INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

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By Email to Dane Templin, Regulations Supervisor [Dane.Templin@onrr.gov] and Luis Aguilar, Regulatory Specialist [Luis.Aguilar@onrr.gov], including RIN 1012-AA27 in subject line.

Office of Natural Resources Revenue
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Re: Comments on the Department of the Interior, Office of Natural Resources Revenue's Proposed Rules, *ONRR Valuation Reform and Civil Penalty Rule*, 85 Fed. Reg. 62054-01 (October 1, 2020), Docket No. ONRR-2020-0001; DS63644000 DRT000000.CH7000 201D1113RT, RIN 1012-AA27

The Independent Petroleum Association of America ("**IPAA**") thanks you for this opportunity to submit comments on the Office of Natural Resources Revenue's ("**ONRR's**") Proposed Rules, the ONRR Valuation Reform and Civil Penalty Rule (the "**2020 Valuation Rule**" or "**Proposed Rule(s)**"). IPAA is the leading national upstream trade association representing approximately eight thousand independent oil and natural gas producers and service companies across the United States. Independent producers generally include non-integrated oil and gas companies that receive nearly all revenue from production at the wellhead. IPAA's members operate in 33 states and offshore and employ an average of just 12 people.

One of IPAA's primary purposes is to advocate for its members' interests in continued and responsible oil and gas development before Congress and federal agencies and in the judicial system. This purpose includes advocating for rational and fair policies on the valuation of royalties on oil and gas from Federal and Indian leases.

On federal, Indian, state, and private land, IPAA's members develop over 91 percent of domestic oil and gas wells, produce 83 percent of domestic oil, and produce 90 percent of domestic natural gas. The importance of oil and gas from federal lands is no longer merely about the jobs they create, the governmental revenues they generate, the transportation and heating fuels they provide, and the power and fertilizer they provide to American agriculture. They provide more, much more, even than all those benefits. The products of oil and gas have been at the forefront of the world's response to COVID-19. Ninety-nine percent of the "feedstock" chemicals for pharmaceuticals comes from petroleum. When the availability of non-reusable N-95 masks became scarce this year, petrochemicals provided the solution. Inventors turned to polypropylene pellets to make masks that could be sterilized and reused every day. Hand sanitizer, protective personal equipment, antiseptics, plastic gloves, and the solvents to keep hospitals free of germs are all based on the products of petroleum.[1]

Petroleum will remain essential to our lives. Excessive royalty burdens on federal lands make petroleum less available to meet our nation's needs. While the nuances of federal royalty policies may seem to be nothing more than the dull domain of accountancy, it is an important subject to a life-sustaining industry. The choices the Department makes in this rulemaking matter greatly.

COMMENTS ON 2020 VALUATION RULE

IPAA appreciates the efforts put into the proposed revisions of the 2016 Valuation Rule[2] for royalties on oil and natural gas. We are supportive of these changes and offer supplemental analysis showing the Department is on the right track. Additionally, we will call attention to additional problems, not only those created by the 2016 Rules, but also by earlier regulations. These problems have arisen either through sharp changes in agency interpretation over the years or through regulations ill-conceived from the start. The Department should address these problems in the final rule.

The Problems with Federal Royalty Valuation

Historically, the Department's valuation rules have suffered in varying degrees from six chief problems. *One* is that while the Department claims to continue to honor the principle that the value of production is the value of production at the lease,[3] the honor is now given in words more than in outcomes. This infidelity to core principles is manifested in the *second* problem: The Department's over-reliance on its own authority to determine value of production. In 1988 the Department adopted regulations to limit that by relying on values received in arm's-length contracts and, when sales were not at arm's length, on values received in comparable arm's-length

[1] "Big Oil to the Coronavirus Rescue," Wall Street Journal Editorial Board (April 23, 2020) (Enclosure 1); "Fighting Climate Change Should Not Come at Expense of Fighting Viruses, Poe Leggette, Houston Chronicle (March 10, 2020) (Enclosure 2). Petrochemicals are essential to the fabrication of turbine blades for windmills, clothing, construction materials, nearly everything made of plastics, including parts for cell phones and computers. (Enclosures 3, 4, and 5).

[2] Throughout these comments, we have abbreviated the Department of the Interior, Office of Natural Resources Revenue's "Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform," 81 Fed. Reg. 43,338, Docket No. ONRR-2012-0004; DS63644000 DR2PS0000.CH7000 167D0102R2, RIN 1012-AA13, as the "**2016 Valuation Rule**" or "**2016 Rule(s)**."

[3] "For example," to choose one among many examples, "nothing in this final rule [the 2016 Rule] changes the Department's requirement that, for purposes of determining royalty, the value of crude oil produced from Federal leases is determined at or near the lease." 81 Fed. Reg. at 43341.

contracts which were used as "benchmarks" governing sales of a lessee to its affiliate.

But that solution led to a third problem and a fourth. The *third* was the Department took guidance from the definitions from securities laws in determining what made a lessee's counter-party an "affiliate." Those ideas were unworkable and could not be implemented by federal auditors, who ended up casting an excessively broad net to catch affiliate transactions. The *fourth* was the 1988 regulations, through poor design, relied on third-party price information not available to the lessee. Lessees could not assure the transactions were correctly valued because they did not have access to those third-party prices.[4]

The Department could have solved these problems allowing lessees to rely on their own arm's-length sales as benchmarks and to adopt a view of "affiliates" relevant to royalty valuation instead of the securities laws. Instead, the Department left the "affiliates" concept unchanged and repealed the "benchmarks." In the benchmarks' place is a rule valuing royalty based on the affiliate's downstream arm's-length price. 30 C.F.R. § 1206.141(b)(2). In so doing, the Department claims faithfulness to the 1988 precept that arm's-length contracts provide the best measure of value. What that claim overlooks is that the Department has moved to point of royalty valuation far downstream from the lease. 81 Fed. Reg. at 43348 ("Simply selling the gas at the wellhead does not mean that the gas is in marketable condition—one must look [downstream] to the requirements of the main sales pipeline.[,]" to the needs "of the dominant end-users").

Fifth, the Department has abandoned its historical recognition that there are tens of thousands of arm's-length markets for produced oil and natural gas in fields around the United States. The Department used to recognize that wells in a single field were a market, and an arm's-length contract buying from the field set both market value and the criteria for marketable condition. *E.g.*, *Xeno, Inc.*, 134 IBLA 172 (1995). Now the Office of Natural Resources Revenue ("**ONRR**") dismisses this view, looking to requirements of "the dominant end-users" in the markets of the Atlantic and Pacific coasts. 81 Fed. Reg. at 43348. That statement means the agency sees no place for the market in the field but seeks the higher value of the second or third market where an interstate pipeline has an interconnection.

That same purpose--pushing the point of valuation far downstream--is served, and the *sixth* problem created, by the Department's extraordinarily expansive interpretation of the lessee's duty to place production in "marketable condition." IPAA members know from their frequent interactions with representatives of ONRR that the agency believes its current interpretation has "always" been how the Department has interpreted the rule. But this view is incorrect. There have only been two value regulations on marketable condition: one in 1920, the other in 1988 (and still in force today). The 1920 marketable condition rule required the lessee to bear the cost, without sharing it with the government lessor, of only one function: initial separation of oil, gas, and

[4] In abandoning benchmarks, the 2016 Rule asserted "that changes industry and the marketplace may make it difficult for a lessee to value its gas using the benchmarks." 81 Fed. Reg. at 43346. The Department failed to identify any changes. The sole failure was the Department's unwillingness to consider a lessee's own arm's-length sales for comparison.

produced water from one another, a function performed immediately near the producing well.

> The lessee shall recover all oil in B.S. [basic sediment] or emulsion and put it into marketable condition if it can be recovered at a profit. If the formation of B.S. or emulsion is not preventable and the oil can not be recovered by the usual modes of treatment, the cost of putting the oil into marketable condition by any unusual mode of treatment shall first be deducted from the amount received for it before royalty is computed.

Operating Regulations to Govern the Production of Oil and Gas—Act of February 25, 1920, 47 L.D. 552 (1920). The second regulation was the one adopted in 1988 and is still in effect.

The expansion of the marketable condition duty through mere agency interpretation has been cataloged elsewhere,[5] but two developments in the last twelve years have made it essential for the Department to limit ONRR's current claims of discretion. Both involve repudiation of a binding interpretation issued by and Assistant Secretary in 2003. One is ONRR's failure to follow the interpretation that a lessee only has to put production in marketable condition once. The other is ONRR's creation of a new interpretation that production has to be fully in marketable condition before <u>any allowances may be taken</u>.[6] In other words, even as this proposed rule would restore transportation deductions for offshore leases, ONRR will strip those deductions away by claiming the production was in some respect not yet in marketable condition until it reached a refinery or processing plant onshore. To further the objectives set out in the Executive and Secretarial Orders, 81 Fed. Reg. 62056-57, the two most important specific tasks these rules can achieve is to place boundaries on the interest of the ONRR to expand royalty obligations by repeated re-interpretations of the marketable condition rule.

<u>Essential Limitations on ONRR's Interpretation of Marketable Condition</u>

ONRR Ignores Lessees Need Meet Production Pressure Only Once

A federal gas lessee has the obligation to place production in marketable condition at no cost to the lessor. 30 C.F.R. §§ 1206.152(i) (unprocessed gas), 1206.153(i) (processed gas). When it is required by sales contracts typical for the field, compression of natural gas has long been considered a component of placing the gas in marketable condition.

In a 2003 royalty valuation determination (the "***Devon* decision**"),[7] the Assistant Secretary, Land and Minerals Management, determined that when a lessee must compress natural gas to reach

[5] Leggette, "Regulatory and legal Issues Relating to Federal Lands (Onshore and Offshore)," Institute for Energy Law 70th Annual Oil and Gas Law Conference (Enclosure 6).
[6] *DCOR, LLC*, ONRR-17-0074-OCS (FE), 2019 WL 6127405 (Aug. 26, 2019), *appeal docketed and pending* IBLA 2020-3.
[7] Devon Energy Corp., Assistant Secretary's Valuation Determination for Coalbed Methane Production from the Kitty, Spotted Horse, and Rough Draw Fields, Power River Basin, Wyoming (Oct. 9, 2003), *aff'd by Devon Energy Corp. v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008).

marketable condition, there are two key limitations on the lessee's obligation. First, a lessee is required to place gas into a marketable pressure at no cost to the government only one time before selling the gas.[8] Second, a lessee may choose "where—and in how many phases or steps" to place the gas in marketable condition.[9] The Department should reaffirm these two principles and clarify how they apply.

The first principle concerns so-called "boosting" costs. When natural gas is processed to remove liquefiable components such as ethane and propane, the pressure of the gas stream may drop as part of the processing. The drop may place the gas leaving the processing plant at a pressure below what is needed to enter a nearby pipeline. Frequently, there will be a compression unit at the tailgate of the processing plant, *i.e.*, upstream of the pipeline inlet, to "boost" the pressure back up to what is needed for the gas to enter the pipeline. In many cases, the pressure of the gas entering the pipeline can be the pressure needed to place the gas into marketable condition. Questions have arisen as to whether a federal lessee may ever deduct the cost of boosting the gas to pipeline pressure under the *Devon* decision.

Under the regulations, a "reasonable amount of residue gas shall be allowed royalty free for operation of the processing plant, but no allowance shall be made for boosting residue gas or other expenses incidental to marketing, except as provided in 30 C.F.R. part 1206." 30 C.F.R. § 1202.151(b). This regulation disallows deduction of boosting costs, unless the deduction is permitted as provided in 30 C.F.R. Part 1206.

Part 1206 includes not only the marketable condition rule, but also sections 1206.157(f)(9) and 1206.158(a). Section 1206.157(f)(9) allows a lessee to deduct "supplemental costs of compression" that "exceed the services necessary to place production into marketable condition."[10] Section 1206.158(a) allows a lessee to deduct "the reasonable actual costs of processing." If the lessee has already placed the gas into a marketable pressure once at no cost to the government, then it may deduct boosting costs permitted by Part 1206. The lessee may also elect to do the opposite. It may deduct certain costs of initially placing the production into a marketable pressure, then not deduct the costs of boosting for an equivalent amount of pressure needed to achieve marketable condition. This is what the *Devon* decision means when it says the lessee may choose "where—an in how many phases or steps" it meets its duty to add pressure required by the marketable condition rule.[11]

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[8] *Devon* decision at 30.

[9] *Devon* decision at 29.

[10] "Compression" is "the process of raising the pressure of gas." 30 C.F.R. § 1206.151. Boosting is a form of compression.

[11] A footnote in the *Devon* decision states, "It may be argued [that] in some circumstances" the section 1202.151(b) boosting provision creates an exception to the general rule that lessees are not required to condition production at their own expense more than once would not apply to circumstances where "part 1206" allows a deduction. Such an argument would contradict the "except as provided in 30 C.F.R. part 1206" language in section 1202.151(b).

The second question concerns the treatment of compression costs when a lessee uses multiple compression stages to place the gas into a marketable pressure. If one of those compression stages adds more pressure than needed to reach marketable condition, then allowable costs of the extra pressure should be measured using the pressure added by that particular stage (the discharge pressure minus the inlet pressure). For example, if gas entered a compressor at 700 psig and exited at 900 psig, which was 50 psig higher than the 850 psig needed to reach marketable condition, then the lessee should be able to deduct 25% ((900-850)/(900-700)) of the costs of that particular stage.

The correct approach to determine what may be deducted has been explained by ONRR.[12] The Department should affirm, through regulatory language provided below, that if the lessee has already met the requirement to compress gas to its marketable pressure before the gas reaches a processing plant, then subsequent costs of "boosting" are fully deductible.

ONRR previously followed a different methodology. It treats the former methodology as a still-acceptable option for enforcement[13] and has issued orders based upon it. This approach requires the lessee to apply more compression than is needed to place natural gas into a marketable pressure once. It is inconsistent with the *Devon* decision and should be disapproved.

Restrictions on Offshore Transportation Deductions Are Irrational

In 1963, the Department published its first acknowledgement that the movement of oil by barge from a fixed OCS platform in the Gulf of Mexico to a sales point onshore was "transportation," and its cost should be deductible from the sales value of the oil. *Shell Oil Co.*, 70 I.D. 393 (1963). The Department followed that principle when addressing movement of oil and gas from fixed platforms in the Santa Barbara Channel to shore, holding that movement to be "transportation," not "gathering." *Sun Oil Co.*, GS-60-O&G (FE), 1974 WL 371665 (1974). Since then, the Department has acknowledged that transportation systems ordinarily begin on OCS platforms and that certain platform equipment is part of the "transportation system" for which deductions may be taken. Shell Oil Company's floating production platforms, Auger and Mars, illustrated the practice.

Recently, however, ONRR has begun a long-planned campaign to establish the principle that a lessee may take no deductions until production is fully in marketable condition. Its bellwether case is *DCOR, LLC*, ONRR-17-0074-OCS-(FE), 2019 WL 6127405 (Aug. 26, 2019), appeal pending, IBLA 2020-3. ONRR has cited *DCOR, LLC* in many subsequent orders. The significance of this campaign should be apparent. It is so significant, in fact, that we must use all available fonts to emphasize it. ***<u>Not only will it revolutionize royalty valuation on all federal leases, onshore and offshore, but will also completely undo the proposal to restore subsea</u>***

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[12] https://www.onrr.gov/unbundling/pdf/How-to-calculate-a-Transportation-UCA.pdf at 4 ("Option #1"); https://www.onrr.gov/unbundling/pdf/How-to-calculate-a-Processing-UCA.pdf at 4 (Option #1)

[13] *See* https://www.onrr.gov/unbundling/pdf/How-to-calculate-a-Transportation-UCA.pdf at 4 ("Option #2"); https://www.onrr.gov/unbundling/pdf/How-to-calculate-a-Processing-UCA.pdf at 4 (Option #2).

transportation allowances through this rulemaking. Under DCOR, LLC, it will not matter that subsea movement of production is no longer automatically "gathering." Its costs will be disallowed anyway on the ground that the production is not yet fully in marketable condition.

ONRR's position is based on a misreading contained in the preamble to the 1988 oil and gas royalty valuation rules. That misreading is explained below when we discuss the current proposal to re-establish deductibility for certain costs of deepwater, subsea transportation. Here we discuss the more pressing point. ONRR's misread interpretation was never followed by the Department until *DCOR, LLC*. The failure to follow this interpretation has not been isolated; it has been widespread. We begin with the cases ONRR does cite in *DCOR, LLC* before turning to those it does not.

In *Devon Energy Corp.*, noted above, the Department found—and the court affirmed—that transportation began near the wells at central delivery points, but that the gas was not fully in marketable condition until it was sold over 120 miles away at the "Buckshot processing plant" where the gas was "in preparation for eventual sale." *Devon Energy Corp. v. Kempthorne*, 551 F.3d at 1034. That case therefore allowed 120 miles worth of transportation costs before the Department deemed the production in marketable condition. Similarly, ONRR has conceded in court that "in certain circumstances, there may be transportation costs incurred prior to treatment that may be deducted from royalty." *Nexen Petroleum U.S.A., Inc. v. Norton*, 2004 WL 722435 at *11 (E.D. La. 2004) *aff'g Nexen Petroleum U.S.A. Inc.*, 157 IBLA 286 (2002). Let us repeat here for emphasis: *Nexen Petroleum* allowed transportation costs from a central offshore platform to shore, contrary to what *DCOR, LLC* attempts to do. And then *Nexen* clarified there are circumstances in which transportation costs are allowed, not only before production is in marketable condition, <u>but also</u> before production is even treated in the first instance. Obviously, that concession would not have been possible, or the *Devon Energy Corporation* decision permissible, if gathering extended until production was in marketable condition. Finally, *DCOR, LLC* cites a decision of the Assistant Secretary for Land and Minerals Management in *Marathon Oil Company*. There, Marathon produced oil and gas from a single subsea well from an OCS block adjacent to the Ewing Bank Block 873's Platform A. The oil and gas flowed from the well through a subsea tieback to the platform. The production flowed together in "bulk:" it was not separated, measured, or treated on the seabed. The Department agreed that the movement of the production was transportation once it left the platform to shore, but not before. The ruling was not based on any claim that the production was in marketable condition, simply that it had first been--for the first time at the platform--separated, treated, then commingled with production from other wells. *Marathon Oil Co.*, MMS-00-0063-OCS (FE), 2005 WL 6733988 (Oct. 20, 2005).

In 1963, the Department published its first acknowledgement that the movement of oil by barge from a fixed OCS platform in the Gulf of Mexico to a sales point onshore was "transportation," and its cost should be deductible from the sales value of the oil. *Shell Oil Co.*, 70 I.D. 393 (1963). The Department again recognized transportation deductions to move offshore production from the platform to the onshore point where the first market was. *Superior Oil Co.*, 12 IBLA 212, 214 & 228 (1973) (pipeline cost allowed from platform to Burns terminal onshore, where oil was commingled with other offshore oil; but not barging costs beyond Burns, because there was a market at Burns to determine value). The Department followed that principle when addressing movement of oil and gas from fixed platforms in the Santa Barbara Channel to shore, holding that movement to be "transportation," not "gathering." *Sun Oil Co.*, GS-60-O&G (FE), 1974 WL 371665 (1974).

Since then, the Department has acknowledged that transportation systems ordinarily begin on OCS platforms and that certain platform equipment is part of the "transportation system" for which deductions may be taken. Shell Oil Company's floating production platforms, Auger and Mars, illustrated the practice. In *Shell Offshore Inc.*, 142 IBLA 71 (1997), the Department conceded that items on-platform, such as compressors, a rise skid, and dehydration equipment were allowed as costs of the "transportation system" from the floating platform. Id. at 73. Overruling the MMS, the Board agreed with Shell that the additional costs of the platform to bear the weight of these items what itself a transportation cost. As for the Mars Platform, Shell sought an allowance to move production from Mississippi Canyon Block 807 Platform A to a platform sixty miles away in West Delta Block 143. At the West Delta platform, the production was to be measured for royalty purposes. MMS agreed. (Enclosure 7). "The location of the royalty meter is often a deciding factor in determining whether movement is transportation or gathering. However, . . . we consider Platform A at MC 807 to be the central accumulation point." Therefore "gathering" ended at Platform A.

