



DEPARTMENT OF THE INTERIOR

30 CFR Parts 1206 and 1210

[Docket No. ONRR-2014-0001; DS63610000; DR2PS0000.CH7000 145D0102R2]

RIN 1012-AA15

Indian Oil Valuation Amendments

AGENCY: Office of Natural Resources Revenue (ONRR), Interior.

ACTION: Proposed rule.

SUMMARY: ONRR proposes to amend its regulations governing the valuation, for royalty purposes, of oil produced from Indian leases. The proposed rule would clarify the major portion valuation requirement found in the existing regulations for oil production. The proposed rule would represent recommendations of the Indian Oil Valuation Negotiated Rulemaking Committee. This proposed rule also contains new reporting requirements to implement the changes to the major portion valuation requirement.

DATES: Comments must be submitted on or before **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

ADDRESSES: You may submit comments to ONRR on this proposed rulemaking by one of the following methods (please reference “1012-AA15” in your comments):

- Electronically go to *www.regulations.gov*. In the entry titled “Enter Keyword or ID,” enter “ONRR–2014–0001,” and then click “Search.” Follow the instructions to submit public comments. ONRR will post all comments.
- Mail comments to Armand Southall, Regulatory Specialist, ONRR, P.O. Box 25165, MS 61030A, Denver, Colorado 80225–0165.

- Hand-carry comments, or use an overnight courier service, to the Office of Natural Resources Revenue, Building 85, Room A-614, Denver Federal Center, West 6th Ave. and Kipling St., Denver, Colorado 80225.

FOR FURTHER INFORMATION CONTACT: For questions on technical issues, contact John Barder at (303) 231-3702, Sarah Inderbitzin at (303) 231-3082, Karl Wunderlich at (303) 231-3663, or Elizabeth Dawson at (303) 231-3653, ONRR. For comments or questions on procedural issues, contact Armand Southall, Regulatory Specialist, ONRR, telephone (303) 231-3221, or email *armand.southall@onrr.gov*.

SUPPLEMENTARY INFORMATION:

I. Background

The Minerals Revenue Management (MRM) program of the Minerals Management Service (MMS), now ONRR, published the existing rule for the major portion provision for the valuation of oil produced from Indian leases, codified at 30 CFR part 1206, subpart B, in the **Federal Register** on January 15, 1988 (53 FR 1184), effective March 1, 1988. Since then, many changes have occurred in the oil market. Also, concerns have arisen about the need for revised valuation methodologies to address the major portion requirement in paragraph 3(c) of standard Indian oil and gas leases for valuation of oil produced from leases on Indian land.

MRM published proposed rules for Indian oil valuation on February 12, 1998 (63 FR 7089) and on January 5, 2000 (65 FR 403). MRM subsequently withdrew each of these proposed rules because of market changes and the passage of time. In addition, MRM held eight public meetings during 2005 to obtain information from, and consult with, Indian Tribes and Indian mineral owners and other interested parties. Then, MRM published a third proposed rule on February 13, 2006 (71 FR 7453). Tribal and industry commenters on the 2006 proposed rule did

not agree on most issues regarding oil valuation, and none of the commenters supported the major portion provisions.

Also in 2006, the Royalty Policy Committee's Indian Oil Valuation Subcommittee evaluated the proposed rule but was unable to reach consensus on recommendations to the Department of the Interior on how to proceed. Thus, MRM decided to make only technical amendments to the existing Indian oil valuation regulations and convene a negotiated rulemaking committee to make specific recommendations regarding the major portion provision. MRM published its final rule addressing the technical amendments on December 17, 2007 (72 FR 71231). The preamble of the final rule stated ONRR's intent to convene a negotiated rulemaking committee to address the major portion valuation requirement for oil produced from Indian leases.

On December 1, 2011, the Secretary of the Interior (Secretary) signed the charter of the Indian Oil Valuation Negotiated Rulemaking Committee (Committee). On December 8, 2011, ONRR published, in the **Federal Register**, a notice (76 FR 76634) that the Department of the Interior established and created the Committee authorized under the Federal Advisory Committee Act. The Secretary established the Committee to make recommendations to replace existing regulations governing the valuation of oil on Indian lands, specifically the portion of the regulations governing the major portion requirement found in most standard Indian leases. The Committee met in May, June, August, September, and October 2012 and in April, June, August, and September 2013.

There were 18 members of the Committee. Members of the Committee consisted of representatives of Tribes, individual Indian mineral owner associations, oil companies with interests in Indian lands, oil and gas trade associations, and the United States government. The Shoshone and Arapaho Tribes, Land Owners Association (Fort Berthold), Navajo Nation,

Oklahoma Indian Land/Mineral Owners of Associated Nations, Ute Indian Tribe, Jicarilla Apache Nation, and Blackfoot Nation represented Tribes and individual Indian mineral owner associations. The American Petroleum Institute, Council of Petroleum Accountants Societies, Western Energy Alliance, Chesapeake Energy, Peak Energy Resources, and Resolute Energy Corporation represented industry. ONRR and the Bureau of Indian Affairs (BIA) represented the United States government. A third-party neutral facilitator led all of the meetings, coordinated caucuses, provided the official minutes, and drafted the final report.

The policy of the Department of the Interior (DOI) is, whenever practicable, to afford the public an opportunity to participate in the rulemaking process. ONRR announced all of the Committee sessions in the **Federal Register**. The meetings were open to the public to provide it the opportunity to participate in the rulemaking process.

ONRR commends the Committee and its facilitator for reaching agreement on addressing the major portion requirement component of the regulations governing the value of Indian oil. The members' ability to compromise and work together resulted in a valuation proposal that would assure Indian Tribes and individual Indian mineral owners will receive, in a timely fashion, royalties based on the highest price paid for a major portion of production from a field or area. In addition, the proposed rule would help members of industry avoid significant administrative costs and will assure that the Department of the Interior meets its trust responsibilities to Indian Tribes and individual Indian mineral owners.

II. General Description of the Proposed Rule

In September 2013, the Committee published its final report summarizing the Committee's proposal for addressing the major portion requirement for valuing Indian oil production. The report forms the basis for this proposed rule and is an essential part of the history for this

proposed rulemaking. You can find the report, along with the minutes and other supporting materials for all meetings at the Committee's website at http://www.onrr.gov/Laws_R_D/IONR/. Alternatively, contact Karl Wunderlich listed under **FOR FURTHER INFORMATION CONTACT** to obtain a mailed copy of the report or to answer any other questions regarding the Committee or this rulemaking.

ONRR is mandated to establish regulations concerning Indian oil valuation based on its Federal trust responsibility to Indians, including the duty to maximize revenue for Indian Tribes and Indian mineral owners. As such, any action the United States takes in relation to Indian-owned trust property, including Indian minerals, must be that of a trustee who must act in a manner that is in the best interest of the Indian owner. Keeping in mind the responsibility to maximize revenue, when faced with more than one reasonable alternative, the Secretary must choose that alternative that most benefits the Indian mineral owner.

Within the context of the Secretary's Federal trust responsibility, the purpose of this rulemaking is to ensure that Indian lessors receive maximum revenues from their mineral resources. In addition, this rule provides simplicity, certainty, clarity, and consistency for Indian oil production valuation for Indian mineral revenue recipients and Indian mineral lessees.

The proposed rule would require a lessee to value its oil produced on Indian tribal or allotted lands based on the higher of (1) the lessee's gross proceeds or (2) an Index-Based Major Portion (IBMP) value adjusted by a Location and Crude Type Differential (LCTD), unique to each designated area and crude oil type. The LCTD would assure that the calculated major portion price represents, on average, the equivalent of a 75% major portion price calculated by arraying all of the prices reported in a designated area from the highest to the lowest price and starting from the top of the array to determine that price associated with the 25th percentile by volume

plus one barrel of oil. ONRR will base the IBMP on the calendar month average of prices the New York Mercantile Exchange (NYMEX) sets, less a differential based on the location and crude oil type of the oil. Generally, ONRR will base the designated areas on reservation boundaries, with exceptions, as discussed further below.

Each sales month, ONRR would monitor each of the designated areas' reported sales volumes to identify when oil sales volumes reported as a lessee's gross proceeds are either more than 28 percent, or less than 22 percent, of the total volumes sold in that designated area for the specified crude oil type. In months where the volumes in a designated area for a particular crude oil type fall outside 22 to 28 percent of the total volumes sold, ONRR would adjust the current month's LCTD up or down by 10 percent. ONRR would then use the adjusted LCTD, along with the NYMEX Calendar Month Average, to calculate the next month's IBMP value. ONRR would continue to adjust the LCTD until the percentage of oil sales volumes reported as gross proceeds reflect between 28 and 22 percent of all sales volumes within a designated area for the specified crude oil type. ONRR would publish the monthly IBMP value on its website at <http://www.onrr.gov>.

In addition, the proposed rule modifies some language in the current regulations to align with the Federal mandate that agencies write all rules in plain language.

III. Section-by-Section Analysis

Before reading the additional explanatory information below, please turn to the proposed rule language that immediately follows the List of Subjects in 30 CFR parts 1202 and 1206 and signature page in this proposed rule. DOI will codify this language in the CFR if we finalize the proposed rule as written.

After you have read this proposed rule, please return to the preamble discussion below. The preamble contains additional information about this proposed rule, such as why we defined a term in a certain manner and why we chose a certain method to value oil from Indian leases.

The derivation table below only shows a crosswalk of the recodified sections of the current and the proposed regulations in part 1206, subpart B.

DERIVATION TABLE FOR PART 1206

The requirements of section:	Are derived from section:
Subpart B	
1206.57.....1206.57(a)
1206.58.....1206.57(b), (f), and (g)
1206.59.....1206.57(d)
1206.60.....1206.57(c) and (e)
1206.61.....1206.58
1206.62.....1206.59
1206.63.....1206.60
1206.64.....1206.61
1206.65.....1206.62

A. Section-By-Section Analysis of Proposed Changes to 30 CFR part 1206—Product Valuation, Subpart B—Indian Oil

ONRR proposes to amend part 1206, subpart B, applicable only to Indian oil valuation. Many of the provisions are the same as in the existing rule in substance. However, ONRR rewrote some sections for purposes of clarity. The main substantive change in the proposed rule is proposed at §1206.54, which reflects the Committee’s recommendations on how lessees should value their oil when their leases have a major portion provision or have a provision where the Secretary has the authority to establish value.

Purpose (Section 1206.50)

This section would substantively remain the same as current §1206.50. However, we propose to write this section in plain language for clarity.

Definitions (Section 1206.51)

While ONRR will retain all existing definitions, ONRR is adding new terms and definitions in this proposed rule to support the new IBMP value used in the proposed rule at §1206.54.

ONRR proposes new definitions for: *Designated area, Location and Crude Type Differential, Major Portion Price, Prompt month, Roll, and Trading month*. ONRR also proposes renaming the term *NYMEX price* to *NYMEX Calendar Month Average Price* and revising its definition. Finally, ONRR proposes a minor revision to the definition *Audit* to specify that ONRR will conduct audits pursuant to the *Governmental Auditing Standards*.

Designated Area would be defined as the area ONRR designates for purposes of calculating Location and Crude Type Differentials applied to the IBMP value. Generally, ONRR would establish designated areas by the reservation boundaries where location and crude oil types are similar to each other. In some cases, such as Oklahoma, several fields may exist within an area that has similar transportation costs and crude oil types. In those cases, more than one reservation or field may be included within a designated area. ONRR would post designated areas on its website at www.onrr.gov.

If there is a significant change that affects the differential for a designated area, affected Tribes, Indian mineral owners, or lessees/operators may petition ONRR to consider convening a technical committee to review, modify, or add designated areas. Criteria to determine any future changes include, but are not limited to:

- Markets served, examples include refineries and/or market centers, such as Cushing, OK;
- Access to markets, examples include, access to similar infrastructure, such as pipelines, rail lines, and trucking; and/or

- Similar geography, for example, no challenging geographical divides, large rivers and/or mountains.

Initially, ONRR proposes the following designated areas:

1. Fort Berthold—Two designated areas:

- North Fort Berthold—all lands within the Fort Berthold Reservation boundary north of the Little Missouri River, including the Turtle Mountain public domain lease lands north of the Little Missouri River that the Fort Berthold Agency of the BIA administers.

- South Fort Berthold—all lands within the Fort Berthold Reservation boundary south of the Little Missouri River, including the Turtle Mountain public domain lease lands south of the Little Missouri River that the Fort Berthold Agency of the BIA administers.

