FINAL REPORT
FEDERAL GAS VALUATION
NEGOTIATED RULEMAKING COMMITTEE

DEPARTMENT OF INTERIOR
MINERALS MANAGEMENT SERVICE

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FEDERAL GAS VALUATION NEGOTIATED RULEMAKING COMMITTEE

COMMITTEE REPORT

EXECUTIVE SUMMARY

AUTHORITY

The Federal Gas Valuation Negotiated Rulemaking Committee (committee) was established under the authority of the Federal Advisory Committee Act (FACA) (5 U.S.C. App.) (Pub.L. 92-463) and the Administrative Procedures Act (APA) (5 U.S.C. 553).

FORMATION AND OPERATION

In 1993, in response to Vice President Gore's National Performance Review (NPR), the Royalty Management Program (RMP) initiated a Reinvention Laboratory Team to examine ways to streamline the royalty management process. One of the recommendations of the NPR Team was to improve the gas valuation benchmark system. The NPR Team recommended conducting a pilot to evaluate the use of spot prices as the second benchmark. In commenting on the recommendations of the NPR Team, the Royalty Management Advisory Committee (RMAC) recommended that the current benchmark system be evaluated by a study group including representatives of Minerals Management Service's (MMS) constituents. The RMAC also recommended that the study be limited to gas produced from Federal leases.

In December 1993, MMS formed an informal group to study the benchmark system and, as a related issue, the valuation of gas produced from approved Federal unit and communitization agreements (Agreements). The scope of the study was later expanded to include valuation of Federal gas production under arm's-length contracts.

Upon review of the requirements of FACA and APA, the Department of the Interior (Department) determined that the study group should operate as a negotiated rulemaking committee. A June 27, 1994, Federal Register Notice (59 F.R. 32943) (Attachment 1), published by MMS, transformed the group into the Federal Gas Valuation Negotiated Rulemaking Committee. Attachment 2 contains the June 2, 1994, charter of the committee signed by the Secretary of the Interior.

Members of the committee included representative of the American Petroleum Institute (API), the Council of Petroleum Accountants Societies (COPAS), the Rocky Mountain Oil and Gas Association (RMOGA), the Independent Petroleum Association of America (IPAA)/ Independent Petroleum Association of Mountain States (IPAMS), the Natural Gas Supply Association (NGSA), an independent marketer, representatives of large independent producers, and personnel from the States of Utah, North Dakota, Montana, and New Mexico representing the State and Tribal Royalty Audit Committee (STRAC).

The informal study group and later the committee agreed to operate based on consensus decision making. Consensus was determined by members indicating their vote in one of three ways: thumbs-"up," "sideways," or "down." A "sideways" thumb meant a qualified "yes" vote and in order to have consensus all thumbs had to be up or sideways. The committee also agreed that its final report and the resulting proposed rule do not prohibit any committee member or his/her constituents from commenting on the proposed rule or challenging the final rule, or any order issued pursuant to the rule.

SCOPE AND OBJECTIVES

The Secretary of the Interior chartered the committee to advise MMS on a rulemaking to address: 1) the valuation of gas produced from approved Federal unit and communitization agreements (Agreements) (particularly when lessees take less than or none of their entitled share), and 2) the benchmark valuation system for valuing gas sold under non-arm's-length contracts. The scope of the committee was limited to examining values for gas (processed and unprocessed) produced from Federal leases.

The original committee charter established specific objectives for improving the process of valuing natural gas for royalty purposes. These objectives were to:

- Develop a method that allows lessees to use information to which they have access and reduces uncertainty on royalty values acceptable to MMS.

- Examine the suitability of using indices (that is, spot prices or other published prices) to value gas where sales do not occur at arm's-length or where there are no sales at all. Related issues such as transportation were to be included in this discussion.

- Establish timely and definitive criteria for lessees and auditors to use in valuing gas, where lessees sell under non-arm's-length contracts or where lessees sell less than or none of their entitled share.

The committee identified additional objectives which included simplicity, administrative cost savings, and revenue neutrality for both lessees and lessors to the extent it could be determined.

PRINCIPLES

The committee charter established certain principles of royalty accounting, required by mineral statutes and lease terms, that form the basis for evaluating options to replace the current rules:

Volume - Royalties must be paid each month on the volume of production allocated to or produced from the Federal lease under the Agreement terms.

Royalty Rate - Royalties must be paid in accordance with the royalty rate specified in each lease unless specified otherwise under the terms of the Agreement.
Value of Production - Value should be determined at the time of production. Value should be based on the fair market value at the lease.

Payment Responsibility - Federal lessees or their working interest owners are ultimately responsible for paying royalties, but other entities can be assigned the royalty payment responsibility.