Most recently, IBLA reaffirmed the usual principle. "A lessee is entitled to deduct from the [gross proceeds] valuation the reasonable, actual costs of transporting oil and gas from the Leases to the offshore sales or valuation location[.]" *W&T Offshore, Inc.*, 189 IBLA 238, 241 (2017) (finding, however, that costs of removing a paraffin plug in the pipeline were not "reasonable" because of imprudent pipeline operation). Thus, once again, the Department recognized that transportation often precedes the location where production is measured for royalty purposes or where it is actually sold.[14] In sum, ONRR's conclusion in *DCOR, LLC* "that gathering does not end until lease production is in marketable condition [,]" Decision at 25, is contrary to precedent.

Solution: Add at the end of proposed 30 C.F.R. § 1206.153(b)(9), *see* 85 Fed. Reg. 62085, proposed 30 C.F.R. § 1206.157(c)(8), *see* 85 Fed. Reg. 62086, and 30 C.F.R. § 1206.159(d)(1), *see id.*, the following language:

> If natural gas has already reached a pressure needed to meet marketable condition before gas reaches a processing plant, a lessee may deduct costs of boosting

[14] One could continue with examples. For example, the Department does not allow transportation costs to the extent "waste" is included in the production fluids. 30 CFR § 1206.111(k) states that waste products are excluded from a per unit calculation for allowances. If allowances cannot be calculated until the production is marketable, then this regulation is a dead-letter, for it makes clear allowances can be calculated for product not yet in marketable condition, as any stream containing waste product would not yet be in marketable condition. For onshore leases, notwithstanding the duty to make production marketable at the lessee's sole expense, lessees can use gas, free of royalty, to fuel compressors to place production into marketable condition. *Plains Expl. & Prod. Co.*, 178 IBLA 327, 335-36 (2010).

> pressure after processing, because gas only need meet marketable pressure once. Gas is not required to be fully in marketable condition before a lessee is entitled to deduct costs of transportation, or supplemental compression, supplemental dehydration, and supplement treatment.

Add a new subsection (c) to 30 C.F.R. § 1206.107:

> (c) Oil is not required to be fully in marketable condition before a lessee is entitled to deduct costs of transportation or other costs for services in excess of what is required to put production in marketable condition

Comments on Particular Proposed Rules: Federal Oil and Gas

Valuation Option for Gas Sold Not at Arm's Length [Request Nos. 1-6]

Under the 2016 Rules, a lessee who sells production to an affiliate must value the production either by using the affiliate's arm's-length resale price or by using an index price minus a certain prescribed deduction to approximate actual costs. 30 C.F.R. §§ 1206.141(c)(iv) (five percent of sales value for Gulf of Mexico leases, ten percent from other areas, but at least ten cents but no more than 30 cents per MMBtu).

The Proposed Rule maintains the concept of an alternative to valuation using published prices for unprocessed gas and residue gas, continuing to rely on the current rule's use of publicly-available "bidweek prices" from approved publications and continuing to allow a specified deduction from those prices. But it would end the current rule's reliance on the "highest monthly bidweek price" in favor of the "average monthly bidweek price." More precisely, "the lessee may use the published bidweek average price rather than the bidweek high price." 85 FR at 62058.

The proposed change is an improvement for the reasons given in the preamble. The goal here is to approximate what a lessee would receive in arm's-length sales prices if the gas were sold at the lease or tailgate of the processing plant. Using the highest price pointless inflates the value to a level above the expected arm's-length price. Using the average "should more closely match what many lessees would otherwise receive as gross proceeds[.]" *Id.*

Removing Caps on Transportation and Processing Allowances [Request No. 7]

Lessees have long been allowed to deduct their "reasonable, actual" costs of transportation. As a precaution against excessive claims of allowance, the Department limited the deduction to an initial fifty percent of the value of oil, unprocessed gas, residue gas, or gas plant products; but the lessee could demonstrate its excess costs were reasonable, actual, and necessary. In the 2016 Rules, the Department eliminated provisions allowing approval of costs in excess of fifty percent. The full sum of its explanation was this: "The 50-percent limitation is a sufficient transportation allowance." 81 Fed. Reg. 43343 (oil) & 43352 (gas). Absolutely nothing in the record for that rulemaking supported the agency's fiat. The Department also removed language allowing lessees to exceed the sixty-six-and two-thirds percent limit on natural gas processing costs. The

Department added not additional reasoning, saying only "[p]lease refer to our comments regarding the 'Fifty-percent allowance cap[.]'" 81 Fed. Reg. at 43353.

This determination that the cap provides an "adequate" allowance is not rational. It disregards the number of occasions in which the agency approved excess costs because they were "necessary, actual, and reasonable." It disregards that the goal of royalty remains determining the value of production at the lease for it cuts of allowances needed to provide an appropriate "net-back" to the lease from a downstream sales price. And it completely ignores that it has been at least since 2015 that transporters of product shared with lessees in the rise and fall of commodity prices, moving away from percentage of proceeds contracts toward fixed-rate transportation services.[15] In sum, the cap on these allowances can be deemed "adequate" only by ignoring longstanding principles of royalty valuation.

In the 2020 Valuation Rule, ONRR appropriately proposes to remove the hard caps of 50% for transportation and 66 2/3% for processing. The proposed rule would allow a lessee to claim allowances exceeding those thresholds upon supplying appropriate documentation and agency review and approval. The logic for these hard caps in the 2016 Valuation Rule did not pass muster. The agency did not seem to envision a world where the transportation and processing allowances are rates under an agreement that do not fluctuate based on market pricing. Under the 2016 Valuation Rule, ONRR no longer has the authority to even consider allowing transportation or processing to exceed the caps put in place. In a situation where a lessee receives a low price for its gas, let's say $0.50, but has a transportation contract that requires it to pay $0.40 to transport that gas, the lessee would only be able to claim 62.5% ($0.25/$0.40) of the reasonable, actual allowance under the regulations. This result fails to fit with the regulatory language that *"ONRR will allow a deduction for the **reasonable, actual costs** to transport residue gas, gas plant products, or unprocessed gas from the lease to the point off of the lease under § 1206.153 or § 1206.154, as applicable." (Emphasis added)* In the early part of 2020, this example quickly became a reality for many lessees. Prices for oil, gas and NGLs were deteriorating quickly due to COVID-19 and a price war between Russia and OPEC. There were even certain days where index market prices for oil closed below $0.

Restoring Transportation Allowances for Offshore Leases [Request Nos. 8-10]

The Department proposes to repeal that part of the 2016 Rules that defined "gathering" to include all movement of oil or gas upstream of an offshore platform. 85 Fed. Reg. 62060. This proposal is a triumph of function over formality. The economics of deepwater development have improved with the ability to place typical platform equipment on the sea floor. If money were no object, one could place all that equipment on a platform and ONRR would recognize the movement of production away from the platform as transportation. But money is an object. Without the efficiencies of subsea development, many of these fields would not be developed. It benefits the United States to receive royalties and share in the costs of subsea transportation rather than forego

[15] John Harpole, 'See Ya, Pops?', Midstream Business 80 (Feb. 2015) (Enclosure 8).

development altogether.

Furthermore, even the formality of the 2016 Rules was flawed because it was based on a legally and historically incorrect statement of Department precedent and policy. The Department has arbitrarily eliminated transportation allowances to move oil and gas from deepwater wells, whose wellheads are on the sea floor, through seabed flowlines starting from the lease boundary all the way to the first production platform. This movement had been recognized as deductible "transportation" since the Clinton Administration, and stated in a policy pronouncement in 1999 called the "Deep Water Policy." (Enclosure 9). The only reason given for the Rule's change was that the Department previously "intended for the Deep Water Policy to incentivize deep water leasing by allowing lessees to deduct broader transportation costs than the regulations allowed." 81 Fed. Reg. 43,340.

This sudden change in legal interpretation was incoherent. When the Department proposed the change, it offered as its only reason that the movement of oil and gas to a point of interconnection of wells on an <u>adjacent</u> lease was "gathering," not transportation. 80 Fed. Reg. 614, 624. IPAA objected, noting that deepwater lessees can move production subsea off lease to platforms up to 50 miles away after the production has already been placed in a single flow line. A blanket rule disallowing subsea transportation costs would be irrational. Movement of production off lease has been considered "transportation" for decades. *See* 30 C.F.R. §§ 1206.102, 1206.156(a) (2016) (former rule defining transportation as movement outside of the lease or unit). The Deep Water Policy was fully consistent with that longstanding regulation. Incongruously, even the Rule itself still defines transportation to mean movement of oil or gas outside the lease or unit. 30 C.F.R. § 1206.20; 81 Fed. Reg. 43,372R ("transportation allowance" means costs of moving oil or gas "to a point of sale off of the lease" or unit).

Agencies may change positions, but they must "provide a reasoned explanation for the change." *Encino Motorcars, LLC v. Navarro*, 136 S. Ct. 2117, 2125 (2016). "It follows that an 'unexplained inconsistency' in agency policy is 'a reason for holding an interpretation to be an arbitrary and capricious change from agency practice.'" *Id.* at 2126 (quoting *Nat'l Cable & Telecomms. Ass'n v. Brand X Internet Servs.*, 545 U.S. 967, 981 (2005)). It is irrational to continue to define transportation to mean movement of production off lease, then disallow costs for movement off lease on the unexplained ground that the former treatment of that movement as transportation was unlawful. This sudden, unexplained, and detrimental change receives no judicial deference. *Kisor v. Willkie*, 139 S.Ct. 2400, 2417-18 (2019) ("[A] court may not defer to a new interpretation . . . that creates 'unfair surprise' to regulated parties.").

The 2016 Rules were influenced by a new approach to defining gathering: production must reach a federally-approved point of royalty valuation before gathering ends. No regulation says so, of course. Instead, the 2016 Rules found support in a quotation from the preamble to the 1988 valuation rules.

> The operational regulations of both BLM and [BSEE] require that a lessee place all production in a marketable condition, if economically feasible, and that a lessee properly measure all production in a manner acceptable to the authorized officials

> of those agencies Unless specifically approved otherwise, the requirements of the regulations must be met prior to the production leaving the lease. Therefore, when approval has been granted for the removal of production from a lease, unit, or communitized area for the purpose of treating the production or accumulating production for delivery to a purchaser prior to the requirements of the operational regulations having been met, MMS does not believe that any allowances should be granted for costs incurred by a lessee in these instances.

See, e.g., 53 Fed. Reg. 1230, 1240 (Jan. 15, 1988) (gas rules).

This statement remains incorrect thirty-two years later. Examining BSEE's regulations (at the time MMS's) shows the regulations in force in 1988 did not require a lessee to place production in marketable condition <u>before</u> it left the lease. "The lessee shall put into marketable condition, if commercially feasible, all products produced from the leased land. In calculating the royalty payment, the lessee may not deduct the costs of treating." 30 C.F.R. § 250.42 (1987). Nothing here prohibited the lessee from deducting the costs of moving the production off the lease before treating it, just the cost of treatment itself. Nor did it require agency approval to move production off lease before it was put in marketable condition.

Nor did this rule require the agency's permission to move production off lease before treatment of any sort. No rule did. But a different rule required the agency's permission to move production off lease without first measuring it:

> Subject to such conditions as the Director may prescribe for the measurement and allocation of production, the Director may authorize the lessee to move production from the leased area to a central point for purposes of treatment, measuring, and storing. In moving such production, the lessee may commingle the production from different wells, leased areas, pools, and fields[.]

Id. at § 250.68. So, if operational or financial reasons made it sensible to commingle production before treating it, measuring it, or storing it, the agency could allow it and provide for allocation of the commingled production back to each lease or, if the agency deemed it necessary, each well within the lease. Again, nothing in this regulation disallows the cost of moving production off lease.

In sum, the difficulty is that the text of the regulations conflicts with the preamble (as the 2016 Rules read it). For this reason, the preamble cannot be relied on. It is well-settled that "language in the preamble of a regulation is not controlling over the language of the regulation itself." *Wyo. Outdoor Council v. U.S. Forest Serv.*, 165 F.3d 43, 53 (D.C. Cir. 1999). A preamble to a rule is "not an operative part" of the rule. *Nat'l Wildlife Fed'n v. EPA*, 286 F.3d 554, 569-70 (D.C. Cir. 2002). While a preamble can inform the meaning of a rule, it is not legally binding because it is not itself subject to notice and comment. *Peabody Coal Co. v. Dir., Office of Workers' Comp. Programs*, 764 F.3d 1119, 1124-25 (9th Cir. 2014). Even a preamble that carefully sets out what conduct is lawful cannot be given force if it is inconsistent with the plain meaning of the rule. "[T] he preamble . . . is not binding and cannot be read to conflict with the language of the regulation itself." *Peabody Twentymile Mining, LLC v. Sec'y of Labor*, 931 F.3d 992, 998 (10th Cir. 2019). And the inconsistency of the preamble with the regulations is demonstrated, as IPAA did above, by the long history of the Department acknowledging that oil and gas must be put in marketable condition before "gathering" ends.

Finally, the 2016 Rules' about-face in their interpretation stems from a fatal misunderstanding of subsea production systems. The proposed 2016 Rules argued gathering lines "move lease production to a central accumulation point" and "bring gas by separate and individual lines to a central point where it is delivered into a single line." 80 Fed. Reg. at 624. But the Deep Water Policy accepted that view. "Movement prior to a central accumulation point is considered gathering. A central accumulation point may be a single well, a subsea manifold, . . . or a platform[.]" A subsea manifold is a piece of equipment on the seabed receiving oil or gas from multiple wells, commingling it, and sending it to a platform through a single flowline. (Enclosure 10). The 2016 Rules failed to, and could not, explain its new view that subsea manifolds are <u>never</u> central accumulation points.

The Department's proposal to remove the limitation on "gathering" is sound policy and good law. The Department's long-standing interpretation is that "gathering" is the movement of production—within the lease, unit, or field in which the well is located—to the first point at which production is treated, or accumulated, or measured for royalty purposes. *Kerr-McGee Corp.*, 22 IBLA 124, 126 (1975) (movement beyond the field is transportation); *Xeno, Inc.*, 134 IBLA 172 (1995) (even though gas was moved in the same field before accumulation, all costs were deductible transportation because the royalty measurement point was at the wellheads); *Phillips Petroleum Co.*, 109 IBLA 4, 13 (1989) (movement of wet gas from "the field" to a processing plant was deductible transportation); *J-W Operating Co.*, MMS-97-0210-O&G (FE), 1999 WL 35128946, * 7 (March 3, 1999) (following the test "[i]s the pipeline segment beyond the initial treatment point, central accumulation point <u>or</u> measurement facilities;" (emphasis added by MMS Director)). The Deep Water Policy limited its application to subsea facilities beyond the boundaries of the lease in which the platform is located and abutting leases. The *Nexen* case on which the 2016 Rule relied was consistent, not inconsistent, with this approach. The 2016 Rule was wrong on this point, and the Department is correct to correct that error.

Revising the Unworkable Misconduct/Default Provisions [Request No. 11]

IPAA incorporates by reference the comments of the American Petroleum Institute.

Requirement to Maintain Signed Contracts [Request No. 13]

IPAA incorporates by reference the comments of the American Petroleum Institute.

Legal Precedents in Valuation Determination Requests [Request No. 14]

IPAA incorporates by reference the comments of the American Petroleum Institute.

Placing Oil in Marketable Condition [Request No. 15]

To further the objectives set out in the Executive and Secretarial Orders, 81 Fed. Reg. at 62056-57, the two most important specific tasks these rules can achieve is to place boundaries on the interest of the ONRR to expand royalty obligations by repeated re-interpretations of the marketable condition rule. (*See, supra*, The Problems with Federal Royalty Valuation.)

Valuing Unprocessed Gas as Processed Gas Is Arbitrary [Request No. 15]

The 2016 Rules ended acceptance of a lessee's arm's-length sales of gas prior to processing and sales under so-called "keepwhole" contracts. 81 Fed. Reg. at 43348; 30 C.F.R. § 1206.142. Under both agreements, the lessee receives no value from natural gas liquid sales. The 2016 Rules demand a share of the value of the liquids the lessee does not receive.

The 2016 Rules are arbitrary in their treatment of arm's-length sales of gas before it is processed into liquid products such as ethane, propane, and butane. It has been common in the industry to sell natural gas at the wellhead to third parties. The pricing clause in those contracts commonly provides that the lessee is paid on a percentage either of (1) an index price for gas sold downstream from the lease or (2) the proceeds the buyer receives from selling the liquids and "residue gas" that result from processing the gas. These are called "percentage-of-index" ("**POI**") and "percentage-of-proceeds" ("**POP**") contracts, respectively.

Under the rule before 2016, arm's-length sales under these contracts were valued as sales of "unprocessed gas." 30 C.F.R. § 1206.152 (2016). The royalty value for the gas was the gross proceeds the lessee actually received. *Id.* § 1206.152(a)(1), (b)(1)(i) (2016). For example, if the buyer resold liquids and residue gas for $100,000, and the POP clause called for the lessee to receive 80 percent, then the total value on which royalty would be based would be $80,000. If the royalty were one-eighth, then the federal royalty share would be $10,000. To report and pay royalties accurately, the lessee did not need to know what it actually cost <u>its buyer</u> to transport the gas away from the lease or the cost to process it. That was the buyer's business.

The Rule now treats arm's-length sales under POI and POP contracts as sales of "processed gas." *Id.* § 1206.142(a)(2); 81 Fed. Reg. at 43,381. Treating gas sold before processing as processed gas is arbitrary. In *Continental Resources, Inc. v. Gould*, 374 F. Supp. 3d 28 (D.D.C. 2019), the Department attempted to value an allegedly non-arm's-length sale of gas sold before processing under a POI contract as if it were processed gas. Among other flaws, the Court found the Department's decision not only "textually and logically inapposite" but also "nonsensical . . . because Continental sold unprocessed gas and, thus, the proceeds of sales of processed gas would never be comparable." *Id.* at 35. The Department has valued unprocessed gas separately from processed gas. *Compare* 30 C.F.R. § 1206.152 (2016) (unprocessed) *with* 30 C.F.R. § 1206.153 (2016) (processed). Treating similar things differently is the very soul of arbitrariness. *Indep. Petroleum Ass'n of Am. v. Babbitt*, 92 F.3d 1248, 1260 (D.C. Cir. 1996). The converse is equally true: without explanation, treating <u>similarly</u> things that the Department has historically treated as <u>dissimilar</u>—processed and unprocessed gas—is just as arbitrary.

Under the 2016 Rules, a lessee must report on the buyer's full proceeds (not just the lessee's percentage share) and must separately file for allowances to reflect the buyer's costs of transportation and processing. 30 C.F.R. § 1206.142(b); 81 Fed. Reg. at 43,381. At the time, IPAA members objected, pointing out that the Department was imputing to the lessee the revenues and costs of the buyers of the gas. Not the least of the problems was that the lessee lacks access to its buyer's actual costs of processing and transportation.

In response to IPAA's concerns, the 2016 Rules were evasive and vague. "[I]f a company is in compliance under the previous rules . . . this change should not be overly burdensome. This change increases data transparency . . . and allows us to better monitor allowances and account for royalty interest more quickly and accurately." 81 Fed. Reg. at 43,348. This statement contradicts actual practice under the prior rules. Under them, the lessee did not have to report its buyer's costs, so "compliance under the previous rules" has little bearing on the burden of the new Rule.