2. Uintah & Ouray—Two designated areas: Uintah and Grand Counties; Duchesne County.

3. Oklahoma—One statewide designated area encompassing all oil production on trust lands, excluding Osage County.

4. Fort Peck—designated area includes all lands within the Fort Peck Reservation boundary and the Turtle Mountain public domain lease lands administered by the Fort Peck Agency of the BIA.

5. Fort Belknap—designated area includes all lands within the Fort Belknap Reservation boundary and the Turtle Mountain public domain lease lands administered by the Fort Belknap Agency of the BIA.

6. Turtle Mountain—designated area includes all lands within the Turtle Mountain Reservation and the Turtle Mountain public domain lease lands administered by the Turtle Mountain Agency of the BIA.

7. The designated area for all other reservations would be the reservation boundary, including any off-reservation allotments or dependent Indian communities. They include, but are not limited to, the:

- Blackfeet Indian Reservation
- Crow Indian Reservation
- Jicarilla Apache Indian Reservation
- Isabella Indian Reservation (Saginaw Chippewa)
- Navajo Indian Reservation
- Ute Mountain Ute Indian Reservation
- Wind River Indian Reservation
- Alabama/Coushatta Indian Reservation
- Southern Ute Indian Reservation
- Rocky Boy's Indian Reservation

Location and Crude Type Differential (LCTD) would mean the difference in value between the average of the monthly NYMEX Calendar Month Average (CMA) for the previous 12 months and the average of the monthly Major Portion Prices for the previous 12 months for a designated area for any given crude oil type. The LCTD also captures the difference in value due to location and quality differences between Light Sweet Crude (WTI) at Cushing, Oklahoma and other crude oil types in each designated area.

Initially, ONRR would establish the LCTD based on the previous year's average annual difference between the NYMEX CMA and the Major Portion Price. ONRR would calculate the Major Portion Price by arraying all of the prices reported in a designated area from the highest to the lowest price and starting from the top of the array to determine that price associated with the

25th percentile by volume plus one barrel of oil. ONRR would calculate a separate LCTD for each crude oil type within each designated area using all calculated values (arm's-length and non-arm's-length) payors report on Form ONRR-2014. The array to establish the initial LCTD also would include sales reported on Form ONRR-2014 as royalty-in-kind (Transaction Code 06). In addition, the sales values ONRR uses in the array would be net of transportation allowances.

To calculate the initial LCTD, ONRR would require payors to report new crude oil types on ONRR Form-2014 using the existing Product Code field. ONRR anticipates having 12 months of new reported data to calculate the initial LCTD. However, should ONRR not have the full 12 months of crude oil types prior to the effective date of the rule, ONRR would assume the crude oil type is the same for those leases/agreements for the months for which ONRR does have crude oil type data reported on Form ONRR-2014s for the same leases and/or agreements.

For leases from which royalty is taken in kind now or in the future, ONRR would require lessees to report their total sales volume and base the sales value reported on Form ONRR-2014 on the higher of: (1) The IBMP value (reported as OINX), or (2) the price the lessee receives for volumes sold (reported as something other than OINX). ONRR would not consider the royalty-in-kind share of production in determining whether ONRR must modify the LCTD for a specific designated area and crude oil type.

Major Portion Price would mean the highest price paid or offered at the time of production for the major portion of oil produced from the same designated area for the same crude oil type.

Prompt month would mean the nearest month of delivery for which NYMEX futures prices are published during the trading month.

Roll would mean a method for adjusting current month prices for future prices to smooth the variation in oil trading prices and reflect market expectations. ONRR proposes to apply a “roll” to the initial NYMEX oil prices from leases in Oklahoma. Because NYMEX prices are future price estimates, and, therefore, inherently reflect increases or decreases in prices based upon expected trends, an adjustment to such estimates is necessary to extrapolate back to current price estimates upon which royalty calculations are based. This adjustment is the “roll.” The roll is added to the initial NYMEX price when the market is falling (to correct for the fact that the current price should be higher than the future price in a falling market) and subtracted from the initial NYMEX prices when the market is rising (to correct for the fact that the current price should be lower than the future price if the market is rising). We propose to use the roll because we believe it represents current market practice in establishing the sales price for crude oil production in Oklahoma.

The roll formula includes the future prices for the two months beyond the prompt month, which is not the same as the prompt month used to determine the initial NYMEX price, and assigns a progressively smaller weight to the second and third months. This is consistent with ONRR’s understanding of the common industry practice, including the weights and basis for the prices in the formula below. Specifically, the roll would be calculated as follows:

$$\text{Roll} = .6667 \times (P_0 - P_1) + .3333 \times (P_0 - P_2), \text{ where:}$$

- P_0 = the average of the daily NYMEX settlement prices for deliveries during the prompt month that is the same as the month of production, as published for each day during the trading month for which the month of production is the prompt month.

- P_1 = the average of the daily NYMEX settlement prices for deliveries during the month following the month of production, as published for each day during the trading month for which the month of production is the prompt month.

- P_2 = the average of the daily NYMEX settlement prices for deliveries during the second month following the month of production, as published for each day during the trading month for which the month of production is the prompt month.

Note that although prices P_0 , P_1 , and P_2 represent separate prices for periods 1, 2, and 3 months beyond the trading month, respectively, they are all determined during the same trading month. The roll may be a positive or a negative number, and, therefore, increase or decrease the royalty value, depending on whether the futures market is falling or rising. For example, assume that the month of production for which you must determine royalty value is March 2013. March was the prompt month on the NYMEX from January 23 through February 20, which is the trading month in this case. April is the first month following the month of production, and May is the second month following the month of production. As explained above, to determine the initial NYMEX price which the roll will adjust, for March 2013 production you first take the average of the daily settlement prices published for each business day from March 1 through March 20 for deliveries in April (the prompt month) and for each business day from March 21 through March 31 for deliveries in May (after May becomes the prompt month).

To calculate P_0 , a different set of days is used. P_0 is the average of the daily NYMEX settlement prices for deliveries during March published for each business day between January 23 and February 20 (the trading month). P_1 is the average of the daily NYMEX settlement prices for deliveries during April published for each business day during the same trading month, *i.e.* between January 23 and February 20. Similarly, P_2 is the average of the daily NYMEX

settlement prices for deliveries during May published for each business day during the same trading month used for P_0 and P_1 . In this example, assume that $P_0 = \$98.00$ per bbl; $P_1 = \$97.70$ per bbl; and $P_2 = \$97.10$ per bbl. In this declining market, the roll = $.6667 \times (\$98.00 \text{ minus } 97.70) + .3333 \times (\$98.00 \text{ minus } 97.10) = \$0.20 + \$0.30 = \0.50 . Fifty cents per barrel would then be added to the initial NYMEX settlement price used as the basis for royalty valuation.

In this example, since the market is falling, prices that traders anticipate during the trading month (March) for deliveries in a future prompt month are lower than the prices at which oil actually is selling during March. The roll accounts for that trend. The roll will have the opposite effect in a rising market. The roll will be a subtraction from the initial NYMEX price calculation (adding a negative number to the NYMEX price) because traders anticipate higher prices for the future prompt months than actually are occurring during the calendar month of production.

The roll would be added to the initial NYMEX price used as the basis for royalty valuation for Indian leases in Oklahoma. This is because sales contracts for Indian oil in Oklahoma typically include the roll, whereas current sales contracts in other designated areas do not.

While ONRR expects the basic operation of the NYMEX market to be the same for the foreseeable future, it is not clear the roll will be a permanent feature of the marketplace. Therefore, ONRR proposes that the Director of ONRR would have the option of terminating use of the roll when ONRR believes that using the roll is no longer a common industry practice. To terminate the roll, ONRR will publish a notice in the **Federal Register**. Further, ONRR also proposes to have the option to redefine how the roll is calculated to comport with changes in industry practice through a notice published in the **Federal Register**. ONRR will explain its rationale when it publishes such notice. ONRR believes this flexibility is appropriate so the

valuation standards more closely reflect market developments. ONRR specifically requests comments on whether these options are necessary.

Trading month would mean the period extending from the second business day before the 25th day of the second calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the second business day before the last business day preceding the 25th day of that month) through the third business day before the 25th day of the calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the third business day before the last business day preceding the 25th day of that month), unless the NYMEX publishes a different definition or different dates on its official Web site, www.nymex.com, in which case the NYMEX definition will apply.

Royalty Value For Oil I or My Affiliate Sells or Exchanges under an Arm’s-Length Contract (Section 1206.52)

This section is unchanged from the existing rule with the exceptions of clarifying (1) that value is the higher of the value calculated under this section or the new major portion provision under §1206.54, (2) that you bear the burden of demonstrating that the contract is arm’s-length and may be required to certify that the contract includes all consideration, and (3) that this provision applies notwithstanding any contrary *Code of Federal Regulation* provisions. Other portions of existing §1206.52 have been moved to other sections of the new regulations.

Oil Royalty Value Not Sold under an Arm’s-Length Contract (Section 1206.53)

This section is unchanged from the existing rule with the exception of clarifying that value is the higher of the value calculated under this section or the new major portion provision under §1206.54.

Value of Production Based on the Major Portion of Like-Quality Oil (Section 1206.54)

This section is the principal new provision of the proposed regulation and is based on the recommendations of the Committee. This proposal removes the existing text of §1206.54 and replaces it with new language explaining how a lessee fulfills the obligation under its lease to value crude oil produced from Indian leases based on the highest prices paid for a major portion of production of like-quality oil from the field. Proposed paragraph (a) states that this would apply to any Indian lease that has a major portion provision. This section also applies to Indian leases where the Secretary of Interior may determine value. For such leases, paragraph (a) would state that the value for royalty purposes is the higher of the value determined under the section or your gross proceeds under §1206.52 or §1206.53.

Under paragraph (b) of the proposed rule, lessees would report royalties on the Form ONRR-2014 using the higher of (1) an IBMP value, or (2) the lessee's gross proceeds.

Where the value of the lessee's oil is the gross proceeds accruing to the lessee under an arm's-length contract, the lessee would report its gross proceeds on its Form ONRR-2014 using Sales Type Code (STC) other than OINX. If the IBMP value is higher than gross proceeds, then the lessee must report the IBMP value using STC OINX. If there is no sale of the crude oil and the lessee bases its value on a weighted average of the affiliates' arm's-length purchases and/or sales under §1206.53, then the lessee must report using STC NARM.

Under paragraph (c) of the proposed rule, ONRR would calculate the IBMP value using the NYMEX CMA (excluding weekends and holidays) for each designated area less the LCTD. As explained above, the LCTD is based on the average difference between the NYMEX CMA and the major portion price at the 25th percentile by volume plus one barrel from highest price to lowest price, starting from the top (the top means that volume associated with the highest price

for any given month). For leases in Oklahoma, the IBMP value would include the “roll,” as defined above.

The IBMP value would be calculated as follows:

$$\text{IBMP value by Designated Area and CrudeType} = \left(\frac{\text{Current Month}}{\text{CMA}} \pm \text{Roll (if applicable)} \right) \times [1 - \text{LCTD}]$$

Paragraph (d) describes how ONRR would calculate the LCTD for each designated area. As explained above, LCTD captures the difference in value due to location and quality differences between Light Sweet Crude (WTI) at Cushing, Oklahoma and other crude oil types in each designated area. The LCTD also ensures that the IBMP price closely reflects the 75% major portion value of a particular crude type within the applicable designated area.

Paragraph (d) provides details on how ONRR would calculate the LCTD for each designated area. Initially, ONRR would establish the LCTD based on the previous year’s average annual difference between the NYMEX CMA and the Major Portion Price calculated by arraying all of the prices reported in a designated area from the highest to the lowest price and starting from the top of the array, determining that price associated with the 25th percentile by volume plus one barrel of oil. Paragraph (1) would explain that ONRR would calculate a separate LCTD for each crude type within each designated area using all data (arm’s-length and non-arm’s-length) payors report on Form ONRR-2014 for the previous 12 production months prior to the effective date of the rule. If ONRR does not have 12 months of data prior to the effective date of the rule, then it would assume the data is the same as that for the months for which data was reported. ONRR would apply this initial LCTD the first month after the effective date of the rule.