RECOMMENDATIONS

As a result of committee negotiations and the above-noted objectives and principles, the committee reached consensus on the following recommendations for valuing: 1) gas sold under arm's-length and non-arm's-length contracts, 2) natural gas liquids, and 3) gas produced from Agreements.

These recommendations apply only to the Btu contributing component of the gas produced from Federal oil and gas leases. Any royalty bearing but not Btu contributing naturally occurring gas comprising all or a significant part of a gas stream from a Federal oil and gas lease will be valued as if it were produced in a zone not eligible for index-based valuation. Where gas streams consist of both Btu contributing and noncontributing components, the Btu contributing portion may be valued according to the recommendations of the committee. The following is a summary of these and other recommendations agreed to by the committee.

- Value of gas sold under arm's-length contracts must be based on gross proceeds. However, in areas where there is an active spot market and valid published indices, if certain criteria are met, value <u>may</u> (at the lessee's option) be based on an index-based method unless the sale is dedicated as defined by the committee. For gross proceeds-based valuation, value will not be based on the higher of gross proceeds or index.

- Value of gas sold under non-arm's-length contracts must be based on an index-based method in areas where there is an active spot market and valid published indices, unless the lessee notifies the MMS of its intent to use its affiliate's arm's-length gross proceeds. Where there are no valid published indices and no active spot market, value must be based on the existing benchmark system or whatever replaces the benchmark system..

- Value of natural gas liquids (NGL) derived from non-dedicated gas produced in areas where there is an active spot market and valid published indices may be based on an index or a residue gas price, as applicable, applied to a wellhead MMBtu. However, lessees reporting NGL on gross proceeds must convert gallons to MMBtu's.

- The committee concurred with MMS' proposal that for gas produced from Agreements which contain only Federal leases with the same royalty rate and funds distribution, and from leases not in an Agreement (stand alone leases), volume and value must be reported and paid on a takes method. The proposal provided for an exception for lessees to request approval to pay on entitlements.

- For gas produced from approved Federal Agreements which contain leases with different lessors, royalty rates, or funds distribution, volume and value must be reported and paid on an entitlements method. Small independents who meet certain production criteria will be granted an exception to this requirement and will be allowed to report and pay on takes, subject to an annual adjustment to an entitlements basis. In addition, all lessees may contractually agree to assign reporting and payment responsibility among themselves in any manner which ensures that entitled royalty volumes allocable to

Federal leases are reported and paid each month.

- The lessee may deduct from value, as a transportation allowance, the cost of moving royalty bearing substances (identifiable, measurable oil and gas, including gas free from impurities) from the point at which it is first identifiable and measurable to the sales point or other point where value is established. The lessee may not deduct from value the cost of gathering. Gathering is defined as the movement of an unseparated, bulk production stream to a point, on or off the lease, where the production stream undergoes initial separation into identifiable oil, gas, or free water.

- Any compression downstream of the facility measurement point (FMP) is deductible as a component of transportation or location differential.

- Transportation and processing allowance forms are no longer required for both gross-proceeds and index-based lessees for Federal leases..

- Dual accounting for Federal gas is no longer required for all lessees.

- Gross proceeds-based lessees may continue to use transportation factors in accordance with 30 CFR § 206.157(a)(5) (1994).

The committee also agreed to the following processes for developing and publishing a rule:

- After the rule is proposed but prior to final publication, MMS and States commit to work with API, COPAS, RMOGA, IPAA/IPAMS, and NGSA to develop the audit method for the zones. The committee recommends very strongly that members of this committee be included on the audit method team.

- Should MMS receive substantive comments on the proposed rule during the public comment period that would warrant major changes to the committee recommendations before final rulemaking, the committee recommends that it be reconvened to resolve any proposed changes.

- The committee recommends that the final rule be prospective <u>only</u>. The rule shall not be applied retroactively in whole or in part.

- The committee reached consensus on the following recommendations regarding the period of time before the new regulations become effective and companies must modify their systems:

  <u>Adjustment Period to Comply</u>

  - Effective date January 1, 1997
  - However, must be at least 6 months from the date of publication of final rule and effective date.
  - If less than 6 months, a new effective date will be established.

FEDERAL GAS VALUATION NEGOTIATED RULEMAKING COMMITTEE

COMMITTEE REPORT

I. COMMITTEE BACKGROUND

AUTHORITY

The Federal Gas Valuation Negotiated Rulemaking Committee (committee) was established under the authority of the Federal Advisory Committee Act (FACA) (5 U.S.C. App.) (Pub.L. 92-463) and the Administrative Procedures Act (APA) (5 U.S.C. 553).