And it is incomprehensible to assert that requiring access to data the lessee lacks "increases data transparency." It rather increases "data impossibility." It is the true essence of arbitrariness to expect a regulated entity to do what the agency knows is impossible. *Messina v. U.S. Citizenship & Immigration Servs.*, Case No. Civ.A. 05-CV-73409-DT, 2006 WL 374564, at *6 (E.D. Mich. Feb. 16, 2006) ("It is arbitrary and capricious to require compliance with a regulation when compliance is impossible"); *see also RxUSA Wholesale, Inc. v. Dep't of Health & Human Servs.*, 467 F. Supp. 2d 285, 305 (E.D.N.Y. 2006) (granting preliminary injunction of regulation requiring re-sellers of prescription drugs to certify the pedigree of drugs the distributors sold because the manufacturers and authorized distributors from whom the re-sellers obtained the drugs were not required to maintain pedigree records).

The 2016 Rules thought they had a solution. ONRR has the power to compel buyers to disclose their cost data to the Department. 81 Fed. Reg. 43,348-49; *see* 30 U.S.C. §§ 1711(c), 1713(a), 1717. The Department decided that if the lessee cannot do it, then the Department will determine the lessee's allowable costs of processing and transportation—using *inter alia* any "[i]nformation available . . . to ONRR." 30 C.F.R. § 1206.144; 81 Fed. Reg. at 43,383; *see* 30 C.F.R. § 1206.152(g)(3) (transportation costs), 1206.159(e)(3) (processing costs); 81 Fed. Reg. at 43,385 (transportation costs), 43,387 (processing costs).

The problem with this "solution" is the Due Process Clause. The Department must give lessees the information on which it relies to support its valuation, as any attempted "deprivation of a protected property interest" must comport with Due Process. *Amoco v. Fry*, 118 F.3d 812, 819 (D.C. Cir. 1997) (Department must disclose data underlying its royalty demands to lessees). But the buyer's cost information cannot be disclosed to the lessees. It is protected by 18 U.S.C. § 1905 and by 5 U.S.C. § 552(b). *Food Marketing Inst. v. Argus Leader Media*, 139 S. Ct. 2356, 2364-65 (2019) (buyer can bar disclosure under FOIA); *Chrysler Corp. v. Brown*, 441 U.S. 281, 317-19 (1979) (buyer can bar disclosure under 18 U.S.C. § 1905). Denying lessees access to the very information they require in order to challenge or comply with ONRR's determined valuation amounts to a denial of due process of law. *Amoco*, 118 F.3d at 819 ("Notice and meaningful opportunity to challenge the agency's decision are the essential elements of due process.").

The 2016 Rules thus "failed to consider an important aspect of the problem" that necessary data is unavailable.[16] *Dine Citizens Against Ruining Our Env't*, 923 F.3d at 858. And it failed to respond to a significant comment. *Action on Smoking & Health v. Civil Aeronautics Bd.*, 699 F.2d 1209, 1216-17 (D.C. Cir. 1983) (reversing agency action where the agency failed to respond to significant comments). Treating arm's-length sales of gas before it is processed as if the lessee processed it is unworkable, is arbitrary, and requires correction.[17]

The Department Should Reinstate "Transportation Factors" in Valuation [Request No. 15]

Before the 2016 Rules, lessees were authorized to report net prices for production if their purchasers had included in the price provisions of the contract a reduction in price for costs to reimburse the buyer for the cost of moving the production from the point of delivery, usually near the lease, a location where the buyer would value the production (through resale or use of index pricing). These deductions were called "transportation factors." They were not "transportation deductions" in the regulatory sense because the oil or gas no longer belonged to the lessee once the production was delivered to the buyer. They were an arm's-length component of an arm's-length price.

To illustrate the point, suppose buyer agrees to purchase oil at a meter on a lease. For the one-year contract, the parties agree the price will be based on a daily average of prices at Cushing, Oklahoma, minus 25 cents per barrel. Suppose further the parties agree that the 25 cents per barrel reasonably represents the difference in the value of the oil between the market in the field at the market at Cushing. If in a given month the Cushing price is $40.00 per barrel, the seller's arm's-length price is $39.75 per barrel. The parties could achieve the same result by having a month to month contract and, at the start of the given month, agree on a price of $39.75. But to have a one-year deal and account for variations in oil prices, they choose the formula instead. Either way, the result is the same to the lessee and, until 2016, to the Department. The Department acknowledged this. "Historically, we used the term '*transportation factor*' to identify the situation when a sales contract contains a provision to reduce the base price by costs that the purchaser incurred to move the production to a downstream location." 81 Fed. Reg. at 43344.

Abandoning fidelity to the principle that arm's-length prices are the best measure of value, the 2016 Rules required lessees "to report such costs as a separate entry on Form ONRR-2014." 81 Fed. Reg. at 43344. Here, at least, the agency offered a reason, but one that is internally inconsistent. "The burden lies with the lessees to support their reasonable actual costs of

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[16] The 2016 Rules do allow lessees to avoid calculation of transportation <u>and</u> processing costs by using an "index based" valuation. 30 C.F.R. § 1206.142(d); 81 Fed. Reg. 43,381R-43,382L. That option is <u>not</u> available, however, to lessees who sell at arm's length. *Id.*

[17] Of course, sales of unprocessed gas under POI and POP contracts were still subject to the requirement that the lessee was responsible for putting production into marketable condition without cost to the lessor, *see* 30 C.F.R. § 1206.152(i) (2016), although what "marketable condition" required in any given market was sometimes disputed between the Department and its lessees. That issue remains unaltered under the Rule. Note, however, that while the Rule mentions the "marketable condition" issue, 81 Fed. Reg. at 43,348, it does not claim that the burdens of determining marketable condition are different under the old rule and the new Rule.

transportation." 81 Fed. Reg. at 43344. Using our illustration above, here the lessee has no cost of transportation. It sold the oil at the lease. As the Department acknowledged, it is the purchaser's cost of transportation; and it remains the purchaser's cost whether the contract price is $39.75 per barrel or ($40.00 minus $0.25) per barrel. The 2016 Rules thus hold the lessee to account for costs incurred by the third-party buyer, which is irrational enough; but it does so only if the sales contract has a price formula with a reduction, not when it lacks that formula.

The Department Should Repeal the "Keepwhole Contracts" Regulation [Request No. 15]

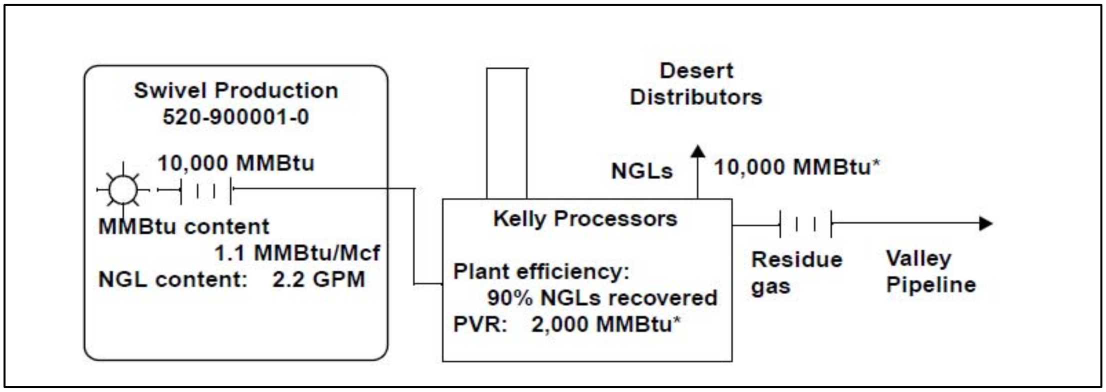
Under the 2016 Rules, keepwhole contracts must now be valued as if the lessee sold processed gas. 30 C.F.R. § 1206.142(a)(3). The 2020 Valuation Rule has not addressed the problems with this approach.

A lessee with a keepwhole contract receives an MMBTU equivalent of gas after processing to be sold as residue gas. Often the lessee does not have the necessary data on how much natural gas liquids the buyer recovered to report. ONRR's requirement to report based on required information that a lessee likely does not have obligates the lessee to use generic or estimated information to derive reporting. This strikes at the very heart of accurate reporting. ONRR requires that a lessee go through multiple calculations to derive estimated volumes and values for NGLs and residue along with associated allowances. These unnecessary calculations do not provide ONRR any additional royalty value that would offset the additional administrative burden. It would be more accurate to allow a lessee to report the volume and value of gas that was sold.

Describing the problems with valuing keepwhole agreements is as tedious as the outcome is pointless. Substantial background is necessary. In 2001, the MMS released the Oil and Gas Payor Handbook, Volume III – Product Valuation (the "Handbook"), which defined a keepwhole contract as an "agreement for the processing of the lessee's gas under which the lessee normally receives 100 percent of its attributable residue gas and consideration from the processor for its attributable PVR [Plant Volume Reduction]. The consideration for the lessee's PVR consists of either an amount of residue gas in Btus equivalent to the amount of Btus contained in the PVR or a cash payment for the PVR." *Id*. The Handbook also explained how to calculate royalties and a processing allowance under such agreement, turning on the concept of an arm's length agreement. Under it, the processor retains natural gas liquids ("NGLs") and returns the processed natural gas to the producer.[18]

[18] For royalty purposes, the gas is valued as processed gas because the lessee has not sold the gas under an arm's-length contract prior to processing. The value for royalty purposes is 100 percent of the values of residue gas and NGLs attributable to processing the gas, less applicable transportation and processing allowances. The volume of NGLs attributable to the gas is determined under the provisions of 30 CFR 206.154 and 30 CFR 206.174[.] . . . The value of NGLs is determined based on their market value (the plant owner's arm's-length sales price, for example). The value of the residue gas is based on whether the sale is arm's-length or non-arm's-length. The lessee's processing costs for the purpose of calculating a processing allowance are calculated as the difference between the value of the compensation received for the PVR and the value of the attributable NGLs at the tailgate, plus any other fees incurred for processing.

Unfortunately, ONRR's methodology is futile, as it requires the use of inaccessible information, imposing more costs of compliance on producers, at no additional benefit to the government.



For example, in the above illustration from the Handbook, "Swivel Production" processes gas under an arm's-length processing agreement with "Kelly Processors." The agreement specifies that all of Swivel's attributable residue gas be delivered to Swivel at the plant tailgate and title to all NGLs recovered from Swivel's gas pass to Kelly. Kelly pays Swivel for its attributable PVR. The payment for PVR is an amount of residue gas containing an equivalent amount of MMBtus as contained in the PVR. 8,000 MMbtu of residue gas are attributable to Swivel. Therefore, Kelly delivers an additional 2,000 MMbtu of residue gas to Swivel. Swivel sells 10,000 MMBtu of residue gas to Valley Pipeline under an arm's-length contract at a price of $1.50/MMBtu. Kelly sells the NGLs to Desert Distributors under an arm's-length contract at a price of $0.23/gal.

Residue gas value: $8{,}000 \text{ MMBtu} \times \$1.50/\text{MMBtu} = \boxed{\$12{,}000.00}$

NGLs volume: $\dfrac{2.2 \text{ GPM} \times 10{,}000 \text{ MMBtu} \times 90\%}{1.1 \text{ MMBtu/Mcf}} = 18{,}000 \text{ gal}$

NGLs value: $18{,}000 \text{ gal} \times \$0.23/\text{gal} = \boxed{\$4{,}140.00}$

Processing allowance:

$$\$4{,}140.00 - (2{,}000 \text{ MMBtu} \times \$1.50/\text{MMBtu}) = \boxed{\$1{,}140.00}$$

FIGURE 4-45. Valuation of gas processed under a keep-whole agreement

In real life, of course, Swivel has no information on how much Kelly sold to Desert Distributors or at what prices. So, on November 21, 2012, ONRR issued a Dear Reporter Letter to active payors and reporters on "Keepwhole Gas Processing Contracts" (the "Dear Reporter

Letter") to "provide[] guidance on valuing and reporting gas sold under keepwhole processing contracts." ONRR also defined keepwhole contract[19] and explained how to calculate royalties and a processing allowance under such agreement.

Attempting to address the real life problem that the producer does not know what the processor does with the liquids, ONRR explained how to calculate royalties under a keepwhole contract, including instances where a gas plant does not provide a producer with the volume of NGLs and residue gas attributable to the producer's delivered gas.[20] It requires the producer to calculate "theoretical NGL volumes, by [each NGL] component." If that is what ONRR wants the lessee to do, then it should amend its regulations, for the regulations require actual, not theoretical, volumes. In the same vein, because the lessee is not selling the liquids, it does not know the price the processor received from the sale. ONRR's solution is to have the lessee go hunt for a published index price for each of the components liquids (such as butane and propane) to use in royalty calculation. Whether the index prices accurately state was the liquids were worth at the tailgate of the plant is anyone's guess.

And what is the benefit of this pair of theoretical calculations? Nothing. Because ONRR requires the lessee to value its dry gas as if part of it were liquids, the lessee is entitled to a deduction from the theoretical proceeds for the costs of processing the gas. Here again is how

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[19] "[A]s a processing agreement whereby the processor delivers to the lessee a quantity of gas after processing equivalent to the quantity of gas the processor received from the lessee prior to processing, normally based on heat content, less gas used as plant fuel and gas unaccounted for and/or lost. This definition includes, but is not limited to, agreements under which the processor retains all NGLs it recovers from the lessee's gas."

[20] [W]hen the gas is processed prior to sale or disposition, you must report and pay royalties on the full volume and value of the residue gas and NGLs recovered from processing, less any applicable transportation or processing allowance. . . . If the gas plant will not provide you with the volume of NGLs and residue gas attributable to your delivered gas, you may use theoretical volumes[.]

ONRR provided a methodology to determine the theoretical volume and value of NGLs in such an instance:

> When the plant will not provide the NGL volumes attributable to your gas, you should calculate the NGL volumes using the gallons per Mcf (GPM) factors from the gas analysis. Multiply the Mcf volumes of the gas by the GPM factor for each component of that gas (ethane, propane, iso- and normal butanes, etc.) to obtain the theoretical NGL volumes, by component. Then, multiply the resulting component volumes by the corresponding gas plant product recovery factors, which provides a more reasonable estimate of the NGLs recovered from your gas. You may be able to obtain the recovery factors from the gas plant. If the gas plant will not provide them, use a reasonable method to approximate them. After determining the theoretical volume of each NGL component, sum the volumes to determine the total NGL volume[.] . . . Because the NGLs the processor retains under a keepwhole contract are not sold by the lessee under an arm's-length contract, the lessee must calculate a theoretical value under the first applicable non-arm's-length benchmark at 30 CFR § 1206.153(c). Usually, lessees can determine value under the second benchmark using an arm's-length NGL sales price from a nearby plant or publicly available prices.

ONRR calculates that deduction, using Swivel and Kelly as the example:

Residue gas value: $8{,}000 \text{ MMBtu} \times \$1.50/\text{MMBtu} = \boxed{\$12{,}000.00}$

NGLs volume: $$\frac{2.2 \text{ GPM} \times 10{,}000 \text{ MMBtu} \times 90\%}{1.1 \text{ MMBtu/Mcf}} = 18{,}000 \text{ gal}$$

NGLs value: $18{,}000 \text{ gal} \times \$0.23/\text{gal} = \boxed{\$4{,}140.00}$

Processing allowance:

$$\$4{,}140.00 - (2{,}000 \text{ MMBtu} \times \$1.50/\text{MMBtu}) = \boxed{\$1{,}140.00}$$

FIGURE 4-45. Valuation of gas processed under a keep-whole agreement

ONRR first imputes a theoretical total value of Swivel's gas at $16,140, the sum of the $12,000 for the dry residue gas and the $4,140 theoretical value of the liquids. But the processing allowance is the difference between the theoretical liquids value of $4,140 and the actual value of the 2,000 MMBtu Kelly gave Swivel to compensate for the liquids Kelly removed. That value is $3,000 (2,000MMBtu times $1.50 per MMBtu). The resulting allowance is $1,140. When that allowance is deducted from the theoretical total value of $16,140, the result is a value of $15,000.

Consider, however, that the lessee actually sold 10,000MMBtus of gas for $1.50 per MMBtu. The lessee actually received $15,000, the same amount as when ONRR requires the theoretical calculations. There is no benefit to the public from the additional calculations ONRR requires, just unnecessary cost to the lessee. It is as if, on a cold winter night, a person took his six-foot blanket, cut off a one-foot swath from the right side, then sewed that swath back onto the left side. The result is still a six-foot blanket, and the person is no warmer.

Comments on Particular Proposed Rules: Civil Penalties

Revising Civil Penalty Rules [Request Nos. 1-3]

IPAA incorporates by reference the comments of the American Petroleum Institute.

Comments on Particular Proposed Rules: Other Matters

Redefining "Affiliate" [Only Request]

Before the 1988 valuation rules, the Department showed no antipathy toward transactions between affiliated companies. A lessee could use the price received from a sale to an affiliate if it was comparable to a price it received at arm's length. *Getty Oil Co.*, 51 IBLA 47 (1980). With the 1988 rules came the definition of "affiliate" that prevails today, focusing (as the Securities and Exchange Commission does) on close questions of "ownership" and "control." *See* 85 Fed. Reg. at 62074 (§ 1206.20 ("Affiliate")).

The problem and the solution are both easier. The question is this: does a lessee have a financial incentive to sell production at a below-market prices, or to pay transportation at above-market prices, to reduce royalties? Suppose Lessee owns all the oil produced in the field, but only seventy percent of the transportation pipeline. Suppose third-party buyers are offering $40/barrel for oil at the terminus of the pipeline. For every extra dollar the pipeline charges Lessee, Lessee receives seventy cents. For every dollar less, Lessee receives all one hundred cents. Suppose the royalty rate is one-tenth. Does the lessee have an incentive to raise the transportation charge to reduce its royalty payment?

Suppose the pipeline's charge is $5/barrel. The value after transportation is $35/barrel. The pipeline receives $5/barrel (of which $1.50 goes to the thirty-percent non-Lessee owner's share), the government receives one-tenth of $35/barrel (or $3.50/barrel), and the Lessee nets $35.00. Now suppose Lessee raises the transportation charge to $8/barrel. The value after transportation is $32/barrel. The pipeline gets $8/barrel (of which $2.40 goes to thirty-percent non-Lessee owner's share), the government receives one-tenth of $32/barrel (or $3.20/barrel), and Lessee nets $34.40/barrel. So Lessee is sixty cents a barrel worse off, the government is thirty cents a barrel worse off, and the non-Lessee is ninety cents a barrel better off. Lessee has no incentive to inflate the transportation rate, for it hurts the Lessee (indeed, here more than it hurts the government).

Under the current concept of affiliation, Lessee's seventy percent ownership of the pipeline makes the transportation contract automatically non-arm's-length. But as the example shows, Lessee and the pipeline have opposing economic interests. It is the existence of a sufficient opposing economic interest that protects the royalty interest here. How much of an opposing interest is sufficient? As long as the percent of interests not owned by Lessee are greater than the royalty interest, the opposing interest is sufficient.

CONCLUSION

Thank you for your time and attention to this matter. IPAA and our member companies stand ready to work with ONRR to improve the royalty valuation process and ensure a fair and equitable return to the American Taxpayers.

Sincerely,

Daniel T. Naatz
Senior Vice President of Government Relations and Political Affairs
Independent Petroleum Association of America

https://www.wsj.com/articles/big-oil-to-the-coronavirus-rescue-11587683239

OPINION | REVIEW & OUTLOOK

Big Oil to the Coronavirus Rescue

Look whose products are crucial for fighting off Covid-19.

By The Editorial Board

April 23, 2020 7:07 pm ET

The Exxonmobil Port Allen Lubricants Plant in Port Allen, Louisiana.

PHOTO: LEE CELANO/REUTERS

Anti-carbon activists don't sleep even during a pandemic, and earlier this week New York City Council members introduced a resolution to divest from banks invested in fossil fuels. Perhaps they don't know that hand sanitizer and personal protective equipment come from hydrocarbons synthesized by their arch-villain Exxon Mobil.

