells. Consistent with BLM's assumptions, the numbers in this analysis are calculated using 3,566 impacted wells. Since the rule was initially proposed, there have been substantial changes in the oil and natural gas marketplace both in the 13 states that are analyzed in this report, and worldwide. Prices for both oil and natural gas have fallen substantially since the revised rule was published in May 2013. Between May 2013 and May 2015 (the latest data available from the Department of Energy), natural gas prices have fallen by 21 percent from $5.55 per thousand cubic feet to just $4.40. Oil prices are off by over 41 percent from $94.75 per barrel to $55.88.[5] These large changes in prices will likely impact the potential number of applications to drill (APDs) requested from the BLM at least in the short term.

Administrative Costs. Under existing regulations, operators must provide the BLM with about 25 different categories of information including:

1. A completed form 3160-3;
2. A well plot and geospatial database prepared by a registered surveyor;
3. A detailed drilling plan, including:
    a. Names and estimated tops of all geologic zones and formations

2 See: 43 C.F.R. § 3162.3(e)(2)(ii).
3 See: 80 Fed. Reg. at 16,197. BLM acknowledges that the agency "does not have credible data on the prevalence of voluntary compliance or the prevalence of CEL requirements as conditions of approval").
4 See: 80 Fed. Reg. at 16,163.
5 Based on average citygate price for Natural Gas and First Purchase Price for Crude Oil. See: *Domestic crude oil first purchase prices*, and *U.S. Natural Gas Citygate Price*, US Department of Energy, Energy Information Administration, at: http://www.eia.gov/ Data for June 15, 2015.

    b. Depth, thickness of zones either containing usable water, oil, gas, valuable minerals, and plans for protecting such resources
    c. Minimum specifications for blowout prevention equipment
    d. Proposed casing program (including design criteria)
    e. Estimated amount and type of cement expected to be used in each casing string
    f. Type and characteristic of the proposed circulating medium or mediums proposed for the drilling of each well bore section
    g. Testing, logging, and coring procedures proposed, including drill stem testing procedures, equipment, and safety measures
    h. Expected botton-hole pressure and anticipated abnormal pressures, temperatures, or potential hazards that the operator expects to encounter
    i. Any other items that the operator would like BLM to consider

4. A detailed surface use plan of operations, including:
    a. a map and plans of improvement for improvement and modification of existing roads
    b. a map, detailed descriptions, and plans for construction for all permanent or temporary access roads planned to be constructed
    c. Location of existing wells within w-mile of the proposed location
    d. Location of existing and/or proposed production facilities
    e. Location and types of water supply
    f. description of all construction materials to be used on the lease
    g. written description of plans to handle all waste materials on site
    h. a map of all ancillary facilities
    i. a diagram of the well site layout
    j. interim and final surface reclamation plans
    k. surface ownership status for the well site and all access roads used to construct or maintain the well
    l. any other information the agency may require

5. A surety bond; and
6. Certification that the APD is accurate.[6]

The new hydraulic fracturing application will add at least 8 new categories of information to this application process including:

1. Detailed information on the wellbore geology including estimated depths of both confining zones and potential occurrences of usable water;
2. A map showing the location and extent of known or suspected faults or fractures that may transect the project;

[6] Requirements under *Onshore Oil and Gas Order 1*, US Department of Interior, Bureau of Land Management at: www.blm.gov/wo/st/en/prog/energy/oil_and_gas/Onshore_Order_no1.html

3. A water usage plan;
4. A detailed hydraulic fracturing plan;
5. A hydraulic fracturing map;
6. A detailed plan for fluid recovery;
7. A surface use plan; and
8. Documentation that casing and cementing are adequate to protect usable water.

The different elements of each of the applications are not equal in terms of the cost and time needed to prepare materials and provide the pertinent information to the BLM. Some, such as detailed drilling plans and plans for fluid recovery, are much more complex than, for example, a signed certification. The BLM did not provide a detailed estimate of the administrative cost burden in the agency's rulemaking process. Now that all of the requirements are outlined, and assuming that the number of informational elements increases by 32 percent (from 25 to 33), a new estimate of the administrative burden can be calculated.

A production model that JDA developed for Western Energy Alliance can be used to calculate the current administrative and regulatory cost per representative well in the 13 western states included in the analysis. The model, which is based on data originally produced by the Bureau of Economic Analysis, suggests that these costs currently average about $19,100 for a representative oil well and $39,133 for a representative gas well.[7] Based on the assumed 3,566 wells and a distribution across the states being analyzed equal to the current distribution of approved APDs, the average administrative costs equal $27,881 per well. If costs are to rise in line with the number of informational elements requested (or about 32 percent) the increase would be $8,922 per well, or $31.744 million. This is $30 million more than BLM assumes in its analysis of the May 2013 proposal, a figure which was used in JDA's earlier estimate of administrative costs.

