authority delegated to the Commissioner of Food and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR part 524 is amended as follows:

PART 524—OPHTHALMIC OR TOPICAL DOSAGE FORM NEW ANIMAL DRUGS

1. The authority citation for 21 CFR part 524 continues to read as follows:

Authority: 21 U.S.C. 360b.

2. Section 524.770 is added to read as follows:

§ 524.770 Doramectin.

(a) *Specifications*. Each milliliter of solution contains 5 milligrams of doramectin.

(b) *Sponsor*. See 000069 in § 510.600(c) of this chapter.

(c) *Related tolerances*. See § 556.225 of this chapter.

(d) *Conditions of use—Cattle*—(1) *Amount*. 5 milligrams per 10 kilograms (5 milligrams per 22 pounds).

(2) *Indications for use*. For treatment and control of infections of gastrointestinal roundworms, lungworms, eyeworms, grubs, biting and sucking lice, and mange mites, and to control infections and to protect from reinfection with *Cooperia oncophora* and *Dictyocaulus viviparus* for 21 days, and *Ostertagia ostertagia*, *C. punctata*, and *Oesophagostomum radiatum* for 28 days after treatment.

(3) *Limitations*. Administer as a single dose. Do not slaughter cattle within 45 days of latest treatment. Not for use in female dairy cattle 20 months of age or older. Do not use in calves to be processed for veal. Consult your veterinarian for assistance in the diagnosis, treatment, and control of parasitism.

Dated: October 22, 1997.

Stephen F. Sundlof,

Director, Center for Veterinary Medicine.

[FR Doc. 97–32807 Filed 12–15–97; 8:45 am]

BILLING CODE 4160–01–F

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 206

RIN 1010–AC06

Amendments to Transportation Allowance Regulations for Federal and Indian Leases to Specify Allowable Costs and Related Amendments To Gas Valuation Regulations

AGENCY: Minerals Management Service, Interior.

ACTION: Final rulemaking.

SUMMARY: The Minerals Management Service (MMS) is amending its regulations governing valuation for royalty purposes of gas produced from Federal and Indian leases. The rule primarily addresses allowances for transportation of gas. The amendments clarify the methods by which gas royalties and deductions for gas transportation are calculated.

DATE: Effective February 1, 1998.

ADDRESSES: David S. Guzy, Chief, Rules and Publications Staff, Royalty Management Program, Minerals Management Service, P.O. Box 25165, MS 3021, Denver, Colorado 80225–0165; courier delivery to Building 85, Denver Federal Center, Denver, Colorado 80225, telephone (303) 231–3432, FAX (303) 231–3385, e-Mail David__Guzy@mms.gov.

FOR FURTHER INFORMATION CONTACT: David S. Guzy, Chief, Rules and Publications Staff, Royalty Management Program, Minerals Management Service, phone (303) 231–3432, FAX (303) 231–3385, e-Mail David__Guzy@mms.gov.

SUPPLEMENTARY INFORMATION: The principal authors of this rule are Theresa Walsh Bayani and Susan Lupinski, from Royalty Valuation Division, MMS, Lakewood, Colorado.

I. Background

MMS published a set of rules in 30 CFR part 206 governing gas valuation and gas transportation calculation methods to clarify and codify the departmental policy of granting deductions for the reasonable actual costs of transporting gas from a Federal or Indian lease when the gas is sold at a market away from the lease (53 FR 1272, January 15, 1988).

Since the 1988 rulemaking, Federal Energy Regulatory Commission (FERC) regulatory actions have significantly affected the gas transportation industry. Before these changes, gas pipeline companies served as the primary merchants in the natural gas industry. During that environment, pipelines:

• Bought gas at the wellhead,
• Transported the gas, and
• Sold the gas at the city gate to local distribution companies (LDC).

In the mid-1980's, FERC began establishing a competitive gas market, allowing shippers access to the pipeline transportation grid. These actions ensured that willing buyers and sellers could negotiate their own sales transactions.

Specifically, starting with the implementation of FERC Order 436, FERC began regulating pipelines as open access transporters and requiring nondiscriminatory transportation. This permitted downstream gas users (such as LDCs and industrial users) to buy gas directly from gas merchants in the production area and to ship that gas through interstate pipelines.

FERC Order 436 and amendments, plus the elimination of price controls, created a vigorous spot market. Producers and marketers, in competition for the sale of gas to end users, are now transporting substantial volumes of gas that they own through interstate pipelines.

In the early 1990's, FERC recognized that pipelines still held an advantage over competing sellers of gas. Pipelines held substantial market power and sold gas bundled with a transportation service. FERC remedied the inequities in the gas market by issuing FERC Order 636, effective May 18, 1992. Under the provisions of this order, FERC:

• Required the separation (unbundling) of sales and gas transportation services;
• Enabled the implementation of a capacity release program; and
• Allowed pipelines to assess shippers surcharges for services such as transition costs and FERC's annual charges (57 FR 13267, April 16, 1992).

The unbundled costs—previously embedded in a lump-sum charge—include:

• Transmission;
• Storage;
• Production; and
• Gathering costs.

Necessity for This Rulemaking

We reviewed our current gas transportation regulations (30 CFR 206.156 and 206.157 (for Federal leases), and 206.176 and 206.177 (for Indian leases) (1996)) and determined that they provide general authority to calculate transportation deductions for cost components resulting from implementing FERC Order 636 and previous FERC orders. However, we have determined that lessees and royalty payors need specific guidance and certainty on which components are deductible as transportation costs from royalty. This guidance is necessary because components previously aggregated and unidentifiable may now be separately identified in transportation contracts, and new costs unique to the FERC Order 636 environment are emerging.

Further, some of the components reflect non-deductible costs of marketing rather than transportation. We believe that without the clarification provided in this rule, lessees and payors may claim improper deductions on their royalty reports and payments.

We issued a proposed rulemaking to clarify for the oil and gas industry which cost components or other charges are deductible (related to transportation) and which costs are not deductible (related to marketing) for Federal and Indian leases (61 FR 39931, July 31, 1996). The purpose of this rulemaking is also to clarify our existing policies. We received comments from 18 separate entities: Six responses from companies, six responses from industry trade associations, two responses from State representatives, one response from a State/Indian association, two responses from Indian tribes, and one response from an Indian tribal association.

This final rulemaking relates primarily to the effects of FERC Order 636 on interstate gas pipelines that FERC regulates. To the extent these same types of changes and issues are relevant for intrastate pipelines, our rule applies equally.

In conjunction with the changes to the transportation allowance regulations, we are also making certain changes to the gas valuation regulations. When FERC approves tariffs, they generally allow pipelines to include provisions ensuring that pipelines can maintain operational and financial control of their systems. These provisions may include requirements that shippers maintain pipeline receipts and deliveries within certain daily or monthly tolerances and that shippers cash-out accumulated imbalances. If a shipper over-delivers production to a pipeline, the pipeline may purchase the excess gas quantities from the shipper. If the gas quantity exceeds certain prescribed tolerances, the shipper may incur a penalty in the form of a substantially reduced price for that gas. We will not accept that penalty price as the value of production, and this rulemaking provides a method for valuing production sold under such circumstances.

Certain additions to revenues from the sale of natural gas may occur in the gas transportation environment. These issues are gas valuation issues beyond the scope of this rulemaking. However, these additions to revenues may be royalty bearing under existing regulations.

We also recognize that certain lessee gas transportation arrangements result in financial transactions not directly associated with the gas value. Such transactions may not have royalty consequences. If you are unsure whether your transactions result in additional royalty obligations, you may request valuation guidance from us.

The amendments discussed below apply to both arm's-length and non-arm's-length situations for valuing gas production and calculating transportation allowances.

II. Comments on Proposed Rule

We published a proposed rule at 61 FR 39931, 7/31/96. The proposed rulemaking provided for a 60-day public comment period which ended September 30, 1996, and was extended to October 30, 1996 (61 FR 48872, 9/17/96).