FORMATION AND OPERATION

In 1993, in response to Vice President Gore's National Performance Review (NPR), the Royalty Management Program (RMP) initiated a Reinvention Laboratory Team to examine ways to streamline the royalty management process. One of the recommendations of the NPR Team was to improve the valuation benchmark system. The NPR Team recommended conducting a pilot to evaluate the use of spot prices as the second benchmark. In commenting on the recommendations of the NPR Team, the Royalty Management Advisory Committee (RMAC) recommended that the current benchmark system be evaluated by a study group including representatives of Minerals Management Service's (MMS) constituents. The RMAC also recommended that the study be limited to gas produced from Federal leases.

In December 1993, MMS formed an informal group to study the benchmark system and, as a related issue, the valuation of gas produced from approved Federal unit and communitization agreements (Agreements). The scope of the study was later expanded to include valuation of Federal gas production under arm's-length contracts.

Upon review of the requirements of FACA and APA, the Department of the Interior (Department) determined that the study group should operate as a negotiated rulemaking committee. A June 27, 1994, Federal Register Notice (59 F.R. 32943) (Attachment 1), published by MMS, transformed the group into the Federal Gas Valuation Negotiated Rulemaking Committee. Attachment 2 contains the June 2, 1994, charter of the committee signed by the Secretary of the Interior.

The negotiated rulemaking committee operated under the following guidelines:

- The committee operated the same as the study group except that the meetings were tape-recorded in order to provide a record to the public if requested in accordance with FACA.

- The committee was governed by FACA, and generally followed the guidelines of the Negotiated Rulemaking Act (NRA).

- The MMS committed to publish a report and a proposed rule reflecting the consensus of the committee.

- The committee will terminate after two years or the publication of a rulemaking, which ever comes first.

The study group and later the committee agreed to operate based on consensus decision-making. Consensus was determined by members indicating their vote in one of three ways: thumbs-"up," "sideways," or "down." A "sideways" thumb meant a qualified "yes" vote and in order to have consensus all thumbs had to be "up" or "sideways."

Initially, MMS stated that if the study group was unable to reach consensus on any of the chartered objectives, MMS would independently develop the proposed rule for that objective. In recognition, however, of the quality of discussions resulting from the negotiated rulemaking process and the progress made toward reaching the objectives, near the end of the proceedings, MMS stated that it would strongly consider the opinion of the majority in addressing any areas where the committee was unable to reach consensus.

Once the study group was converted to a negotiated rulemaking committee, the committee agreed to not sign an "agreement in principle". An "agreement in principle" would have prohibited any committee member from challenging the final rule.

The committee's final report and resulting proposed rule do not prohibit any committee member or his/her constituents from commenting on the proposed rule, challenging the final rule, or any order issued pursuant to the rule.

As a result of the conversion to a negotiated rulemaking committee, MMS added two additional members representing larger independents to the committee. The final negotiated rulemaking committee was comprised of members from each of the following organizations:

Organization	Number of Representatives
Council of Petroleum Accountants Societies	1
American Petroleum Institute	2
Rocky Mountain Oil and Gas Association	1
Independent Petroleum Association of America/ Independent Petroleum Association of Mountain States	1
Representatives from Large Independent Producers	2
Gas Marketing Consultants	1
Natural Gas Supply Association	1
Minerals Management Service	6
State and Tribal Royalty Audit Committee	4

(Attachment 3 lists the committee's membership.)

SCOPE AND OBJECTIVES

On June 2, 1994, the Secretary of the Interior chartered the committee to advise MMS on a rulemaking to address 1) the valuation of gas produced from Agreements (particularly when lessees take less than or none of their entitled share), and 2) the benchmark valuation system for valuing gas sold under non-arm's-length contracts. The scope of the committee was limited to examining values for gas (processed and unprocessed) produced from Federal leases.

The original committee charter established specific objectives for improving the process of valuing natural gas, CO_2, for royalty purposes. These objectives were to:

- Develop a method that allows lessees to use information to which they have access and reduces uncertainty on royalty values acceptable to MMS.

- Examine the suitability of using indices (that is, spot prices or other published prices) to value gas where sales do not occur at arm's-length or where there are no sales at all. Related issues such as transportation were to be included in this discussion.

- Establish timely and definitive criteria for lessees and auditors to use in valuing gas where lessees sell under non-arm's-length contracts or where lessees sell less than or none of their entitled share.

The committee identified additional objectives which included simplicity, administrative cost savings, and revenue neutrality for both lessees and lessors to the extent it could be determined.

PRINCIPLES

The committee charter established certain principles of royalty accounting, required by mineral statutes and lease terms, that form the basis for evaluating options to replace the current rules:

Volume - Royalties must be paid each month on the volume of production allocated to or produced from the Federal lease under the Agreement terms.

Royalty Rate - Royalties must be paid in accordance with the royalty rate specified in each lease unless specified otherwise under the terms of the Agreement.

Value of Production - Value should be determined at the time of production. Value should be based on the fair market value at the lease.