As an example, assume that for the initial LCTD for a specific designated area and crude type, ONRR calculated a prior year average annual major portion value of \$81.54. Further, assume that ONRR calculated a prior year average annual NYMEX CMA of \$95.12. Then assume that the effective date of the rule is March 30, 2015. Lastly, assume the NYMEX CMA for April 2015 is \$94.56. ONRR would calculate the LCTD for Designated Area X as follows:

$$\left(\frac{\$95.12 - \$81.54}{\$95.12}\right) = 0.1428 \text{ or } 14.28\%$$

ONRR would then apply the initial LCTD to the April 2015 NYMEX CMA to calculate the IBMP value as follows:

$$\$94.56 \times (1 - 0.1428) = \$81.06$$

If your gross proceeds value is more than the \$81.06 IBMP value, you would have to report your gross proceeds on Form ONRR-2014 using the appropriate STC other than OINX, such as ARMS. If your gross proceeds value is less than the \$81.06 IBMP value, then you would have to report the IBMP value using STC OINX.

Paragraph (d)(2) of the proposed rule outlines how ONRR would monitor the LCTD after its initial calculation. ONRR would monitor each of the designated areas' monthly sales volumes lessees report on their Form ONRR-2014s to identify when oil sales volumes not reported as STC OINX are either more than 28 percent or less than 22 percent of the total sales volumes reported in that designated area for a specific crude oil type. When sales volumes not reported as OINX for a specific crude oil type in a designated area exceed 28 percent or fall below 22 percent of the total volumes sold, ONRR would adjust the next month's LCTD down or up by 10 percent of the current month's LCTD. ONRR would then use the adjusted LCTD, along with the NYMEX CMA to calculate the next month's IBMP value. ONRR would continue to adjust the LCTD each month until the percentage of oil sales volumes not reported as OINX reflects

between 28 and 22 percent of all sales volumes within a designated area for the specified crude oil type. ONRR would publish the monthly IBMP value on its website at <http://www.onrr.gov>. The proposed rule provides two examples demonstrating how the trigger for the LCTD works. Paragraph (e) provides that ONRR would use its discretion to determine an appropriate IBMP value where there are insufficient royalty lines reported to ONRR on Form ONRR-2014 to determine a differential for a specific crude oil type. For example, there will be some instances, including, but not limited to, sales of condensate, where it is impossible for ONRR to calculate an appropriate differential. In those circumstances, ONRR would determine the IBMP value. ONRR is concerned that if an LCTD were to vary to a significant degree, for example +/- 20 percent, it could take ONRR numerous months to bring the LCTD back to within +/- 3 percent of the 25 percent of total oil sales volumes reported in a designated area for a specific crude oil type. Therefore, we specifically request comments on whether ONRR should modify paragraph (e) to provide that ONRR would use its discretion to determine an appropriate IBMP value where there are insufficient lines reported to ONRR on Form ONRR-2014 to determine a differential for a specific crude oil type or when the LCTD varies more than +/- 20 percent. We also request comments on what could constitute a significant variation.

Responsibility to Place Production into Marketable Condition and Market Production

(Section 1206.55)

This section would remain the same as current §1206.55. However, we propose to divide this section into two subsections, (a) and (b), and to write this section in plain language for clarity.

General Transportation Allowance Requirements (Section 1206.56)

This section would remain the same as current §1206.56 except for adding language from (1) the current §1206.57(a) stating that transportation allowances are subject to monitoring, review, adjustment, and audit and (2) the current §1206.51 and §1206.52 stating that you may not deduct gathering costs as transportation allowances or deductions. In addition, we propose to rewrite this section and its section name in plain language to provide clarity.

Arm’s-Length Contract Transportation Allowances (Section 1206.57)

Non-Arm’s-Length Contract or No Contract Transportation Allowances (Section 1206.58)

Late Payment Interest for Improper Transportation Allowance Reporting (Section 1206.59)

Reporting Adjustments for Transportation Allowances (Section 1206.60)

ONRR would reorganize §1206.57 into proposed new §§1206.57, 1206.58, 1206.59, and 1206.60. Proposed §1206.57 would govern how to determine and report transportation allowances if there is an arm’s-length transportation contract, currently in §1206.57(a) and (c)(1). Proposed §1206.58 would govern how to determine and report transportation allowances under non-arm’s-length transportation contracts, which is currently in §1206.57(b) and (c)(2). Section 1206.58 also includes existing paragraphs (f) and (g) of §1206.57 as proposed §1206.58(c) and (d). ONRR proposes to add §1206.59 to show how ONRR would calculate interest where a lessee improperly reports a transportation allowance. Currently, interest assessments for transportation allowances can be found in §1206.57(d). ONRR proposes to move the current provision in §1206.57(e)—adjusting transportation allowances—under proposed §1206.60.

ONRR Determination of Correct Royalty Payments (Section 1206.61)

Because of the changes in the proposed rule regarding transportation allowances, the proposed rule redesignates §1206.58 as §1206.61. In the proposed rule, the provisions are the same as in the existing rule in §1206.58 in substance but clarify how ONRR will determine if royalty payments are correct and what to do when royalty payments are incorrect.

Valuation Determination Requests (Section 1206.62)

Because of the changes in the proposed rule regarding transportation allowances, the proposed rule redesignates §1206.59 as §1206.62. This new section is the same as in the existing rule in substance in 1206.59. However, the proposed rule provides clarity by expanding how to request a valuation determination and how ONRR responds to such requests.

Determination of Royalty Quantity and Quality (Section 1206.63)

Because of the changes in the proposed rule regarding transportation allowances, the proposed rule redesignates §1206.60 as §1206.63. The provisions are the same as in the existing §1206.60.

Recordkeeping Requirements (Section 1206.64)

This proposed section is the same as current §1206.61. However, we propose to write this section in plain language for clarity.

ONRR's Protection of Information Submitted (Section 1206.65)

This proposed section is the same as current §1206.62. However, we propose to divide this section into three subsections, (a), (b), and (c), and to write in plain language for clarity.

B. Section-By-Section Analysis of Proposed Changes to 30 CFR Part 1210—Forms and Reports, Subpart B—Royalty Reports—Oil, Gas, and Geothermal Resources.

ONRR proposes to amend Part 1210 by adding §1210.61 that contains additional reporting requirements for crude oil. The new proposed §1210.61(a) requires payors to report Sales Type

Code ARMS on their Form ONRR-2014 when valuing oil under §1206.52. The new proposed §1210.61(b) requires payors to report Sales Type Code NARMS on their Form ONRR-2014 when valuing oil under §1206.53. The new proposed §1210.61(c) requires payors to report Sales Type Code OINX on their Form ONRR-2014 when valuing oil under §1206.54. Under §1210.61(d), crude oil type payors would report five crude oil types: (1) Sweet as product code 61; (2) sour as product code 62; (3) asphaltic as product code 63; (4) black wax as product code 64; and (5) yellow wax as product code 65.

Before the effective date of the rule, ONRR would explain that payors should report using the additional product codes reflecting the crude oil type of the Indian oil within a particular designated area on the payors' Form ONRR-2014s. Prior to the effective date of the rule, ONRR would issue a letter to all payors explaining when to begin reporting such product codes and how to report the crude oil types.

IV. Other Possible Changes ONRR May Consider

A. Transportation Allowances—Form Filing

For arm's-length transportation agreements, ONRR would like comments on removing the requirement under the current rule to file a Form ONRR-4110, Oil Transportation Allowance Report. Instead, the lessee would have to submit to ONRR copies of its arm's-length transportation contract(s) and any amendments thereto within 2 months after the lessee reported a transportation allowance on its Form ONRR-2014. This change would mirror the requirement to file arm's-length transportation contracts with ONRR, instead of a form, under the current Indian Gas Valuation Rule at §1206.178(a)(1)(i).

For non-arm's-length transportation arrangements, ONRR would like comments on eliminating the requirement that lessees submit a Form ONRR-4110 in advance with estimated

information. Lessees would still be required to submit the Form ONRR-4110. However, the lessee would submit actual cost information in support of the allowance on its Form ONRR-4110 within 3 months after the end of the 12-month period to which the allowance applies. This change would also mirror the 1999 Indian Gas Rule.

Of note, under the proposed rule, there would be no form filing requirements where a lessee values its oil under the IBMP value (proposed rule §1206.54). Thus, these changes to the form filing requirements would only apply to those lessees reporting their oil royalties as either gross proceeds under §1206.52 or as non-arm's-length under §1206.53.

As ONRR explained when it proposed these changes in the 1999 Indian Gas Rule, ONRR believes these changes “would ease the burden on industry and still provide ONRR with documents useful to verify the allowance claimed.”

ONRR requests comments on (1) eliminating the form filing requirement for arm's-length contracts and instead submitting the contract(s) to ONRR; and (2) removing the current rule's requirement that lessees reporting non-arm's-length transportation arrangements submit a Form ONRR-2014 with estimated information prior to taking the transportation allowance.

B. Transportation Factors:

ONRR requests comments on eliminating transportation factors from the regulations. Currently, §1206.57(a)(5) allows lessees to reduce their gross proceeds where their arm's-length transportation contract includes a provision reducing the applicable price by a transportation factor. Under the current rule, lessees report their gross proceeds net of the transportation factor on their Form ONRR-2014s. Thus, unlike the transportation allowances, which lessees report on their Form ONRR-2014s, ONRR cannot tell if lessees are taking a deduction for transportation when lessees report their gross proceeds net of a transportation factor. As such, the reporting

requirements for transportation factors are not transparent. Eliminating the ability to net an arm's-length transportation fee would require lessees to report these transportation fees as a transportation allowance. ONRR specifically requests comments on whether to eliminate transportation factors completely, which would require reporting of the arm's-length transportation as a transportation allowance on Form ONRR-2014.

C. Limiting Allowances:

ONRR is also considering removing the exception to the 50-percent limitation on transportation allowances. Under the current rule at §1206.56(b)(2), a lessee may request an exception to the rule that transportation allowances cannot exceed 50 percent of the value of the oil at the point of sale. ONRR seeks input on whether it would be a better exercise of the Secretary's trust responsibility to not allow cost allowances for transporting production from Indian leases to exceed 50 percent of the value of the oil. To date, ONRR has not received any requests to exceed the 50-percent limitation for transportation allowances. ONRR specifically requests comments on removing any exceptions to the 50-percent limitation on transportation allowances, under §1206.56(b)(1).

V. Procedural Matters

1. Summary Cost and Royalty Impact Data

We estimated the costs and benefits that this rulemaking may have on all potentially affected groups: Industry, Indian Lessors, and the Federal Government. The proposed amendment would result in an estimated annual increase in royalty collections of between \$19.4 million and \$20.6 million to be disbursed to Indian lessors. This net impact represents a minimal increase of between 3.82 percent and 3.93 percent of the total Indian oil royalties ONRR collected in 2012.

We also estimate that Industry and the Federal Government would experience one-time increased system costs of approximately \$ 4.84 million and \$247 thousand, respectively.

A. Industry

The table below lists ONRR’s low, mid-range, and high estimates of the costs that Industry would incur in the first year (excluding one-time system costs). Industry would incur these costs in the same amount each year thereafter.

Summary of Royalty Impacts to Industry		
Low	Mid	High
\$19,400,000	\$20,000,000	\$20,600,000

Cost—Using the Higher of the Index-Based Major Portion Formula Value or Gross Proceeds to Value Indian Oil Sales

As discussed above, we propose to add a provision under 30 CFR 1206.54 that explains how a lessee must meet its obligation to value oil produced from Indian leases based on the highest price paid for a major portion of like-quality oil from the field. The proposed rule defines the monthly IBMP value that lessee must compare to its gross proceeds and pay on the higher of those two values.

To perform this economic analysis, ONRR used royalty data we collected for Indian oil (product code 01) for calendar year 2012. We chose calendar year 2012 because most data reported has gone through ONRR edits and lessees have made most of their adjustments. We did not distinguish crude oil type within each designated area because (1) based on our experience, crude oil type within each designated area is generally the same and (2) lessees currently do not report crude oil type to ONRR.

We then segregated the data into the following 14 Designated Areas:

1. Uintah & Ouray—Uintah and Grand Counties

2. Uintah & Ouray—Duchesne County
3. North Fort Berthold
4. South Fort Berthold
5. Oklahoma—One statewide area excluding Osage County
6. Fort Peck
7. Turtle Mountain
8. Blackfeet Indian Reservation
9. Crow Indian Reservation
10. Jicarilla Apache Indian Reservation
11. Isabella Indian Reservation (Saginaw Chippewa)
12. Navajo Indian Reservation
13. Ute Mountain Ute Indian Reservation
14. Wind River Indian Reservation

We first arrayed the monthly reported prices net of transportation from highest to lowest and then calculated the monthly major portion price as that price at which 25 percent plus 1 barrel (by volume) of the oil is sold (starting from the highest price). Next, we calculated the difference between the reported prices and the major portion price. For any price below the major portion price, we multiplied the price difference by the royalty volume to estimate additional royalties.