General Comments

The tribes believe that allowable deductions should be scrupulously examined and limited to the minimum amount for the economic best interest of the lessor tribe. They state that FERC-approved tariffs are not the actual, reasonable cost of transportation paid by the producer and should not be accepted. A few commenters stated that careful examination of tariffs is needed to assure revenue protection and accountability. These respondents claim that lessees believe tariffs are beyond our scrutiny once we permitted their use. They urge us to clearly state in this rulemaking that review of costs included in a tariff is not beyond audit review and that transportation allowances may be recalculated when the tariff does not reasonably reflect a lessee's actual costs.

One State commented that under no circumstances should the lessee be allowed to deduct transportation costs, including tariffs, in excess of the actual, reasonable costs incurred or paid, regardless of whether the transportation is arm's-length or non-arm's-length. One tribe and one Indian tribal association suggested that the preamble language should specify that allowances are limited to reasonable actual costs of transportation and are limited to no more than 50 percent of the value of the production. One tribe believes that this regulation changes the annual rent or royalty rate without the written consent of the tribe.

Several States and Indian commenters claim that clarifying the allowable charges under FERC Order 636 is important and pressing and urged us not to consider this rule an end to transportation allowance issues. They believe each cost must be evaluated against the lessees' duty to market production and that marketing costs are not a deductible expense. They also state that on each debatable cost, our proposal clearly benefits the lessees. Although they oppose several provisions of the rule, these commenters recognize that the FERC Order 636 environment raises difficult issues for royalty valuation, and they commend MMS for attempting a compromise proposal. In addition, one State commenter added that with modifications, they generally supported our efforts to amend the transportation allowance regulations.

In addition to the general comments, one tribe offered the following comments regarding the economic analysis of the rule. They believe that the Department has not complied with Department Manual, Chapter 2, Part 512 and that the economic analysis shows a deficiency of acting in the best economic interests of the tribe. They also believe that we have not taken seriously our obligation to ensure maximum revenue to the tribe. In the tribe's view, the statement that this proposal meets MMS's goal of certainty, clarity, and consistency is not an adequate basis to reduce Tribal royalties. The tribe asserts that MMS's statement in the July 31, 1996, proposed rulemaking that the rule will have a neutral or beneficial impact on Indian royalties is devoid of any real economic demonstration. Finally, the tribe stated that they are skeptical that the rule will have a neutral or beneficial impact or that it will enhance MMS's ability to fulfill its trust responsibility.

Six industry trade associations and three companies also offered general comments. Every respondent believes that this rulemaking is cumbersome and does not meet the goal of regulatory simplification or streamlining. They believe the proposal:

- Represents an extreme departure from current practice;
- Exceeds MMS's statutory authority;
- Is not supported by case law; and
- Illegally extends the lessee's obligations.

Several industry trade associations commented that the proposal will create heavy administrative expenses for producers to track gas molecules to the burnertip. In today's complex marketplace, these commenters believe the required tracking is impossible. One respondent stated that pipelines are not consistent in billing and frequently do not segregate costs, adding to the difficulty in compliance and likelihood of being second guessed by us in later audits. One industry trade association strongly urged us to withdraw this rule. If necessary, it believes that changes can be addressed in a negotiated rulemaking where all parties come to an equitable agreement. One industry trade association stated that this proposal:

- Fails to recognize the producer's lack of control over fees; and

• Penalizes and requires the producer to absorb all costs and risks of marketing downstream.

One industry trade association believes that the burdens and disincentives created by the rule dictate that we should allow producers to make royalty payments in kind.

Response. One of the main purposes of this rulemaking is to clarify the specific allowable and nonallowable costs of transportation. This rule is a continuation of our commitment to assure that lessees deduct only the actual, reasonable costs of transportation. We have carefully considered each cost component and are not allowing any costs of marketing as a deduction in the final rule.

Although one tribe believes that MMS did not comply with the economic analysis required by the Departmental Manual, Chapter 2, Part 512, we believe that the changes under FERC Order 636 will enable us to identify nonallowable costs of marketing. Prior to FERC Order 636, lessees deducted some bundled marketing costs. Under the FERC Order 636 environment, these costs are now separately identified. Consequently, this rulemaking limits the transportation allowance to the actual, reasonable costs of transportation. Our rulemaking will have a neutral or beneficial impact to the tribes, States, and Federal Treasury because lessees will not be able to deduct these previously bundled marketing costs.

We disagree with industry's statement that the Department does not have the authority to promulgate this rule. MMS is mandated by law to ensure that royalties are properly collected and distributed. See 30 U.S.C. 1701 *et. seq.* This responsibility includes providing clear guidance to the oil and gas industry regarding which costs are allowable transportation deductions and what are nonallowable marketing costs. The comment that pipelines are not consistent in billing and frequently do not segregate costs is contrary to FERC's requirement that every pipeline make rate filings publicly available. Under FERC's procedure, the pipeline must identify and justify the cost components. Any shipper can analyze these filings and protest any inequitable costs. Based on these reasons, MMS is publishing this rule as final.

MMS amends its regulations and deletes the existing sections 206.157(f) and 206.177(f) of 30 CFR part 206. (We retain the substance of these paragraphs in later revised paragraphs.) Further, we redesignate paragraph (g) of these sections as paragraph (h) and add two new paragraphs. New paragraph (f) describes the types of costs we will allow as part of a transportation allowance. A new paragraph (g) lists those costs that we expressly disallow. Because some of the nonallowable costs affect valuation, we also amend sections 206.152, 206.153, 206.172 and 206.173. These amendments address valuation of certain cash-out volumes and expressly reaffirm that marketing costs are not allowable deductions from royalty value.

Specific Comments

Comments on §§ 206.152, 206.172, 206.153, and 206.173 (relating to paragraph (b)(1)(iv)) How to value over-delivered volumes under a cash-out program.

We received comments from one State on the cash-out program. This State agrees with our amendments to the valuation regulations for cash-out programs.

Two industry trade associations and three companies commented on the cash-out program. All industry commenters disagree with our cash-out valuation proposal. They believe that we should accept the price specified in the FERC-approved tariff for valuation purposes. Many industry respondents stated that lessees cannot market production downstream of the lease without being subject to cash-out provisions under transportation contracts. These respondents also believe that:

• Our proposal ignores that imbalances are inevitable; and

• A cash-out provision is the best means to sell gas.

They also state that MMS is arbitrary and capricious if we do not first determine that the lessee acted imprudently before disallowing use of the cash-out provision outside the tolerance or using the benchmarks to value gas. One company disagrees with our assertion that volumes outside the tolerance (for over-delivery specified in the transportation contract) are a violation of the duty to market for the benefit of the lessee and lessor. This commenter believes that we should only disallow the FERC-approved cash-out value when we determine that the lessee is negligent.

Response. Pipelines developed tolerances in recognition of the fact that nominations never match actuals, and receipts never match deliveries. Because pipelines no longer own system supply gas to cover imbalances, they must maintain strict controls over shippers to assure system integrity. Pipelines developed the cash-out programs to penalize those shippers outside the tolerances while allowing for minor imbalances within tolerance. MMS also believes lessees must act diligently in scheduling shipments on pipelines. In the final rule, we retain the provision accepting the cash-out value within tolerance and not accepting the value outside the tolerance. We also retain the provision to value production under the benchmarks when the cash-out provision results in an unreasonable value for royalty purposes. This is consistent with the current valuation regulations requiring arm's-length contracts to meet total consideration and reasonable value criteria.

We amend paragraph (b)(1) of 30 CFR 206.152 and 206.172 (for unprocessed gas), and 30 CFR 206.153 and 206.173 (for processed gas) by adding another exception to the general rule that the gross proceeds under an arm's-length contract are acceptable as the royalty value. This exception adds new paragraph (iv) to these sections and provides that over-delivered volumes outside the pipeline tolerances are valued at the same price the pipeline purchases over-delivered volumes within the tolerances. We will not accept the penalty cash-out price as royalty value.