Exxon's predecessor Standard Oil invented isopropyl alcohol (IPA), the key ingredient in disinfectants and hand sanitizer, in 1920. Its Baton Rouge chemical plant is now the world's largest producer of IPA. While refineries have been throttled back, Exxon has ramped up IPA production by 3,000 tons per month, which is enough to produce 50 million four-ounce bottles of sanitizer.

The oil giant recently noted in a press release that the state of New York has turned to the Baton Rouge plant for critical supplies. Gov. Andrew Cuomo should be grateful Exxon isn't holding a grudge after the state's four-year inquisition for allegedly deceiving itself about its climate impact, which finally ended last December when a state judge tossed the state lawsuit as entirely without merit.

Exxon is also increasing production of a specialized polypropylene that is used in medical masks and gowns by about 1,000 tons per month, which is enough to manufacture up to 200 million medical masks or 20 million gowns. At the same time, it is applying its expertise in material science to develop new face shields that utilize a filtration fabric.

Working with Boeing, Exxon plans to manufacture as many as 40,000 masks an hour. According to an Exxon engineer, this new design and production method won't be vulnerable to the supply-chain hiccups that have led to widespread mask shortages. No Defense Production Act coercion necessary.

As for the cries to divest from fossil fuels, oil and gas generate energy but are also the feedstock for an inestimable number of essential products. Do liberals want to divest from using those to fight off the coronavirus?

Appeared in the April 24, 2020, print edition as '.'

OPINION // OUTLOOK

Fighting climate change should not come at expense of fighting viruses [Opinion]

By Poe Leggette
March 10, 2020

Meli Jimenez, sales manager, talks about the four shelves where face masks are usually stocked at Spring Branch Medical Supply, 8700 Long Point Rd., Friday, Feb. 28, 2020, in Houston.
Photo: Melissa Phillip, Staff photographer / Houston Chronicle

Some Democratic presidential candidates are vowing to end America's reliance on oil and natural gas. Think tanks call it "deep decarbonization." Activists call it "keeping it in the ground." What if keeping it in the ground means putting people in the ground — prematurely?

Overlooked in the climate debate is that oil and natural gas have provided the foundation on which global population has tripled since 1950. From 1950 on, a graph of greenhouse gas emissions tightly correlates with a graph of global population. It takes energy, medicine and food to sustain today's population of 7.7 billion people. Oil and gas contribute overwhelmingly to all three.

The links between oil, gas and global health care are too numerous to list, but too vital to ignore. Since the days of the horse and carriage, when Felix Hoffmann at Bayer linked the petrochemical acetyl group with tea from willow bark to make aspirin (1897), petrochemistry has been the basis for pharmaceuticals. The petrochemicals cumene, phenol and others are used to create penicillin and cancer-fighting drugs. Petrochemicals provide the polymers that make both time-release drugs and the capsules they come in. Drugs from petrochemicals aid infants in respiratory distress. In all, approximately 99 percent of pharmaceutical feedstocks are derived from petrochemicals.

Hospitals are also heavily dependent on petrochemicals for everything that keeps medical services antiseptic: plastic gloves, sutures coated with triclosan to reduce infection and antibacterial soaps and other cleansers. Prosthetics, too. And of course the energy to power hospitals, ambulances and helicopters.

Just a decade ago, the American Journal of Public Health feared running out of oil would impair the future of health care. Since then, hydraulic fracturing has ended that risk: There is plenty of oil and gas for the rest of the century. Oil and gas continue to put the "modern" in modern medicine. Oil and gas are the horse, medicine the carriage. How will renewable energy replace their benefits? It can't. Will we lightly give up these gains before we understand the alternatives?

Recently, House Energy and Commerce Committee Chairman Frank Pallone of New Jersey released a draft bill on climate change. Called the "CLEAN Future Act," Chairman Pallone's bill seeks "net-zero" emissions of greenhouse gases by 2050. The goal is to “decarbonize” the economy. The bill would not eliminate oil and gas, but as currently drafted could substantially limit the benefits they give our civilization.

Chairman Pallone’s bill is a serious effort. It merits substantial input from the oil and gas industry. So too does legislation being developed by Rep. Bruce Westerman of Arkansas, the “Trillion Tree Act.” This idea, recently championed at the World Economic Forum in Davos, Switzerland, would harness the power of photosynthesis to store atmospheric carbon in the Earth’s vast grasslands and forests.

The CLEAN Future Act, and the drastic plans for the Green New Deal, all rely on eliminating new emissions of greenhouse gases. Reducing emissions is part of a strategy for fighting climate change. But more focus must be given to removing those gases once they are in the atmosphere. Technology to remove carbon dioxide from the open air is already commercial. Long-term carbon storage projects are already in operation. And a trillion trees alone could remove all the carbon dioxide that the Intergovernmental Panel on Climate Change says we need to remove by 2,100. Humanity is inventive enough to turn down the temperature without turning off medical innovation.

While climate activists focus on rising sea levels, the Centers for Disease Control and Prevention focuses on rising viruses. There are sensible ways to fight both; all require continued use of oil and gas. When the choices are studied seriously, we will find that it is safer, healthier and cheaper to decarbonize the atmosphere than to decarbonize the economy.

Leggette is an attorney in Houston, Texas, with 40 years’ experience in energy issues.

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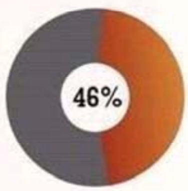
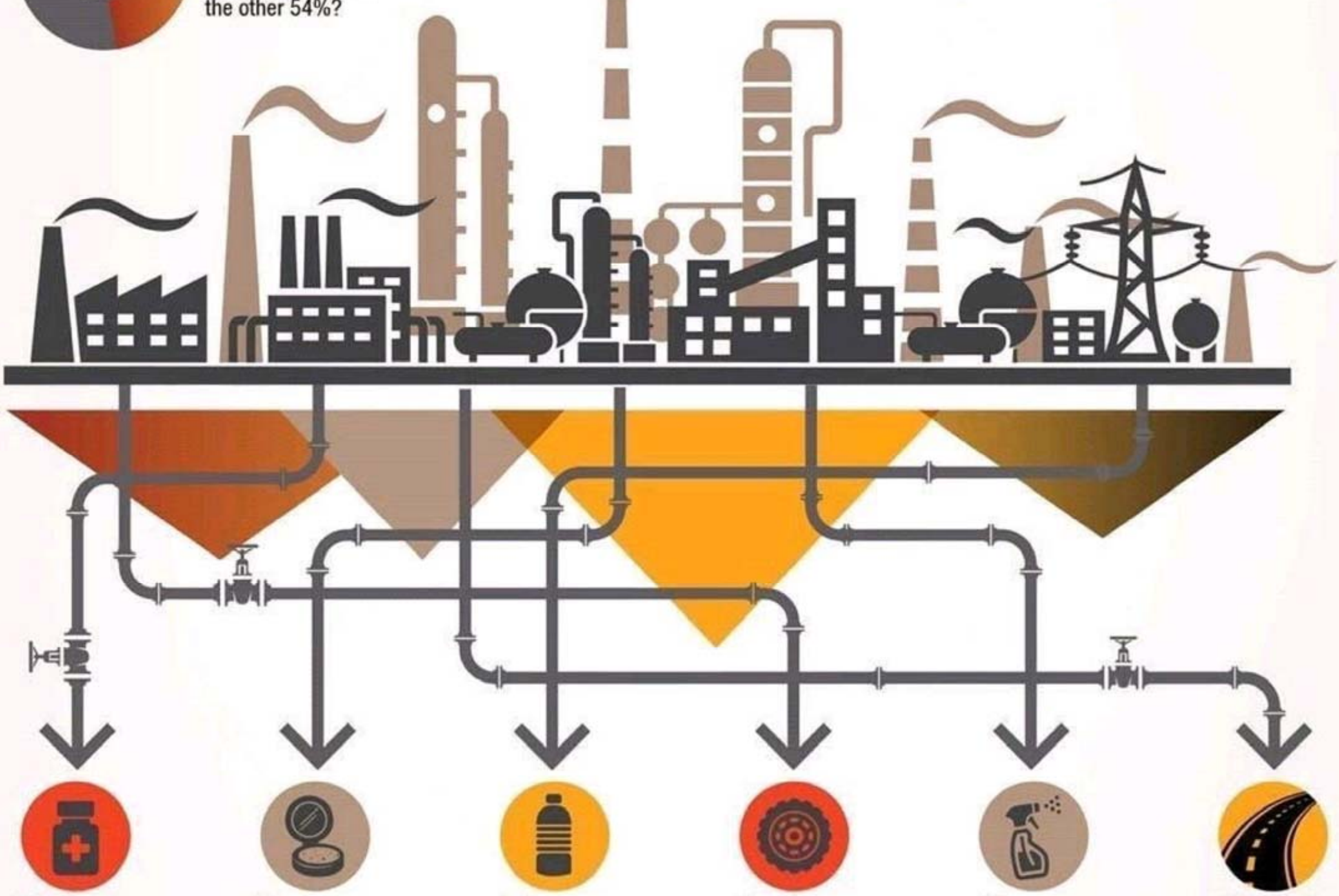
Life Without Oil

NOT AS SIMPLE AS YOU MAY THINK



46% of oil goes to making gasoline, but what makes up the other 54%?



Medicine
Most over the counter medications, homeopathic products and vitamins are derived from benzine, a product of petroleum.

Cosmetics
Makeup and shampoo that has oils, perfumes, waxes and color are all produced with the help of petrochemicals.

Plastics
Almost all plastics are made from petrochemicals, from your iPhone to that bottle of water. It is 4-5% of the total petroleum consumption.

Synthetic Rubber
Thousands of products rely on rubber such as shoes, tires, wet suits, breast implants, gloves.

Cleaning Products
All those ingredients you can't pronounce in the ingredients list, all of which are very poisonous.

Asphalt
There are over 11 million miles of paved road in the world. Asphalt aka bitumen is the glue that binds the minerals together.

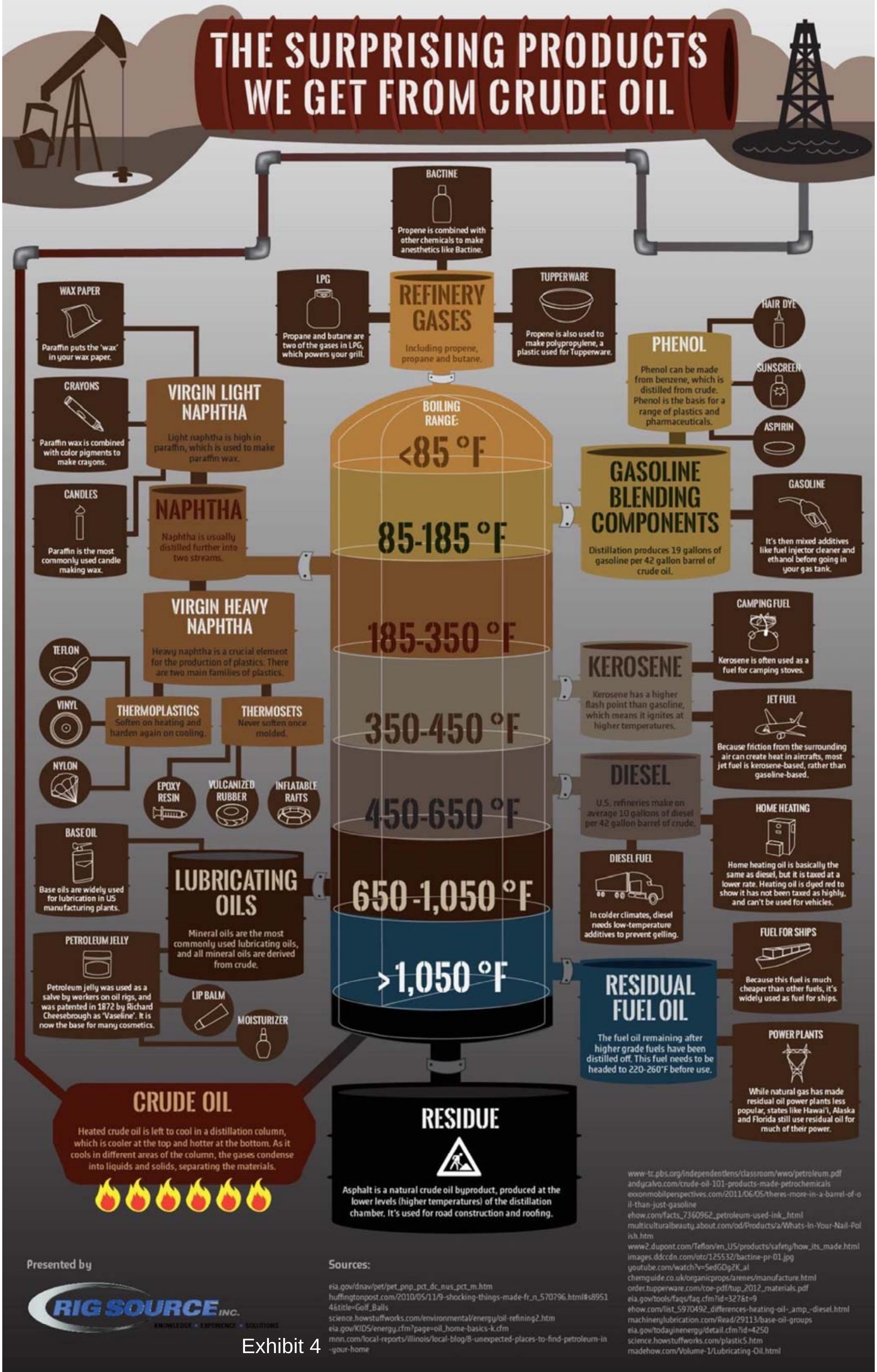
A few other products made with Oil

Insecticides, Ink, Floor Wax, Pens, Upholstery, Clothing, Boats, Sports Car Bodies, Nail Polish, Fishing Lures, Bags, Perfumes, Cassettes, Dishwasher Parts, Tool Boxes, Shoe Polish, Helmets, Caulking, Petroleum Jelly, Tape, Washers, Antiseptics, Curtains, Food Preservatives, Basketballs, Soap, Antihistamines, Purses, Dashboards, Cortisone, Deodorant, Footballs, Putty, Dyes, Panty Hose, Refrigerant, Percolators, Life Jackets, Rubbing Alcohol, Linings, Skis, TV Cabinets, Shag Rugs, Electrician's Tape, Tool Racks, Car Battery Cases, Epoxy, Paint, Mops, Slacks, Insect Repellent, Oil Filters, Umbrellas, Yarn, Fertilizers, Hair Coloring, Roofing, Toilet Seats, Fishing Rods, Lipstick, Denture Adhesive, Linoleum, Speakers, Plastic Wood, Electric Blankets, Glycerin, Tennis Rackets, Rubber Cement, Dice, Nylon Rope, Candles, Trash Bags, Paint, Water Pipes, Hand Lotion, Roller Skates, Surf Boards, Shampoo, Wheels, Paint Rollers, Shower Curtains, Guitar Strings, Luggage, Safety Glasses, Antifreeze, Awnings, Eyeglasses, Toothbrushes, Ice Chests, Combs, CD's & DVD's, Brushes, Detergents, Vaporizers, Balloons, Sun Glasses, Tents, Heart Valves, Crayons, Parachutes, Telephones, Enamel, Pillows, Dishes, Cameras, Anesthetics, Artificial Turf, Artificial Limbs, Bandages, Dentures, Model Cars, Folding Doors, Hair Curlers, Cold Cream, Movie Film, Soft Contact Lenses, Drinking Cups, Fan Belts, Car Enamel, Shaving Cream, Ammonia, Refrigerators, Golf Balls, Toothpaste, and of course Solvents, Diesel Fuel, Motor Oil, Bearing Grease etc. etc. etc.

Maybe it isn't as simple as we thought?

Exhibit 3

SOURCES: HUFFINGTONPOST.COM, OILANDGASINFO.CA, RANKEN-ENERGY.COM, EARTHSCIWEEK.ORG, LISTVERSE.COM, RANKEN-ENERGY.COM, WIKIPEDIA.ORG



THE SURPRISING PRODUCTS WE GET FROM CRUDE OIL
BACTINE
Propene is combined with other chemicals to make anesthetics like Bactine.
LPG
Propane and butane are two of the gases in LPG, which powers your grill.
REFINERY GASES
Including propene, propane and butane.
TUPPERWARE
Propene is also used to make polypropylene, a plastic used for Tupperware.
WAX PAPER
Paraffin puts the 'wax' in your wax paper.
CRAYONS
Paraffin wax is combined with color pigments to make crayons.
VIRGIN LIGHT NAPHTHA
Light naphtha is high in paraffin, which is used to make paraffin wax.
CANDLES
Paraffin is the most commonly used candle making wax.
NAPHTHA
Naphtha is usually distilled further into two streams.
VIRGIN HEAVY NAPHTHA
Heavy naphtha is a crucial element for the production of plastics. There are two main families of plastics.
TEFLON
VINYL
NYLON
THERMOPLASTICS
Soften on heating and harden again on cooling.
THERMOSETS
Never soften once molded.
EPOXY RESIN
VULCANIZED RUBBER
INFLATABLE RAFTS
BASE OIL
Base oils are widely used for lubrication in US manufacturing plants.
LUBRICATING OILS
Mineral oils are the most commonly used lubricating oils, and all mineral oils are derived from crude.
PETROLEUM JELLY
Petroleum jelly was used as a salve by workers on oil rigs, and was patented in 1872 by Richard Cheesebrough as 'Vaseline'. It is now the base for many cosmetics.
LIP BALM
MOISTURIZER
CRUDE OIL
Heated crude oil is left to cool in a distillation column, which is cooler at the top and hotter at the bottom. As it cools in different areas of the column, the gases condense into liquids and solids, separating the materials.
BOILING RANGE:
<85 °F
85-185 °F
185-350 °F
350-450 °F
450-650 °F
650-1,050 °F
>1,050 °F
RESIDUE
Asphalt is a natural crude oil byproduct, produced at the lower levels (higher temperatures) of the distillation chamber. It's used for road construction and roofing.
PHENOL
Phenol can be made from benzene, which is distilled from crude. Phenol is the basis for a range of plastics and pharmaceuticals.
HAIR DYE
SUNSCREEN
ASPIRIN
GASOLINE BLENDING COMPONENTS
Distillation produces 19 gallons of gasoline per 42 gallon barrel of crude oil.
GASOLINE
It's then mixed additives like fuel injector cleaner and ethanol before going in your gas tank.
KEROSENE
Kerosene has a higher flash point than gasoline, which means it ignites at higher temperatures.
CAMPING FUEL
Kerosene is often used as a fuel for camping stoves.
JET FUEL
Because friction from the surrounding air can create heat in aircrafts, most jet fuel is kerosene-based, rather than gasoline-based.
DIESEL
U.S. refineries make on average 10 gallons of diesel per 42 gallon barrel of crude.
DIESEL FUEL
In colder climates, diesel needs low-temperature additives to prevent gelling.
HOME HEATING
Home heating oil is basically the same as diesel, but it is taxed at a lower rate. Heating oil is dyed red to show it has not been taxed as highly, and can't be used for vehicles.
RESIDUAL FUEL OIL
The fuel oil remaining after higher grade fuels have been distilled off. This fuel needs to be headed to 220-260°F before use.
FUEL FOR SHIPS
Because this fuel is much cheaper than other fuels, it's widely used as fuel for ships.
POWER PLANTS
While natural gas has made residual oil power plants less popular, states like Hawai'i, Alaska and Florida still use residual oil for much of their power.
Presented by
RIG SOURCE INC.
Sources:
eia.gov/dnav/pet/pet_pnp_pct_dc_nus_pct_m.htm
huffingtonpost.com/2010/05/11/9-shocking-things-made-fr_n_570796.html#s89514&title=Golf_Balls
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eia.gov/KIDS/energy.cfm?page=oil_home-basics-k.cfm
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www-tc.pbs.org/independentlens/classroom/wwo/petroleum.pdf
andycalvo.com/crude-oil-101-products-made-petrochemicals
exxonmobilperspectives.com/2011/06/05/theres-more-in-a-barrel-of-oil-than-just-gasoline
ehow.com/facts_7360962_petroleum-used-ink_.html
multiculturalbeauty.about.com/od/Products/a/Whats-In-Your-Nail-Polish.htm
www2.dupont.com/Teflon/en_US/products/safety/how_its_made.html
images.ddccdn.com/otc/125532/bactine-pr-01.jpg
youtube.com/watch?v=SedGDg2K_al
chemguide.co.uk/organicprops/arenes/manufacture.html
order.tupperware.com/coe-pdf/tup_2012_materials.pdf
eia.gov/tools/faqs/faq.cfm?id=327&t=9
ehow.com/list_5970492_differences-heating-oil-_amp_-diesel.html
machinerylubrication.com/Read/29113/base-oil-groups
eia.gov/todayinenergy/detail.cfm?id=4250
science.howstuffworks.com/plastic5.htm
madehow.com/Volume-1/Lubricating-Oil.html

Exhibit 4

What can you make from one barrel of oil?