Payment Responsibility - Federal lessees or their working interest owners are ultimately responsible for paying royalties, but other entities can be assigned the royalty payment responsibility.

II. DISCUSSION OF RECOMMENDATIONS

As a result of committee negotiations and the above-noted objectives and principles, the committee reached consensus on the following recommendations for valuing: 1) gas sold under arm's-length and non-arm's-length contracts, 2) natural gas liquids, and 3) gas produced from Agreements.

These recommendations apply only to the royalty-bearing, Btu contributing component of the gas produced from Federal oil and gas leases. Any royalty bearing but not Btu contributing naturally occurring gas comprising all or a significant part of a gas stream from a Federal oil and gas lease will be valued as if it were produced in a zone not eligible for index-based valuation.

The committee recommends that it be reconvened to resolve any proposed changes if MMS receives substantive comments on the proposed rule during the public comment period that would warrant major changes to the committee recommendations before final rulemaking.

The committee recommends that the final rule be prospective only. The rule shall not be applied retroactively in whole or in part.

The committee reached consensus on the following recommendations regarding the period of time before the new regulations become effective and companies must modify their systems:

Adjustment Period to Comply

- Effective date January 1, 1997

- However, must be at least 6 months from the date of publication of final rule and effective date.

- If less than 6 months, a new effective date will be established.

Certain aspects of the committee's recommendations apply to Federal lessees using the index-based method and Federal lessees using the gross proceeds method. Such aspects include:

- Elimination of transportation/processing allowance forms (Forms MMS-4295 and MMS-4109)

- Determination of a transportation allowance/location differential (LD).

- Option for elimination of natural gas liquids (NGL) valuation and reporting.

- New definition of gathering v. transportation.

- New definition of compression.

- Takes-based valuation and reporting for Agreements containing only Federal leases and leases not in an Agreement.

- Entitlements based valuation and reporting for mixed Agreements, with exceptions including an annual takes provision for small producers.

- Elimination of Federal dual accounting requirement.

- States and industry involvement in the development of the audit methodology for safety net verifications.

- The committee agreed that in the rule, the value for royalties paid by gross proceeds payors will not be based on the higher of index or gross proceeds and that the values derived from an index-based method will not be used to impact the values paid under the gross proceeds method.

Other aspects apply only to index payors or gross proceeds payors as referenced in the discussion. For example, gross proceeds lessees reporting natural gas liquids must convert gallons to MMBtu's.

A. VALUATION OF GAS SOLD UNDER ARM'S-LENGTH SALES CONTRACTS AND UNDER NON-ARM'S-LENGTH SALES CONTRACTS IN AREAS WITH AN ACTIVE SPOT MARKET

Summary of Recommendation

Value of gas sold under arm's-length contracts must be based on gross proceeds. However, if certain criteria are met, value may (at the lessee's option) be based on an index-based method unless the sale is dedicated as defined by the committee. For gross proceeds-based valuation, value will not be based on the higher of gross proceeds or index.

Value of gas sold under non-arm's-length contracts must be based on an index-based method in areas where there is an active spot market and valid published indices, unless the lessee notifies the MMS of its intent to use its affiliate's arm's-length gross proceeds. Where there is no active spot market or valid published indices, value must be based on the existing benchmark system or whatever replaces the benchmark system.

1. Background

The original charter of the committee did not include the valuation of gas sold under arm's-length contracts in its scope and objectives. However, because a new gas marketing environment has recently evolved as a result of deregulation and open access particularly with the recent issuance of the Federal Energy Regulatory Commission (FERC) Order No. 636 (Order No. 636), the committee expanded the original scope and objectives to include gas sold under arm's-length contracts. The MMS Associate Directors for Royalty Management and Policy and Management Improvement concurred with this decision.

Under the current valuation regulations, gas sold under arm's-length contracts is valued based on gross proceeds. Gross proceeds is increasingly difficult to determine in today's natural gas market. Historically, producers/lessees sold directly to natural gas pipelines at the wellhead or outlet of a processing plant. The pipeline then transported and sold the gas to markets directly connected to its systems or to local distribution companies (LDC). The LDC's in turn sold the gas to end users such as households, and commercial and industrial users. Generally, the MMS received their royalty on the price paid the producer/lessee. However, with the advent of deregulation and open access, some producer/lessees began aggregating gas produced from many sources and selling it directly to LDC's and end-users. These sales generally guaranteed the delivery of specified volumes without regard to the source of production. This resulted in a far more complicated valuation of gas for MMS royalty purposes because gas was sold through the use of pools, market centers, and hubs.