The rule also provides that if we determine that the cash-out price is unreasonably low, lessees must use the benchmarks to value the gas instead of the cash-out price. Lessees should also note that for production from Indian leases, other valuation provisions in the regulations still apply; *i.e.*, major portion and dual accounting.

Comments on §§ 206.152(i), 206.172(i) (for unprocessed gas); and 206.153(i), and 206.173(i) (for processed gas).

One Indian tribe responded that all marketing costs must be borne by the lessee and that the lessee must make every reasonable and prudent effort to market production for the benefit of the lessor. All other State and Indian respondents support this position but offered no specific comments.

Five industry trade association groups and four companies submitted responses regarding costs of placing production in marketable condition and marketing costs. The following paragraphs summarize industry specific responses.

General Comments. One industry trade association recommends deleting the language "and to market the gas for the mutual benefit of the lessee and the lessor" that we proposed adding to the existing regulations. Several industry commenters stated that this marketing language is beyond MMS's statutory authority and is bad public policy. One industry commenter also stated the marketing language was a thinly disguised attempt to increase revenue to the government at the expense of lessees. Several industry commenters believe that the marketing language will impose royalty on marketing services long after production is saved, removed, or sold from the lease and that the point of royalty valuation is moved from the lease to the burnertip. These industry commenters also believe that even though the producer sold marketable gas under an arm's-length contract at the lease, lessees must trace gas all the way to the burnertip and pay royalty on the value at a ''new'' marketplace. A few industry commenters stated that we do not rely on a ''principled basis'' to determine what will or will not be a marketing cost, and it will be impossible for lessees to anticipate what downstream costs we will disallow. Commenters assert that this will create a loss of certainty for lessees. One company believes that the marketing language changes value determination from the current policy of accepting arm's-length gross proceeds to the highest-obtainable price anywhere from the lease to the resale at the burnertip.

Duty to market/implied obligation to market. Almost every industry trade association and company commenter stated that no obligation exists to market production away from the lease. They asserted that lessees are only obligated to market production at or near the lease. In addition, they claim that even if this obligation to market production is not new, the obligation to market production away from the lease is new. All industry commenters believe that the rule creates an unprecedented duty to market and imposes an elaborate new marketing standard. These commenters also believe that the creation of this new duty to market violates applicable statutes and lease terms. These industry commenters also state that the implied obligation to market for the mutual benefit of the lessee and the lessor never embodied the obligation to market *at no cost* to the lessor. Several commenters stated that this obligation is not implied simply because the agency says so and the rule leaps from the realities of past precedent by merely stating that the obligation to market production is implied. Several commenters claim that the implied obligation to market is not supported by *Walter Oil and Gas*, 111 IBLA 265 (1989) as cited by MMS.

Production in marketable condition. Several industry commenters claimed that we erroneously link the obligation to place production in marketable condition with the obligation to market that production. One industry trade association stated that in *Beartooth Oil and Gas Co.* v. *Lujan*, CV 92–99–BLG–RWA (D. Mont. Sept. 22, 1993, vacated and remanded) (*Beartooth*), the court determined that the marketable condition rule does not require the lessee to condition the gas so that it is suitable for secondary or retail markets. They further state that a series of markets exists between the lease and the burnertip but the lessee's obligation to place production in marketable condition refers only to the first market. Several industry commenters believe that the preamble to the March 1, 1988, regulations clearly shows that our intent was not to encompass any and all marketing costs but only those to place production in marketable condition. Most commenters state that the market for which production is conditioned is the market at or near the lease. They further claim that the definition of marketable condition in the March 1, 1988, rule focuses on gas that is sufficiently free from impurities and not on marketing that gas.

Share in marketing costs. Three companies and two industry trade associations claim that MMS is not entitled to a ''free ride'' on marketing costs. They believe that if we benefit from marketing activities then we should share in those costs. Two companies and one industry trade association state that the proposal shows that we are unwilling to share in costs to market but want to share in any higher price gained when the lessee performs marketing. This is not for mutual benefit of the lessee and lessor.

Breach of duty. Several industry trade associations and company commenters offered the following comments on the lessees' duty to market production. Because marketing costs are disallowed under the rule, if lessees don't incur marketing costs, these commenters are concerned that we will consider the lessee as breaching its duty to market production. They are also concerned that MMS will question all marketing decisions made by the lessee and make arbitrary determinations that producers failed to obtain the highest price.

Response. We recognize that the obligation to place production in marketable condition is legally distinct from the issue of marketing the gas. However, the implied covenant of the lease dictates that lessees must market production at no cost to the lessor. Both principles are expressly stated in the March 1, 1988, gas regulations; the definition for marketable condition at 30 CFR 206.151 discusses the physical treatment of gas for placing gas in marketable condition and 30 CFR 202.151 states that no allowance will be made for other expenses incidental to marketing. Based on these principles, MMS has consistently applied the concept that the lessee must market gas at no cost to the lessor and denied marketing costs as an allowable deduction. See *Arco Oil and Gas Co.*, 112 IBLA 8, 11 (1989); *Walter Oil and Gas Corp.*, 111 IBLA 260, 265 (1989). We have not changed the principle of accepting gross proceeds under arm's-length contracts and would not trace value beyond a true arm's-length transaction to the burner tip, as commented. The rule simply clarifies which cost components or other charges are deductible (transportation), and which costs are not deductible (marketing). This is consistent with the ruling in the *Beartooth* decision that addressed whether downstream compression was the cost of placing production in marketable condition or a transportation cost.

The final rule clarifies the principle that lessees cannot deduct from royalty value the costs of marketing production from Federal and Indian leases. The final rule adds specific language to paragraph (i) of 30 CFR 206.152, 206.153, 206.172, and 206.173 to expressly state lessees' obligation to incur all marketing costs. In all sections, we amend paragraph (i) to add the words ''and to market the gas for the mutual benefit of the lessee and the lessor'' after the words ''place gas in marketable condition'' and before the words ''at no cost to the Federal Government (or Indian lessor, as applicable).'' We also add the words ''or to market the gas'' at the end of the last sentence of that paragraph to accomplish this objective. We believe that the added language contains the concept embodied in the implied covenant to market for the mutual benefit of Federal and Indian oil and gas lessees and lessors. We further believe this imposes no additional marketing burden on the lessee than existing requirements.

Comments on §§ 206.157(f)(1) and 206.177(f)(1) Firm demand charges paid to pipelines.

One Indian tribal association, one State/Indian association, two tribes, and two States offered comments on firm demand charges. One tribe stated that if we allow firm demand charges, we must timely review and audit the actual amount claimed. The tribe believes that situations exist where lessees claim FERC-allowed costs, but lessees do not actually pay these costs for transportation. The State commenter agrees with our proposal allowing firm demand charges—limited to the applicable rate per MMBtu multiplied by the actual volumes transported. The State believes that it should not be liable for the additional costs for two reasons.

First, the lessee has ways to mitigate costs for unused capacity. Second, the lessor should not be liable for marketing mistakes caused by overbuying capacity. One State/Indian association, one tribe, and one State debated whether these charges are transportation charges or marketing costs. However, these commenters agreed that MMS's position is a reasonable compromise with the following two caveats. First, we should review and adjust firm demand charges if they include otherwise nondeductible costs or do not represent a lessee's reasonable actual costs. Second, the lessee should reduce the claimed allowance if a purchaser reimburses, directly or indirectly (through reservation charges or fees) all or some of the producer's demand charges.

Three trade associations and four companies offered the following comments on firm demand charges. All industry commenters believe that we should allow the entire demand charge actually paid by the lessee. One industry trade association and four companies believe that the demand charge is a legitimate cost that often enables the gas to be sold at a higher price. They believe the lessor should share in the entire demand charge even if only a portion is used because the royalty share benefits. Several industry commenters stated that the firm demand charge is not allocated between used and unused capacity. They stated that firm demand charges are consideration for transportation irrespective of capacity used. Many of the industry commenters stated that allowances should be reduced only when the lessee releases capacity and receives a credit. Many commenters stated that factors beyond the lessees' control can prevent them from using all reserved capacity. By denying part of the firm demand, we imply lessees acted imprudently and failed to market gas for the mutual benefit of the lessee and the lessor. One company stated that we should allow the demand/reservation charge because the charge is a transportation cost that is indistinguishable from any other transportation service.