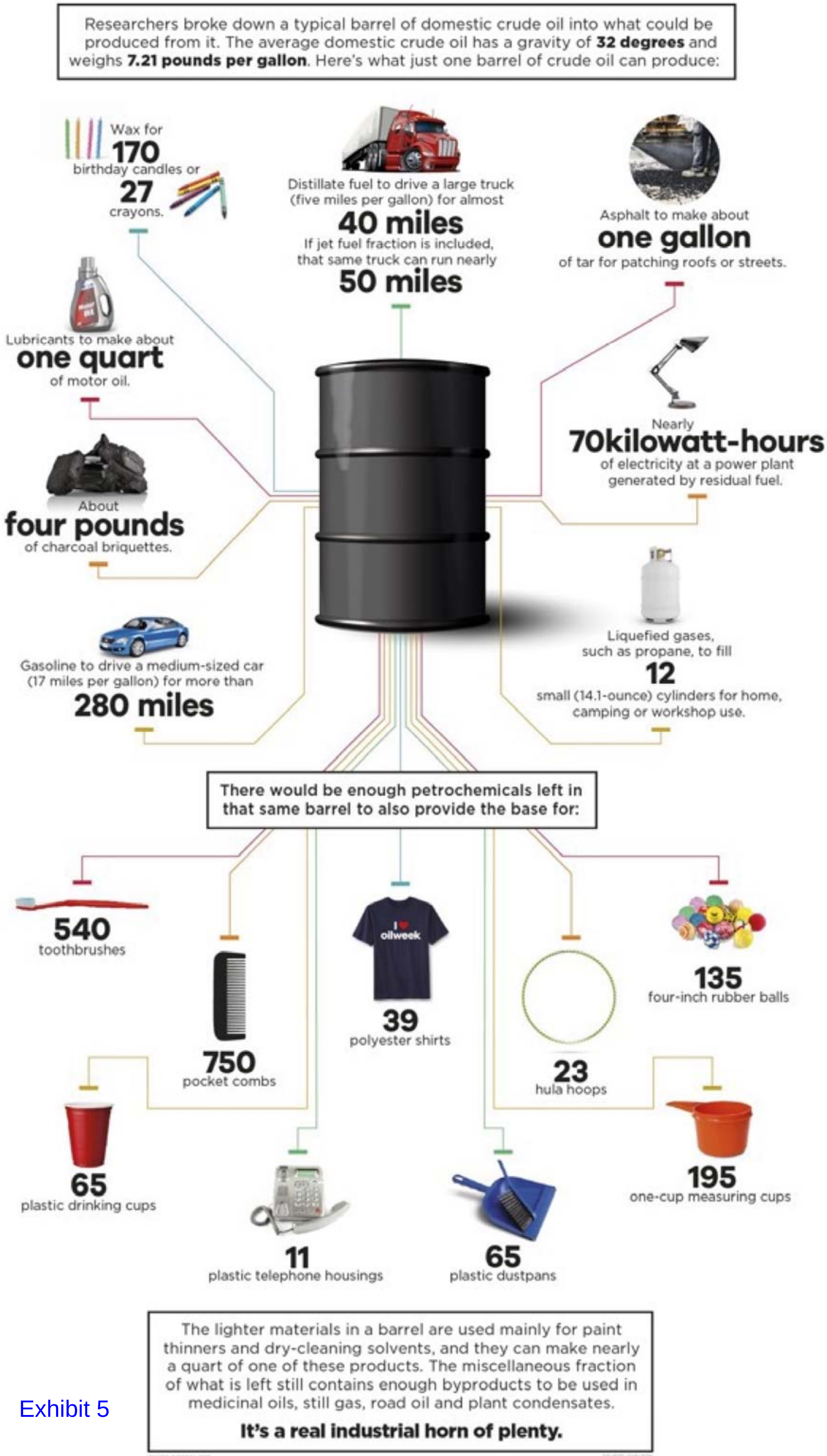

Exhibit 5

70TH ANNUAL OIL AND GAS LAW CONFERENCE

Regulatory and Legal Issues Relating to Federal Lands (Onshore and Offshore)

L. Poe Leggette[1]

ABSTRACT

The presentation to which this paper is an accompaniment review significant administrative and judicial decisions affecting oil and gas development on federal offshore and onshore lands. This paper, however, covers only one of the five topics to be discussed orally. It pays closer attention to the issue of the federal duty to place production in marketable condition without cost to the lessor. This is not a real "paper," but is really more like the "album notes" one would read when albums were played at 33 rpm and records were packaged in cardboard. Of course, much longer than album notes, and intrinsically less interesting.

SECTION ONE: INTRODUCTION, PENALTIES, AND JURISDICTION

The presentation will divide litigation thematically. To catch everyone's attention early, it will first discuss civil penalties cases and cases brought under the False Claims Act. It will turn to several of the more bread-and-butter issues in federal royalty law. To what extent is production not subject to the royalty obligation? How does one distinguish an arm's-length sale of production from one that is not? How does one distinguish the non-deductible costs of gathering from the deductible costs of transportation?

The presentation will also cover the nettlesome topic of those circumstances under which an administrative entity or court lacks jurisdiction to hear a royalty dispute. It will consider two recent decisions challenging ONRR regulations. It will, as time allows, cover other topics that Mr. Marchetti deems noteworthy. Finally, it will address the issue of marketable condition.

A. Civil Penalties under 30 U.S.C. § 1719

Two decisions of the Interior Board of Land Appeals ("IBLA") illustrate the scope of ONRR's authority to impose a penalty and the factors it is to consider in setting a penalty amount.

Statoil USA E&P, Inc. v. ONRR, 185 IBLA 302 (2015). By order issued in August 2010, ONRR directed the company to correct reporting of gas volumes, giving the company until January 10, 2011, to do so. Id. at 307. Statoil did not correct the reports and did not appeal the order. The record suggests multiple communications between ONRR and Statoil staff, id. n. 9, without results to ONRR's satisfaction. In February 2012, ONRR issued a notice of civil penalty.

The chief issue was whether ONRR could penalize Statoil simply for failing to correct after notice of a violation or for knowingly maintaining incorrect reports. IBLA assumed the evidence

[1] L. Poe. Leggette is the head of Baker & Hostetler LLP's national energy industry team. Formerly the managing partner of the Firm's Denver office, he now practices in its Houston office. This paper is his alone. The presentation, however, will be joint, with Jasper Mason of Gibson, Dunn & Crutcher LLP and David Carsey, Senior Counsel with Chevron North America Exploration and Production Company, a division of Chevron U.S.A. In..

supported a finding of Statoil's knowledge and focused on whether the company's failure to correct reports meant it "maintained" inaccurate information in ONRR's database within the meaning of 30 U.S.C. § 1719(d). IBLA held Statoil "maintained" inaccurate records by failure to correct them. Id. at 317-19.

Quinex Energy Corp., 192 IBLA 88 (2017). This case concerns the criteria ONRR is to consider in assessing penalties. Here ONRR ordered Quinex to correct reports for royalties. Quinex corrected them eventually, taking eight to twenty-two months to complete the corrections. An administrative law judge found that "'Quinex was knowingly gaming the electronic filing system and clearly had knowledge of the falsity and inaccuracy of its data.'" Id at 91. Quinex's underpayments totaled only $120,242, but ONRR imposed a penalty of $3,217,250. Affirming the penalty, IBLA ruled that ONRR could only consider those factors identified in the regulation in 30 C.F.R. § 1241.70. ONRR therefore could not consider the violator's ability to pay or the fact that the penalty amount was 26 times the amount of the underpayment. Id. 99-100.

B. Jurisdictional Matters

Jicarilla Apache Nation v. Dep't of the Interior, 892 F.Supp.2d 285 (D.D.C 2012). Although this case also raises an interesting issue about the Department's trust responsibility when interpreting its regulations, the main issue is whether a recipient of a civil penalty notice, who had not appealed an earlier order to pay, may challenge both the proposed penalty and the underlying order. IBLA held that, as long as the lessee requested a nearing on the notice of civil penalty, it could also challenge the order it had not previously appealed. The court upheld that interpretation as reasonable. In the course of so doing, it observed "the royalties program for federal and Indian oil and gas royalties is a complex and highly technical regulatory program which requires significant expertise and the exercise of judgment grounded in policy concerns[.]" Id. at 292. It does seem implausible that whether a lessee has waived the right to challenge an order is matter that a court would find complex or highly technical.

Statoil USA E&P, Inc., 183 IBLA 61 (2012), concerns the power of ONRR to issue a subpoena in a matter relevant to a case already on appeal to IBLA. Although there are significant limitations on what an agency may do with a decision once it is on appeal, subpoenas by regulation are not appealable. Id. at 68.,

XTO Energy, Inc., 193 IBLA 101 (2018), raises a recurring problem in the administration of the federal royalties program. A lessee appeals an order to pay. The Director adopts a rule of decision (referred to the "legal standard" in the decision) that may be incorrect, but remands the matter to the auditors to apply that legal standard. From the lessee's perspective, the remand is wasteful, focusing on facts to be applied to the wrong legal standard. IBLA held, however, that the lessee cannot appeal the decision as to the legal standard until the Director issues another decision after the remand. Id. at 108. Until then, the IBLA lacks jurisdiction.

Continental Resources, Inc. v. Jewell, 846 F.3d 1232 (D.C. Cir. 2017), also addressed an issue of court jurisdiction over appeals of royalty decisions. It reversed a ruling of the lower court that Continental had failed to seek judicial review of a decision of the Interioir Department within the 180 days allowed by 30 U.S.C. § 1724.

SECTION TWO: MARKETABLE CONDITION

In 2018, the most visible issue is one that has been raised by the Department of the Interior's (the "Department's") prolonged efforts to develop a reasonable interpretation of its marketable condition rule. The issue is called "unbundling." Unbundling refers to the task of taking a unified (or "bundled") fee--charged by a third party to gather, treat, and process natural gas—and splitting into those parts that are deductible as transportation or processing from those that are not.. The Department is now in its fourth decade of trying to unbundle third-party charges, issuing subpoenas to midstream companies with whom it has no privity of contract to extract sensitive internal cost information.

Although the marketable condition rule is stated identically for both oil and natural gas valuation, its application has been different. There has been no publicized effort (if any effort at all) to unbundle charges in connection with royalties on crude oil.

So, what makes federal royalty litigation high-stakes? A paraphrase of Paul's letter to the Corinthians sums it up: Risk, cost, and uncertainty, but the greatest of these is uncertainty. This section of the paper will begin with a description of the federal marketable condition rule. It will summarize some of the key turning points in the evolution of the Department's interpretation. It will also analyze in detail the Department's current project to compel lessees to unbundle those third-party charges. Finally, it will conclude with a few observations on the government's enforcement mechanisms that allow treble damages and penalties.

I. THE TEXT OF THE FEDERAL MARKETABLE CONDITION RULE

Under federal regulation, the marketable condition rule is in two parts. One part states the general obligation, the other defines the term. The basic idea is that although there are some costs a lessee can deduct from its gross proceeds from sale, costs to make the production "marketable" are not among them. But even at this most basic level, uncertainty emerges instantly from the terms used in the obligation.

First, for oil:

> You must place oil in marketable condition and market the oil for the mutual benefit of the lessee and the lessor at no cost to the federal government. If you use gross proceeds under an arm's-length contract in determining value, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that the seller normally would be responsible to perform to place the oil in marketable condition or to market the oil.[2]

Next, for natural gas[3]:

> The lessee must place gas in marketable condition and market the gas for the mutual

[2] 30 C.F.R. § 1206.106 (2018).

[3] The marketable condition rule is functionally identical for unprocessed gas, on the one hand, and residue gas and gas

> benefit of the lessee and the lessor at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition or to market the gas.[4]

Someone new to federal royalty law, but who is mindful of the usual rule that contracts, regulations, and statutes are to read to give meaning to every word,[5] might immediately encounter difficulty. The opening sentence of the rule says the lessee must market "for the mutual benefit of the lessee and the lessor," but that only one of them shoulders the burden for the costs of marketable condition. It is not that this phrasing is linguistically impossible. After all, you can take a guest to dinner at your sole expense but for the benefit of both enjoying a meal. But there is tension in the text by saying the benefit is mutual but the cost is not.

Of greater concern, however, is whether the phrase "for the mutual benefit" contributes anything to the obligation. Is it mere regulatory fluff (despite the canon against presuming words have no meaning[6]), or is the duty to market separate from the duty to put production in marketable condition? And if it is an independent duty, could one bear all the costs of making production marketable and still fail to market for the mutual benefit of the lessee and the lessor? And is the phrase "at no cost to the lessor" applicable both to marketing and placing production in marketable condition? To pose the question more directly, does the obligation simply mean: "Do not deduct marketing costs or costs to make production marketable from the value of your production?" If so,

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plant products created by processing, on the other. "Residue gas" refers to "that hydrocarbon gas consisting principally of methane resulting from processing gas." 30 C.F.R. § 1206.151 (2018). "Gas plant products" refer to "separate marketable elements, compounds, or mixtures, whether in liquid, gaseous, or solid form, resulting from processing gas, excluding residue gas." 30 C.F.R. § 1206.151 (2018). And "processing" refers to "any process designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes which normally take place on or near the lease, such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, and compression, are not considered processing. The changing of pressures and/or temperatures in a reservoir is not considered processing." 30 C.F.R. § 1206.151 (2018).

[4] 30 C.F.R. § 1206.152(i) (2018) (unprocessed gas); *see* 30 C.F.R. § 1206.153(i) (2018) (residue gas and gas plant products)

[5] "If possible, every word and every provision is to be given effect (*verba cum effectu sunt accipienda*). None should be ignored. None should needlessly be given an interpretation that causes it to duplicate another provision or to have no consequence." Antonin Scalia, Bryan A. Garner, "Reading Law" at 174 (citing to Ulpian, *Digest* 2.7.5.2 ("Words are to be taken as having an effect.").) *See also*, *e.g.*, *United States v. Butler*, 297 U.S. 1, 65 (1936) ("These words cannot be meaningless, else they would not have been used."); *Sturges v. Crowninshield*, 17 U.S. (4 Wheat.) 122, 202 (1819) (per Marshall, C.J.) ("It would be dangerous in the extreme, to infer from extrinsic circumstances, that a case for which the words of an instrument expressly provide, shall be exempted from its operation."); Ernst Freund, *Interpretation of Statutes*, 65 U. Pa. L. Rev. 207, 218 (1917) ("[T]he legislator is presumed to, as in fact he does, choose his words deliberately intending that every word shall have a binding effect."); *Lowe v. SEC*, 472 U.S. 181, 207 n.53 (1985) (per Stevens, J.) ("[W]e must give effect to every word that Congress used in the statute."); *Reiter v. Sonotone Corp.*, 442 U.S. 330, 339 (1979) (per Burger, C.J.) ("In construing a statute we are obliged to give effect, if possible, to ever word Congress used."); *Burdon Cent. Sugar Ref. Co. v. Payne*, 167 U.S. 127, 142 (1897) (per Fuller, C.J.) ("[T]he contract must be so construed as to give meaning to all its provisions, and . . . that interpretation would be incorrect which would obliterate one portion of the contract in order to enforce another part . . .").

[6] *See*, *supra*, note 5.

the rule is eighty words, but its meaning is only seventeen.

Then, there is also the problem posed by the second sentence. One senses it is designed to address the following example. Lessee A sells natural gas for $2.15 per million British thermal units (MMBtu). Buyer B then ships the gas to a nearby plant to remove hydrogen sulfide from the gas. The Department wants to add to the $2.15 the "cost" of removing the hydrogen sulfide. Does the Department first have to show it is "ordinarily" the responsibility of a lessee to remove hydrogen sulfide? If yes, how would it make that showing? If no, is it a permissible reading of the word "ordinarily" for the Department to assert it is "always" the responsibility of the lessee to remove the hydrogen sulfide?

Perhaps the definition of "marketable condition" could resolve these difficulties. First, for oil:

> *Marketable condition* means oil sufficiently free from impurities and otherwise in a condition a purchaser will accept under a sales contract typical for the field or area.[7]

Next, for natural gas (showing the government's former preference for the passive voice):

> *Marketable condition* means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area.[8]

Two observations are in order. First, the definition of "marketable condition" does not clarify whether the phrase "mutual benefit" adds anything other than distraction to the text of the rule. Second, the definition does suggest the word "ordinarily" means something less than "always." The definition says the government will live with what the parties agree to on the quality of the oil or gas, as long as the sales contract is "typical for the field or area."

Returning to our example of the hydrogen sulfide, if buyers "typically" buy gas with hydrogen sulfide unremoved, then it would seem it is not "ordinarily" the responsibility of the lessee to remove the hydrogen sulfide. But how successful can analysis of the text of the marketable condition rule be in predicting its application? Indeed, could one have guessed from the first federal rules on royalty valuation that a lessee would ultimately have to bear alone the cost of placing production in marketable condition?

II. THE MAJOR LANDMARKS IN THE DEVELOPMENT OF THE FEDERAL MARKETABLE CONDITION RULE

A. Sharing in the Costs of Altering Production's Chemical Characteristics

The first regulations addressing federal royalty obligations were issued in 1920.[9] They

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[7] 30 C.F.R. § 1206.101 (2018) (emphasis in original).
[8] 30 C.F.R. § 1206.151 (2018) (emphasis in original).
[9] "Operating Regulations to Govern the Production of Oil and Gas—Act of February 25, 1920, 47 L.D. 552 (1920).

contained a limited duty respecting marketable condition.

> The lessee shall recover all oil in B.S. [basic sediment] or emulsion and put it into marketable condition if it can be recovered at a profit. If the formation of B.S. or emulsion is not preventable and the oil can not be recovered by the usual modes of treatment, the cost of putting the oil into marketable condition by any unusual mode of treatment shall first be deducted from the amount received for it before royalty is computed.[10]

The mode of treatment, then as now, was to run the raw production through a separator to separate the sediment, water, oil, and gas from one another. Under the regulation, if the mode of separation were "unusual," its cost was deductible from royalty, despite the obligation to put the oil into marketable condition. And nothing in the regulations imposed a duty to place any product other than oil into marketable condition.

The regulations were amended in 1926.[11] The requirement for placing oil in marketable condition was removed; and no other mention of "marketable condition" was to be found. But the regulations, in the context of natural gas processing, provided a key insight into the Department's view on what federal leases meant when they claimed royalty was due on "the value of production."

