



June 19, 2015

Mr. Neil Kornze  
Director, Bureau of Land Management  
U.S. Department of Interior  
1849 C St. NW, Room 2134LM  
Washington, DC 20240

Re: ***American Petroleum Institute Comments on the ANPRM Oil and Gas Leasing; Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessments, 80 Fed. Reg. 22148 (April 21, 2015)***

**Submitted via Regulations.gov and by U.S. Mail**

Dear Director Kornze:

On April 21, 2015, the Bureau of Land Management (“BLM”) issued an Advanced Notice of Proposed Rulemaking (“ANPR”) seeking comments and suggestions that may be used to update the BLM’s regulations related to royalty rates, annual rental payments, minimum acceptable bids, bonding requirements and civil penalty assessments for Federal onshore oil and gas leases. Although the American Petroleum Institute (“API”) appreciates this opportunity to submit comments on these topics given the scope of comments sought, API’s comments will be less detailed than they might otherwise have been given the short time period allowed for comment.<sup>1</sup>

API represents over 640 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America’s energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and since 2000, has invested nearly \$2 trillion in U.S. capital projects to advance all forms of energy, including alternatives.

On the subject of royalties to be paid from production from leases on lands administered by BLM, the Mineral Leasing Act (“MLA”), 30 U.S.C. §§ 181-287, and Mineral Leasing Act for Acquired Land, 30 U.S.C. §§ 351-359, and the Federal Onshore Oil and Gas Leasing Reform Act of 1987 comprise the statutory foundation for BLM’s oil and gas leasing program and

---

<sup>1</sup> API appreciates the additional 2-week time extension granted by BLM for comment. However, the 59-day total comment period was still an insufficient time period given that BLM sought substantive and well-reasoned comments to 24 questions – many of which had multiple parts and covered a wide range of Federal onshore oil and gas leasing topics related to royalty rates, annual rental payments, minimum acceptable bids, bonding requirements, and civil penalty assessments. If BLM pursues rulemaking in these areas, API strongly urges the BLM to allow sufficient time for public comment.

associated royalty and bonus bid authority. By statute, lands leased by the competitive bidding process are to be awarded to the highest qualified bidder and are conditioned on payment of a royalty rate of not less than 12.5 percent of the value of the production removed or sold from the lease. 30 U.S.C. §226(b).

Two other statutes complete the core statutory framework. Drawing on the 1982 Report of the Linowes Commission, “Fiscal Accountability of the Nation’s Energy Resources,” the 1983 Federal Oil and Gas Royalty Management Act (“FOGRMA”), 30 U.S.C. §§ 1701-1759, gave specific direction to the Department of the Interior’s (“DOI”) audit, investigative and enforcement authorities. FOGRMA laid an explicit basis for cooperative arrangements between DOI, States and Indian tribes, and established civil and criminal penalties for violation of royalty-related responsibilities of lessees, operators and transporters. The 1996 Federal Oil and Gas Royalty Simplification and Fairness Act (“RSFA”), Pub. L. 104-185, amended FOGRMA. Among other things, RSFA established a statute of limitations with respect to judicial proceedings or demands arising from royalty obligations, prescribing time periods for record retention and agency decisions, and allowing interest on overpayments.

BLM’s advanced notice of proposed rulemaking seeks substantive and well-reasoned comments on a wide range of Federal onshore oil and gas leasing topics related to royalty rates, annual rental payments, minimum acceptable bids, bonding requirements, and civil penalty assessments. These topics are very complex and intertwined. Any regulatory changes must be viewed in light of other regulatory revisions BLM and the Office of Natural Resources Revenue (“ONRR”) have recently proposed (or are expected to propose) which could both affect the amount of royalty the government receives and further delay development of federal resources thereby significantly impacting American energy development. These changes could further disincentivize leasing of Federal lands. The energy renaissance taking place in our country as a result of increased oil and natural gas production supports millions of jobs, generates billions of dollars in Federal and State revenue each year, and has made our nation more energy secure. Clear, consistent leasing and royalty terms are part of what makes investments possible, so preserving certainty in the process is critical for the consumers and workers that benefit from domestic production.