Response. Our valuation regulations require that we allow the reasonable, actual costs of transportation. However, only the firm demand rate per MMBtu is an actual cost of transportation. We do not consider the amount paid for unused capacity as a transportation cost. Therefore, in §§ 206.157(f)(1) and 206.177(f)(1), we are allowing firm demand charges—limited to the applicable rate per MMBtu multiplied by the actual volumes transported—as allowable costs in computing the transportation allowance.

Capacity release program. We also received comments on the capacity release program. One Indian tribal association responded that they agree with permitting allowances for those portions of both demand and commodity charges that reflect the costs paid for gas actually shipped, but not permitting allowances for the potential business costs associated with purchases of surplus or unused capacity.

One company commenter would support including capacity release gains and losses if all firm demand charges were allowed. Several companies stated that there are no gains under the capacity release program. One industry trade association and two companies recommend rewriting the third sentence under firm demand charges to clearly state that any gains or losses from the sale of unused firm charges are not royalty bearing. These commenters also recommended clarifying the fourth sentence which includes the term ''other reasons.'' These respondents suggest using the term ''other refunds'' and clarifying the sentence to state that any refunds received are not considered gross proceeds if no firm demand charge was claimed on Form MMS–2014, Report of Sales and Royalty Remittance (Form MMS–2014).

Response. We do not consider the gains and losses associated with release of firm transportation as part of the actual cost of transporting gas. In §§ 206.157(f)(1) and 206.177(f)(1), lessees with firm transportation may only claim the firm demand charge per MMBtu multiplied by actual volumes transported, regardless of whether they release part or all of their reserved capacity. If a lessee/shipper acquires released capacity on a pipeline, we allow the cost of buying that capacity to the extent that capacity is used. The final rule provides that we will not participate in gains or losses associated with released capacity.

We agree that the third sentence under firm demand charges should be clarified and have replaced this sentence in the final rule with the following sentence: ''The lessee also may not include any gains associated with releasing firm capacity.''

Pipeline rate adjustments. The last issue under firm demand is pipeline rate adjustments. We also requested comments on how to simplify reporting for these adjustments. One Indian tribal association agrees that any allowances taken that are later rebated are royalty bearing. However, monitoring will be complicated if the refund or rebate is credited against future charges.

Four industry trade associations and five companies responded to pipeline rate adjustments. Several companies and industry trade associations believe that the proposal is unfair because it disallows deductions for penalties paid by the shipper but requires lessees to pay their share of penalty monies refunded to other pipeline customers. However, one company agreed that penalty refunds and rate case payments should be subject to royalty. Individual companies responded that rate case refunds don't segregate individual components into the allowable/nonallowable items as defined by MMS. Therefore, differentiating disallowed components will be unduly burdensome to the lessee. Another company stated that the rule implies that penalty refunds are refunded to the party who paid the penalty which may not be the case.

Most companies agree that monthly adjustments would be unduly burdensome and that MMS should establish a distinct transaction code and/or adjustment reason code for pipeline rate adjustments. Several companies do not believe that a simplified reporting method for Indian leases is possible because of major portion requirements. One company suggested that lessees be allowed to assess a ''Royalty Administration Fee'' to offset the costs associated with tracking all the exceptions spelled out in this rule.

Response. Pipelines charge a specific rate for transportation services. When FERC later requires pipelines to adjust these charges through a pipeline rate refund, these adjustments reduce the transportation allowance already taken by the lessee on the Form MMS–2014. We considered several options for simplifying reporting, but concluded that any form of rolled-up reporting would prohibit us from determining royalty properly for both Federal onshore and offshore and Indian lands. We use data reported on Form MMS–2014 from both Federal and Indian leases to calculate major portion prices for Indian leases. Rolling up transportation allowances will skew these major portion calculations. We also use Form MMS–2014 data to monitor valuation reporting and for settlement negotiation purposes. Therefore, in the final rule, we have not modified reporting requirements for pipeline rate adjustments. To reflect the FERC-modified transportation charge, the lessee must adjust the allowance to account for the refund they receive by reducing the allowance originally taken.

Comments on §§ 206.157(f)(2) and 206.177(f)(2) Gas supply realignment (GSR) costs.

One State/Indian association, two States and one tribe oppose MMS's position that gas supply realignment (GSR) costs are transportation costs. These respondents state that GSR costs are transitory and are not related to a pipeline's transportation costs. Instead, these costs relate only to money paid by pipelines to reform or terminate contracts. They believe there is inherent inequity in industry's position that industry is not required to pay royalties on contract reformation payments but are entitled to deduct GSR costs when embedded in a tariff.

One Indian tribal association questioned why we allow only that portion of firm demand charges actually used, but allow recovery of GSR costs paid through demand charges. They believe this negates the initial objective of limiting firm demand to charges for actual volumes transported. They also believe that the GSR cost ''carries'' the royalty owner along on a myriad of business decisions by pipelines and producers that have nothing to do with actual transportation of gas.

One State/Indian association, one State, and one tribe claim that our position is inconsistent because contract reformation payments are both royalty bearing and deductible. These commenters are opposed to allowing GSR costs but as a compromise, suggest the following options:

- If lessees receive contract settlement money and agree to pay royalties on it, we could allow those lessees to deduct GSR costs;
- If lessees do not receive contract settlement money, we could allow those lessees to deduct GSR costs; and
- If all lessees are required to pay royalties on contract settlement money, we could allow GSR costs across the board.

One State commenter believes that allowing GSR costs violates the gross proceeds rule.

All industry respondents agree that GSR costs should be deductible and should not be tied to royalty consequences of gas contract settlements or the outcome of any pending litigation. Several commenters state that GSR costs are costs of transporting gas charged to all pipeline customers.

Response. GSR costs stemmed specifically from FERC's regulatory actions under FERC Order 636. FERC is mandated to recognize prudently incurred costs in establishing just and reasonable rates for transportation. We consider these costs as an actual cost of transportation under the existing regulations and will allow GSR costs as a transportation deduction in §§ 206.157(f)(2) and 206.177(f)(2).

Comments on §§ 206.157(f)(3) and 206.177(f)(3) Commodity charges.

One Indian tribal association responded to this issue, stating that they do not share MMS's assumption that demand and commodity charges permit pipelines to recover only their fixed and variable costs. The association claims that profit margins are built into both these components as return on equity.

We received no comments from industry on this issue.

Response. The actual volumes transported on a firm transportation contract are charged a firm transportation commodity charge in addition to the reservation fee. All interruptible transportation rates are billed at commodity charges only. These commodity charges represent the pipeline's transportation-related variable costs. These are actual costs incurred by lessees for transporting gas, and we will specifically allow the commodity charge as a deduction in the final rule. We recognize that valuation implications result from a lessee's choice of securing firm versus interruptible services. If the gas sales transaction is not arm's-length, the lessee would apply the comparability criteria in §§ 206.152, 206.153, 206.172, and 206.173 and compare values of gas transported under the same transportation arrangement—firm to firm and interruptible to interruptible. In §§ 206.157(f)(3) and 206.177(f)(3), we allow the commodity charges paid to pipelines as allowable costs in computing the transportation allowance.

Comments on §§ 206.157(f)(4) and 206.177(f)(4) Wheeling costs.

One Indian tribal association stated that wheeling is an incidental cost associated with shunting gas to a siding then back into the transportation system. This respondent believes that these costs should be treated like banking/parking fees and be disallowed. However, they stated that if we allow wheeling, those costs should be limited to actual reasonable costs.

We received no comments from industry on this issue.

Response. Wheeling is a physical transfer of gas from one pipeline through the hub to either the same or another pipeline. This service is directly related to transportation. We allow the costs of wheeling as a transportation deduction in §§ 206.157(f)(4) and 206.177(f)(4) of the final rule.