<u>Initial Delay Costs</u>. The BLM recognizes that it does not have the capacity to implement these regulations with its current staffing levels, but nevertheless stated in the proposed rule that the agency will be able to review the new permits in conjunction with the APD and within "normal APD processing time frames."[8] Considering that the agency already takes an average of 10 months, and often two or three years to process an APD, it is difficult to determine what a "normal APD time frame" may actually be. Using the 32 percent increase in the number of data elements required as a proxy suggests it might take the BLM as much as 3.2 additional months to process the paperwork. If this is the case the administrative cost per well could be as high as $5,054 – a total of $18.024 million. This includes the costs of delayed tax and royalty payments to leaseholders (primarily the federal government).[9] The figure is substantially higher than the figure that was calculated in JDA's prior analysis of the rule. In its previous analysis, JDA used an estimate based on a one-month delay, a period which was used as a representative figure rather than a modeled actual delay time.

---

7 Unweighted costs. Based on IMPLAN data for 2012. Representative wells include all oil and gas wells drilled in a state, including exploratory wells, dry holes, disposal wells, production wells, etc. A representative well should not be used to represent any single producing facility.

8 See: US Bureau of Land Management, *Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis*, at: www.regulations.gov/#!documentDetail;D=BLM-2012-0001-0003.

9 John Dunham and Associates calculations for the Western Energy Alliance, 2012. Based on an interest rate of 7 percent to match the discount rate used in the BLM analysis.

Elimination of "Type Well" CELs. The final rule removes the requirement that cement logs be required on certain "type wells" before approval of an application for authorization to conduct hydraulic fracturing. This change could lead to substantial savings over the costs of the May 2013 proposed rule. Removing this requirement reduces the direct costs from the earlier estimate by $2.603 million, and eliminates delay costs of as much as $5.914 million.[10]

The final rule requires CELs on every well, not just "type wells," on all intermediate or production casing where cement is not returned to the surface.[11] BLM estimates that the cost of complying with this requirement would be $112,000 per well, but concedes that the agency does not have reliable data regarding how frequently this will actually be required.[12] Since there is a meaningful difference between individual oil and natural gas wells, and no data are available to determine how many wells this rule will impact, JDA has not incorporated any cost in its estimates associated with this requirement. This omission suggests that JDA's overall estimates understate the costs attributable to the final rule.

Additional Surface and Intermediate Casings. The final rule does not change the definition of "usable water" from the definition advanced in the May 2013 proposal. Nor does it eliminate the requirement that for nearly all wells operators will likely have to run deeper surface casing, two-stage cementing on the production casing or the addition of an intermediate string of casing. Since ground water levels vary greatly across states, it is difficult to determine exactly how much additional casing will be required for an "average" well.[13] According to the BLM in its Regulatory Impact Analysis, there would be no cost related to this provision, since operators already have to protect usable water. This assertion is based on the idea that the definition of usable water in the final rule is the same as currently exists in Onshore Oil & Gas Order Number 2, which provides a set of standards that operators currently observe. Discussions with operators suggest, however, that this new rule places additional requirements on the industry.

Among other requirements, the new rule places the burden of identifying the location of usable water on operators, a task that state regulators and BLM field officers currently perform. The final rule requires operators to obtain more hydrologic data which may or may not match data state and federal regulators currently rely upon to determine the depths at which protective casing and cement must be set. The new rules will lead to instances where operators will face the additional costs of casing and cementing associated with isolating formations that meet the numerical definition of usable water under the final rule, but which are located at depths deeper than the zones that state agencies and BLM field offices have previously designated as requiring isolation.

Current laws in the states require operators to case their wells to protect drinking water aquifers and other "usable" water aquifers, with the recognition that for aquifers to be deemed usable, they should be economically viable. In North Dakota and Montana, for example, operators are

10 This includes about $281,600 in delay costs for intermediate casings.

11 See: 43 C.F.R. § 3162.3(e)(2)(ii).

12 See 80 Fed. Reg. at 16,197 which acknowledges that t BLM "does not have credible data on the prevalence of voluntary compliance or the prevalence of CEL requirements as conditions of approval."