We offer the following comments to address the questions raised in the ANPR.

**1. The U.S. Federal Oil and Gas Fiscal System should balance attracting the investments needed to produce domestic oil and gas with the amount of revenue received by the government.**

As we have seen throughout this current energy renaissance, increased production of U.S. oil and natural gas produces many benefits for the country, including billions of dollars in capital investments, creation of thousands upon thousands of additional well-paying jobs, continued improvement in our balance of trade, and increased energy security for the U.S. and our allies abroad. Increased access to U.S. oil and natural gas supplies promotes affordable energy that helps drive the economy. The Government Accountability Office (“GAO”) recognized the vital role energy development plays in its May 2007 report.

As part of an energy strategy to meet the nation's energy needs and balance the impacts of energy use on the environment and climate, a healthy domestic oil and natural gas industry is essential, and that means that the United States must continue to create a market that is competitive in attracting investment in oil and natural gas development.<sup>2</sup>

Any changes to onshore royalty rates, annual rental payments, minimum acceptable bids, bonding requirements, and civil penalty assessments should not be made at the expense of future investments in U.S. energy development. With respect to BLM's specific question regarding flexibility to adjust royalty rates in response to changes in the oil and gas market, API is opposed to any such provision.

**2. Onshore royalty rates should be considered in relation to other benefits provided through energy development.**

Although we do not believe that there is any justification for BLM to raise existing royalty rates at this time, if BLM decides otherwise, we strongly recommend that any consideration of proposed changes include a consideration of the many benefits, other than royalty payment, provided to the Federal Government through energy development. BLM should weigh the impacts increased rates might have on future investments and account for the higher development costs incurred during development of federal minerals compared to fee and state minerals. Royalties are only one of many benefits the U.S. realizes through energy development. U.S. energy development provides billions of dollars in capital investments, well-paying jobs, and increased energy security – all of which drive the American economy, which was one of the original intents of the MLA, as amended. The title intent of the MLA was in fact “An Act to promote the mining of coal, phosphate, oil, oil shale, gas and sodium on the public domain”.

BLM must recognize that, in addition to royalties, U.S. energy development provides revenue directly to the U.S. Treasury in the form of rental payments, bonuses and taxes. Together, these various payments constitute the government's share of revenues from production from federal leases that is often referred to as “government take”. As recognized in the IHS CERA Study,<sup>3</sup> bonus bid payments to secure leases through competitive tender also constitute an important component of the income accruing to governments under such a system. The IHS CERA study further notes that the current Federal oil and gas system relies heavily on front ended bonus bids which “provide no guarantee that the lessee will be able to discover oil and gas in paying quantities effectively shifting the risk of exploration onto the oil companies.” Indeed on a discounted basis, the BLM has extracted more value in recent decades from bonus payments than from royalty payments. Bonuses create a self-correcting mechanism within the overall fiscal system – lease and project economics are evaluated based on the combination of the upfront

---

<sup>2</sup> Government Accountability Office (May 2007). Oil and Gas Royalties: A Comparison of the Share of Revenue Received from Oil and Gas Production by the Federal Government and Other Resource Owners, GAO-07-676R, p. 3.

<sup>3</sup> IHS CERA (2011). Comparative Assessment of the Federal Oil and Gas Fiscal System (“IHS CERA Study”).

bonus cost and the royalty rate. An increase in royalties on top of the current bonus structure could potentially drive away investment from Federal lands. As the IHS CERA Study found, government take should not be the only measure to determine attractiveness of a fiscal system.

If [government take] is used at all, it should be combined with other measures of profitability, fiscal system flexibility, revenue risk, and fiscal stability in order to properly assess petroleum fiscal systems. Such analysis should be combined with a proper understanding of the resource potential and the relative prospectivity of the federal lands. Fiscal design should be a reflection of the jurisdiction's relative prospectivity, economic development needs, dependence on hydrocarbon revenues, and environmental protection policies.<sup>4</sup>

The IHS CERA Study assessed several alternative royalty rates against the current U.S. Federal Oil and Gas Fiscal System and found that

When other factors, such as resource potential, potential reduction in revenue collected via signature bonuses and income tax, and the comparable royalty rates for the specific environment are considered, the alternative royalty rates suggested for this study could deter investment and in turn affect timely resource development, which could ultimately lead to reduced federal revenue.<sup>5</sup>

Any changes to the Federal fiscal system should incentivize development, not disincentivize it.