Comments on §§ 206.157(f)(5) and (6) and 206.177(f)(5) and (6) Gas Research Institute (GRI) fees and Annual Charge Adjustment (ACA) fees.

Two tribes, one Indian tribal association, and two State/Indian associations oppose allowing Gas Research Institute (GRI)/Annual Charge Adjustment (ACA) fees. All respondents believe that these fees are not transportation-related costs.

We received no specific comments from industry.

Response. FERC requires member pipelines of GRI to charge customers a fee for funding GRI programs. The GRI conducts research, development and commercialization programs on natural gas related topics for the benefit of the U.S. gas industry and gas customers. FERC allows pipelines to charge customers an ACA fee. This fee allows a pipeline to recover its allocated share of FERC's operating expenses. Because such fees are required transportation charges, we will allow GRI and ACA fees under §§ 206.157(f)(5) and (6), and 206.177(f)(5) and (6) of the final rule. However, MMS is aware that GRI funding may become completely voluntary. Therefore, we will allow GRI fees only as long as they are mandatory fees in FERC-approved tariffs.

Comments on §§ 206.157(f)(7) and 206.177(f)(7) Payments (either volumetric or in value) for actual or theoretical losses.

One Indian tribal association, one State/Indian association, one State, and one tribe believe that actual or theoretical losses are nondeductible costs and should not be allowed even if they appear in a tariff.

Four companies and three industry trade associations agree that actual or theoretical losses should be allowed as a deduction in arm's-length contracts and non-arm's-length transportation contracts if a FERC or State regulatory agency-approved tariff includes these costs. However, they believe that MMS's position on non-arm's-length situations where no tariff exists is a discriminatory treatment of non-arm's-length transportation situations. These respondents believe that actual and theoretical losses should be allowed in all cases.

In addition to comments on actual or theoretical losses, five industry respondents commented that MMS should clarify that gas supply to the transporter for fuel (whether provided in kind or cash reimbursement) will be an allowable transportation cost.

Response. We allow the cost of fuel as a deduction when it is used for gas transportation. This policy has not changed under this rule. We will continue to allow payments (either volumetric or in value) for actual or theoretical losses for arm's-length transportation arrangements and for non-arm's-length transportation arrangements if based on a FERC or State-regulatory approved tariff. However, we clarified the wording in the new §§ 206.157(f)(7) and 206.177(f)(7). There is no substantive change from the existing rules.

Comments on §§ 206.157(f)(8) and 206.177(f)(8) Temporary storage services.

One Indian tribal association agreed that MMS should not allow storage fees as a deduction. They believe that MMS should treat temporary or short-term storage fees (commonly known as banking and parking fees) as well as wheeling costs as nonallowable costs that are incidental to marketing. The Indian tribal association believes that MMS makes an exception to the gross proceeds rule regarding long-term storage. This Indian tribal association also believes that if a lessee stores gas for later sale, the lessee should pay an estimated royalty and pay additional royalties due when production is actually sold.

Three industry trade associations and four companies disagree with MMS's position that banking and parking are storage fees and not deductible. They state that these fees are part of the transportation process similar to wheeling, and we should allow these fees as a deduction. Most respondents state that banking and parking are necessary services to ensure balancing at market centers and hubs. These commenters state that we have no justification to disallow these fees, especially if the lessee is charged these fees in the same month as a sale.

Response. After reviewing the comments, we agree that temporary storage costs are different than long-term storage. Banking and parking are short-term storage services that give pipelines and shippers flexibility to avoid penalties related to imbalances. We agree with industry, and we will change the final rule by adding new sections 206.157(f)(8) and 206.177(f)(8) titled "Temporary storage services." These sections will allow short-term storage services as a transportation deduction but will retain the sections 206.157(g)(1) and 206.177(g)(1) disallowing long-term storage. We define short-term storage as temporary storage occurring at a hub or market center for a duration of 30 days or less.

Comments on §§ 206.157(f)(9) and 206.177(f)(9) Supplemental costs for compression, dehydration, and treatment of gas.

One Indian tribal association, one State/Indian association, one tribe, and one State believe these costs are part of the lessee's duty to place production in marketable condition at no cost to the lessor. They assert that they are not allowable no matter where they occur in the transportation process. They further maintain that this provision invites dispute and litigation over what is "typical" or "unusual." One Indian/State association commented that the economic rationale for permitting transportation allowances is that economic value is added by transporting production away from the lease. That transportation cost is then deducted from the enhanced value to determine value at the lease. There is no indication that value is added by "supplemental services." Therefore, these costs should not be allowed.

Most of the industry commenters oppose the use of the word "supplemental" and recommend that it be replaced with the word "other." These commenters stated that these services are an integral part of the transportation process and not an activity to put gas in marketable condition. They believe that once gas is in marketable condition, all subsequent services should be deductible. Several commenters state that compression, dehydration, and treatment of gas are not supplemental to transportation, they are an integral part of the transportation process.

A few industry trade associations and companies maintain that gas entering mainline pipelines is already in marketable condition, and we should allow deduction of all these costs. One company suggested that we look at the intent of the services; are these costs to place gas in marketable condition or for transportation? This company stated that gas may be acceptable to the transporter without compression, however, compression is necessary to offset line pressure in order to maintain deliverability and effectively manage reservoirs. They assert that this indicates that costs are due to transportation, not marketing restraints.

Response. The supplemental services indicated in the rule are not costs for placing gas in marketable condition. It is clear that Federal and Indian lessees must put production in marketable condition at no cost to the lessor. The costs addressed in the rule are costs that may occur in unusual circumstances where the pipeline performs additional compression, dehydration, or other treatment of gas for transportation purposes. These costs exceed the services necessary to place production in marketable condition. We allow charges for these supplemental services as a deduction in the final rule by renumbering sections 206.157(f)(9) and 206.177(f)(9).

Comments on §§ 206.157(g)(1) and 206.177(g)(1) Fees or costs incurred for storage.

See comments under §§ 206.157(f)(8) and 206.177(f)(8) above for detailed discussion on short duration storage fees.

Response. The regulation at 30 CFR § 202.150 (1996), the language of the various mineral leasing statutes, and terms of Federal leases require that royalty be a percentage of the amount or value of the production *removed or sold* from the lease. We consider gas removed from a Federal or Indian lease and stored at a location off the lease for future sale subject to royalty at the time of removal from the lease. The final rule is consistent by not allowing any costs incurred for storing production in a storage facility, whether on or off the lease, for a duration of greater than 30 days.

Comments on §§ 206.157(g)(2) and 206.177(g)(2) Aggregator/marketer fees.

The State and Indian commenters support MMS's position of not allowing aggregator/marketer fees as a transportation deduction. They believe that aggregator/marketer fees are not transportation costs and should be disallowed.

Four industry trade associations and three company respondents objected to disallowing aggregator/marketer fees from the transportation deduction. These respondents believe that lessees have no duty to market production downstream of the lease and no obligation to do so free of charge after production is placed in marketable condition. Industry believes that aggregating production results in enhanced value. Because MMS benefits from this enhanced value, industry believes that we should also share in these costs.

One industry trade association stated that denying aggregator/marketer fees will adversely affect independents because they do not have the ability to aggregate large volumes of production and, therefore, receive an enhanced value for gas.

Response. Aggregator/marketer fees are fees a producer pays to another person or company including its affiliates to market its gas. As previously discussed, the implied covenant to market the production is the lessee's obligation and the lessor does not share in marketing costs. The final rule in sections 206.157(g)(2) and 206.177(g)(2) reflects this principle by not allowing aggregator/marketer fees as a transportation deduction.

Comments on §§ 206.157(g)(3)(i)–(iv) and 206.177(g)(3)(i)–(iv) Penalties the lessee incurs as shipper.

One Indian tribal association and one State agree that penalties for cash-out, scheduling, imbalance, and curtailment or operational flow orders should be borne by the lessee. They believe that these penalties are not associated with reasonable actual costs of transportation. The State commenter believes that the lessee should bear any unrecouped losses incurred by their own marketing mistakes.