Order No. 636 required natural gas pipelines to unbundle their sales services from their transportation services and to provide transportation services on a nondiscriminatory basis. As a result, the pipeline's traditional customers, LDC's and end-users, began purchasing gas directly from producers/lessees and gas marketers. Producer/lessees and gas marketers began to perform and receive compensation for downstream services traditionally performed by the pipeline companies. Among these services and costs were firm and interruptible transportation, storage, swing supply, capacity release, market hub services, pipeline imbalance resolution, and transportation refunds and penalties.

2. Alternative Proposals Considered

The committee agreed that arm's-length sales under dedicated contracts must under all circumstances be valued on gross proceeds. The committee then developed alternative valuation proposals to use in situations involving non-arm's-length sales and arm's-length non-dedicated sales. While an index-based method was initially considered, many committee members felt uncomfortable with proceeding with this proposal until other potential alternatives had been discussed. The committee considered several alternatives for valuing gas. The most significant alternatives considered were: (1) Secretarial established value, (2) Unrestricted lessee-election, (3) Case-by-case approval, and (4) Gross proceeds/weighted average pool pricing.

a. Secretarial established value

This method was proposed under the Secretary's vested authority to establish a reasonable value for royalty purposes. Under this option, MMS would publish a price monthly by region or area, including a deduction for transportation. The MMS could compute the price based on sales data reported on the Report of Sales and Royalty Remittance (Form MMS-2014), or by an MMS survey of prices similar to that performed currently by index publications.

In Alberta, Canada (Alberta), the government collects pricing information from each purchaser in one year and invoices lessees for royalties based a weighted-average of those reported prices the next year. It was suggested that MMS could perform a similar function.

This method was rejected because the United States pipeline/gathering system infrastructure is far more sophisticated and intricate than its neighboring system in Alberta and involves many more purchasers, marketers, and complex sales transactions. Therefore, while a regionalized price may closely approximate value throughout Alberta, diverse markets in the United States may result in significant variations in the market value of gas from field to field.

While providing some clear advantages such as certainty of value and simplification of audit, this method was rejected for a number of reasons:

- Regional/area-wide prices do not reflect differing market conditions or transportation costs for each lease.

- The MMS administrative costs would increase as a result of collecting extensive and complex transactions for establishing prices.

- Lessees may be paying royalties on values exceeding the lessee's actual proceeds, leading to extensive litigation.

- The MMS is not a disinterested third-party as are the existing index publications.

b. Unrestricted lessee-election

Under a pure lessee-election system, lessees would choose to use either index prices or gross proceeds to value their gas on a lease, field, or area basis. This method was favored by several industry representatives, because it allows lessees to use index valuation in areas where gross proceeds calculations are cumbersome and gross proceeds valuation in areas where index may not be appropriate. At the same time, this method avoids the difficulties of a forced-election system, that is where criteria determine whether the lessee must use index or gross proceeds valuation.

The concept of unrestricted lessee-election, however, concerned many MMS and State members. The greatest concern stemmed from the possibility of lessees deliberately choosing one method over the other in order to minimize royalties. Another concern was that unrestricted lessee-election could result in different valuation procedures within a lease and would complicate audit/verification and validation of market value.

c. Case-by-case approval

Under this option, lessees would request from MMS approval to apply index pricing to a lease, a field, an area, or a larger domain. This method would operate much the same as the lessee election method but would minimize the lessee's ability to reduce their royalty obligation by choosing one payment method over another by requiring up-front review and approval by MMS.

This method was rejected on the basis that it would impose too great an administrative burden on MMS, and would lead to long delays in obtaining approval from MMS. In addition, this option did not provide certainty and created possible disparate treatment among companies.

d. Gross proceeds/weighted average pool pricing

Use of the current method to value production, gross proceeds, received different levels of support from the committee members. Generally, small independents, States, and MMS favored a valuation method based on actual proceeds received from an arm's-length sale of production. Small independents favor gross proceeds for royalty valuation for three key reasons:

1. Gross proceeds represents actual value received,

2. Gross proceeds does not impose a significant administrative burden on some smaller companies that sell gas at or near the wellhead as it does on larger companies which have multiple marketing arrangements and transactions, and

3. Royalties have historically been due on gross proceeds.

Small independents generally do not have the resources to pool gas at market centers and sell under numerous contracts. They generally sell gas at the wellhead to marketers or aggregators, or, in limited cases, downstream under a single transaction.

For MMS and the States, gross proceeds at or near the lease have always been the primary benchmark of market value under the regulations. The Interior Board of Land Appeals (IBLA) and the courts have long upheld gross proceeds in valuing production.

For major oil and gas companies and larger independents, use of gross proceeds can become complicated if the production is commingled, or pooled, with production from other sources prior to sale. With the multitude and complexity of sales transactions in the Order No. 636 environment, companies have found it increasingly difficult, if not impossible, and costly to determine the weighted-average sales values and allocate those values back to the Federal leases for royalty purposes. As LDC's become deregulated, gas will in all probability be sold directly by the producer/lessees to commercial and smaller end-users, further complicating the myriad of transactions.