Last, we totaled all of the monthly additional royalties for each designated area and then totaled all of the areas to arrive at an additional average royalty amount of \$20 million. This represents 3.70 percent of all Indian oil royalties collected in 2012 or approximately \$0.558/bbl.

Of note, we did not use the LCTD in this analysis. The LCTD is used in the IBMP value to

keep the gross proceeds volume near the 25th percentile, through monthly monitoring and adjustments to the LCTD. Rather, we used the actual monthly major portion price in our analysis. Because we used the actual monthly major portion price, we did not account for the potential +/- 3 percent volume variation adjustments the rule would allow. Instead, we created a +/- 3 percent range of royalty impacts above and below the estimated additional royalties, reflected in the table above.

Cost—System Changes to Accommodate Reporting of Crude Oil Type

ONRR needs to know crude oil types to calculate and publish the IBMP value. Therefore, proposed §1210.61 requires a lessee to report crude oil types using new product codes on the Form ONRR-2014. ONRR anticipates a lessee would need to make computer system changes to add these new product codes to their automated reporting.

We identified 205 Indian payors (those reporting and paying royalties to ONRR) in 2012. Of those, ONRR identified 32 as large businesses and 173 as small businesses (based on the SBA definition of a small business having 500 employees or less). To more accurately reflect the Indian payor community based on our experience, we reclassified the 173 small businesses into two categories – medium and small companies. We defined a medium company as those companies with between 250 and 500 employees. We also defined small companies as those companies with 250 or less employees. We classified 58 companies as medium companies and 115 companies as small companies.

ONRR first identified the changes we must make to our systems to accommodate the requirements (adding product codes and edits, changing and adding reports, and modifying Oil and Gas Operations Reports, Form ONRR-4054 (OGORs)) of this proposed rule and then estimated the number of hours needed to make those changes. We then multiplied those hours

by our estimated hourly cost (including contractors) to implement system changes. Some of the hours calculated for ONRR include costs Industry would not incur, such as eCommerce updates, changes to the compliance management tool, and web publishing.

We used this same process for large businesses, reducing or eliminating the hours for some categories but used the same hourly cost because most large companies employ system contractors similar to those ONRR employs, and, therefore, would have similar system change costs.

We reduced the hours for the medium (200 hours) and small companies (100 hours) to reflect the fact that their systems are smaller and less complex. We also reduced the hourly rate for medium and small businesses to \$100 and \$75, respectively, reflecting lower contractor costs.

The table below provides our estimate of system change costs for both ONRR and Industry.

System Changes	ONRR	Large Business	Medium Business	Small Business
Adding product codes to ONRR 2014–PS	100	100	100	50
Adding product codes to ONRR 2014–eCommerce	100	0	0	0
Adding new edit	150	75	0	0
Changing reports	250	100	0	0
Changes to CPT	150	0	0	0
Changes to Web publishing	150	0	0	0
Changes to OGOR/PASR form	150	100	100	50
Total hours	1,050	375	200	100
Average hourly rate	x \$235	x \$235	x \$100	x \$75
Cost per entity [Total hours x Average hourly rate]	\$246,750	\$88,125	\$20,000	\$7,500
Number of Businesses	N/A	x 32	x 58	x 115
Total cost		\$2,820,000	\$1,160,000	\$862,500
		Industry Grand Total		\$4,842,500

The table below lists the overall estimated first year economic impact to industry from the proposed changes, based on the mid-range estimate of costs:

Description	Annual (Cost)/Benefit Amount
Cost—Major Portion	(\$20,000,000)
Cost—System Changes	(\$4,842,500)
Net First Year Cost to Industry	(\$24,842,500)

After the first year, we anticipate the estimated cost to Industry to be approximately \$20,000,000 each year, based on 2012 data.

B. Indian Lessors

The impact to Indian Lessors would be a net overall increase in royalties as a result of this proposed change. This royalty increase would equal the royalty increase from Industry, or \$20 million.

C. Federal Government

Cost—System Changes to Accommodate Reporting of Crude Oil Type

The Federal Government would incur system costs to accommodate crude oil type reporting similar to Industry. As detailed above, ONRR estimates that it would take 1,050 hours to implement system changes related to the proposed rule equating to a total cost of \$246,750.

This rulemaking would have no impact on Federal royalties. We also believe that there would be no administrative cost increases to the Federal Government because the additional work needed to monitor and adjust the LCTD and IBMP value would be offset by administrative savings due to decreased audit and litigation costs.

D. Summary of Royalty Impacts and Costs to Industry, Indian Lessors, and the Federal Government.

In the table below, the negative values in the Industry column represent their estimated royalty and cost increases, while the positive values in the other columns represent the increase

in Indian royalty receipts. For purposes of this summary table, we assumed that the average for royalty increases is the midpoint of our range.

Summary of Costs & Royalties the First Year:			
	Industry	Indian	Federal Government
Annual Additional Royalties Paid	(\$20,000,000)	\$0	\$0
Cost to Modify Systems	(\$4,842,500)	\$0	(\$246,750)
Additional Royalties Received	\$0	\$20,000,000	\$0
Total	(\$24,842,500)	\$20,000,000	(\$246,750)

After the first year, the proposed rule will cost industry approximately \$20 million a year and Indian lessors will increase their annual royalty receipts by approximately \$20 million. The Federal Government will not incur any additional costs after the first year.

2. Regulatory Planning and Review (Executive Orders 12866 and 13563)

Executive Order (E.O.) 12866 provides that the Office of Information and Regulatory Affairs (OIRA) of the Office of Management and Budget (OMB) will review all significant rulemaking. OIRA has determined that this proposed rule is not significant.

Executive Order 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The executive order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. We have developed this proposed rule in a manner consistent with these requirements.

3. Regulatory Flexibility Act

The Department of the Interior certifies that this proposed rule would not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). Lessees of Federal and Indian mineral leases are generally companies classified under the North American Industry Classification System (NAICS) Code 211111, which includes companies that extract crude petroleum and natural gas. For this NAICS code classification, a small company is one with fewer than 500 employees. Approximately 205 different companies submit royalty and production reports from Indian leases to ONRR each month. In addition, approximately 32 companies are large businesses under the U.S. Small Business Administration definition because they have over 500 employees. The remaining 173 companies are considered to be small business.

As provided in *IA Industry* in the **Procedural Matters** section, we believe industry would incur a one-time cost to comply with the proposed rule. On average, ONRR estimates that each small business would incur a one-time cost of between of \$7,500 and \$20,000 to modify their systems to comply with this rulemaking.

As we stated earlier, we believe, based on 2012 Indian oil sales, the proposed rule would cost industry approximately \$20 million dollars a year. Small businesses only accounted for 13.55 percent of the oil volumes sold in 2012. Applying that percentage to industry costs, ONRR estimates that the proposed major portion provision would cost all small-business lessors approximately \$2,710,000 per year. The amount would vary for each company depending on the volume of production each small business produces and sells each year. We believe reduced administrative costs, such as reduced accounting, auditing, and litigation expenses, would offset some of these costs.

In sum, we do not believe this rulemaking would result in a significant economic effect on a substantial number of small entities because (1) the initial one-time cost to a small business to modify its system would be between \$7,500 and \$20,000; and (2) this proposed rule would cost the small businesses a collective total of \$2,710,000 per year.

ONRR encourages small businesses to comment on this proposed rule.

4. Small Business Regulatory Enforcement Fairness Act (SBREFA)

This proposed rule would not be a major rule under 5 U.S.C. 804(2), the Small Business Regulatory Enforcement Fairness Act. This rulemaking:

a. Would not have an annual effect on the economy of \$100 million or more. The effect would be limited to a maximum estimated at \$2,710,000 which equals the \$20,000,000 yearly cost of the proposed rule to industry at large multiplied by 13.55% (volumes sold attributable to small businesses).

b. Would not cause a major increase in costs or prices for consumers, individual industries, Federal, State, Indian, or local government agencies, or geographic regions.

c. Would not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of United States-based enterprises to compete with foreign-based enterprises.

5. Unfunded Mandates Reform Act

This proposed rule would not impose an unfunded mandate on State, local, or Tribal governments or the private sector of more than \$100 million per year. This rulemaking would not have a significant or unique effect on State, local, or Tribal governments or the private sector. A statement containing the information required by the Unfunded Mandates Reform Act (2 U.S.C. 1501 et seq.) would not be required.

6. *Takings (E.O. 12630)*

Under the criteria in section 2 of E.O. 12630, this proposed rule would not have any significant takings implications. This proposed rule would not impose conditions or limitations on the use of any private property. Therefore, a takings implication assessment is not required.

7. *Federalism (E.O. 13132)*

Under the criteria in section 1 of E.O. 13132, this proposed rule would not have sufficient federalism implications to warrant the preparation of a Federalism summary impact statement. This rulemaking would not substantially and directly affect the relationship between the Federal and State governments. The management of Indian leases is the responsibility of the Secretary of the Interior, and all royalties ONRR collects from Indian leases are distributed to Tribes and individual Indian mineral owners. Because this proposed rule would not alter that relationship, a Federalism summary impact statement is not required.

8. *Civil Justice Reform (E.O. 12988)*

This rulemaking would comply with the requirements of E.O. 12988. Specifically, this proposed rule:

- a. Would meet the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation.
- b. Would meet the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

9. *Consultation with Indian Tribal Governments, (E.O. 13175)*

The Department of the Interior strives to strengthen its government-to-government relationship with Indian Tribes through a commitment to consultation with Indian Tribes and recognition of their right to self-governance and Tribal sovereignty.

Under the Department's consultation policy and the criteria in E.O. 13175, we evaluated this proposed rule and determined that it would have no tribal implications that would impose substantial direct compliance costs on Indian tribal governments. Also, under this consultation policy and Executive Order criteria with Indian tribes and individual Indian mineral owners on all policy changes that may affect them, ONRR scheduled public meetings in three different locations for the purpose of consulting with Indian tribes and individual Indian mineral owners and to obtain public comments from other interested parties.

ONRR held consultation sessions with Tribes and individual Indian mineral owners on October 29, 2013, at the Civic Center in New Town, North Dakota; November 6, 2013, at Ft. Washakie, Wyoming; and December 14, 2013, at the Wes Watkins Technology Center at Wetumka, Oklahoma. ONRR plans to schedule additional consultation sessions with Tribes and individual Indian mineral owners to discuss and hear comments, including sessions in Albuquerque, New Mexico; Browning, Montana; and Ft. Duchesne, Utah.

10. Paperwork Reduction Act of 1995

This rulemaking would not contain new information collection requirements, and a submission to the Office of Management and Budget (OMB) would not be required under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). The proposed rule would modify §1210.61 to require a lessee of Indian leases to report additional product codes for crude oil types on Form ONRR-2014. Currently, OMB approved a total of 239,937 burden hours for lessees to file their Form ONRR-2014s under OMB Control Number 1012-0004. ONRR estimates no additional burden hours, beyond the initial hours that industry must incur to modify systems to accommodate the rule, to report the applicable crude oil type in the product code field.

11. National Environmental Policy Act

This proposed rule would not constitute a major Federal action significantly affecting the quality of the human environment. We are not required to provide a detailed statement under the National Environmental Policy Act of 1969 (NEPA) because this proposed rule qualifies for categorical exclusion under 43 CFR 46.210(c) and (i) and the DOI Departmental Manual, part 516, section 15.4.D: “(c) Routine financial transactions including such things as...audits, fees, bonds, and royalties... (i) Policies, directives, regulations, and guidelines: that are of an administrative, financial, legal, technical, or procedural nature.” We have also determined that this rulemaking is not involved in any of the extraordinary circumstances listed in 43 CFR 46.215 that would require further analysis under NEPA. The procedural changes resulting from the IBMP value would have no consequence on the physical environment. This proposed rule would not alter, in any material way, natural resources exploration, production, or transportation.

12. Effects on the Nation’s Energy Supply (E.O.13211)

This rulemaking would not be a significant energy action under the definition in E.O. 13211, and, therefore, would not require a Statement of Energy Effects.