### **3. Federal onshore royalty rates should not be driven by State and private royalty rates.**

In the ANPR, BLM points to royalty rates for State and private lands as a potential metric to use when considering increases to the Federal onshore royalty rates. However, there are significant differences between these regimes which limit the extent to which they can be directly compared to the Federal regime. In many cases, State leases are positioned to command higher royalty rates because these leases are widely scattered among areas dominated by fee mineral ownership, on which reserve potential can be ascertained or estimated with greater accuracy than on BLM lands on which oil and gas potential has not yet been established. In addition, leases offered on Federal land are in many cases found in "frontier" or undeveloped areas that carry substantially increased geologic and business risk, greater distance from infrastructure, and likely much greater costs, as well as the time required and complexity of the process to obtain permits to operate on Federal land. In fact, the IHS CERA study noted that for Wyoming Federal lands "the **current** (emphasis added) royalty rates on federal land do not reflect the maturity of the basins and the high cost of bringing these supplies to market."<sup>6</sup> In many areas on Federal land, a minimum of

---

<sup>4</sup> IHS CERA Study, p. 28.

<sup>5</sup> IHS CERA Study, p. 147

<sup>6</sup> IHS CERA Study, p. 29

one year is needed just to collect the comprehensive cultural resources and wildlife data required to be provided in support of BLM drilling permits. Field surveys for collection of cultural resources and wildlife data on federal mineral leases are typically subject to seasonal limitations.

Data already show that trends in lease acquisition, permitting and drilling on Federal land show declines relative to State and fee land.<sup>7</sup> Further increases in royalty costs by BLM are likely to accelerate this trend, to the detriment of the ability to realize value from energy resources the agency manages for the benefit of the American people. Moreover, in the current environment when making leasing decisions, the relative attractiveness of leasing on Federal lands vis-à-vis private or State lands is diminished by at least 2 significant factors. The first factor is the relative speed with which the lease can be developed, resulting in early positive cash flow from the lease, while the second factor is the ultimate cost of compliance associated with the complexity of the underlying valuation and reporting requirements. With regard to the relative speed with which a federal lease can be developed, delays by BLM in processing (a) Applications for Permit to Drill (“APD”) and Rights of way and associated permits, and (b) approvals of federal communitization agreements and related allocation schedules, each often have adverse effects on industry and the Federal government, because delays in processing APDs cause some wells not to be drilled, or cause those wells that are drilled to be less economic.

According to the Final Evaluation Report – Onshore Oil and Gas Permitting, U.S. Department of the Interior (Report No. CR-EV-MOA-0003-2013) issued by the Office of Inspector General, U.S. Department of the Interior dated June 2014, 94% of APDs approved by BLM take longer than the 30-day deadline required by the Energy Policy Act of 2005 and BLM’s Onshore Order No. 1. While average processing times may vary by BLM office, the national average was approximately 228 days in 2012 with no apparent improvement by 2014 – the last year for which comparative statistics are available. It is not uncommon in Wyoming and Utah for the APD approval process to take a year or more. By contrast State governments may take 80 days or less to process.<sup>8</sup> Further compounding delays in processing APDs, according to a report issued by the GAO, BLM also takes longer than the statutorily mandated time frame of 120 days for approval of allocation schedules pursuant to federal communitization agreements which in turn delays the payment and distribution of Federal and Indian royalties.