Producers also expressed serious doubts about whether compensation received for downstream services was part of gross proceeds. Many producers maintained that numerous downstream costs should be included in transportation and processing allowances if compensation for downstream services was includeable in gross proceeds. The committee discussed Order No. 636 related issues and agreed, after extensive presentation on the marketing environment of today and anticipated in the future, that it would not address the royalty implications of Order No. 636, because the committee was unlikely to reach consensus on these issues.

3. Discussion of Final Recommendation

a. Background of Index Pricing

As stated above, the committee agreed that arm's-length sales under dedicated contracts must under all circumstances be valued on gross proceeds.

However, after review of the above alternative proposals, the committee agreed that for arm's-length non-dedicated sales, the most viable valuation method to reach the committee's goals and objectives was a form of index pricing as an alternative valuation method. Specifically, the committee discussed and is recommending using the index prices that are compiled by third party publications which survey buyers and sellers for prices at specific geographic locations. Members of the committee from industry maintained that these prices do represent market value while committee members from MMS and the States felt that these index prices failed to capture any premiums associated with long-term or aggregated sales. As a result of this disparity, certain aspects of the proposal were developed in order to address these concerns. Independents expressed concern that adoption of an index-based method would negatively impact gross proceeds lessees; that MMS would attempt to collect additional royalties from gross proceeds lessees when index exceeds gross proceeds; and that MMS would abandon the gross proceeds method in favor of an index-based method. The committee agreed that in the rule, value for gross proceeds lessees will not be based on the higher of index or gross proceeds.

In the current gas marketing environment, many gas contracts reference some form of an index price as the sale price. Index publications survey several buyers and sellers in each geographic area, reject all prices which are anomalies, compile the numbers, and calculate the price using varying statistical methodologies including volume weighted average, arithmetic mean, etc.

A key concern of the States and MMS was that index prices may not be representative of market value, may be less than gross proceeds at the lease, and may result in a marked decrease in royalty revenues. Likewise, some industry members noted that index prices, in some instances, may increase their royalty payments relative to their gross proceeds. The committee agreed in concept that any index-based valuation method must be revenue neutral for MMS, States and lessees.

To examine revenue impact, a subcommittee comprised of industry, State, and MMS representatives studied royalty data reported for a 30 month period on Form MMS-2014 and compared it to index prices. In order to compare representative data, the subcommittee deducted transportation allowances (transaction code 11) from royalty due values (transaction code 01) on Form MMS-2014 and compared the results with index prices, adjusted for location differential, where applicable. Thus, wellhead values based on gross proceeds were measured against index prices adjusted back to the wellhead. The study encountered many problems with the 1) the quality of data reported to MMS, 2) the inability to segregate the data by index areas, and 3) transportation allowances that are netted from value. This study was performed on pre-Order No. 636 data and the impact in the post-Order No. 636 environment could not be determined due to its recent implementation. Therefore, revenue neutrality could not be demonstrated empirically by this particular study.

The committee acknowledged that any administrative cost savings realized by using published indices would have an impact on revenue neutrality. Therefore, while revenue neutrality could not be documented by this study, the committee anticipated that the use of published indices may ultimately reduce MMS' and industry's administrative costs related to royalty payments.

After considering all options for valuing Federal gas, the committee concluded that some form of index-based valuation should be adopted. The committee agreed that use of indices should be based on criteria, should only be adopted in certain geographic areas with active spot markets, and should result in minimal revenue impact to both MMS and industry. The committee undertook an intense examination of the concerns and mechanics of using index pricing.

b. <u>Final Recommendation</u>

Definition of Dedicated: *Production (or a specified portion) from a lease or is dedicated when production from that lease/well is specified in a sales contract(s) <u>and</u> that production must be sold pursuant to that contract(s) to the extent that production occurs from that lease/well.*

Royalties must be based on arm's-length gross proceeds (including weighted average gross proceeds allocation, where appropriate). Production dedicated to an arm's-length contract must be valued using gross proceeds.

For all other arm's-length situations (including wellhead sales under non-dedicated contracts), royalties <u>may</u> (at the lessee's option) be based on an index-based method provided the criteria listed below are met. Lessees will notify MMS of their intention to base value on index via a special code to be established on the Form MMS-2014. Arm's-length non-dedicated sales that do not meet the criteria listed below, will be valued using weighted average gross proceeds. For gross proceeds-based valuation, value will not be based on the higher of gross proceeds or index.

Value of gas sold under non-arm's-length contracts must be based on an index-based method in areas where there is an active spot market and valid published indices, unless the lessee notifies the MMS of its intent to use its affiliate's arm's-length gross proceeds as explained below. Where there is no active spot market or valid published indices, value must be based on the existing benchmark system or whatever replaces the benchmark system.