At the time, natural gas processing was largely limited to the extraction of natural gasoline for use as a component of motor vehicle fuel. The gasoline was understood to be comprised of the heaviest of the liquefiable hydrocarbon molecules, starting with pentane. The Department recognized that processing added significant value to the gas:

> Natural-gas gasoline (also known as casing-head gasoline) is a manufactured product. The value of this product is contingent upon the value of the raw material and the cost of its manufacture. The Government does not wish to collect royalty on that part of the value which is derived from the cost of manufacturing, inasmuch as the Government's equity is confined to the value of the raw material involved.[12]

The Department "assumed" only one-third of the value of the gasoline came from the "raw" gas, with two-thirds attributed to the value added by "the cost of manufacture."[13] The regulations also allowed the Department to, upon application, reduce the one-third assumption to one-fifth

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[10] Id. at 554 (§ 12).
[11] "Operating Regulations to Govern the Production of Oil and Gas—Acts of February 25, 1920, June 4, 1920, and March 4, 1923," 52 L.D. 1 (1926). Before 1935, the various United States Executive branch agencies (as well as the Office of the President) would each publish their own regulations in separate publications – *e.g.*, via bulletins, certificates, codes, digests, gazettes, notices, orders, pamphlets, rulings, *etc.* "A Research Guide to the Federal Register and the Code of Federal Regulations," Law Librarians' Society of Washington, D.C., *available at* http://www.llsdc.org/fr-cfr-research-guide (retrieved May 15, 2018); *see generally* Griswold, E.N. Government in Ignorance of the Law; a Plea for Better Publication of Executive Legislation, 48 Harv. L. Rev. 198-215 (1934).
[12] "Operating Regulations to Govern the Production of Oil and Gas—Acts of February 25, 1920, June 4, 1920, and March 4, 1923," 52 L.D. 1, 11 (1926).
[13] "Operating Regulations to Govern the Production of Oil and Gas—Acts of February 25, 1920, June 4, 1920, and March 4, 1923," 52 L.D. 1, 11 (1926).

when needed to address "[a]dverse climatic and economic conditions in certain portions of the Rocky Mountain district [which] result in unusually high operating and marketing costs."[14]

Granted, the regulation addressed the manufacture of natural gasoline only, and not oil and gas generally. It is hard to see, however, why the Department's approach should differ. The regulation saw a distinction between the raw product of the well and its enhanced value after additional costs were incurred to change its physical characteristics. The regulation required the Department to share (generously) in those costs and did so by taking into account the lessee's "operating and marketing costs."

One might conclude the distinction is based on the fact that the manufacturing costs resulted in the creation of a separately marketable product—the gasoline—and that is why the Department might share in those costs but not the costs of removing other components from a stream of natural gas that might not be independently marketable. But one might equally conclude the opposite.

B. The 1938 Code of Federal Regulations

In the very first edition of the Code of Federal Regulations, published in 1938,[15] certain of the Department's rules (relevant for our purposes) were codified at 30 C.F.R. §§ 221.35, 221.47, and 221.51. However, none of them codified any language akin to the "marketable condition rule" we have today.

The first of those regulations codified the requirement for royalty to be paid on natural gas and codified the requirement that "gas" included all kinds of gas, except gas used for production purposes on the leasehold and gas *unavoidably* lost:

> Measurement of gas. *Gas of all kinds (except gas used for purposes of production on the leasehold or unavoidably lost) is subject to royalty*, and all gas shall be measured by meter (preferably of the orifice-meter type) unless otherwise agreed

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[14] "Operating Regulations to Govern the Production of Oil and Gas—Acts of February 25, 1920, June 4, 1920, and March 4, 1923," 52 L.D. 1, 12 (1926).

[15] In 1935, Congress passed the Federal Register Act, empowering the Archivist of the United States to create a division within the National Archives responsible for publishing a daily *Federal Register*, along with the Government Publishing Office. "A Research Guide to the Federal Register and the Code of Federal Regulations," Law Librarians' Society of Washington, D.C., *available at* http://www.llsdc.org/fr-cfr-research-guide (retrieved May 15, 2018) (citing Act of July 26, 1935, ch. 417, 49 Stat. 500-503 (current version at 44 U.S.C. §§ 1501-1511)). The Federal Register Act originally provided for a complete compilation within six months of all existing regulations. "A Research Guide to the Federal Register and the Code of Federal Regulations," Law Librarians' Society of Washington, D.C., *available at* http://www.llsdc.org/fr-cfr-research-guide (retrieved May 15, 2018). But in 1937, the Act was amended to provide for a codification of all regulations every five years. "A Research Guide to the Federal Register and the Code of Federal Regulations," Law Librarians' Society of Washington, D.C., *available at* http://www.llsdc.org/fr-cfr-research-guide (retrieved May 15, 2018) (citing Act of June 19, 1937, ch. 369, 50 Stat. 304-305). The first edition of the new *Code of Federal Regulations* was thereafter published in 1938, and it included all finalized regulations that had been published in the *Federal Register* from March 14, 1936, to June 1, 1938, as well as agency regulations still in effect that had been deposited with the Archivist and which may have been published before March 14, 1936. "A Research Guide to the Federal Register and the Code of Federal Regulations," Law Librarians' Society of Washington, D.C., *available at* http://www.llsdc.org/fr-cfr-research-guide (retrieved May 15, 2018).

> to by the supervisor.
>
> (a) Term "gas" defined. The term "gas," as used in the regulations in this part, shall be interpreted to mean any gas released by or produced from a well.
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> (b) Meters; standards of computation. All meters must be approved by the supervisor or [her] representative and installed at the expense of the lessee at such places as may be agreed to by the supervisor or [her] representative. *For computing the volume of all gas produced, sold, or subject to royalty, the standard of pressure shall be 10 ounces above an atmospheric pressure of 14.4 pounds to the square inch, regardless of the atmospheric pressure at the point of measurement, and the standard of temperature shall be 60° F.* All measurements of gas shall be adjusted by computation to these standards, regardless of the pressure and temperature at which the gas was actually measured, unless otherwise authorized in writing by the supervisor. In fields at high altitudes the absolute pressure of the flowing gas may be taken as the gage pressure plus the actual average atmospheric pressure existing at the points of measurement, in order to reduce equitably the quantity of gas to the Government standard of 10 ounces above an atmospheric pressure of 14.4 pounds to the square inch.[16]

Any gas avoidably lost or wasted remained subject to royalty. The regulation also codified the ability for the Secretary of the Interior (the "Secretary") to establish metering locations, pressure requirements, and temperature requirements.

The second regulation codified the first glimpse of the government's assessment of ever-culminating fines and penalties against lessees for improper royalty calculations:

> Payment of fines shall not relieve operator from compliance with operating regulations; effect of waiver. Payment of any of the fines set forth above shall not relieve the operator from compliance with the provisions of the operating regulations in this part. *A waiver of any particular cause for fines shall not be construed as precluding the imposition of a fine for any other cause or for the same cause occurring at any other time.*[17]

And the third codified the requirement that lessees monthly operations reports:

> Lessee's monthly report of operations (Form 9-329). *A separate report of operations for each lease must be made for each calendar month, beginning with the month in which drilling operations are initiated*, and must be filed in duplicate with the supervisor or [her] local representative on or before the sixth day of the succeeding month, unless an extension of time for the filing of such report is granted by the supervisor or [her] representative. The report on this form constitutes a general summary of the status of operations on the leased lands and, whatever such status may be, the report must be submitted each month until the lease is

[16] 30 C.F.R. § 221.35 (1938) (emphasis added).
[17] 30 C.F.R. § 221.47 (1938) (bolding of title removed, emphasis added).

> terminated or until omission of the report is authorized by the supervisor or [her] representative.[18]

Again, the limited duty from 1920 to place oil in marketable condition was not present in the regulations, and no other reference to the duty appeared.

C. 1957: The General Marketable Condition Rule Is Born by Interpretation

Thirty years would pass before the general marketable condition rule would emerge from the Louisiana bayou. The issue arose from operations in the Duck Lake Field in 1955, a field at the time having no more than 100 wells producing from multiple geologic horizons.[19]

The Texas Company owned two oil wells under federal lease. Once oil came to the surface, gas held in suspension in the oil came out of the liquid at the separator near the casingheads of the wells. This "casinghead gas" or "associated gas" had to be disposed of. The Humble Oil and Refining Company owned three gathering systems in the field. One operated at 1100 pounds per square inch ("psi") and needed no compressors. Another operated at 400 psi with one stage of compression. A third operated at 225 psi with two stages of compression. The Texas Company's two wells were on one of the lower-pressure systems.[20] Humble's systems connected to a pipeline owned by United Gas Pipeline Company, which purchased gas from the field.

Humble charged The Texas Company a fee for use of the gathering system. The Texas Company deducted the fee from the proceeds it received from the United Gas Pipeline Company. The lessee acknowledged it had an implied duty to market the production, but the duty ended at the lease. Its movement of the gas to the sales point made the fee deductible.

The Director of the U.S. Geological Survey, then responsible for federal royalties (along with other lease operations responsibilities), asserted there was "an obligation on the part of the lessee to put the gas into marketable condition."[21] That obligation was not satisfied until the gas had been moved to the inlet of United's pipeline and at a pressure sufficient to enter United's line.[22]

The Texas Company appealed to the Secretary of the Interior. The Texas Company's argument touched on the core themes behind the application of the marketable condition rule to natural gas:

> [The lessee-appellant] admits that the gas *when it comes from the wells* is in an unmarketable condition but contends that *when the gas is separated* from the oil, which it admits is part of the lease operation, the gas is in a marketable condition

[18] 30 C.F.R. § 221.51 (1938) (bolding of title removed, emphasis added).
[19] E.R. Turner, "The Duck Lake Field St. Martin Parish, Louisiana" (abstract of Gulf Coast Association of Geological Societies Transactions, vol. 3, page 150 (1953), *available at* http://archives.datapages.com/data/gcags/data/003/003001/0150.htm.

[20] *The Texas Co.*, 64 I.D. 76, 77 (1957).
[21] *The Texas Co.*, 64 I.D. 76, 78 (1957).
[22] *The Texas Co.*, 64 I.D. 76, 78 (1957).

> and that it needs *no further treatment* to be marketed. However, the appellant also states that the gas cannot be marketed until the pressure of the gas has been stepped up so that it can enter the market. It argues that the compression necessary to accomplish this *cannot be called a process to change the condition* of the gas to put it in a marketable condition because, it says, it is already in that condition when it leaves the separator. Appellant states that the facilities for the use of which the deductions were made are marketing facilities and, being such, the charge for the use of such facilities should have been allowed.[23]

Restated, The Texas Company might have said, "Sure, what comes up out of the well is a mix of oil, gas, and water; that mix cannot be marketed. But once the oil, gas, and water are separated from each other, the oil can be sold and the gas can be sold. We have to get it to the buyer, however. The oil goes into trucks or into a pipeline with a pump; the gas goes through Humble's gathering line and compressor. We haven't treated the gas to change its chemical composition. We deduct the truck or pipeline cost for the oil, so we should also deduct the cost for the gas."

The Texas Company apparently did say the gas is marketable when it leaves the separator but cannot be marketed until it reaches United's pipeline pressure. The Department seized on that pair of statements as inconsistent: "The appellant seems to be arguing, first, that the gas is in a condition to market when it comes from the separator and, second, that it is not in such a condition until after it has been raised to the pressure which will permit it to enter the buyer's line."[24] But, in the final analysis, what made the gas unmarketable in the Department's view is that United's purchase contract said, in effect, "We'll pay you so many cents for each thousand cubic feet of gas, but you have to pay the cost of getting it into our pipeline."[25]

So, the Department concluded, it was the lessee's legal obligation to bear the gathering and compression costs. But what was the source of that duty? The Department found it among series of peripheral regulations. First, the lessee had a duty not to waste the gas,[26] so it had to reinject it, use it, or market it. Second, the lessee had a duty to pay royalty on the gross proceeds from its sale.[27] Third, the lessee could not deduct the cost of boosting [*i.e.*, recompressing] gas after extracting natural gas liquids.[28]

Although conceding no boosting costs were at issue, the Secretary nevertheless stressed "appellant has advance no sound reason why it should be relieved of this cost of marketing its oil well gas" when a lessee who processes gas cannot.[29] The Department did not consider whether the two-thirds allowance created by the 1920 and 1926 rules was intended to cover boosting and

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23 *The Texas Co.*, 64 I.D. 76, 78 (1957) (emphasis added).
24 *The Texas Co.*, 64 I.D. 76, 79 (1957).
25 *See The Texas Co.*, 64 I.D. 76, 79 (1957) (the lessee "agreed to deliver the gas at a given pressure presumably in order to sell the gas. It cannot reasonably expect the lessor to assume the cost of meeting the lessee's obligation in this respect.").
26 *See*, *e.g.*, 30 C.F.R. § 221.35 (1938).
27 *See* 30 C.F.R. § 221.35 (1938).
28 *See*, *e.g.*, 30 C.F.R. § 221.35 (1938).
29 *The Texas Co.*, 64 I.D. 76, 79 (1957).

marketing, and that the subsequent rule simply meant to stop a lessee from double-dipping.

By this point in the analysis, the Department had determined three points. First, the lessee has an express duty to avoid waste by marketing the gas (unless it reinjects or uses it). Second, it owes royalties on its gross proceeds of sale. Third, the lessee must meet the location and pressure conditions in its natural gas sales contract without deduction from federal royalties.

At least two difficulties with the Department's three points come to mind. One, the duty to avoid waste applies to oil as well as gas. Why treat oil pumps differently from gas compressors? Two, if the lessee's sales contract requires it to move the gas to a market off the lease, then it would appear the lessee must also bear that cost alone. But the Department made sure to address the second of these difficulties.

> The situation presented here is not comparable to the situations dealt with in the textbooks and cases cited by the appellant wherein the cost of transportation was said to be allowable. In those cases there was *no market in the field* for the product and the lessee had to transport the product elsewhere in order to market it. Here a market for oil well gas exists in the Duck Lake Field and the cost of gathering the gas from the wells and transporting it to the point of sale in the field is deemed to be one of the *ordinary incidents of lease operations*.[30]

The Department cited no authority in support of this conclusion. It certainly was not the view of The Texas Company that bearing those costs was an ordinary incident of lease operations.

In sum, the duty to compress arises from the express (the Department emphasized) duty to avoid waste, which included a duty "to market" as one option the lessee holds. The express duty to market is not expressly limited to marketing "in the field." On what basis, then, does the Department distinguish marketing "in the field" from marketing "elsewhere?" The student of royalty law is left with plenty to ponder. And it is still just 1957.

D. The Case of The California Company

Only four years after *The Texas Company* was issued, the seminal court ruling on the federal duty to place production was handed down in *California Co. v. Udall* ("*Calco*").[31] Calco concerned production from the Romere Pass Field in southern Louisiana which, like the Duck Lake Field, produced oil and gas from multiple geological formations.

> The gas produced from this field is from a number of separate and independent horizons and is not all of the same nature of quality. Some horizons produce dry gas alone, some oil, and some gas associated with oil and gas distillate. The gas

[30] *The Texas Co.*, 64 I.D. 76, 79-80 (1957) (emphasis added).
[31] California Co. v. Udall, 296 F.2d 384 (D.C. Cir. 1961). The district court opinion in this case was decided and published during the tenure of Secretary Stewart Udall's predecessor, Fred A. Seaton, as so was styled California Co. v. Seaton, 187 F.Supp. 445 (D.D.C. 1960).

> as it comes from the wells therefore varies in water content, pressure and liquid hydrocarbons.[32]

Seventy percent of the gas produced was already at a pressure sufficient to enter the pipeline of the buyer, the Southern Natural Gas Company. Some of the gas contained more water vapor than the purchase contract allowed, and some had too much liquefiable hydrocarbons to meet contract specifications.

The California Company wished to deduct from the sales price of twelve cents per thousand cubic feet all of its costs between the separators and the inlet to the pipeline. The company calculated that amount to be 5.05 cents per thousand cubic feet. As the court noted, the "major part of this cost (4.5 cents) was attributable to compression[.]"[33] The Secretary, in contrast, disallowed all these costs, failing even to note that 70% of the gas was produced at a pressure that required no further compression to enter the pipeline, and that most of the costs in dispute were for compression.

As the court saw the case, the issue was whether the Secretary had reasonably construed the word "production" as it appears in the statutory phrase "value of production." (This is in contrast to the focus of the Secretary in *The Texas Company*, where the issue was what the duty to "market" encompassed.)[34] What followed this statement of the issue is perhaps the most quoted passage on marketable condition in any jurisdiction.

> Does it ["production"] mean the raw product as it comes from the well, no matter what its condition? Or does it mean that product readied for the market in and to which it is being sold?
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> * * *
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> The premise for the Secretary's decision . . . was that, since the lessee was obliged to market the product, he was obligated to put it in marketable condition; and that the 'production' was the product in marketable condition. Theoretically, any gas—any 'production'—is 'marketable.' We can assume that, if the price were low enough to justify capital expenditures for conditioning equipment, someone would undertake to buy low pressure gas having a high water and hydrocarbon content. A lessee who sold unconditioned gas at such a price would, in a rhetorical sense, be fulfilling his obligation to 'market' the gas, and by thus saving on overhead he might find such business profitable. There is a clear difference between 'marketing' and merely selling. For the former there must be a market, an established demand for an identified product. We suppose almost anything can be sold, if the price is no consideration. In the record before us there is no evidence of a market for the gas in the condition it comes from the wells. The

[32] Id. at 386.
[33] Id. n. 2.
[34] In this respect, the Interior Department is on both sides of the debate in private lease law over whether disallowing post-production costs is achieved through the duty to market or through judicial interpretation of the "production" on which royalties are due. See texts accompanying notes __ through __, supra.

> only market, as far as this record shows, was for this gas at certain pressure and certain minimum [sic, should be 'maximum'] water and hydrocarbon content.[35]

The court also noted that "[n]either are manufacturing costs involved here. The product was not transformed by a manufacturing processs."[36]

The court concluded by noting the "limited function" it played in reviewing the Secretary's interpretation of a statute he is tasked to administer. "We are of the opinion that the Secretary has authority to define for administrative purposed the 'production' to be valued, and we are unable to find that he has abused his discretion in this case."[37]

The role of the courts in reviewing the Secretary's decisions on federal royalty matters is, of course, in stark contrast to that of courts addressing private royalty disputes. Courts give deferential review to the Secretary's decisions, even though the Secretary is interpreting a lease agreement that bears his signature as a party. Interpretation of privates leases are left to the courts. Certain rules of private contract interpretation, such as construing ambiguous language against the party who drafted it, can produce outcomes similar to a deferential review of the Secretary's interpretation, with one ironic difference: it is the Secretary who drafts the federal oil and gas lease, yet he is free to resolve his own ambiguities in favor of the federal lessor.

Perhaps of equal importance is the one significant caveat the court placed on the scope of its holding. The court emphasized, in the passage quoted above, that "marketing" required "a market, an established demand for an identified product." It would seem to follow from that statement that if the market were at some distance from the wells, it would be the duty of the lessee to get marketable production to that market at no cost to the federal lessor. (Recall, after all, that this is the position of the Supreme Court of Colorado.[38] But the court said its rationale should not be so understood.

> Let us here insert a cautionary parenthesis. No transportation costs are involved in this case. The Secretary is not here claiming that costs incurred in moving gas from the field *in the neighborhood* of the wells to a distant selling point are includable in the royalty base. This gas was conditioned by the seller and delivered to the purchaser in the field within a short distance of the wells. There were no transportation costs.[39]

One should not fault the court for failing to reveal the test that would distinguish "the neighborhood of the wells" from a "distant selling point;" but faultlessly or not, the court offered no test. Forty years later, however, the Department would develop new approaches to the marketable condition rule rendering this distinction (between "the neighborhood" and "distant") and this conclusion ("no transportation costs") obsolete.[40] We will not detain the reader here with

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[35] Id. at 387-88.
[36] Id. at 387.
[37] Id. at 388.
[38] See text accompanying notes __ through __ supra.
[39] Id. at 387 (emphasis added).
[40] See text accompanying notes __ through __ infra.

a comparison. It suffices to note that the movement of gas prior to the sales point in the Romere Pass Field would now likely be treated as "transportation" and that the cost of re-compression of the 70% of the gas that came out of the wells at pipeline pressure would be regarded as a deductible transportation cost.