There can be no dispute that leasing and operating on federal minerals administered by BLM is more complex than leasing and operating on fee or State acreage. Added to this complexity, compliance with the Office of Natural Resources Revenue (“ONRR”) valuation and reporting requirements has become increasingly more complicated and burdensome over time. Although ONRR’s recently proposed valuation reform is being put forward to have greater simplicity, administrative savings and early certainty for industry and the government, as proposed, industry

---

<sup>7</sup> EIS Solutions. “Employment, Government Revenue, and Energy Security Impacts of Current Federal Lands Policy in the Western U.S.” (2012)

<sup>8</sup> The State of North Dakota has testified to taking on average 30 days to process. See Testimony by Lynn D. Helms, Director, North Dakota Industrial Commission, Department of Mineral Resources, at field hearing of U.S. House of Representatives Committee on Oversight and Government Reform, July 14, 2012, in Fargo, North Dakota.

will actually experience greater uncertainty and increased cost of compliance, in addition to paying more royalties.

An additional distinction between Federal and fee and State royalties is allowable deductions for post-production costs (e.g., processing, transportation). Federal regulations typically allow fewer deductions – with even less deductions being allowed in ONRR’s recently proposed valuation rule<sup>9</sup>– resulting in higher effective royalty rates for Federal royalties. These deductions also result in a far larger reporting burden and increased compliance costs associated with Federal oil and gas leases.

Moreover, the government take related to Federal properties must be viewed in light of several ongoing initiatives that significantly raise effective royalty rates well above those set by statute. These activities are based on expansive interpretations of existing regulations that result in additional royalty payments. Examples of recent reinterpretations are the reporting of field fuel including lost and unaccounted for volumes, unbundling including unallowable percentages of plant fuel, and orders to report related to allegedly deficient compliance filings. Interest is also assessed for all of these items.

**4. Any changes to onshore royalty rates should be simple, certain, clear and consistent with other Interior royalty policies.**

API members are committed to compliance with royalty reporting and payment requirements consistent with their lease obligations and the applicable regulations, guidance, and mineral leasing statutes. Extensive statutory and regulatory precedent has emphasized the importance of simplicity, certainty, clarity, and consistency in royalty management and valuation.<sup>10</sup> In fact, as referred to above, DOI recently enunciated these stated goals in a separate proposed rulemaking on royalty valuation which is intended to “(1) offer greater simplicity, certainty, clarity, and consistency in product valuation for mineral lessees and mineral revenue recipients; (2) [be] more understandable; (3) decrease industry's cost of compliance and ONRR's cost to ensure industry compliance; and (4) provide early certainty to industry and ONRR that companies have paid every dollar due.”<sup>11</sup> At a minimum, any proposed rulemaking by BLM should adhere to those basic precepts. In addition to providing fairness to all stakeholders, it is critical that any proposed rulemaking provide for ease of administration necessary to promote accurate and timely compliance.

“Fixed” royalty rates, which are the norm in the current environment, best satisfy that basic criteria and are the only proposed method which achieves certainty. Signature “bonus bids” associated with the issuance of “fixed” rate competitive leases meet the criteria of certainty since

---

<sup>9</sup> Office of Natural Resources Revenue Proposed Rule, “Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform,” Docket No. ONRR-2012-0004.

<sup>10</sup> See MLA, FOGPMA, RSFA, and regulations promulgated thereunder.

<sup>11</sup> Office of Natural Resources Revenue Proposed Rule, “Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform,” Docket No. ONRR-2012-0004.

those amounts are paid at the inception of the lease and future royalty rates would not vary based on relative production or pricing levels. The IHS CERA Study noted that “[t]he bonus bid system adopted by the federal government is an objective and fair way to allocate acreage. Since the bid value represents the economic rent investors expect to receive from developing the resource, the bonus bid serves as a self-correcting mechanism within the fiscal system.”<sup>12</sup>

In contrast, the proposal to use “variable” royalty rates is contrary to DOI’s stated goals and would introduce far greater complexity to implement. Although the majority of current onshore federal leases have “fixed” royalty rates, a few leases apply “sliding scale” or “step scale” royalty rates which may vary from month to month based on production volumes. The existing sliding/step scale royalty rates are strictly volumetric in nature and the associated monthly calculations are frequently complex. Such volumetric sliding scale royalty rates are difficult for industry to handle within otherwise automated accounting systems and usually require manual processing. Shifting the entire onshore fiscal regime to a similar “variable” structure would not only increase the cost of compliance for industry, but it would also greatly increase the burden for BLM and ONRR, who are not currently staffed to handle such protocols. BLM and ONRR would not only have to agree on production data management processes, but also auditing practices as well. There would have to be much closer coordination between BLM and ONRR than exists today through both systems enhancements as well as interagency collaboration.