In zones where there is an active spot market and valid published indices where the lessee sells or transfers gas to a marketing affiliate (defined by MMS under 30 § 206.151 (1994)) the value of the gas may be determined under this rule depending on how the marketing affiliate resells the gas as follows:

<u>Resale by Marketing Affiliate</u>	*<u>Value of the Gas</u>*
Arm's-length dedicated	*Affiliate's gross proceeds*
Arm's-length non-dedicated	*Index, or Affiliate's gross proceeds*
Non-arm's-length	*Index, or Netback from the first arm's-length sale.*

Criteria for Index-Based Method

1. ***Active spot market for the gas produced. Active spot market is defined as one or more valid publications, publishing bidweek prices (or if bidweek prices are not available, first of the month prices) with at least one index pricing point in the zone.***

2. ***Valid published index for the gas produced. Wellhead indices are not acceptable because they are imputed. The index to be used is from the bidweek (if not available, then the first of the month) issue of a publication.***

3. ***The index-based method election must be made by the lessee for a minimum of two years for all of the lessee's non-dedicated production in a zone. An election to index method does not bind a lessee's successor to the same valuation method.***

4. ***The index-based method is subject to a comparison to the arm's-length gross proceeds payors in a particular zone. If the index-based value is less than the arm's-length gross proceeds value, then the lessee may owe additional royalties as determined under the safety net calculation described below.***

1. Explanation:

Based on factors and conditions developed by the Committee, MMS will determine what zones are eligible for index pricing based on whether there is a valid published index for the area and if there is an active spot market (see discussion of zone determination). Provided the criteria are met, a lessee may elect by zone to pay royalties based on an index price for a period of two years.

The driving force behind the lessee's election to use index is the gas sales contract. If gas produced from a lease/well is dedicated (defined above), then that producer is required to pay royalties on gross proceeds, that is, the index-based method is not an option. Generally, percentage-of-proceeds (POP) contracts are dedicated.

The only arm's-length situation in which a lessee may elect to use index is where the gas is not dedicated. Generally, if the gas is dedicated, the producer is only obligated to deliver the quantity of gas the well or lease can physically produce. Under non-dedicated contracts, a certain quantity of gas must be delivered, regardless of the source. If the production previously sold under a non-dedicated contract becomes dedicated, then the lessee must change to gross proceeds for that production beginning the first of the month following such change in dedication.

Example 1:

If all production from four leases is committed and sold under one and only one sales contract, then gas from all four leases would be dedicated.

Example 2:

Assume that there are four leases with the following monthly production:

lease 1 - 1000 MMBtu (Million British Thermal Units)
lease 2 - 4000 MMBtu
lease 3 - 5000 MMBtu
lease 4 - 3000 MMBtu

The contract states that 10,000 MMBtu may come from any source including, but not limited to, one or more of these leases. Gas from all four leases would be non-dedicated.

2. Negotiation:

The MMS and States were uncomfortable with the element of lessee election under an alternative valuation proposal. Therefore, the committee initially avoided lessee election as an option.

Early discussions centered on distinguishing between <u>source-specific gas sales contracts</u> and <u>non-source-specific gas sales contracts.</u> Gas under a source-specific contract would be valued on gross proceeds; gas under a non-source-specific-contract would be valued under the index valuation method. The independents wishing to pay on gross proceeds expressed concern regarding which contracts would be defined as non-source-specific thereby forcing them into an index method. They felt strongly they should be able to continue to use gross proceeds to determine value.

Creating a distinction between source-specific and non-source-specific for the purpose of valuation proved to be problematic from a definitional and auditing standpoint. As an alternative, the committee considered distinguishing gas as either <u>traceable</u> or <u>untraceable</u>. One concern was that certain pipeline companies require specific receipt and delivery points for nominating gas for transportation. Therefore, the contract incorrectly appears to be a source-specific contract and the gas incorrectly appears to be traceable. These proposals were eventually rejected by the committee.

The MMS, sympathetic to the independents wishing to pay on gross proceeds, proposed an exception whereby lessees with non-traceable contracts could petition MMS to pay on gross proceeds. The MMS could not identify any criteria upon which gross proceeds would be denied for valuation. Therefore, the committee agreed that gross proceeds lessees do not need to request an exception.

<u>The committee agreed that a limited amount of lessee election was warranted.</u> The committee agreed that the lessee should be able to elect under certain criteria to use either gross proceeds or index to value all of its non-dedicated production in an eligible zone. The final definition of dedicated/non-dedicated was agreed upon by the committee because it was simple, clear, and certain.

Relative to required criteria for index-based method, the committee agreed that certain criteria must exist before an index method can be used. For example, some geographic locations in the Rocky Mountain region do not have a significant active spot market with valid indices. Therefore, an index-based method is not appropriate for those locations.