13. Clarity of this Regulation

We are required by E.O. 12866 (section 1(b)(12)), E.O. 12988 (section 3(b)(1)(B)), E.O. 13563 (section 1(a)), and Presidential Memorandum of June 1, 1998, to write all rulemaking in plain language. This means that each rulemaking we publish must: (a) be logically organized; (b) use the active voice to address readers directly; (c) use common, everyday words, and clear language rather than jargon; (d) be divided into short sections and sentences; and (e) use lists and tables wherever possible.

If you feel that we have not met these requirements, send us comments by one of the methods listed in the **ADDRESSES** section. To help revise the proposed rule, write your comments as specific as possible. For example, you should tell us the numbers of the sections or paragraphs that you find unclear, which sections or sentences are too long, and the sections where you feel lists or tables would be useful, etc.

14. Public Availability of Comments

We will post all comments, including names and addresses of respondents, at *www.regulations.gov*. Before including Personally Identifiable Information (PII), such as address, phone number, email address, or other personal information in your comment(s), be advised that your entire comment (including PII) may be made available to the public at any time. While you can ask us, in your comment, to withhold PII from public view, we cannot guarantee that we will be able to do so.

List of Subjects in 30 CFR Parts 1206 and 1210

30 CFR Parts 1206

Coal, Continental shelf, Geothermal energy, Government contracts, Indians-lands, Mineral royalties, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements.

30 CFR Part 1210

Continental shelf, Indian leases, Geothermal energy, Government contracts, Indians-lands, Mineral royalties, Oil and gas reporting, Phosphate, Potassium, Reporting and recordkeeping requirements, Royalties, Sales contracts, Sales summary, Sodium, Solid minerals, Sulfur.

Dated: May 13, 2014.

Rhea Suh,
*Assistant Secretary for
Policy, Management and Budget.*

Authority and Issuance

For the reasons discussed in the preamble, ONRR proposes to amend 30 CFR parts 1206 and 1210 as follows:

PART 1206—PRODUCT VALUATION

1. The authority for part 1206 continues to read as follows:

AUTHORITY: 5 U.S.C. 301 *et seq.*; 25 U.S.C. 396 *et seq.*, 396a *et seq.*, 2101 *et seq.*; 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*; 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, and 1801 *et seq.*

2. Revise subpart B of part 1206 to read as follows:

Subpart B—Indian Oil

Sec.

1206.50 What is the purpose of this subpart?

1206.51 What definitions apply to this subpart?

1206.52 How do I calculate royalty value for oil that I or my affiliate sell(s) or exchange(s) under an arm's-length contract?

1206.53 How do I calculate royalty value for oil that I or my affiliate do(es) not sell under an arm's-length contract?

1206.54 How do I fulfill the lease provision regarding valuing production on the basis of the major portion of like-quality oil?

1206.55 What are my responsibilities to place production into marketable condition and to market production?

1206.56 What general transportation allowance requirements apply to me?

1206.57 How do I determine a transportation allowance if I have an arm's-length transportation contract?

1206.58 How do I determine a transportation allowance if I have a non-arm's-length transportation contract or have no contract?

1206.59 What interest applies if I improperly report a transportation allowance?

1206.60 What reporting adjustments must I make for transportation allowances?

1206.61 How will ONRR determine if my royalty payments are correct?

1206.62 How do I request a value determination?

1206.63 How do I determine royalty quantity and quality?

1206.64 What records must I keep to support my calculations of value under this subpart?

1206.65 Does ONRR protect information I provide?

Subpart B—Indian Oil

§1206.50 What is the purpose of this subpart?

(a) This subpart applies to all oil produced from Indian (tribal and allotted) oil and gas leases (except leases on the Osage Indian Reservation, Osage County, Oklahoma). This subpart does not apply to Federal leases, including Federal leases for which revenues are shared with Alaska Native Corporations. This subpart:

(1) Explains how you as a lessee must calculate the value of production for royalty purposes consistent with Indian mineral leasing laws, other applicable laws, and lease terms.

(2) Ensures the United States discharges its trust responsibilities for administering Indian oil and gas leases under the governing Indian mineral leasing laws, treaties, and lease terms.

(b) If you dispose of or report production on behalf of a lessee, the terms “you” and “your” in this subpart refer to you and not to the lessee. In this circumstance, you must determine and report royalty value for the lessee’s oil by applying the rules in this subpart to your disposition of the lessee’s oil.

(c) If the regulations in this subpart are inconsistent with:

(1) A Federal statute;

(2) A settlement agreement between the United States, Indian lessor, and a lessee resulting from administrative or judicial litigation;

(3) A written agreement between the Indian lessor, lessee, and the ONRR Director establishing a method to determine the value of production from any lease that ONRR expects at least would approximate the value established under this subpart; or;

(4) An express provision of an oil and gas lease subject to this subpart then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(d) ONRR or Indian Tribes, which have a cooperative agreement with ONRR to audit under 30 U.S.C. 1732, may audit, or perform other compliance reviews, and require a lessee to adjust royalty payments and reports.

§1206.51 What definitions apply to this subpart?

For purposes of this subpart:

Affiliate means a person who controls, is controlled by, or is under common control with another person.

(1) Ownership or common ownership of more than 50 percent of the voting securities, or instruments of ownership, or other forms of ownership, of another person constitutes control.

Ownership of less than 10 percent constitutes a presumption of noncontrol that ONRR may rebut.

(2) If there is ownership or common ownership of 10 through 50 percent of the voting securities or instruments of ownership, or other forms of ownership, of another person, ONRR will consider the following factors in determining whether there is control in a particular case:

(i) The extent to which there are common officers or directors;

(ii) With respect to the voting securities, or instruments of ownership, or other forms of ownership:

(A) The percentage of ownership or common ownership;

(B) The relative percentage of ownership or common ownership compared to the percentage(s) of ownership by other persons;

(C) Whether a person is the greatest single owner; and

(D) Whether there is an opposing voting bloc of greater ownership;

(iii) Operation of a lease, plant, or other facility;

(iv) The extent of participation by other owners in operations and day-to-day management of a lease, plant, or other facility; and

(v) Other evidence of power to exercise control over or common control with another person.

(3) Regardless of any percentage of ownership or common ownership, relatives, either by blood or marriage, are affiliates.

Area means a geographic region at least as large as the defined limits of an oil and/or gas field in which oil and/or gas lease products have similar quality, economic, and legal characteristics.

Arm's-length contract means a contract or agreement between independent persons who are not affiliates and who have opposing economic interests regarding that contract. To be considered arm's length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed.

Audit means a review, conducted under the generally accepted *Governmental Auditing Standards*, of royalty reporting and payment activities of lessees, designees, or other persons who pay royalties, rents, or bonuses on Indian leases.

BLM means the Bureau of Land Management of the Department of the Interior.

Condensate means liquid hydrocarbons (generally exceeding 40 degrees of API gravity) recovered at the surface without resorting to processing. Condensate is the mixture of liquid hydrocarbons that results from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

Contract means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

Designated area means an area ONRR designates for purposes of calculating Location and Crude Type Differentials applied to an IBMP value. ONRR will post designated areas on its website at www.onrr.gov. ONRR will monitor the market activity in the designated areas and, if necessary, hold a technical conference to review, modify, or add a particular designated area. ONRR will post any change to the designated areas on its website at www.onrr.gov. Criteria to determine any future changes to designated areas include, but are not limited to: Markets served, examples include refineries and/or market centers, such as Cushing, OK; Access to markets, examples include, access to similar

infrastructure, such as pipelines, rail lines, and trucking; and/or similar geography, for example, no challenging geographical divides, large rivers and/or mountains.

Exchange agreement means an agreement where one person agrees to deliver oil to another person at a specified location in exchange for oil deliveries at another location, and other consideration. Exchange agreements:

- (1) May or may not specify prices for the oil involved;
- (2) Frequently specify dollar amounts reflecting location, quality, or other differentials;
- (3) Include buy/sell agreements, which specify prices to be paid at each exchange point and may appear to be two separate sales within the same agreement, or in separate agreements; and
- (4) May include, but are not limited to, exchanges of produced oil for specific types of oil (e.g., WTI); exchanges of produced oil for other oil at other locations (location trades); exchanges of produced oil for other grades of oil (grade trades); and multi-party exchanges.

Field means a geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface. Onshore fields usually are given names, and their official boundaries are often designated by oil and gas regulatory agencies in the respective States in which the fields are located.

Gathering means the movement of lease production to a central accumulation 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 operations personnel.

Gross proceeds means the total monies and other consideration accruing for the disposition of oil produced. Gross proceeds also include, but are not limited to, the following examples:

(1) Payments for services, such as dehydration, marketing, measurement, or gathering that the lessee must perform at no cost to the lessor in order to put the production into marketable condition;

(2) The value of services to put the production into marketable condition, such as salt water disposal, that the lessee normally performs but that the buyer performs on the lessee's behalf;

(3) Reimbursements for harboring or terminalling fees;

(4) Tax reimbursements, even though the Indian royalty interest may be exempt from taxation;

(5) Payments made to reduce or buy down the purchase price of oil to be produced in later periods, by allocating those payments over the production whose price the payment reduces and including the allocated amounts as proceeds for the production as it occurs; and

(6) Monies and all other consideration to which a seller is contractually or legally entitled but does not seek to collect through reasonable efforts.

IBMP means the Index-Based Major Portion value calculated under §1206.54.

Indian Tribe means any Indian Tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any minerals or interest in minerals is held in trust by the United States or that is subject to Federal restriction against alienation.

Individual Indian mineral owner means any Indian for whom minerals or an interest in minerals is held in trust by the United States or who holds title subject to Federal restriction against alienation.

Lease means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under an Indian mineral leasing law that authorizes exploration

for, development or extraction of, or removal of lease products. Depending on the context, lease may also refer to the land area covered by that authorization.

Lease products means any leased minerals attributable to, originating from, or allocated to Indian leases.

Lessee means any person to whom the United States, a Tribe, or individual Indian mineral owner issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. Lessee includes:

- (1) Any person who has an interest in a lease (including operating rights owners); and
- (2) An operator, purchaser, or other person with no lease interest who reports and/or makes royalty payments to ONRR or the lessor on the lessee's behalf.

Lessor means an Indian Tribe or individual Indian mineral owner who has entered into a lease.

Like-quality oil means oil that has similar chemical and physical characteristics.

Location and Crude Type Differential (LCTD) means the difference in value between the average of the monthly NYMEX Calendar Monthly Averages (CMA) for the previous 12 months and the average of the monthly Major Portion Prices for the previous 12 months for a designated area for each crude oil type calculated under §1206.54.

$$\left[\frac{\text{Average of the Monthly NYMEX CMA for the Previous 12 Months} - \text{Average of the Monthly Major Portion Prices for the Previous 12 Months}}{\text{Average of the Monthly NYMEX CMA for the Previous 12 Months}} \right]$$

Location differential means an amount paid or received (whether in money or in barrels of oil) under an exchange agreement that results from differences in location between oil delivered in exchange and oil received in the exchange. A location differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell exchange agreement.

Major Portion Price means the highest price paid or offered at the time of production for the major portion of oil produced from the same designated area for the same crude oil type.

Marketable condition means 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.

Net means to reduce the reported sales value to account for transportation instead of reporting a transportation allowance as a separate entry on Form ONRR-2014.

NYMEX Calendar Month Average Price means the average of the New York Mercantile Exchange (NYMEX) daily settlement prices for light sweet oil delivered at Cushing, Oklahoma, calculated as follows:

(1) Sum the prices published for each day during the calendar month of production (excluding weekends and holidays) for oil to be delivered in the nearest month of delivery for which NYMEX futures prices are published corresponding to each such day; and

(2) Divide the sum by the number of days on which those prices are published (excluding weekends and holidays).

Oil means a mixture of hydrocarbons that existed in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities and is marketed or used as such. Condensate recovered in lease separators or field facilities is considered to be oil.

ONRR means the Office of Natural Resources Revenue of the Department of the Interior.

Operating rights owner, also known as a working interest owner, means any person who owns operating rights in a lease subject to this subpart. A record title owner is the owner of

operating rights under a lease until the operating rights have been transferred from record title (see Bureau of Land Management regulations at 43 CFR 3100.0-5(d)).

Person means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

Processing means any process designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes that 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.

Prompt month means the nearest month of delivery for which NYMEX futures prices are published during the trading month.