E. 1963: When Transportation Clearly Stops Being an Issue for Marketable Condition

In the late 1950s, very early in the administration of the Outer Continental Shelf Lands Act of 1953, the U.S. Geological Survey took exception to royalty payments tendered by six lessees for oil produced from OCS leases. The lessees contended that in determining what the "value of production" was under their leases, the value for royalty should be the "value of production at the wellhead or on the lease premises."[41] Accordingly, they urged, the value "should therefore be determined by deducting the cost of moving the crude oil from the lease premises to the onshore point of sale from the selling price at that point."[42] The Secretary of the Interior took jurisdiction over the appeals "because of their importance to the interests of the United States and for the reason that they involve novel questions of fact and law[.]" The appeals were decided under the name *Shell Oil Company*.

The Secretary framed the issue under his authority under the lease and regulations to determine royalty value after considering various specific factors as well as "other relevant matters." The topic of barging costs had been under consideration by the Geological Survey. Relying on its work, the Secretary found that there were "numerous unusual and complex factors attendant to barging[, including] "the unusually high costs involved in the purchase and maintenance of sea-going barges and tugs…."[43] With little additional legal analysis, the Secretary reversed the decisions of the Geological Survey, directing the agency "to determine a reasonable barging allowance and to consider the allowance so determined as one of the 'other relevant matters' referred to in the regulations[.]"[44]

One can be forgiven for thinking that *Shell Oil Company* limited the deductibility of transportation from OCS leases to cases where costs of transportation were "unusually high," but not subsequent decision found the decision limited in that way. *Shell Oil Company* appears to be the pivotal point in which the Department determined that neither the marketable condition principle nor the Department's discretion to determine royalty value compelled lessees to bear alone the cost of transporting production from the lease to the market.

Also decided in 1963 was *Placid Oil Company*.[45] Although this case has been cited by the Office of Natural Resource Revenues as a key precedent on marketable condition, and is

[41] Shell Oil Co., 70 I.D. 393 (1963).
[42] Id.
[43] Id. at 395.
[44] Id. at 396. The Secretary did note that in a case involving leases onshore under the Mineral Leasing Act had allowed for the deduction of transportation costs with computing the "value of production." Id. at 395 n. 6 (citing United States v. General Petroleum Corp., 73 F. Supp. 225, 263 (S.D. Cal. 1946), aff'd sub nom. Continental Oil Co. v. United States, 184 F.2d 802 (9th Cir. 1950)). But the Secretary made clear he did not feel bound by that decision.
[45] 70 I.D. 438 (1963).

mentioned here for that reason, it is actually on the opposite end of the spectrum of importance. The issues there were twofold. One was whether the lessee was authorized to deduct from the value of NGLs the costs of processing the gas. The other concerned the lessee's deduction of costs of dehydration, gathering, and compression.

Ordinarily, of course, processing costs are deductible.[46] In this case, however, the deductions were denied. They reason had nothing to do with the marketable condition rule, but rather with express lease language that stated that in computing royalty on gasoline or other NGLs, "no allowance will be made for the cost of extraction or processing."[47] The Department read that prohibition to apply even if someone other than the lessee performed the processing.

As for the other disputed costs, the Department determined that *The Texas Company* prohibited the deduction. Here the sales contract had specified that the lessee's gas meet certain quality specifications as a condition of the purchase.[48] *Placid Oil Company* therefore does not mark any evolution in the Department's thinking on the marketable condition rule.

F. 1988: Interior Finally Codifies the Marketable Condition Rule

On January 19, 1982, the Minerals Management Service (the "MMS" and predecessor agency to the Office of Natural Resources Revenue (the "ONRR")) was established by Secretarial Order.[49] The MMS became responsible for a variety of functions previously held by other organizational units,[50] and one of the agency's primary functions was to address the government's fear of lessee underreporting of production and underpayment of royalties:

> This organization was established by Secretarial Order 3071 which transferred resources from the Geological Survey, the Bureau of Land Management, and the Office of the Secretary. *The reorganization was the result of the underreporting of oil and gas production from Federal and Indian lands, theft of oil from those lands, and underpayment and inadequate collection of royalties owed to the United States.*[51]

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[46] See 30 C.F.R. § 1206.158.
[47] Id. at 439.
[48] Id. at 440.
[49] The 1982 administrative reorganization that created the MMS was carried out under the authority of the Secretary and without congressional or presidential action or approval. Henry B. Hogue, Analysis in American National Government, "Reorganization of the Minerals Management Service in the Aftermath of the Deepwater Horizon Oil Spill" at 5 (Nov. 10, 2010), *available at* https://fas.org/sgp/crs/misc/R41485.pdf (retrieved May 15, 2018) (citing Department of the Interior, Secretarial Order 3071, January 19, 1982).
[50] Henry B. Hogue, Analysis in American National Government, "Reorganization of the Minerals Management Service in the Aftermath of the Deepwater Horizon Oil Spill" at 5 (Nov. 10, 2010), *available at* https://fas.org/sgp/crs/misc/R41485.pdf (retrieved May 15, 2018) (citing Part 118 of the *Department of the Inteior Departmental Manual*, *available at* http://elips.doi.gov/app_DM_/index.cfm).
[51] Henry B. Hogue, Analysis in American National Government, "Reorganization of the Minerals Management Service in the Aftermath of the Deepwater Horizon Oil Spill" at 5 (Nov. 10, 2010), *available at* https://fas.org/sgp/crs/misc/R41485.pdf (retrieved May 15, 2018) (citing U.S. Congress, House Committee on Appropriations, *Department of the Interior and Related Agencies Appropriation Bill, 1983*, report to accompany H.R. 7356, 97th Cong., 2nd sess. (Washington: GPO, 1982), p. 40 (emphasis added)).

Thereafter in 1988, and in response to the government's fear, the MMS (acting under delegated authority from the Secretary) substantially revised the federal regulations on royalties.

The "marketable condition rule" present in the royalty regulations today was originally included as a part of the Department's Revision of Gas Royalty Valuation Regulations, which became effective March 1, 1988.[52] Those rules, stated in full above,[53] have not changed since 1988, although they have been renumbered. But the "marketable condition rule" has substantially been re-defined and re-interpreted ever since—without any change to the actual text of the regulations.

G. The Stepchildren of the 1990s

Since the 1990s, two of the most famous cases cited by lessees and distinguished by the Department in federal royalty litigation have been that of *Exxon Corp.*[54] and *Xeno, Inc.*[55] In the years since these cases, the Department has gone to great lengths to distinguish both—to the point of disavowal.

Exxon Corp. concerned the company's LaBarge Project in western Wyoming's Sublette County. There, within a federal unit producing from the Madison geologic formation, Exxon produced natural gas that was 65% carbon dioxide, 22% methane, eight% nitrogen, 4% hydrogen sulfide, and less than 1% helium. Through a combination of transportation and processing, Exxon sold methane, nitrogen, and helium at the tailgate of the processing plant, and carbon dioxide and sulfur downstream from the plant.[56]

The infrastructure of the Project through the points of sale was complex. Exxon shipped the gas from the unit to a dehydration facility outside the unit. The dehydration was needed because the carbon dioxide and hydrogen sulfide each interact with water vapor in the gas stream to create a highly corrosive mixture, corroding the insides of the pipe.[57] From that facility, the gas was sent through a forty-mile pipeline to the Shute Creek processing plant. After processing, the sulfur was transported by rail to a sales point. The carbon dioxide was transported by pipeline to sales points in Rock Springs and Bairoil, Wyoming.

In relevant part, Exxon sought to deduct the capital and operating costs of its dehydration facilities as part of the cost of transporting the gas. The Minerals Management Service disallowed the deduction on the ground that dehydration is in all cases a cost incurred to place production in marketable condition (or were otherwise incidental to "marketing"). The Interior Board of Land Appeals disagreed. "We believe it important that the Director consider the purpose of dehydration in determining whether an allowance is proper. In the instant case, dehydration at the central dehydration facility serves only one purpose: transportation."[58] The Board determined that "Exxon's dehydration of the LaBarge gas stream . . . was not performed to satisfy market

[52] *See* 53 F.R. 1184 (oil) (Jan. 15, 1988); 53 F.R. 1230 (natural gas) (Jan. 15, 1988).
[53] *See* 30 C.F.R. §§ 206.101 (oil), 206.106 (oil) 206.151 (natural gas), 2016.152(i) (natural gas) (1988).
[54] 118 IBLA 221 (1991).
[55] 134 IBLA 172 (1995).
[56] Exxon Corp., 118 IBLA at 223-24.
[57] Id. at 233.
[58] Id. at 240-41.

specifications. Indeed, the record is plain that no market existed for the dried [i.e., dehydrated] LaBarge gas stream, even at Shute Creek."[59] Therefore, to "read California Co. v. Udall as precluding a deduction of dehydration costs in all circumstances is error."[60]

In *Xeno, Inc.*, the Interior Board of Land Appeals (the "IBLA") considered a case where the lessee (Xeno) sold unprocessed gas to a purchaser under a "gas purchase agreement."[61] Xeno's purchaser later resold the gas at a higher price downstream.[62] Xeno, however, paid royalties based on the proceeds it received under its purchase contract and not based on the proceeds its purchaser received downstream upon resale.[63] Given this background, the State of Montana (acting under delegated authority from the Secretary) contended that Xeno had underpaid royalties from a series of leases.[64]

Emphasizing the operator's obligation to put production in marketable condition at no cost to the government, the Director of the MMS rejected Xeno's argument that "because the gas is sold at the wellhead . . ., it is 'marketable' at that point."[65] The Director found that Xeno's sales reflected a deduction for downstream costs its purchaser incurred, and so the Director ordered Xeno to pay royalties based upon the higher downstream resale price.[66]

But the IBLA rejected the Director's approach, noting that "the record reflects no analysis [by the auditors or by the MMS] of what constitutes marketable condition in the context of gas produced in the field at issue."[67] The IBLA noted that despite the fact that the gas Xeno sold was unprocessed, there was evidence that a market existed for the unprocessed gas. The IBLA observed that Xeno had "negotiated to market the unprocessed gas from the field with numerous firms and that competing offers to purchase the gas at the wellhead were made,"[68] that Xeno's unprocessed gas was produced at sufficient pressure to deliver the gas into its purchaser's pipelines,[69] and that the net price Xeno received "was the highest net price paid for a majority of like quality production in the field or area."[70]

Relying on this evidence, the IBLA distinguished *Xeno* from previous cases in which lessees were required to include the costs of compression, gathering, and processing in the lessee's royalty valuations because "the evidence shows that in this case the gas is in marketable condition at the wellhead."[71] Since this holding, both the IBLA and the federal courts have affirmed the continued vitality of the holding in *Xeno*.[72]

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[59] Id. at 242.
[60] Id.
[61] 134 IBLA 172 (1995).
[62] 134 IBLA 172 (1995).
[63] 134 IBLA 172 (1995).
[64] *See* 134 IBLA 172 (1995).
[65] 134 IBLA 172, 175 (1995).
[66] 134 IBLA 172, 174-75 (1995).
[67] 134 IBLA 172, 182 (1995).
[68] 134 IBLA 172, 183 (1995).
[69] *See* 134 IBLA 172, 176, 184 (1995).
[70] 134 IBLA 172, 184 (1995).
[71] 134 IBLA 172, 183 (1995).
[72] *See*, *e.g.*, *Amoco Prod. Co. v. Watson*, 410 F.3d 722, 730 (D.C. Cir. 2005); *Amerada Hess Corp. v. Dep't of Interior*,

Under *Xeno* and its progeny, the government may not presume a lessee's gas is not in marketable condition simply because it is sold at the wellhead or in the field before downstream compression, transportation, or processing.[73] The government instead has an affirmative obligation to analyze what constitutes marketable condition for the gas at issue.[74] Federal courts applying *Xeno* have since identified two primary indicia demonstrating gas sold in the field has reached marketable condition: (i) the existence of multiple offers to purchase the gas before processing; and (ii) evidence the unprocessed gas was suitable for pipeline access.[75]

But as recently as February 2017, the Department's Office of Natural Resource Revenues has described the holding of *Xeno, Inc.* for the following major principle: "Gas may be in marketable condition at the wellhead if there is a market at the wellhead evidenced by competing offers from multiple purchasers, the sales price is the same as that for gas that is compressed, and the pressure of the gas at the wellhead is adequate to gain access to the pipeline market."[76] That principle, however, significantly overstates what *Xeno* held.

H. Now Proceeding into the Present Era of the Department's "Thinking"

Turning to the present era, the two most-often cited cases in federal royalty litigation have been that of *Amoco Prod. Co. v. Watson*[77] and that of *Devon Energy Corp. v. Kempthorne*,[78] under which the Department has sought not only to push the sole "market" for purposes of "marketable" production as far downstream as possible—in an effort to garner higher sales values and thus higher royalty values—but has also sought to deny lessee's allowances along the way under the Department's latest theory of "unbundling."

III. IS UNBUNDLING THIRD-PARTY POST-PRODUCTION COSTS POSSIBLE UNDER THE DEPARTMENT'S REGULATIONS?

Today, the Office of Natural Resources Revenue (the "ONRR") is the federal agency responsible for management of all revenues associated with federal offshore and onshore mineral leases, and like its predecessor agency the MMS, the ONRR has also continued to twist and mold the "marketable condition rule." These latest efforts have created the current "unbundling" requirement upon federal lessees who contract with third parties to provide post-production services for natural gas.

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170 F.3d 1032, 1037 (10th Cir. 1999); *Bailey D. Gothard*, 144 IBLA 17, 22 (1998).

[73] *See Amoco Prod. Co. v. Baca*, 300 F. Supp. 2d 1, 11-12 (D.D.C. 2003) (acknowledging the agency acted arbitrarily and capriciously when it "assumed that gas was not in marketable condition unless it was compressed").

[74] *See*, *e.g.*, *Amoco Prod. Co. v. Baca*, 300 F. Supp. 2d 1, 11 (D.D.C. 2003).

[75] *Amoco Prod. Co. v. Watson*, 410 F.3d 722, 730 (D.C. Cir. 2005); *Amoco Prod. Co. v. Baca*, 300 F. Supp. 2d 1, 11 (D.D.C. 2003); *Bailey D. Gothard*, 144 IBLA 17, 22 (1998).

[76] "Updates on the Marketable Condition Rule and its Application" at 13, *available at* http://paso-tulsa.org/wp-content/uploads/2012/06/PASO-2017-Marketable-Condition-Combined-Presentation-Final.pptx (retrieved May 15, 2018).

[77] 410 F.3d 722 (D.C. Cir. 2005).

[78] 551 F.3d 1030 (D.C. Cir. 2008).

Recall that "marketable condition" in the natural gas context since 1988 has always meant lease products that are "sufficiently free from impurities and otherwise in a condition *that they will be accepted by a purchaser under a sales contract typical for the field or area*."[79] And the regulations have required lessees to place the gas "in marketable condition and market" the gas "for the mutual benefit of the lessee and the lessor at no cost to the [f]ederal [g]overnment."[80]

Recently, however, the ONRR has increasingly re-interpreted these regulations to allow the government to effectively remove the requirement that "marketable condition" be determined on a sales-contract basis.[81] To the Department, it has interpreted "marketable condition" on a somewhat nationwide basis,[82] thereby allowing it to collect higher royalties—not by increasing the royalty rate, but instead by chipping away at federal lessee natural gas deductions and allowances.

Often times, the ONRR has presumed "marketable condition" refers not to the requirements under a typical sales contract but instead the requirements for delivery into an intra-state or inter-state pipeline.[83] And today, the ONRR has identified several "processes" the agency construes as necessary to place federal natural gas in "marketable condition" no matter the sales contract, no matter the field, and no matter the area. Costs for the following "processes", according

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[79] *See* 30 C.F.R. § 1206.151 (2018) (emphasis added).
[80] *See* 30 C.F.R. §§ 1206.152(i) (unprocessed gas), 1206.153(i) (residue gas and gas plant products) (2018).
[81] *See* "Updates on the Marketable Condition Rule and its Application" at 13, *available at* http://paso-tulsa.org/wp-content/uploads/2012/06/PASO-2017-Marketable-Condition-Combined-Presentation-Final.pptx (retrieved May 15, 2018) (stating, "The fact that a purchaser agrees to accept untreated gas does not mean the gas was marketable in its natural state. In other words, the fact that you sell or transfer title at the wellhead does not mean the gas is in marketable condition at the wellhead," and citing *Amoco Prod. Co. v. Watson*, 410 F.3d 722, 725 (D.C. Cir. 2005), *aff'd sub nom.*, *BP Amoco Prod. Co. v. Burton*, 549 U.S. 84 (2006) and *Devon Energy Corporation v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 86 (2009)).
[82] *See* "Updates on the Marketable Condition Rule and its Application" at 13, *available at* http://paso-tulsa.org/wp-content/uploads/2012/06/PASO-2017-Marketable-Condition-Combined-Presentation-Final.pptx (retrieved May 15, 2018) (stating, "There is no bright line or 'geographic limitation' to the marketable condition rule, except for gathering," and citing *Amoco Prod. Co. v. Watson*, 410 F.3d 722, 725 (D.C. Cir. 2005), *aff'd sub nom.*, *BP Amoco Prod. Co. v. Burton*, 549 U.S. 84 (2006) and *Devon Energy Corporation v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 86 (2009)).
[83] *See* "Updates on the Marketable Condition Rule and its Application" at 14, *available at* http://paso-tulsa.org/wp-content/uploads/2012/06/PASO-2017-Marketable-Condition-Combined-Presentation-Final.pptx (retrieved May 15, 2018) (stating, "Marketable condition means gas treated so that it is marketable for delivery to the pipeline," and citing *Amoco Prod. Co. v. Watson*, 410 F.3d 722, 725 (D.C. Cir. 2005), *aff'd sub nom.*, *BP Amoco Prod. Co. v. Burton*, 549 U.S. 84 (2006), *Devon Energy Corporation v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 86 (2009), and *J-W Operating Co.*, 159 IBLA 1 (2003)).

to the agency, are presumed nondeductible: gathering;[84] compression;[85] dehydration'[86] and sweetening/treating[87].

In sum, the state of royalty litigation today involves increasing Departmental re-interpretation of (without modification of) the text of the "marketable condition rule." The Department seeks to require lessees who contract with third-party service providers to conform to downstream inter- and intra- state pipeline requirements, regardless of the lessee's actual sales contract. The Department has also created presumed nondeductible services. Furthermore, to add to this extensive re-interpretation, the Department has now also created the impossible requirement known as "unbundling." All this, in turn, results in higher royalties and higher costs of litigation.

To explain "unbundling," we must start with the text of the regulations, which have remain unchanged. Per the regulations, the agency "shall" allow federal lessees both transportation and processing allowances for the "reasonable, actual costs incurred." First, transportation allowances:

> Where the value of gas has been determined pursuant to § 1206.152 or § 1206.153 of this subpart at a point (e.g., sales point or point of value determination) off the lease, *ONRR shall allow a deduction for the reasonable actual costs incurred by the lessee to transport* unprocessed gas, residue gas, and gas plant products from a lease to a point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the

[84] "Gathering" means "the movement of lease production to a central accumulation and/or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or BSEE OCS operations personnel for onshore and OCS leases, respectively." 30 C.F.R. § 1206.151 (2018). *See* "Updates on the Marketable Condition Rule and its Application" at 11, *available at* http://paso-tulsa.org/wp-content/uploads/2012/06/PASO-2017-Marketable-Condition-Combined-Presentation-Final.pptx (retrieved May 15, 2018) (citing *Devon Energy Corporation v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 86 (2009) for the sweeping proposition that "[t]he lessee must gather, dehydrate, and compress gas at no cost to the lessor.").