13 It is nearly impossible to develop an exact figure for the additional casing costs required under the proposed rule. The new definition of "usable water" is so broad that in practical terms, casings may be required to be run to significantly deeper depths than may be economically practical (particularly for gas wells located on federal lands. In addition, calculating an exact figure would require an engineering examination of each of the geologic basins and the well designs in use – something which is not practical based on the available data.

currently directed to install protective casing to a depth below the Pierre Shale formation, but BLM's final rule could require additional casing and cement when water meeting BLM's numeric definition of "usable water" is found at depths deeper than that formation. In Wyoming, casing needs to be set to a level 100 feet below the deepest water well within a one mile radius of either an oil or gas well-- with some exceptions, drinking water aquifers are generally above 1,000 feet in Wyoming.[14] Again, when water meeting BLM's definition of usable water is found below these depths, additional casing requirements will apply under the final rule.

Because of the significant differences in aquifer depth across states, a Monte Carlo simulation model was used based on the depths of existing water wells in each state to arrive at a conservative estimate. In the analysis of the proposed rule JDA used an average of approximately 2,350 feet of additional intermediate casing per well in its calculations. Further analysis of the rule suggests that this might be a very conservative figure. When BLM's "usable water" is found at great depths, significant additional casing costs are likely to be incurred. Because of the differences in aquifer depths between basins, and because the definition of usable water was not changed in the final rule, we continue to use the figure of 2,350 feet per well of additional casing that came from the initial Monte Carlo simulation model. At a cost of $37 per foot, these additional casing would add $310.064 million in costs.

<u>Mechanical Integrity Test Requirement:</u> The new rule will require that operators perform a mechanical integrity test on all casing and fracturing string that will be subject to pressure during hydraulic fracturing operations. The agency contends that this MIT test is distinct from the casing integrity tests that operators must now perform under Onshore Oil and Gas Order No. 2, but at the same time suggests that there would be no additional costs associated with this new test. According to engineering estimates Western Energy Alliance member firms developed, for a horizontal well (where the lateral portion of the well is entirely in the zone to be completed), the MIT requirement can be expensive. To conduct these tests operators will have to use complicated tools to seal off the toe of the well during testing or rely on tubing conveyed perforation techniques after the pressure test. Either method is likely to increase costs of completing a well, with the lowest potential additional cost being $10,000 per well. If any problems occur as a result of the MIT, these costs could rise by $75,000 to $100,000 per well.

Table 2
Rotary Rig Count by Type

Type	Number	Percent
Directional	86	10.9%
Horizontal	591	75.1%
Vertical	110	14.0%
Total	787	100.0%

The overwhelming majority of new wells being proposed for Federal leaseholds today are horizontal wells; however, using rig counts as a proxy should provide a conservative estimate of how frequently the additional costs associated with testing the horizontal portion of the lateral

[14] There are some exceptions to this. Based on well permit data from the Wyoming State Engineer's Office, the deepest domestic ground water well in the state is 10,660 feet deep. See: https://seoweb.wyo.gov/e-Permit/common/login.aspx?ReturnUrl=/e-Permit/Default.aspx

should apply. As Table 2 shows, as of October 16, 2015, about 75 percent of rigs in operation in North America were drilling horizontal wells.[15]

Using the 75.1 percent as a proxy, this would mean that of the 3,566 wells anticipated to be permitted, 2,678 would be horizontal wells. Assuming the minimal additional cost of $10,000 per well, this provision would add $26.8 million to the overall costs calculated for the May 2013 version of the rule.

<u>Cost of Tanks over Pits</u>. This was not included in our initial analysis of the proposed rule but was added as an informational item during the analysis of the revised rule. According to the BLM, the cost of renting storage tanks could be about $6,000 to $17,000 per well, while the cost of lining pits is about $6,000 per pit. The production model that JDA developed for Western Energy Alliance can be used to calculate the differences in costs between tanks (which are generally rented for a short period during the completion process) and pits which once constructed can be used for a number of different wells. The model which is based on data originally produced by the Bureau of Economic Analysis suggests that the costs of fluid storage tanks for a representative well in the 13 western states is about $4,250 and the cost for digging and lining pits is $365.[16] Based on the assumed 3,566 wells and a distribution across the states being analyzed equal to the current distribution of approved APDs, the average cost to rent water storage tanks per representative well would be $5,111 and for preparing and lining pits $439. Based on these differences in costs, the additional costs across 3,566 wells would be $16.66 million, a figure that is included in this analysis and is slightly lower than the estimated $19.6 million calculated for the May 2013 version of the rule.

In sum, the above analysis suggests that these proposed regulations will have a significant impact on the oil and gas production industry even without considering future discounted costs.

---

15 Williams, James L., *North American Rotary Rig Counts*, WTRG Economics, online at: http://www.wtrg.com/rotaryrigs.html. Based on data from Baker Hughes.

16 Unweighted costs. Based on IMPLAN data for 2012. Representative wells include all oil and gas wells drilled in a state, including exploratory wells, dry holes, disposal wells, production wells, etc. A representative well should not be used to represent any single producing facility.