Quality differential means an amount paid or received under an exchange agreement (whether in money or in barrels of oil) that results from differences in API gravity, sulfur content, viscosity, metals content, and other quality factors between oil delivered and oil received in the exchange. A quality differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell agreement.

Roll means an adjustment to the NYMEX price that is calculated as follows: $Roll = .6667 \times (P_0 - P_1) + .3333 \times (P_0 - P_2)$, where: P_0 = the average of the daily NYMEX settlement prices for deliveries during the prompt month that is the same as the month of production, as published for each day during the trading month for which the month of production is the prompt month; P_1 = the average of the daily NYMEX settlement prices for deliveries during the month following the month of production, published for each day during the trading month for which the month of

production is the prompt month; and P_2 = the average of the daily NYMEX settlement prices for deliveries during the second month following the month of production, as published for each day during the trading month for which the month of production is the prompt month. Calculate the average of the daily NYMEX settlement prices using only the days on which such prices are published (excluding weekends and holidays).

(1) *Example 1. Prices in Out Months are Lower Going Forward:* The month of production for which you must determine royalty value is December 2012. December was the prompt month from October 23 through November 20. January was the first month following the month of production, and February was the second month following the month of production. P_0 therefore is the average of the daily NYMEX settlement prices for deliveries during December published for each business day between October 23 and November 20. P_1 is the average of the daily NYMEX settlement prices for deliveries during January published for each business day between October 23 and November 20. P_2 is the average of the daily NYMEX settlement prices for deliveries during February published for each business day between October 23 and November 20. In this example, assume that $P_0 = \$95.08$ per bbl; $P_1 = \$95.03$ per bbl; and $P_2 = \$94.93$ per bbl. In this example (a declining market), $\text{Roll} = .6667 \times (\$95.08 - \$95.03) + .3333 \times (\$95.08 - \$94.93) = \$0.03 + \$0.05 = \0.08 . You add this number to the NYMEX price.

(2) *Example 2. Prices in Out Months are Higher Going Forward:* The month of production for which you must determine royalty value is November 2012. November was the prompt month from September 21 through October 22. December was the first month following the month of production, and January was the second month following the month of production. P_0 therefore is the average of the daily NYMEX settlement prices for deliveries during November published for each business day between September 21 and October 22. P_1 is the average of the

daily NYMEX settlement prices for deliveries during December published for each business day between September 21 and October 22. P_2 is the average of the daily NYMEX settlement prices for deliveries during January published for each business day between September 21 and October 22. In this example, assume that $P_0 = \$91.28$ per bbl; $P_1 = \$91.65$ per bbl; and $P_2 = \$92.10$ per bbl. In this example (a rising market), $\text{Roll} = .6667 \times (\$91.28 - \$91.65) + .3333 \times (\$91.28 - \$92.10) = (-\$0.25) + (-\$0.27) = (-\$0.52)$. You add this negative number to the NYMEX price (effectively a subtraction from the NYMEX price).

Sale means a contract between two persons where:

- (1) The seller unconditionally transfers title to the oil to the buyer and does not retain any related rights such as the right to buy back similar quantities of oil from the buyer elsewhere;
- (2) The buyer pays money or other consideration for the oil; and
- (3) The parties' intent is for a sale of the oil to occur.

Sales type code means the contract type or general disposition (e.g., arm's-length or non-arm's-length) of production from the lease. The sales type code applies to the sales contract, or other disposition, and not to the arm's-length or non-arm's-length nature of a transportation allowance.

Trading month means the period extending from the second business day before the 25th day of the second calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the second business day before the last business day preceding the 25th day of that month) through the third business day before the 25th day of the calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the third business day before the last business day preceding the 25th day of that month), unless the NYMEX publishes

a different definition or different dates on its official Web site, *www.nymex.com*, in which case the NYMEX definition will apply.

Transportation allowance means a deduction in determining royalty value for the reasonable, actual costs of moving oil to a point of sale or delivery off the lease, unit area, or communitized area. The transportation allowance does not include gathering costs.

WTI means West Texas Intermediate.

You means a lessee, operator, or other person who pays royalties under this subpart.

§1206.52 How do I calculate royalty value for oil that I or my affiliate sell(s) or exchange(s) under an arm's-length contract?

(a) The value of production for royalty purposes for your lease is the higher of either the value determined under this section or the IBMP value calculated under §1206.54. The value of oil under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the arm's-length contract, less applicable allowances determined under §1206.56 or §1206.57. You must use this paragraph (a) to value oil when:

- (1) You sell under an arm's-length sales contract; or
- (2) You sell or transfer to your affiliate or another person under a non-arm's-length contract and that affiliate or person, or another affiliate of either of them, then sells the oil under an arm's-length contract.

(b) If you have multiple arm's-length contracts to sell oil produced from a lease that is valued under paragraph (a) of this section, the value of the oil is the volume-weighted average of the values established under this section for all contracts for the sale of oil produced from that lease.

(c) If ONRR determines that the gross proceeds accruing to you or your affiliate does not reflect the reasonable value of the production due to either:

(1) Misconduct by or between the parties to the arm's-length contract; or

(2) Breach of your duty to market the oil for the mutual benefit of yourself and the lessor,

ONRR will establish a value based on other relevant matters.

(i) ONRR will not use this provision to simply substitute its judgment of the market value of the oil for the proceeds received by the seller under an arm's-length sales contract.

(ii) The fact that the price received by the seller under an arm's-length contract is less than other measures of market price is insufficient to establish breach of the duty to market unless ONRR finds additional evidence that the seller acted unreasonably or in bad faith in the sale of oil produced from the lease.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's-length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include all of the consideration the buyer paid you or your affiliate, either directly or indirectly, for the oil.

(f) You must base value on the highest price that you or your affiliate can receive through legally enforceable claims under the oil sales contract.

(1) Absent contract revision or amendment, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate make timely application for a price increase or benefit allowed under your or your affiliate's contract but the purchaser refuses and you or your affiliate take reasonable documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting

from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of oil.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing and all parties to the contract must sign the contract, contract revisions, or amendments.

(2) This provision applies notwithstanding any other provisions in this title 30 of the *Code of Federal Regulations* to the contrary.

(h) If you or your affiliate enter(s) into an arm's-length exchange agreement, or multiple sequential arm's-length exchange agreements, then you must value your oil under this paragraph.

(1) If you or your affiliate exchange(s) oil at arm's length for WTI or equivalent oil at Cushing, Oklahoma, you must value the oil using the NYMEX price, adjusted for applicable location and quality differentials under paragraph (h)(3) of this section and any transportation costs under paragraph (h)(4) of this section and §1206.56 and §1206.57 or §1206.58.

(2) If you do not exchange oil for WTI or equivalent oil at Cushing, but exchange it at arm's length for oil at another location and following the arm's-length exchange(s) you or your affiliate sell(s) the oil received in the exchange(s) under an arm's-length contract, then you must use the gross proceeds under you or your affiliate's arm's-length sales contract after the exchange(s) occur(s), adjusted for applicable location and quality differentials under paragraph (h)(3) of this section and any transportation costs under paragraph (h)(4) of this section and §1206.56 and §1206.57 or §1206.58.

(3) You must adjust your gross proceeds for any location or quality differential, or other adjustments, you received or paid under the arm's-length exchange agreement(s). If ONRR determines that any exchange agreement does not reflect reasonable location or quality

differentials, ONRR may adjust the differentials you used based on relevant information. You may not otherwise use the price or differential specified in an arm's-length exchange agreement to value your production.

(4) If you value oil under this paragraph, ONRR will allow a deduction, under §1206.56 and §1206.57 or §1206.58, for the reasonable, actual costs to transport the oil:

(i) From the lease to a point where oil is given in exchange; and

(ii) If oil is not exchanged to Cushing, Oklahoma, from the point where oil is received in exchange to the point where the oil received in exchange is sold.

(5) If you or your affiliate exchange(s) your oil at arm's length, and neither paragraph (c)(1) nor (c)(2) of this section applies, ONRR will establish a value for the oil based on relevant matters. After ONRR establishes the value, you must report and pay royalties and any late payment interest owed based on that value.

§1206.53 How do I calculate royalty value for oil that I or my affiliate do(es) not sell under an arm's-length contract?

(a) The value of production for royalty purposes for your lease is the higher of either the value determined under this section or the IBMP value calculated under §1206.54. The unit value of your oil not sold under an arm's-length contract under this section for royalty purposes is the volume-weighted average of the gross proceeds paid or received by you or your affiliate, including your refining affiliate, for purchases or sales under arm's-length contracts.

(1) When calculating that unit value, use only purchases or sales of other like-quality oil produced from the field (or the same area if you do not have sufficient arm's-length purchases or sales of oil produced from the field) during the production month.

(2) You may adjust the gross proceeds determined under paragraph (a) of this section for transportation costs under paragraph (c) of this section and §1206.56 and §1206.57 or §1206.58 before including those proceeds in the volume-weighted average calculation.

(3) If you have purchases away from the field(s) and cannot calculate a price in the field because you cannot determine the seller’s cost of transportation that would be allowed under paragraph (c) of this section and §1206.56 and §1206.57 or §1206.58, you must not include those purchases in your volume-weighted average calculation.

(b) Before calculating the volume-weighted average, you must normalize the quality of the oil in your or your affiliate’s arm’s-length purchases or sales to the same gravity as that of the oil produced from the lease. Use applicable gravity adjustment tables for the field (or the same general area for like-quality oil if you do not have gravity adjustment tables for the specific field) to normalize for gravity, as shown in the example below.

Example (1) to paragraph (b): Assume that a lessee, who owns a refinery and refines the oil produced from the lease at that refinery, purchases like-quality oil from other producers in the same field at arm’s length for use as feedstock in its refinery. Further assume that the oil produced from the lease that is being valued under this section is Wyoming general sour with an API gravity of 23.5°. Assume that the refinery purchases at arm’s-length oil (all of which must be Wyoming general sour) in the following volumes of the API gravities stated at the prices and locations indicated:

10,000 bbl	24.5°	\$34.70/bbl	Purchased in the field.
8,000 bbl	24.0°	\$34.00/bbl	Purchased at the refinery after the third-party producer transported it to the refinery, and the lessee does not know the transportation costs.
9,000 bbl	23.0°	\$33.25/bbl	Purchased in the field.
4,000 bbl	22.0°	\$33.00/bbl	Purchased in the field.

Example (2) to paragraph (b): Because the lessee does not know the costs that the seller of the 8,000 bbl incurred to transport that volume to the refinery, that volume will not be included in the volume-weighted average price calculation. Further assume that the gravity adjustment scale provides for a deduction of \$0.02 per $\frac{1}{10}$ degree API gravity below 34°. Normalized to 23.5° (the gravity of the oil being valued under this section), the prices of each of the volumes that the refiner purchased that are included in the volume-weighted average calculation are as follows:

10,000 bbl	24.5°	\$34.50/bbl	(1.0° difference over 23.5° = \$0.20 deducted).
9,000 bbl	23.0°	\$33.35/bbl	(0.5° difference under 23.5° = \$0.10 added).
4,000 bbl	22.0°	\$33.30/bbl	(1.5° difference under 23.5° = \$0.30 added).

Example (3) to paragraph (b): The volume-weighted average price is $((10,000 \text{ bbl} \times \$34.50/\text{bbl}) + (9,000 \text{ bbl} \times \$33.35/\text{bbl}) + (4,000 \text{ bbl} \times \$33.30/\text{bbl})) / 23,000 \text{ bbl} = \$33.84/\text{bbl}$. That price will be the value of the oil produced from the lease and refined prior to an arm's-length sale, under this section.

(c) If you value oil under this section, ONRR will allow a deduction, under §1206.56 and §1206.57 or §1206.58, for the reasonable, actual costs:

(1) That you incur to transport oil that you or your affiliate sell(s), which is included in the volume-weighted average price calculation, from the lease to the point where the oil is sold; and

(2) That the seller incurs to transport oil that you or your affiliate purchase(s), which is included in the volume-weighted average cost calculation, from the property where it is produced to the point where you or your affiliate purchase(s) it. You may not deduct any costs of gathering as part of a transportation deduction or allowance.

(d) If paragraphs (a) and (b) of this section result in an unreasonable value for your production as a result of circumstances regarding that production, the ONRR Director may establish an alternative valuation method.

§1206.54 How do I fulfill the lease provision regarding valuing production on the basis of the major portion of like-quality oil?