[85] "Compression" means "the process of raising the pressure of gas." 30 C.F.R. § 1206.151 (2018). *See* "Updates on the Marketable Condition Rule and its Application" at 11, *available at* http://paso-tulsa.org/wp-content/uploads/2012/06/PASO-2017-Marketable-Condition-Combined-Presentation-Final.pptx (retrieved May 15, 2018) (citing *Devon Energy Corporation v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 86 (2009) for the sweeping proposition that "[t]he lessee must gather, dehydrate, and compress gas at no cost to the lessor.").

[86] "Dehydration" means the removal of water vapor. "Updates on the Marketable Condition Rule and its Application" at 11, *available at* http://paso-tulsa.org/wp-content/uploads/2012/06/PASO-2017-Marketable-Condition-Combined-Presentation-Final.pptx (retrieved May 15, 2018). *See* "Updates on the Marketable Condition Rule and its Application" at 11, *available at* http://paso-tulsa.org/wp-content/uploads/2012/06/PASO-2017-Marketable-Condition-Combined-Presentation-Final.pptx (retrieved May 15, 2018) (citing *Devon Energy Corporation v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 86 (2009) for the sweeping proposition that "[t]he lessee must gather, dehydrate, and compress gas at no cost to the lessor.").

[87] "Sweetening" or "treating" means the removal of acid gases – *i.e.*, usually the removal of hydrogen sulfide or carbon dioxide. "Updates on the Marketable Condition Rule and its Application" at 11, *available at* http://paso-tulsa.org/wp-content/uploads/2012/06/PASO-2017-Marketable-Condition-Combined-Presentation-Final.pptx (retrieved May 15, 2018); *see* "Updates on the Marketable Condition Rule and its Application" at 11, *available at* http://paso-tulsa.org/wp-content/uploads/2012/06/PASO-2017-Marketable-Condition-Combined-Presentation-Final.pptx (retrieved May 15, 2018) (citing *Amoco Prod. Co. v. Watson*, 410 F.3d 722, 725 (D.C. Cir. 2005), *aff'd sub nom.*, *BP Amoco Prod. Co. v. Burton*, 549 U.S. 84 (2006) for the sweeping proposition that "[t]he lessee must remove sulphur (H2S) and carbon dioxide (CO2) at no cost to the lessor.").

> plant.
>
> . . .
>
> For transportation costs incurred by a lessee under an arm's-length contract, *the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting* the unprocessed gas, residue gas and/or gas plant products under the contract[.][88]

Next, processing allowances:

> Where the value of gas is determined pursuant to § 1206.153 of this subpart, *a deduction shall be allowed for the reasonable actual costs of processing*.
>
> . . .
>
> For processing costs incurred by a lessee under an arm's-length contract, *the processing allowance shall be the reasonable actual costs incurred by the lessee for processing* the gas under that contract[.][89]

Because the Department has re-interpreted its "marketable condition" regulations as allowing the agency to identify various "processes" it deems nondeductible in all situations, lessees who contract for services at arm's-length are now obligated to "remove" or "unbundle" the costs of these nondeductible processes and only claim only the costs of agency-deemed deductible processes as allowances. This proves very difficult because in this industry, third-party service contracts typically charge a single rate from receipt to delivery for "all services incurred." This also proves impossible because in this industry, like any industry, third parties regard the integral costs of their services as confidential business information. As a rule, third parties do not give this information to their contract counter-parties—the federal lessees.

Thus, as a result, federal lessees now cannot know the "actual costs" of their deductible transportation costs or their deductible processing costs. On the other hand, ONRR can force—and has forced—third parties to provide internal cost information to ONRR under compulsion of a subpoena. Third parties, as a rule however, invoke 18 U.S.C. § 1905 to bar ONRR from providing that information to federal lessees. The ONRR regularly provides presentations, workshops, and training to industry participants to assist with proper payment of royalty revenues, and throughout many of these presentations, ONRR has recognized the difficulties royalty payors face in "unbundling" their third-party fees: Lessees lack the information required to "unbundle" under the agency's interpretation of "marketable condition."

So, by 2011 ONRR had developed its own strategy.[90] ONRR hired an ONRR Contractor

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[88] 30 C.F.R. §§ 1206.156(a), 1206.157(a)(1)(i) (2018) (emphasis added).
[89] 30 C.F.R. §§ 1206.158(a), 1206.159(a)(1)(i) (2018) (emphasis added).
[90] Deborah Gibbs Tschudy, Deputy Dir., Office of Natural Res. Revenue, Presentation at Petroleum Accountants Society of Oklahoma: Overview and Updates (Sept. 8, 2011), *available at* http://www.onrr.gov/About/pdfdocs/PASO_Sept82012 (retrieved July 22, 2015).

to assist,[91] and ONRR uses its ability to subpoena third-party internal costs information from third-party service providers and combs through that data to publish what are commonly known as "Unbundling Cost Allocations" or "UCAs," for short.[92] These "UCAs" are unbundled rates the agency publishes on its website. For arm's-length agreements, ONRR alerts visitors that when a lessee pays a bundled rate, the lessee must unbundle that rate in order to comply with regulations. ONRR further alerts visitors that "[a] lessee may use the Unbundling Cost Allocations (UCAs) posted on this website as a means of unbundling."[93]

Of course, these rates are not specific to any particular lessee or any particular lessee's natural gas production. Instead, these are generalized rates offered as estimates to apply to all federal lessees, regardless of their actual purchase contracts and regardless of their actual service contracts. The UCAs do not bind the agency or the lessee. They are subject to, and have been the subject of frequent, change.

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[91] Deborah Gibbs Tschudy, Deputy Dir., Office of Natural Res. Revenue, Presentation at National Oil & Gas Royalty Conference: ONRR Overview and Updates (Oct. 17, 2012), *available at* http://www.onrr.gov/About/Presentations.htm (follow "ONRR Overview and Updates" hyperlink) (retrieved July 22, 2015).

[92] Deborah Gibbs Tschudy, Deputy Dir., Office of Natural Res. Revenue, Presentation at National Oil & Gas Royalty Conference: ONRR Overview and Updates at 28 (Oct. 17, 2012), *available at* http://www.onrr.gov/About/Presentations.htm (follow "ONRR Overview and Updates" hyperlink) (retrieved July 22, 2015).

[93] *Disclaimer for ONRR Unbundling Website*, Office of Natural Res. Revenue, http://www.onrr.gov/unbundling (last visited July 22, 2015).

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Royalty Management Program
P.O. Box 25165
Denver, Colorado 80225-0165

IN REPLY REFER TO:

MMS-RVD-EVB: 99-0380
Mail Stop 3151

SEP 30 1999

CERTIFIED MAIL--
RETURN RECEIPT REQUESTED

Mr. Michael E. Coney
Attorney At Law
Shell Deepwater Production Inc.
P.O. Box 60834
New Orleans, Louisiana 70160-0834

Dear Mr. Coney:

Thank you for the information you provided on August 27, 1999. This information allowed the Royalty Valuation Division (RVD) to further evaluate Shell Offshore Inc.'s (Shell) request for a transportation allowance for the movement of gas production from Mississippi Canyon Block 807 (MC 807) to the West Delta 143 Platform (WD 143).

On May 20, 1999, the Associate Director for Royalty Management (ADRM) issued a memorandum providing guidance for determining transportation allowances for production from leases in water depths greater than 200 meters. (See Enclosure.) The memorandum states that any previously-received requests for the transportation of deepwater production should be reviewed under these guidelines. This response results from our review of your situation under the new guidelines, and is a follow-up to our August 28, 1998, letter that withdrew our original decision of July 6, 1998.

The guidelines and our responses are as follows:

Guideline 1

The transportation allowance must be determined in accordance with the current regulations.

RVD Analysis

To determine an allowance for non-arm's-length transportation, the regulations at 30 CFR § 206.105(b) (1999) prescribe the allowable and non-allowable expenses.

Guideline 2

The costs of movement must be allocated between the royalty and non-royalty bearing substances.

RVD Analysis

The information submitted shows that the MC 807 Platform is located in deepwater Gulf of Mexico, approximately 60 miles from WD 143. Gas production comes to the surface at Platform A located at MC 807. The liquids are then separated and transferred to the oil line and moved to shore. The dehydrated gas is moved to WD 143 via separate pipeline. Upon reaching WD 143, the gas enters into a dedicated slug catcher at which time retrograde condensate falls out. The gas is then measured for royalty purposes and transported from WD 143 to shore via two separate pipelines.

The Payor Handbook, Volume III, pg.5-10, states:

> Non-Royalty-Bearing Products
>
> The lessee is not permitted to deduct the costs of transporting non-royalty-bearing products without MMS approval (30 CFR § 206.105(a)(2)(i) and 30 CFR § 206.105(b)(3)(i)). In computing a transportation allowance for a gaseous and (or) liquid stream that contains both royalty-bearing and non-royalty-bearing products, only the costs associated with transporting the royalty-bearing portion of the stream are deductible. [Emphasis added.]

Thus, the costs of movement must be allocated between royalty and non-royalty-bearing substances, and Shell may deduct only the costs associated with royalty-bearing production. Separation, dehydration, and treatment costs are not related to transportation and cannot be included in the transportation allowance.

Guideline 3

Movement prior to a central accumulation point is considered gathering. A central accumulation point may be a single well, a subsea manifold, the last well in a group of wells connected in a series, or a platform extending above the surface of the water. Movement beyond this point is considered transportation.

RVD Analysis

The location of the royalty meter is often a deciding factor in determining whether movement is transportation or gathering. Your (Shell's) request is for movement of production from MC 807 to WD 143, with the royalty meter located at WD 143. However, in applying the ADRM's May 20, 1999, guidance, we consider Platform A at MC 807 to be the central accumulation point. Although the royalty meter is at WD 143, we consider gathering, consistent with the new guidance, to terminate at Platform A. Thus the movement beyond

Platform A, MC 807, is transportation, subject to the other qualifications in the ADRM's May 20, 1999, guidance.

Guideline 4

Leases and units are treated similarly.

RVD Analysis

Production is from the MC 807 unit only.

Guideline 5

To qualify for a transportation allowance, the movement must be to a facility that is not located on a lease adjacent to the lease on which the production originates. An adjacent lease is defined as any lease with at least one point of contact with the producing lease/unit. Typically, for a single lease, there would be eight leases adjacent to a qualifying deep-water lease.

RVD Analysis

A review of leases on the Outer Continental Shelf, Gulf of Mexico, shows that the unit where the production originates, MC 807, is not adjacent to WD 143. Platform A on MC 807 is about 60 miles from WD 143.

Guideline 6

Allowances for subsea completions not located in water deeper than 200 meters may still be considered on a case-by-case basis.

RVD Analysis

In an affidavit dated August 29, 1999, you state that MC 807 is located in a water depth of more than 200 meters.

Using the referenced guidelines, and subject to future review and audit, we approve your request for a transportation allowance for movement of gas production from MC 807 to WD 143. This approval is subject to RVD modification, should the circumstances change in the future. If your transportation allowance exceeds the 50-percent limitation as prescribed in 30 CFR § 206.104 (1999), you must apply for an exception to the limitation, and provide sufficient documentation to support your request before claiming the excess amount.

If you have any questions, please call Mr. James Morris at (303) 275-7213.

Sincerely,

Deborah Gibbs Tschudy
Chief, Royalty Valuation and
Standards Division

Enclosure

'See Ya, Pops!'

By John Harpole

My 18-year-old daughter will depart for college next fall, and every time she leaves the house with the salutation, "See ya, Pops!" I cringe a little. I know the day will come all too soon when I will hear it with more finality in her voice.

The recent plummet in oil prices is also causing everyone in the sector to cringe. The synchronous dive in NGL pricing has caused the all-important fractionation (frac) spread to evaporate.

During the last six years, the strength of that spread caused some analysts to refer to the period as "The Golden Age of Natural Gas Processing." The winners (if any) and losers in this new pricing world are still being determined by analysts who are burning the midnight oil—thank God for their incremental demand.

Questions?

To the uninitiated, many questions arise. What is a frac spread? What are POP (percent of proceeds), keep-whole and fee-based natural gas processing contracts? How long will the frac spread be gone and when might it recover?

The frac spread is the value of the NGL—ethane, propane, butane, isobutane and natural gasoline—less the price of natural gas required to make up for the Btus extracted in a process known as fractionation. If frac spreads are positive, the liquids contained in the raw natural gas are more valuable as NGL and the producer/processor will maximize liquid recovery. If frac spreads are negative, the liquids contained in the gas are less valuable than gas and the producer/processor will minimize liquid recovery. Each NGL component has its own frac spread.

A POP contract is used when the producer receives a predetermined percentage of the recovered gas liquids plus 100% of the remaining residue gas.

A keep-whole contract is used when a producer receives 100% of the Btu value of the natural gas originally delivered to the processor, and the processor keeps 100% of the NGL extracted from the processed gas and purchases natural gas to replace the Btu value of the extracted gas liquids.

A fee-based contract is an agreement where the producer pays the processor a fee, and the producer receives 100% of the recovered NGL plus 100% of the residue gas, less "shrink" of the missing NGL and fuel used.

Admittedly, the midstream industry has shifted away from the POP and keep-whole contract world in favor of more predictable and less volatile fee-based arrangements. But many POP contracts and life-of-lease dedications still exist in the older producing basins such as Texas' Permian Basin or Colorado's Denver-Julesburg Basin. The newer, shale-revolution producing areas for the most part rely on fee-based processing.

Under today's NGL price environment, there is no financial incentive to fractionate NGL from the wet gas stream. It costs more to separate them out than to leave them in the mix of wet gas. The producers' age-old favorite natural gas processing POP contract has turned sour. Is it then also time to say, "See ya, Pops?"

The important thing to remember here is that any entity that was relying on the value of NGL will continue to suffer economically. Obviously the degree, depth and duration of that pain will depend on the individual companies' exposure.

It is critical for the industry to understand and admit that midstream gas processing is a must-run industry. It is not in the best interest of E&P companies to have unprofitable or failing gas processors. If processing companies fail, how do E&P companies get gas to market? Should minimum payments to processors be considered to carry a processor through difficult times?

The future

Nearly every MLP has seen its unit price drop in reaction to the oil price decline. The markets presumed that they were all guilty of having a portfolio of POP or keep-whole contracts with a corresponding exposure to the NGL prices.

One midstream company executive recently told me his company had to call most of the analysts covering the company's stock and reiterate that the company had converted its POP contract exposure with producers and replaced them with fee-based processing arrangements.

Evidently it's up to the industry to disprove the negative to stock analysts. We should have seen and accepted that burden when we saw the recent meager midnight oil consumption numbers.

And finally on the question of when the frac spread might recover? No one really knows, but by my own midnight oil calculations it will be Feb. 29, 2017, at 2 p.m. Eastern time, give or take. ■

John Harpole *is senior advisor and an editorial advisory board member to* Midstream Business. *He is founder and president of Mercator Energy LLC and can be reached at* ***jharpole@hartenergy.com*** *or* ***303-825-1100****.*

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Washington, D.C. 20240

MAY 20 1999

Memorandum

To: RMP Audit Managers
Chief, Royalty Valuation Division

From: Associate Director for Royalty Management Lucy Querques Denett

Subject: Guidance For Determining Transportation Allowances for Production from Leases in Water Depths Greater Than 200 Meters

The following guidance is provided to assist you in determining the proper transportation allowances for movement of production from leases in water depths greater than 200 meters. This guidance was agreed to by the Minerals Management Service's Quality Council at its monthly meeting on March 26, 1999. Please disseminate this information as appropriate.

Guidance

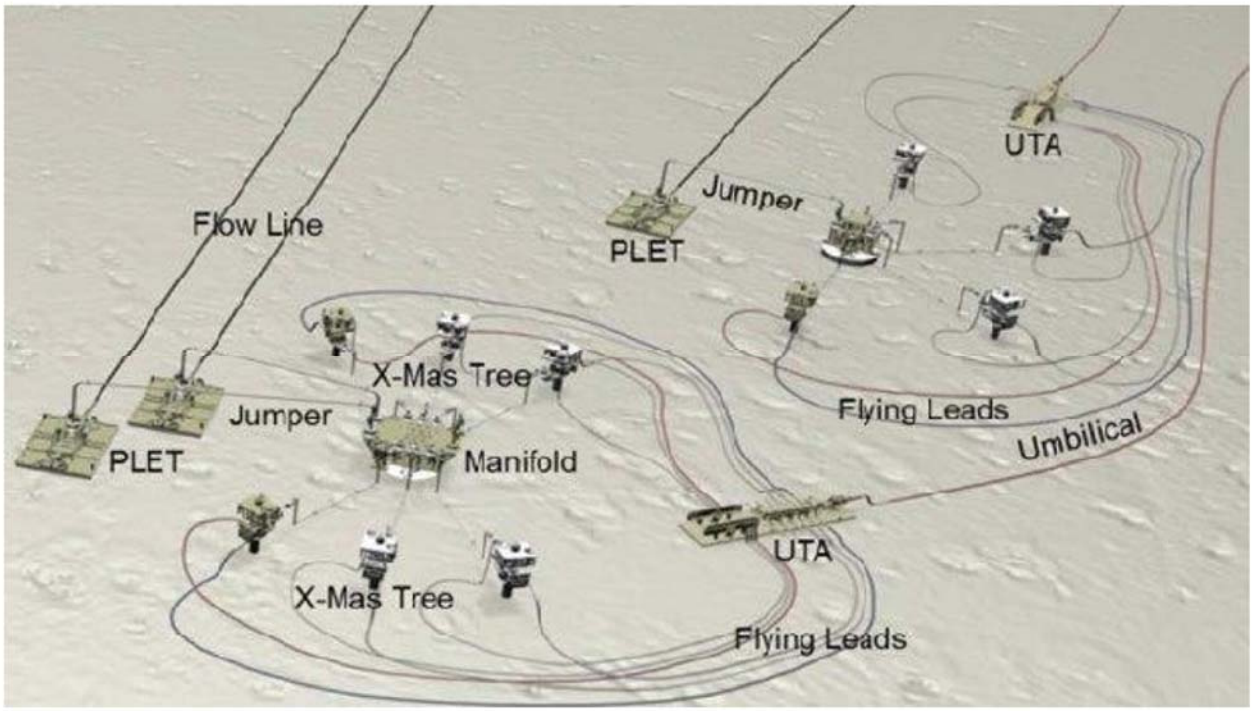
Production from a lease, any part of which, lies in water deeper than 200 meters may qualify for a transportation allowance. The following guidelines also apply:

- The transportation allowance must be determined in accordance with the current regulations.
- The costs of movement must be allocated between the royalty bearing and non-royalty bearing substances.
- Movement prior to a central accumulation point is considered gathering. A central accumulation point may be a single well, a subsea manifold, the last well in a group of wells connected in series, or a platform extending above the surface of the water. Movement beyond this point is considered transportation.
- Leases and units are treated similarly.
- To qualify for a transportation allowance, the movement must be to a facility that is not located on a lease adjacent to the lease on which the production originates. An adjacent lease is defined as any lease with at least one point of contact with the producing lease/unit. Typically, for a single lease, there would be eight leases adjacent to the qualifing deep-water lease.
- Allowances for subsea completions not located in water deeper than 200 meters may still be considered on a case-by-case basis.

Application

Apply this guidance prospectively. Any previously received requests for guidance should be reviewed. If the above criteria are met, and the previously issued decision conflicts with this guidance the company must be notified.

Questions concerning the applicability of this guidance to specific situations should be referred to the Royalty Valuation Division (RVD). Additionally, requests for determinations on a case-by-case basis should be referred to RVD.



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