Furthermore, API members do not support establishing different royalty rates or rate schedules by region, State, lease sale, formation, resource type or other commodity factor as this proposal would also impose significant complexity and administration burden for both the industry and the Agency. Injecting uncertainty and variability into the reporting and payments process will adversely impact system responsiveness on the part of BLM, ONRR, and lessees. Variability could cause challenges to BLM/ONRR interfaces, impairment of reporters’ ability to deliver timely and accurate reports and payments, and increased likelihood of civil penalties being assessed as a result of reporter inability to cope with the uncertainty of monthly royalty rate variability.

For reasons stated elsewhere herein, we do not believe that there is any justification for the BLM to raise existing royalty rates. In assessing the competitive position of the agency’s fiscal system, BLM must examine the ability of that system to strike the proper balance between attracting investment and generating appropriate returns to the government, which should include the multiplying factor of providing millions of well-paying jobs and affordable energy and security for our country. However should the BLM ultimately decide to increase the variety of possible lease royalty rates, the agency would also need to address the effect of such an increase on, among other things, the additional costs and administrative burdens that will necessarily result related to the permitting and reporting in areas where surface commingling has been approved. This is true in areas where companies are evaluating or developing unconventional

---

<sup>12</sup> IHS CERA Study. p. 29.

shale resources with horizontal wells as well as conventional production areas where there are multiple producing zones.

The BLM currently mandates extensive infrastructure to separately meter each federal lease to account for the different royalty rates in 1/8th leases and rate-dependent Schedule B, C or D tiered leases. Doing so is costly, administratively burdensome and contrary to BLM and industry efforts to reduce unnecessary infrastructure and surface disturbances. BLM environmental, land management and wildlife staff have been at the forefront of encouraging operators on federal leases to use centralized gathering, processing and transportation infrastructure, which is generally contrary to the BLM requirements for segregating individual well production and measurement. Additional royalty rates would only exacerbate this burden, particularly with unconventional development since, as horizontal reach increases, the likelihood of crossing leases with different royalty rates also increases. Thus, if the BLM does decide to increase rates, it should also allow State and local offices flexibility in determining solutions to address the resulting additional costs and burdens. Without such flexibility, companies could be discouraged from fully developing federal mineral leases, particularly, as noted, unconventional shale resources.<sup>13</sup>

Also, if BLM does pursue increases to royalty rates, it should consider increases to natural gas royalties independent of oil royalties. Current Federal valuation practices involving unbundling of costs have resulted in many post-production costs now being disallowed, creating a higher effective royalty rate for gas. As pointed out in the Federal ANPR, the Van Meurs Study (2011) supports this premise.

The Van Meurs Study looked at a wide range of jurisdictions and regions across North America and provided a comparison of the oil and gas fiscal systems on Federal, State, and private lands throughout the United States and the provinces in Canada. At the time it was published, the Van Meurs Study suggested that in the United States:...(2) Government take was higher for gas than for oil; and (3) The internal rate of return on leases was lower for gas than for oil.<sup>14</sup>

In light of these findings, if BLM decides to raise royalty rates, the royalty rates for natural gas should be lower than oil.

---

<sup>13</sup> In a separate communication with BLM on the agency's Proposal to Replace Onshore Orders 3, 4, and 5 with New BLM Rules, API has stated that any new regulations should not impose additional restrictions on the use of commingling, but rather address how or under what circumstance commingling should be approved, thereby offering greater certainty and process than the current regulations provide. See 43 CFR 3162.7-2 and 3162.7-3.

<sup>14</sup> 80 Fed. Reg. 22150-51 (April 21, 2015).