Two industry trade associations and three companies responded to the penalty provision. They agree that, within reasonable tolerances, costs due to negligence or mismanagement by the lessee should not be borne by the lessor. However, MMS should not disallow costs based on an assumption of breach of duty to market. Instead, MMS should review penalties on a case-by-case basis to determine if they were unavoidable. These respondents believe that if penalties are unavoidable, they should be deductible.

One company believes that MMS should share in all imbalance cash-out penalties regardless of whether a portion of the imbalance exceeds the pipeline tolerance level. This company believes that this proposal is contrary to MMS's acceptance of arm's-length contract sales as the basis for royalty value. They claim that imbalances are inevitable.

Response. We recognize that some imbalances occur. In cash-out situations, we will allow lessees within tolerance to determine value using that pipeline's specified rate. However, cash-out imbalances outside the tolerance and scheduling, imbalance, and operational penalties are costs incurred as a result of the lessee breaching its duty to market the production to the mutual benefit of the lessee and the lessor. These costs are marketing expenses the lessee must bear because there are a variety of mitigating devices available to help the lessee balance production and nominations. These devices include:

- Swapping or transferring imbalances;
- Establishing debit/credit accounts;
- Using electronic bulletin boards to adjust for variations between deliveries and nominations;
- Using swing supply and flexible receipt point authority;
- Entering into predetermined allocation agreements; or
- Insisting upstream operators enter into operational balancing agreements with downstream transporters.

In the final rule, we disallow as a transportation deduction:

- Over-delivery cash-out penalties (§§ 206.157(g)(3)(i) and 206.177(g)(3)(i));
- Scheduling penalties (§§ 206.157(g)(3)(ii) and 206.177(g)(3)(ii));
- Imbalance penalties (§§ 206.157(g)(3)(iii) and 206.177(g)(3)(iii)); and
- Operational penalties (§§ 206.157(g)(3)(iv) and 206.177(g)(3)(iv)).

Comments on §§ 206.157(g)(4) and 206.177(g)(4) Intra-hub transfer fees.

We received no comments from any Indian tribes or associations or States regarding intra-hub transfer fees.

Four industry trade associations and three companies offered the following responses. Several industry respondents stated that these fees track the ownership of the gas through the pipeline and MMS should consider these fees as part of the transportation cost. One industry trade association stated that if these fees are not deductible because it is the duty of the lessee to perform these services at no cost to the lessor, then MMS is implying that the small producer that doesn't provide this service is breaching its duty. Most industry commenters believe MMS should allow these fees because they are essential to efficient management of transportation and are necessary to transport gas through a hub. These commenters state that disallowing intra-hub transfer fees unjustly punishes aggressive marketers seeking to get the highest price.

Response. Intra-hub transfer fees are administrative costs and not actual costs of gas transportation. We disallow these fees as part of the transportation allowance in §§ 206.157(g)(4) and 206.177(g)(4).

Comments on §§ 206.157(g)(5) and 206.177(g)(5) Other nonallowable costs.

One Indian tribal association emphatically agrees that marketing costs are solely the province and duty of the producer. They stated that no deductions against royalties should be permitted for marketing costs. One State/Indian association, one tribe, and one State particularly support MMS's proposal on other nonallowable costs.

Two industry trade associations and four companies responded to this issue. All respondents believe that these costs, previously bundled prior to FERC Order 636, should be allowed. Several respondents claim that all these charges were allowable transportation costs for decades and, while it may now be easier for us to examine pipeline tariffs, we always had the ability to do so. These respondents believe that disallowing such costs creates a new obligation. Several industry commenters claim that MMS's concern about lessees relabelling or restructuring nondeductible costs as transportation costs is unfounded and unfair. Most commenters believe that this section will make it difficult for the lessee to determine which costs are allowable and nonallowable and prevents a fair examination of a particular fee's acceptance as a transportation expense.

Response. MMS has never allowed marketing costs as deductions from royalty value and maintains this position in the final rule. The fact that these costs were embedded in a bundled charge does not mean that we allow such charges. In the FERC Order 636 environment, component costs previously aggregated are now separately identified in transportation contracts. Some of these component costs are clearly costs of marketing and we continue to consider these as nonallowable costs under §§ 206.157(g)(5) and 206.177(g)(5) as we have always done.

III. Other Matters

Retroactive Effective Date

Six companies and six industry trade associations strongly disagree with the retroactive effective date of May 18, 1992. Industry believes that the rule is not merely a clarification but rather a substantive rule that creates a whole new duty to market. They state that without this rule we have no clear authority to collect royalties on several of the issues under this rule and that it is a radical departure from MMS's past practice and standards.

Industry maintains that we cannot legally apply the rule retroactively for the following reasons:

- We have not been delegated authority to retroactively apply rules;
- Retroactivity is against the Administrative Procedures Act,
- It is unlawful;
- Retroactivity is against MMS's policy of prospective rulemaking only; and
- We are barred from action without specific Congressional authority.

Finally, industry believes that they should not be penalized for MMS's 4-year lack of instruction and that retroactivity will be an excessive administrative burden. In addition, industry claims that data may not exist for prior periods or cannot be recreated and that retroactivity will require lessees to go to the burnertip to chase charges such as intra-hub title transfer fees and aggregator/marketer fees.

Response. Based on advice provided by the Department of the Interior's Office of the Solicitor, we have determined that MMS does not have express statutory authority to implement a retroactive effective date for this rule. However, we disagree that this is a substantive rule that changes or increases our existing authority and policies. This rule merely clarifies and codifies long standing MMS policies in terms of the revised FERC vernacular. Therefore, MMS is making this final rule effective February 1, 1998.

Indian Leases

One tribe and one Indian tribal association strongly recommend that separate transportation regulations should be adopted for Indian leases. Because Federal and Indian lease terms differ, these commenters believe that while excessive transportation deductions may be allowed for Federal leases, such deductions should not be allowed for Indian leases. They stated that this proposal does not recognize the narrower permissibility of deductions under Indian lease terms and that we should recognize the propriety of treating tribal leases different from Federal leases. In addition, one Indian tribal association stated that the Secretary's trust responsibility and duty to maximize revenues to Indian mineral owners compel us to protect Indian royalties from being subjected to transportation allowances that are not contemplated in the lease.

We received no specific comments from industry respondents on the subject of separate regulations for Indian gas.

Response. Although we recently separated existing valuation and transportation regulations into individual sections for Federal and Indian leases, the principles used to determine both value and transportation were not changed. This rule is written to insert pertinent individual paragraphs into the separate sections for Federal and Indian leases. We will not publish a separate rule for Indian leases. If we finalize new regulations for gas valuation on Indian leases, this rulemaking may be superseded for Indian lands.

IV. Procedural Matters

The Regulatory Flexibility Act

The Department certifies that this rule will 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.*). Approximately 2,600 entities pay royalties to MMS on production from Federal and Indian lands and the majority of these entities are small businesses because they employ 500 or less employees. However, this rule will not significantly impact these small businesses because this rule does not add any reporting or valuation requirements. Likewise, this regulation will not significantly or uniquely affect small governments because the rule will not change the valuation principles embodied in existing regulations. The sole purpose of this rule is to clarify which costs are allowable transportation deductions or nonallowable marketing costs.

Executive Order 12630

The Department certifies that the rule does not represent a governmental action capable of interference with constitutionally protected property rights. Thus, there is no need to prepare a Takings Implication Assessment under Executive Order 12630, ''Governmental Actions and Interference with Constitutionally Protected Property Rights.''

Executive Order 12866

This rule has been reviewed under Executive Order 12866 and is not a significant regulatory action. MMS estimates that this rule may result in a maximum of $3.37 million in additional royalties collected annually. However, this maximum revenue impact is based on the assumption that all tariffs for all Federal and Indian leases contained a nonallowable deduction of $0.01/MMBtu for a fee such as a intra-hub transfer fee.

Executive Order 12988

The Department has certified to OMB that this regulation meets the applicable standards provided in Section 3(a) and 3(b)(2) of E.O. 12988.