(a) This section applies to any Indian leases that contain a major portion provision for determining value for royalty purposes. This section also applies to any Indian leases that provide that the Secretary may establish value for royalty purposes. The value of production for royalty purposes for your lease is the higher of either the value determined under this section or the gross proceeds you calculated under §1206.52 or §1206.53.

(b) You must submit a monthly Form ONRR-2014 using the higher of IBMP value determined under this section or your gross proceeds under §1206.52 or §1206.53. Your Form ONRR-2014 must meet the requirements of 30 CFR 1210.61 of this chapter.

(c) ONRR will determine the monthly IBMP value for each designated area and crude oil type and post those values on its website at *www.onrr.gov*. The monthly IBMP value by designated area and crude oil type is calculated as follows:

(1) For Indian leases located in Oklahoma:

$$\left[\left(\frac{\text{NYMEX CMA}}{\text{Price}} \right)_{\pm} (\text{Roll}) \right] \times (1 - \text{LCTD})$$

(2) For all other Indian leases:

$$\left(\frac{\text{NYMEX CMA}}{\text{Price}} \right) \times (1 - \text{LCTD})$$

(d) ONRR will calculate the LCTD for each designated area (the same designated areas posted on its website at *www.onrr.gov*) and crude oil type using the following formula:

$$\frac{[(\text{Average of Monthly NYMEX CMA for Previous 12 Months} - \text{Average of Monthly Major Portion Prices for Previous 12 Months})]}{\text{Average of Monthly NYMEX CMA for Previous 12 Months}}$$

(1) For the first full production month after this rule is effective, ONRR will calculate the monthly Major Portion Prices using data reported on the Form ONRR-2014 for the previous 12 production months prior to the effective date of this rule (Previous Twelve Months). To the extent ONRR does not have data on the Form ONRR-2014 regarding the crude oil type for the entire previous twelve months, ONRR will assume the crude oil type is the same for those months for which ONRR does not have data as the months for which the crude oil type was reported on the Form ONRR-2014 for the same leases and/or agreements.

(i) ONRR will array the calculated prices net of transportation by month from highest to lowest price for each designated area and crude oil type. For each month, ONRR will calculate the Major Portion Price as that price at which 25 percent plus 1 barrel (by volume) of the oil (starting from the highest) is sold;

(ii) To calculate the average of the monthly Major Portion Prices for the previous 12 months, ONRR will add the monthly Major Portion Prices calculated in paragraph (A) and divide by 12.

(2) For every month following the first full production month after this rule is effective, ONRR will monitor the LCTD using data reported on the Form ONRR-2014 for the previous month.

(i) ONRR will use the oil sales volume reported by lessees on Form ONRR-2014 to monitor and, if necessary, to modify the LCTD used in the IBMP value.

(ii) ONRR will monitor oil sales volumes not reported under the sales type code OINX, as provided in 30 CFR 1210.61(a) and (b), on the Form ONRR-2014 on a monthly basis by designated area and crude oil type.

(iii) If the monthly oil sales volumes not reported under the sales type code OINX varies +/- 3 percent from 25 percent of the total reported oil sales volume for the month, then ONRR will revise the LCTD prospectively starting with the following month.

(A) If monthly oil sales volumes not reported under the sales type code OINX on the Form ONRR-2014 by the designated area and crude oil type fall below 22 percent, ONRR will increase the LCTD by 10 percent every month until the monthly oil sales volumes reported under the sales type code for gross proceeds on the Form ONRR-2014 fall within the +/- 3 percent range. In Example 1, assume the IBMP value is \$81.06 and the LCTD for the designated area is 14.28%. In the table below, the Percent of Volume not as OINX reported is less than 22%, which triggers a modification to the LCTD. ONRR will adjust the LCTD upward by 10% (14.28% x 1.10). Therefore, for the next month the LCTD will be 15.71%. In the following month, the IBMP value will equal the next month's NYMEX CMA multiplied by (1 - 0.1571). ONRR will continue to make adjustments in subsequent months, until monthly sales volumes not reported as OINX fall within 22–28% of total monthly sales volume.

Example 1: Differential Adjustment When ARMS Sales Volume for the Current Month Falls Below 22% of Total Monthly Sales Volume					
Lease	Sales Volume	Unit Price	Sales Type Code	Cumulative Volume	Percent of Volume
1	220	81.95	ARMS	220	9.02%
2	275	81.71	ARMS	495	20.29%
3	400	81.06	OINX	895	36.68%
4	425	81.06	OINX	1,320	54.10%
5	370	81.06	OINX	1,690	69.26%
6	400	81.06	OINX	2,090	85.66%
7	350	81.06	OINX	2,440	100.00%
	2,440				

(B) If monthly oil sales volumes not reported under the sales type code OINX on the Form ONRR-2014 by designated area and crude oil type exceed 28 percent, then ONRR will decrease the LCTD by 10 percent every month until the monthly oil sales volumes reported under the sales type code for gross proceeds on the Form ONRR-2014 fall within the +/- 3 percent range. In Example 2, assume the IBMP value is \$81.06 and the LCTD is 14.28%. However, as noted in the table below, the Percent of Volume not reported as OINX is 32.69%, exceeding the 28% threshold, which triggers a modification to the LCTD. ONRR will adjust the LCTD downward by 10% (14.28% x 0.90). Therefore, for the next month the LCTD will be 12.85%. In the following month, the IBMP will equal the next month's NYMEX CMA multiplied by (1 – 0.1285). ONRR will continue to make adjustments in subsequent months, until monthly sales volumes reported as ARMS fall within 22 – 28% of total monthly sales volume.

Example 2: Differential Adjustment When ARMS Sales Volume Not Reported as OINX for the Current Month Exceeds 28% of Total Monthly Sales Volume					
Lease	Sales Volume	Unit Price	Sales Type Code	Cumulative Volume	Percent of Volume
1	230	81.95	ARMS	230	11.06%
2	275	81.71	ARMS	505	24.28%
3	175	81.45	ARMS	680	32.69%
4	250	81.06	OINX	930	44.71%
5	425	81.06	OINX	1,355	65.14%
6	325	81.06	OINX	1,680	80.77%
7	400	81.06	OINX	2,080	100.00%
	2,080				

(e) In areas where there is insufficient data reported to ONRR on Form ONRR-2014 to determine a differential for a specific crude oil type, ONRR will use its discretion to determine an appropriate IBMP value.

§1206.55 What are my responsibilities to place production into marketable condition and to market production?

(a) 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 Indian lessor unless the lease agreement provides otherwise.

(b) If you must use gross proceeds under an arm's-length contract or your affiliate's gross proceeds under an arm's-length exchange agreement to determine value under 30 CFR 1206.52 or 1206.53, 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.

§1206.56 What general transportation allowance requirements apply to me?

(a) ONRR will allow a deduction for the reasonable, actual costs to transport oil from the lease to the point off the lease under §1206.52 or §1206.53, as applicable. You may not deduct transportation costs to reduce royalties where you did not incur any costs to move a particular volume of oil. ONRR will not grant a transportation allowance for transporting oil taken as Royalty-In-Kind (RIK).

(b)(1) Except as provided in paragraph (b)(2) of this section, your transportation allowance deduction on the basis of a sales type code may not exceed 50 percent of the value of the oil at the point of sale as determined under §1206.52 of this subpart. Transportation costs cannot be transferred between sales type codes or to other products.

(2) Upon your request, ONRR may approve a transportation allowance deduction in excess of the limitation prescribed by paragraph (b)(1) of this section. You must demonstrate that the transportation costs incurred in excess of the limitation prescribed in paragraph (b)(1) of this

section were reasonable, actual, and necessary. An application for exception (using Form ONRR-4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation necessary for ONRR to make a determination. Under no circumstances may the value, for royalty purposes, under any sales type code, be reduced to zero.

(c) You must express transportation allowances for oil in dollars per barrel. If you or your affiliate's payments for transportation under a contract are not on a dollar per barrel basis, you must convert whatever consideration you or your affiliate are paid to a dollar per barrel equivalent.

(d) You must allocate transportation costs among all products produced and transported as provided in §1206.57.

(e) All transportation allowances are subject to monitoring, review, audit, and adjustment.

(f) If, after a review or audit, ONRR determines you have improperly determined a transportation allowance authorized by this subpart, then you must pay any additional royalties due, plus late payment interest calculated under §1218.54 of this chapter or report a credit for, or request a refund of, any overpaid royalties without interest under §1218.53 of this chapter.

(g) You may not deduct any costs of gathering as part of a transportation deduction or allowance.

§1206.57 How do I determine a transportation allowance if I have an arm's-length transportation contract?

(a) *Arm's-length transportation.* (1) If you incur transportation costs under an arm's-length contract, your transportation allowance is the reasonable, actual costs you incur to transport oil under that contract. You have the burden of demonstrating that your contract is arm's-length.

(2) Before you may take any deduction, you must submit a completed page one and Schedule 1 of Form ONRR-4110, Oil Transportation Allowance Report, under paragraph (b)(1) of this section. You may claim a transportation allowance retroactively for a period of not more than 3 months prior to the first day of the month that you filed Form MMS-4110 with ONRR, unless ONRR approves a longer period upon you showing good cause.

(3) If ONRR determines that the consideration paid under an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then ONRR shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When ONRR determines that the value of the transportation may be unreasonable, ONRR will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(4)(i) If an arm's-length transportation contract includes more than one liquid product, and the transportation costs attributable to each product cannot be determined from the contract, then you must allocate the total transportation costs in a consistent and equitable manner to each of the liquid products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all liquid products (excluding waste products which have no value). Except as provided in this paragraph, you may not take an allowance for the costs of transporting lease production which is not royalty-bearing without ONRR approval.

(ii) Notwithstanding the requirements of paragraph (4)(i) of this section, you may propose to ONRR a cost allocation method on the basis of the values of the products transported. ONRR

shall approve the method unless it determines it is not consistent with the purposes of the regulations in this part.

(5) If an arm's-length transportation contract includes both gaseous and liquid products, and the transportation costs attributable to each product cannot be determined from the contract, you must propose an allocation procedure to ONRR.

(i) You may use the oil transportation allowance determined in accordance with its proposed allocation procedure until ONRR issues its determination on the acceptability of the cost allocation.

(ii) You must submit to ONRR all available data to support your proposal.

(iii) You must submit your initial proposal within 3 months after the last day of the month for which you request a transportation allowance, whichever is later (unless ONRR approves a longer period).

(iv) ONRR will determine the oil transportation allowance based on your proposal and any additional information ONRR deems necessary.

(6) Where an arm's-length sales contract price includes a provision whereby the listed price is reduced by a transportation factor, ONRR will not consider the transportation factor to be a transportation allowance. You may use the transportation factor to determine your gross proceeds for the sale of the product. The transportation factor may not exceed 50 percent of the base price of the product without ONRR approval.

(b) *Reporting requirements.* (1) With the exception of the transportation allowances specified in paragraph (b)(5) of this section, you must submit page one and Schedule 1 of the initial Form ONRR-4110, Oil Transportation Allowance Report, prior to, or at the same time as you report the transportation allowance you determined under an arm's-length contract on Form

ONRR-2014, Report of Sales and Royalty Remittance. If ONRR receives your Form ONRR-4110 by the end of the month the Form ONRR-2014 is due, ONRR will consider it timely received.

(2) Your initial Form ONRR-4110 is effective for a reporting period beginning the month you are first authorized to deduct a transportation allowance and will continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(3) After the initial reporting period and for succeeding reporting periods, you must submit page one and Schedule 1 of Form ONRR-4110 within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless ONRR approves a longer period (during which period you must continue to use the allowance from the previous reporting period).

(4) ONRR may require you to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. You must submit documents within a reasonable time ONRR determines.

(5) ONRR may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

§1206.58 How do I determine a transportation allowance if I have a non-arm's-length transportation contract or have no contract?

(a) *Non-arm's-length or no contract.* (1) If you have a non-arm's-length transportation contract or no contract, including those situations where you or your affiliate perform(s) transportation services for you, the transportation allowance is based on your reasonable, actual costs as provided in this paragraph.

(2) Before you may take any estimated or actual deduction, you must submit a completed Form ONRR-4110 in its entirety under paragraph (b) of this section. You may claim a transportation allowance retroactively for a period of not more than 3 months prior to the first day of the month that you filed Form ONRR-4110 with ONRR, unless ONRR approves a longer period upon you showing good cause.