**5. Prior to changing onshore royalty rates, BLM should assure industry and the public that its measurement regulations are appropriate for industry practices, incorporating the current measurement technologies and standards (GAO-15-39, 2015).**

BLM recognized the need to update its measurement and commingling regulations, and initiated public workshops in 2013 to receive input from industry, mineral owners and the public. BLM is currently developing draft revisions to BLM Onshore Orders #3, #4 and #5, for improving oil and gas measurements, and for consistently developing agreements for commingling of production streams. BLM should delay changes to royalty rates until the ongoing measurement and commingling rulemaking is completed, to avoid introducing any conflicts or inconsistencies with the pending, revised measurement and commingling regulations.

**6. BLM should maintain current annual rental payment levels.**

Current annual rental payment levels are sufficient to encourage operators to develop leaseholds in a timely manner. Increased rentals would not incentivize companies to develop leases faster. The timing of the development of leases is based on many other factors – including delays due to the time and complexity of obtaining permits – not the costs associated with rentals. Although improved technology has reduced drilling time, the increased costs demand that operators take additional time to develop and analyze economic drilling opportunities. As such, BLM should not penalize prudent exploration with increased rental rates. BLM does not have the flexibility to respond quickly to market forces should a reduction in rates be warranted to encourage exploration for oil and gas. In addition, an increase in minimum annual rentals may cause operators to bid less up front.

**7. BLM should maintain current minimum acceptable bid levels.**

API does not support any increase in the minimum acceptable bid. As BLM notes in the ANPR, “BLM’s experience indicates that most parcels sell for well in excess of the current minimum acceptable bid.” Given this fact, it is hard to discern a reason or need to increase the minimum acceptable bid. Raising the minimum bid will penalize small independent oil and gas producers who bid in less competitive areas and will not increase revenues as such tracts are necessarily in less desirable areas.

**8. Any changes to bonding or civil penalty provisions should be limited to adjustments only to account for inflation.**

API does not support any changes to the current bonding or civil penalty provisions; however, in the event BLM chooses to move forward with proposed changes, the change should be limited to adjusting the amounts to account for inflation.

In the ANPR, BLM has not provided any information justifying a need to increase the bond amount other than the fact that it hadn’t been increased in a while. In addition, API favors


continuation of the use of bonding as the mechanism for the agency to ascertain the financial responsibility of an operator. Alternatives to bonding, such as agency inquiries into and assessments of an operator's financial responsibility involve highly subjective decisions that have the potential to be arbitrary and/or inconsistent among operators and could propel BLM and its lease operators into conflict over such decisions. The current approach that depends upon bonding can take advantage of markets for a wide variety of financial instruments that can be tailored to the needs of individual firms, operations, and regulatory needs.

### **Conclusion**

In summary, onshore royalty rates, annual rental payments, minimum acceptable bids, bonding requirements, and civil penalty assessments, together with taxes that the companies pay, constitute the government's share of revenues from oil and gas production from Federal lands or, in an often used term, "government take". Government take is but one element of the design of a fiscal system that should avoid disincentives to investors, offer fiscal system flexibility, promise fiscal and regulatory stability, and recognize the investor/operator's financial risk, in order to maximize the value of the Government's mineral estate to the people of the United States. Changes to any of the elements of government take arising from a leasehold interest in Federal minerals should not be made at the expense of future investments in U.S. energy development and should be considered in the overall cost and complexity of operating on Federal lands.

Thank you for your time and attention to our comments on BLM's Advanced Notice of Proposed Rulemaking. API and its member companies remain committed and look forward to working with BLM on valid, reasonable efforts to improve and strengthen its royalty and leasing regulations. In particular, we invite a dialogue with BLM regarding the nature of the oil and gas markets, which should provide further guidance to BLM as it proceeds with any federal oil and gas rulemaking. Please do not hesitate to contact me (202-682-8260, hague@api.org) if you have any questions.

Sincerely,



---

Emily Hague  
Senior Policy Advisor  
Industry and Upstream Operations  
American Petroleum Institute