Unfunded Mandates Reform Act of 1995

The Department of the Interior has determined and certifies according to the Unfunded Mandates Reform Act, 2 U.S.C. 1502 *et seq.*, that this rule will not impose a cost of $100 million or more in any given year on local, tribal, State governments, or the private sector. A mandate is a legal, statutory, or regulatory provision that imposes an enforceable duty. A mandate does not include duties arising from participation in a voluntary Federal program. MMS funds audits performed by State and Indian auditors under voluntary cooperative agreements. Since participation in these cooperative agreements is voluntary and this rule will not require additional monies to perform audits of FERC-approved tariffs, no Federal mandates will be imposed on State, local, or tribal governments.

Paperwork Reduction Act

This rule has been examined under the Paperwork Reduction Act of 1995 and has been found to contain no new reporting or information collection requirements.

National Environmental Policy Act of 1969

We have determined that this rulemaking is not a major Federal Action significantly affecting the quality of the human environment, and a detailed statement under section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)) is not required.

List of Subjects in 30 CFR 206

Coal, Continental Shelf, Geothermal energy, Government contracts, Indian lands, Mineral royalties, Natural gas, Petroleum, Public lands—mineral resources, Reporting and recordkeeping requirements.

Dated: December 3, 1997.

Bob Armstrong,

Assistant Secretary—Land and Minerals Management.

For the reasons set out in the preamble, MMS amends 30 CFR part 206 as follows:

PART 206—PRODUCT VALUATION

1. The authority citation for part 206 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.*

Subpart D—Federal Gas

2. Section 206.152 is amended by revising the first sentence of paragraph (b)(1)(i) and adding a new paragraph (b)(1)(iv) to read as follows:

§ 206.152 Valuation standards—unprocessed gas.

* * * * *

(b)(1)(i) The value of gas sold under an arm's-length contract is the gross proceeds accruing to the lessee except as provided in paragraphs (b)(1)(ii), (iii), and (iv) of this section. * * *

* * * * *

(iv) *How to value over-delivered volumes under a cash-out program.* This paragraph applies to situations where a pipeline purchases gas from a lessee according to a cash-out program under a transportation contract. For all over-delivered volumes, the royalty value is the price the pipeline is required to pay for volumes within the tolerances for over-delivery specified in the transportation contract. Use the same value for volumes that exceed the over-delivery tolerances even if those volumes are subject to a lower price under the transportation contract. However, if MMS determines that the price specified in the transportation contract for over-delivered volumes is unreasonably low, the lessee must value all over-delivered volumes under paragraph (c)(2) or (c)(3) of this section.

* * * * *

5. Section 206.153, paragraph (i) is revised to read as follows:

§ 206.152 Valuation standards—unprocessed gas.

* * * * *

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

* * * * *

4. Section 206.153 is amended by revising the first sentence of paragraph (b)(1)(i) and adding a new paragraph (b)(1)(iv) to read as follows:

§ 206.153 Valuation standards—processed gas.

* * * * *

(b)(1)(i) The value of residue gas or any gas plant product sold under an arm's-length contract is the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii), (iii), and (iv) of this section. * * *

* * * * *

(iv) *How to value over-delivered volumes under a cash-out program.* This paragraph applies to situations where a pipeline purchases gas from a lessee according to a cash-out program under a transportation contract. For all over-delivered volumes, the royalty value is the price the pipeline is required to pay for volumes within the tolerances for over-delivery specified in the transportation contract. Use the same value for volumes that exceed the over-delivery tolerances even if those volumes are subject to a lower price under the transportation contract. However, if MMS determines that the price specified in the transportation contract for over-delivered volumes is unreasonably low, the lessee must value all over-delivered volumes under paragraph (c)(2) or (c)(3) of this section.

* * * * *

5. Section 206.153, paragraph (i), is revised to read as follows:

§ 206.153 Valuation standards—processed gas.

* * * * *

(i) The lessee must place residue gas and gas plant products in marketable condition and market the residue gas and gas plant products for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition or to market the residue gas and gas plant products.

* * * * *

6. In § 206.157, paragraph (f) is removed; paragraph (g) is redesignated as paragraph (h) and revised; and new paragraphs (f) and (g) are added to read as follows:

§ 206.157 Determination of transportation allowances.

* * * * *

(f) *Allowable costs in determining transportation allowances.* Lessees may include, but are not limited to, the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Firm demand charges paid to pipelines.* You must limit the allowable costs for the firm demand charges to the applicable rate per MMBtu multiplied by the actual volumes transported. You may not include any losses incurred for previously purchased but unused firm capacity. You also may not include any gains associated with releasing firm capacity. If you receive a payment or credit from the pipeline for penalty refunds, rate case refunds, or other reasons, you must reduce the firm demand charge claimed on the Form MMS–2014. You must modify the Form MMS–2014 by the amount received or credited for the affected reporting period;

(2) *Gas supply realignment (GSR) costs.* The GSR costs result from a pipeline reforming or terminating supply contracts with producers to implement the restructuring requirements of FERC Orders in 18 CFR part 284;

(3) *Commodity charges.* The commodity charge allows the pipeline to recover the costs of providing service;

(4) *Wheeling costs.* Hub operators charge a wheeling cost for transporting gas from one pipeline to either the same or another pipeline through a market center or hub. A hub is a connected manifold of pipelines through which a series of incoming pipelines are interconnected to a series of outgoing pipelines;

(5) *Gas Research Institute (GRI) fees.* The GRI conducts research, development, and commercialization programs on natural gas related topics for the benefit of the U.S. gas industry and gas customers. GRI fees are allowable provided such fees are mandatory in FERC-approved tariffs;

(6) *Annual Charge Adjustment (ACA) fees.* FERC charges these fees to pipelines to pay for its operating expenses;

(7) *Payments (either volumetric or in value) for actual or theoretical losses.* This paragraph does not apply to non-arm's-length transportation arrangements unless the transportation allowance is based on a FERC or State regulatory-approved tariff;

(8) *Temporary storage services.* This includes short duration storage services offered by market centers or hubs (commonly referred to as ''parking'' or ''banking''), or other temporary storage services provided by pipeline transporters, whether actual or provided as a matter of accounting. Temporary storage is limited to 30 days or less; and

(9) *Supplemental costs for compression, dehydration, and treatment of gas.* MMS allows these costs only if such services are required for transportation and exceed the services necessary to place production into marketable condition required under §§ 206.152(i) and 206.153(i) of this part.

(g) *Nonallowable costs in determining transportation allowances.* Lessees may not include the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Fees or costs incurred for storage.* This includes storing production in a storage facility, whether on or off the lease, for more than 30 days;

(2) *Aggregator/marketer fees.* This includes fees you pay to another person (including your affiliates) to market your gas, including purchasing and reselling the gas, or finding or

maintaining a market for the gas production;

(3) *Penalties you incur as shipper.* These penalties include, but are not limited to:

(i) *Over-delivery cash-out penalties.* This includes the difference between the price the pipeline pays you for over-delivered volumes outside the tolerances and the price you receive for over-delivered volumes within the tolerances;

(ii) *Scheduling penalties.* This includes penalties you incur for differences between daily volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point;

(iii) *Imbalance penalties.* This includes penalties you incur (generally on a monthly basis) for differences between volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point; and

(iv) *Operational penalties.* This includes fees you incur for violation of the pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline;

(4) *Intra-hub transfer fees.* These are fees you pay to hub operators for administrative services (e.g., title transfer tracking) necessary to account for the sale of gas within a hub; and

(5) *Other nonallowable costs.* Any cost you incur for services you are required to provide at no cost to the lessor.

(h) *Other transportation cost determinations.* Use this section when calculating transportation costs to establish value using a netback procedure or any other procedure that requires deduction of transportation costs.

Subpart E—Indian Gas

7. Section 206.172 is amended by revising the first sentence of paragraph (b)(1)(i) and adding a new paragraph (b)(1)(iv) to read as follows:

§ 206.172 Valuation standards—unprocessed gas.