(3) You must base a transportation allowance for non-arm's-length or no-contract situations on your actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment under paragraph (a)(3)(iv)(A) of this section, or a cost equal to the initial capital investment in the transportation system multiplied by a rate of return under paragraph (a)(3)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) You may use either depreciation or a return on depreciable capital investment. After you have elected to use either method for a transportation system, you may not later elect to change to the other alternative without approval of ONRR.

(A) To compute depreciation, you may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services or on a unit-of-production method. After you make an election, you may not change methods without ONRR approval. A change in ownership of a transportation system shall not alter the depreciation schedule the original transporter/lessee established for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. You may not depreciate equipment below a reasonable salvage value.

(B) ONRR will allow as a cost an amount equal to the initial capital investment in the transportation system multiplied by the rate of return determined under paragraph (a)(3)(v) of this section. No allowance shall be provided for depreciation.

(v) The rate of return is the industrial rate associated with Standard and Poor's BBB rating. The rate of return you must use is the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the reporting period for which the allowance is applicable and is effective during the reporting period. You must redetermine the rate at the beginning of each subsequent transportation allowance reporting period (which is determined under paragraph (b) of this section).

(4)(i) You must determine the deduction for transportation costs based on your or your affiliate's cost of transporting each product through each individual transportation system. Where more than one liquid product is transported, you must allocate costs to each of the liquid products transported in the same proportion as the ratio of the volume of each liquid product

(excluding waste products which have no value) to the volume of all liquid products (excluding waste products which have no value) and you must make such allocation in a consistent and equitable manner. Except as provided in this paragraph, you may not take an allowance for transporting lease production which is not royalty-bearing without ONRR approval.

(ii) Notwithstanding the requirements of paragraph (4)(i) of this section, you may propose to ONRR a cost allocation method on the basis of the values of the products transported. ONRR will approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(5) Where both gaseous and liquid products are transported through the same transportation system, you must propose a cost allocation procedure to ONRR.

(i) You may use the oil transportation allowance determined in accordance with its proposed allocation procedure until ONRR issues its determination on the acceptability of the cost allocation.

(ii) You must submit to ONRR all available data to support your proposal.

(iii) You must submit your initial proposal within 3 months after the last day of the month for which you request a transportation allowance, whichever is later (unless ONRR approves a longer period).

(iv) ONRR will determine the oil transportation allowance based on your proposal and any additional information ONRR deems necessary.

(6) You may apply to ONRR for an exception from the requirement that you compute actual costs under paragraphs (a)(1) through (a)(5) of this section.

(i) ONRR will grant the exception only if you have a tariff for the transportation system the Federal Energy Regulatory Commission (FERC) has approved for Indian leases.

(ii) ONRR will deny the exception request if it determines the tariff is excessive as compared to arm's-length transportation charges by pipelines, owned by the lessee or others, providing similar transportation services in that area.

(iii) If there are no arm's-length transportation charges, ONRR will deny the exception request if:

(A) No FERC cost analysis exists and the FERC has declined to investigate under ONRR timely objections upon filing; and

(B) The tariff significantly exceeds the lessee's actual costs for transportation as determined under this section.

(b) *Reporting requirements.* (1) With the exception of those transportation allowances specified in paragraphs (b)(1)(v), (b)(1)(vii) and (b)(1)(viii) of this section, you must submit an initial Form ONRR-4110 prior to, or at the same time as, the transportation allowance you determine under a non-arm's-length contract or no-contract situation is reported on Form ONRR-2014. If ONRR receives your Form ONRR-4110 by the end of the month the Form ONRR-2014 is due, ONRR will consider it timely received. You may base the initial report on estimated costs.

(ii) Your initial Form ONRR-4110 is effective for a reporting period beginning the month you are first authorized to deduct a transportation allowance and will continue until the end of the calendar year, or until transportation under the non-arm's-length contract or the no-contract situation terminates, whichever is earlier.

(iii) After the initial reporting period, you must submit a completed Form ONRR-4110 containing the actual costs for the previous reporting period. If oil transportation is continuing, you must include on Form ONRR-4110 your estimated costs for the next calendar year. You

must estimate your oil transportation allowance based on the actual costs for the previous reporting period plus or minus any adjustments which are based on your knowledge of decreases or increases that will affect the allowance. ONRR must receive the Form ONRR-4110 within 3 months after the end of the previous reporting period, unless ONRR approves a longer period (during which period you must continue to use the allowance from the previous reporting period).

(iv) For new transportation facilities or arrangements, your initial Form ONRR-4110 must include estimates of the allowable oil transportation costs for the applicable period. You must base cost estimates on the most recently available operations data for the transportation system or, if such data are not available, you must use estimates based upon industry data for similar transportation systems.

(v) Non-arm's-length contract or no-contract transportation allowances which are in effect at the time these regulations become effective are allowed to continue until such allowances terminate. For the purposes of this section, only those allowances ONRR has approved in writing qualify as being in effect at the time these regulations become effective.

(vi) ONRR may require you to submit all data you used to prepare your Form ONRR-4110. You must submit the data within a reasonable period of time ONRR determines.

(vii) ONRR may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(viii) If you are authorized to use your FERC-approved tariff as your transportation cost under paragraph (a)(6) of this section, you must follow the reporting requirements of §1206.57(b).

(3) ONRR may establish reporting dates for you that are different from those specified in this subpart to provide more effective administration. We will notify you of any change in your reporting period.

(4) You must report transportation allowances as a separate entry on Form ONRR-2014 unless ONRR approves a different reporting procedure.

(c) Notwithstanding any other provisions of this subpart, for other than arm's-length contracts, no cost shall be allowed for oil transportation which results from payments (either volumetric or for value) for actual or theoretical losses. This section does not apply when the transportation allowance is based upon a FERC or State regulatory agency approved tariff.

(d) The provisions of this section shall apply to determine transportation costs when establishing value using a netback valuation procedure or any other procedure that requires deduction of transportation costs.

§1206.59 What interest applies if I improperly report a transportation allowance?

(a) If you deduct a transportation allowance on Form ONRR-2014 without complying with the requirements of §1206.56 and §1206.57 or §1206.58, you must pay additional royalties due, plus late payment interest calculated under §1218.54 of this chapter.

(b) If you erroneously report a transportation allowance which results in an underpayment of royalties, you must pay any additional royalties due, plus late payment interest calculated under §1218.54 of this chapter.

§1206.60 What reporting adjustments must I make for transportation allowances?

(a) If your actual transportation allowance is less than the amount you claimed on Form ONRR-2014 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under §1218.54 of this chapter from first day

of the first month you were authorized to deduct a transportation allowance to the date you repay the difference.

(b) If the actual transportation allowance is greater than the amount you claimed on Form ONRR-2014 for any month during the period reported on the allowance form, you may report a credit for, or request a refund of, any overpaid royalties without interest under §1218.53 of this chapter.

(c) If you make an adjustment under paragraph (a) or (b) of this section, then you must submit a corrected Form ONRR-2014 to reflect actual costs, together with any payment, using instructions ONRR provides.

§1206.61 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties you report, and, if ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR may direct you to use a different measure of royalty value.

(2) If ONRR directs you to use a different royalty value, you must pay any additional royalties due, plus late payment interest calculated under §1218.54 of this chapter or you may report a credit for, or request a refund of, any overpaid royalties without interest under §1218.53 of this chapter.

(b) When the provisions in this subpart refer to gross proceeds, in conducting reviews and audits, ONRR will examine if your or your affiliate's contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to you or your affiliate for the oil. If ONRR determines that a contract does not reflect the total consideration, you must value the oil sold as the total consideration accruing to you or your affiliate.

§1206.62 How do I request a value determination?

(a) You may request a value determination from ONRR regarding any oil produced. Your request must:

(1) Be in writing;

(2) Identify specifically all leases involved, all interest owners of those leases, the designee(s), and the operator(s) for those leases;

(3) Completely explain all relevant facts. You must inform ONRR of any changes to relevant facts that occur before we respond to your request;

(4) Include copies of all relevant documents;

(5) Provide your analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and

(6) Suggest your proposed valuation method.

(b) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Indian Affairs issue a valuation determination;

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance.

Situations in which ONRR typically will not provide any determination or guidance include, but are not limited to:

(i) Requests for guidance on hypothetical situations; and

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A value determination the Assistant Secretary for Indian Affairs signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a value determination, you must make any adjustments to royalty payments that follow from the determination and, if you owe additional

royalties, you must pay the additional royalties due, plus late payment interest calculated under §1218.54 of this chapter.

(3) A value determination the Assistant Secretary signs is the final action of the Department and is subject to judicial review under 5 U.S.C. 701–706.

(d) Guidance ONRR issues is not binding on ONRR, the Indian lessor, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR’s decision whether or not to issue guidance or request an Assistant Secretary determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

(2) If you receive an order requiring you to pay royalty on the same basis as the guidance, you may appeal that order under 30 CFR part 1290.

(e) ONRR or the Assistant Secretary may use any of the applicable valuation criteria in this subpart to provide guidance or make a determination.

(f) A change in an applicable statute or regulation on which ONRR or the Assistant Secretary based any determination or guidance takes precedence over the determination or guidance, regardless of whether ONRR or the Assistant Secretary modifies or rescinds the determination or guidance.

(g) ONRR or the Assistant Secretary generally will not retroactively modify or rescind a value determination issued under paragraph (d) of this section, unless:

(1) There was a misstatement or omission of material facts; or

(2) The facts subsequently developed are materially different from the facts on which the guidance was based.

(h) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under §1206.65.

§1206.63 How do I determine royalty quantity and quality?

(a) You must calculate royalties based on the quantity and quality of oil as measured at the point of royalty settlement that BLM approves.

(b) If you determine the value of oil under §1206.52, §1206.53, or §1206.54 of this subpart based on a quantity and/or quality that is different from the quantity and/or quality at the point of royalty settlement BLM approves for the lease, you must adjust that value for the differences in quantity and/or quality.

(c) You may not make any deductions from the royalty volume or royalty value for actual or theoretical losses incurred before the royalty settlement point unless BLM determines that any actual loss was unavoidable.

§1206.64 What records must I keep to support my calculations of value under this subpart?

If you determine the value of your oil under this subpart, you must retain all data relevant to the determination of royalty value.

(a) You must show:

(1) How you calculated the value you reported, including all adjustments for location, quality, and transportation; and

(2) How you complied with these rules.

(b) On request, you must make available sales, volume, and transportation data for production you sold, purchased, or obtained from the field or area. You must make this data available to ONRR, Indian representatives, or other authorized persons.

(c) You can find recordkeeping requirements in §§1207.5, 1212.50, and 1212.51 of this chapter.

(d) ONRR, Indian representatives, or other authorized persons may review and audit your data, and ONRR will direct you to use a different value if they determine that the reported value is inconsistent with the requirements of this subpart.

§1206.65 Does ONRR protect information I provide?

(a) Certain information you or your affiliate submit(s) to ONRR regarding valuation of oil, including transportation allowances, may be exempt from disclosure.

(b) To the extent applicable laws and regulations permit, ONRR will keep confidential any data you or your affiliate submit(s) that is privileged, confidential, or otherwise exempt from disclosure.

(c) You and others must submit all requests for information under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

PART 1210—FORMS AND REPORTS

3. The authority citation for part 1210 continues to read as follows:

AUTHORITY: 5 U.S.C. 301 *et seq.*; 25 U.S.C. 396, 2107; 30 U.S.C. 189, 190, 359, 1023, 1751(a); 31 U.S.C. 3716, 9701; 43 U.S.C. 1334, 1801 *et seq.*; and 44 U.S.C. 3506(a).

Subpart B—Royalty Reports—Oil, Gas, and Geothermal Resources

4. Add §1210.61 to subpart B to read as follows:

§1210.61 What additional reporting requirements must I meet for Indian oil valuation purposes?

(a) If you must report and pay under §1206.52 of this chapter, you must use Sales Type Code ARMS on Form ONRR-2014.

(b) If you must report and pay under §1206.53 of this chapter, you must use Sales Type Code NARM on Form ONRR-2014.

(c) If you must report and pay under §1206.54 of this chapter, you must use Sales Type Code OINX on Form ONRR-2014;

(d) You must report one of the following crude oil types in the product code field of Form ONRR-2014:

(1) Sweet (code 61);

(2) Sour (code 62);

(3) Asphaltic (code 63);

(4) Black Wax (code 64); or

(5) Yellow Wax (code 65);

(e) All of the remaining requirements of this subpart apply.

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