* * * * *

(b)(1)(i) The value of gas sold under an arm's-length contract is the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii), (iii), and (iv) of this section. * * *

* * * * *

(iv) *How to value over-delivered volumes under a cash-out program.* This paragraph applies to situations where a pipeline purchases gas from a lessee according to a cash-out program under a transportation contract. For all over-delivered volumes, the royalty value is the price the pipeline is required to pay for volumes within the tolerances for over-delivery specified in the transportation contract. Use the same value for volumes that exceed the over-delivery tolerances even if those volumes are subject to a lower price under the transportation contract. However, if MMS determines that the price specified in the transportation contract for over-delivered volumes is unreasonably low, the lessee must value all over-delivered volumes under paragraph (c)(2) or (c)(3) of this section.

* * * * *

8. Section 206.172, paragraph (i), is revised to read as follows:

§ 206.172 Valuation standards—unprocessed gas.

* * * * *

(i) The lessee must place gas in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Indian lessor. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition or to market the gas.

* * * * *

9. Section 206.173 is amended by revising the first sentence of paragraph (b)(1)(i) and adding a new paragraph (b)(1)(iv) to read as follows:

§ 206.173 Valuation standards-processed gas.

* * * * *

(b)(1)(i) The value of residue gas or any gas plant product sold under an arm's-length contract is the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii), (iii), and (iv) of this section.

* * * * *

(iv) *How to value over-delivered volumes under a cash-out program.* This paragraph applies to situations where a pipeline purchases gas from a lessee according to a cash-out program under a transportation contract. For all over-delivered volumes, the royalty value is the price the pipeline is required to pay for volumes within the tolerances for over-delivery specified in the transportation contract. Use the same value for volumes that exceed the over-delivery tolerances even if those volumes are subject to a lower price under the transportation contract. However, if MMS determines that the price specified in the transportation contract for over-delivered volumes is unreasonably low, the lessee must value all over-delivered volumes under paragraph (c)(2) or (c)(3) of this section.

* * * * *

10. Section 206.173, paragraph (i), is revised to read as follows:

§ 206.173 Valuation standards—processed gas.

* * * * *

(i) The lessee must place residue gas and gas plant products in marketable condition and market the residue gas and gas plant products for the mutual benefit of the lessee and the lessor at no cost to the Indian lessor. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition or to market the residue gas and gas plant products.

* * * * *

11. In § 206.177, paragraph (f) is removed; paragraph (g) is redesignated as paragraph (h) and revised; and new paragraphs (f) and (g) are added to read as follows:

§ 206.177 Determination of transportation allowances.

* * * * *

(f) *Allowable costs in determining transportation allowances.* Lessees may include, but are not limited to, the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Firm demand charges paid to pipelines.* You must limit the allowable costs for the firm demand charges to the applicable rate per MMBtu multiplied by the actual volumes transported. You may not include any losses incurred for previously purchased but unused firm capacity. You also may not include any gains associated with releasing firm capacity. If you receive a payment or credit from the pipeline for penalty refunds, rate case refunds, or other reasons, you must reduce the firm demand charge claimed on the Form MMS–2014. You must modify the Form MMS–2014 by the amount received or credited for the affected reporting period;

(2) *Gas supply realignment (GSR) costs.* The GSR costs result from a pipeline reforming or terminating supply contracts with producers to

implement the restructuring requirements of FERC Orders in 18 CFR part 284;

(3) *Commodity charges.* The commodity charge allows the pipeline to recover the costs of providing service;

(4) *Wheeling costs.* Hub operators charge a wheeling cost for transporting gas from one pipeline to either the same or another pipeline through a market center or hub. A hub is a connected manifold of pipelines through which a series of incoming pipelines are interconnected to a series of outgoing pipelines;

(5) *Gas Research Institute (GRI) fees.* The GRI conducts research, development, and commercialization programs on natural gas related topics for the benefit of the U.S. gas industry and gas customers. GRI fees are allowable provided such fees are mandatory in FERC-approved tariffs;

(6) *Annual Charge Adjustment (ACA) fees.* FERC charges these fees to pipelines to pay for its operating expenses;

(7) *Payments (either volumetric or in value) for actual or theoretical losses.* This paragraph does not apply to non-arm's-length transportation arrangements unless the transportation allowance is based on a FERC or State regulatory-approved tariff;

(8) *Temporary storage services.* This includes short duration storage services offered by market centers or hubs (commonly referred to as ''parking'' or ''banking''), or other temporary storage services provided by pipeline transporters, whether actual or provided as a matter of accounting. Temporary storage is limited to 30 days or less; and

(9) *Supplemental costs for compression, dehydration, and treatment of gas.* MMS allows these costs only if such services are required for transportation and exceed the services necessary to place production into marketable condition required under §§ 206.172(i) and 206.173(i) of this part.

(g) *Nonallowable costs in determining transportation allowances.* Lessees may not include the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Fees or costs incurred for storage.* This includes storing production in a storage facility, whether on or off the lease, for more than 30 days;

(2) *Aggregator/marketer fees.* This includes fees you pay to another person (including your affiliates) to market your gas, including purchasing and reselling the gas, or finding or maintaining a market for the gas production;

(3) *Penalties you incur as shipper.* These penalties include, but are not limited to:

(i) *Over-delivery cash-out penalties.* This includes the difference between the price the pipeline pays you for over-delivered volumes outside the tolerances and the price you receive for over-delivered volumes within the tolerances;

(ii) *Scheduling penalties.* This includes penalties you incur for differences between daily volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point;

(iii) *Imbalance penalties.* This includes penalties you incur (generally on a monthly basis) for differences between volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point; and

(iv) *Operational penalties.* This includes fees you incur for violation of the pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline;

(4) *Intra-hub transfer fees.* These are fees you pay to hub operators for administrative services (e.g., title transfer tracking) necessary to account for the sale of gas within a hub; and

(5) *Other nonallowable costs.* Any cost you incur for services you are required to provide at no cost to the lessor.

(h) *Other transportation cost determinations.* Use this section when calculating transportation costs to establish value using a netback procedure or any other procedure that requires deduction of transportation costs.

[FR Doc. 97–32802 Filed 12–15–97; 8:45 am]

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FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 97–162; RM–9112]

Radio Broadcasting Services; Hutchinson, KS

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: The Commission, at the request of Gary L. Violet, allots Channel 240A at Hutchinson, Kansas. *See* 62 FR 41016, July 31,1997. Channel 240A can be allotted to Hutchinson in compliance with the Commission's minimum distance separation requirements without the imposition of a site restriction. The coordinates for Channel 240A at Hutchinson are 38–04–54 NL and 97–55–42 WL. With this action, this proceeding is terminated.

DATES: Effective January 20, 1998. A filing window for Channel 240A at Hutchinson, Kansas, will not be opened at this time. Instead, the issue of opening a filing window for this channel will be addressed by the Commission in a subsequent order.

FOR FURTHER INFORMATION CONTACT: Pam Blumenthal, Mass Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's Report and Order, MM Docket No. 97–162, adopted November 5, 1997, and released December 5, 1997. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC Reference Center (Room 239), 1919 M Street, NW, Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractor, ITS, Inc., (202) 857–3800, 1231 20th Street, NW, Washington, DC 20036.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Part 73 of title 47 of the Code of Federal Regulations is amended as follows:

PART 73—[AMENDED]

1. The authority citation for Part 73 continues to read as follows:

Authority: 47 U.S.C. 154, 303, 334, 336.

§ 73.202 [Amended]

2. Section 73.202(b), the Table of FM Allotments under Kansas, is amended by adding Channel 240A at Hutchinson.

Federal Communications Commission.

John A. Karousos,

Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 97–32702 Filed 12–15–97; 8:45 am]

BILLING CODE 6712–01–F

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 97–32; RM–8931; RM–9065]

Radio Broadcasting Services; Calico Rock and Leslie, AR

AGENCY: Federal Communications Commission.

ACTION: Final rule.