The following section describes the proper location(s), or index pricing point(s) (IPP) to use when applying the index-based method in eligible zones.

Index Pricing Point (IPP)

A single connect is where the IPP is established before the pipeline to which the well, lease, platform, central delivery point, or plant (collectively referred to as well) is physically connected, interconnects with other pipelines. For a single connect, the index pricing point will be the first pipeline interconnect for which there is a valid published index.

A split connect is defined as more than one pipeline connected directly to the well. A multiple connection is defined as one pipeline connected to the well, but that pipeline splits prior to an index point. (These definitions are illustrated on page 19.)
To determine the index value in the case of split/multiple connects, the lessee has two options:

1. ***Weighted Average - Calculate the volume weighted average (based on confirmed nominations - either first of the month or total for the month, applied consistently, with no prior period adjustments for allocation or corrections to actual flows) of all of the index pricing points to which the well is physically connected, or***

2. ***Fixed Index - For all of the index pricing points to which the well is physically connected and for which there is a valid published index, array the publication's previous calendar year's average indices within the selected publications from highest to lowest and starting from the top:***

    - ***For two index pricing points choose the first index***
    - ***For three or more index pricing points choose the second index***

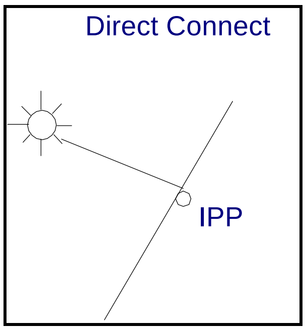
    This location establishes the IPP to be used throughout the entire calendar year. Current month's prices at this location must be used.

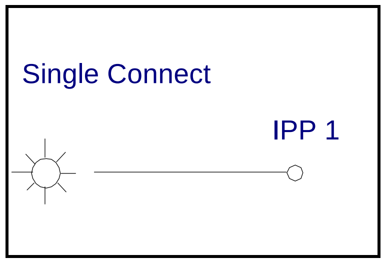
    In the case of a tie, meaning the same annual average index price of the individual months (as noted in price publications) at two or more index pricing points, the lessee would average individual months and choose the point with the largest average carried out to eight decimal points. If there is still a tie, the lessee chooses the index. LD is not a factor in selecting the first or second index.

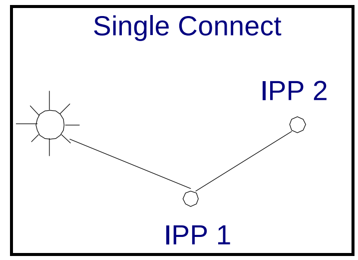
The lessee must choose beginning January 1, one of the two above options for a period of two years (to coincide with gross proceeds versus index election) for all leases connected to a common split or multiple connection point prior to the index pricing point.

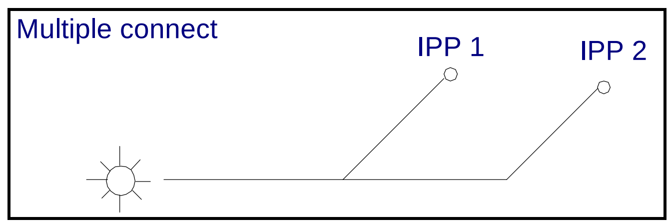
1) Explanation

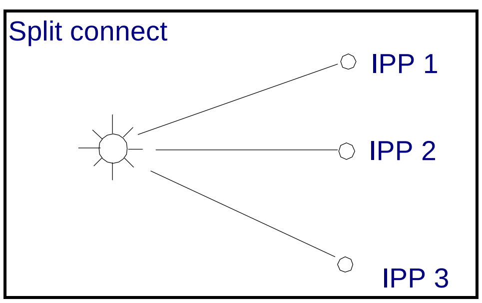
A well may be physically connected as a direct, single, split, or multiple connection. The following diagrams are only meant to illustrate how the committee has defined each of these connections. These diagrams are not meant to identify the IPP used for valuation:

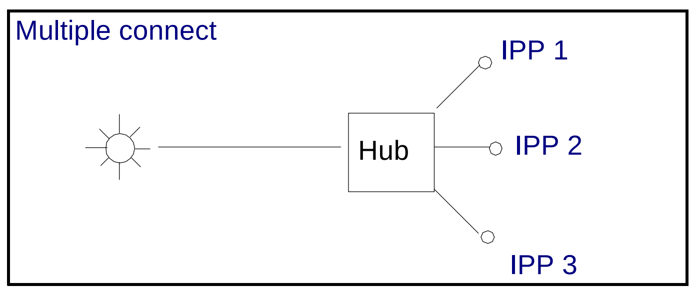




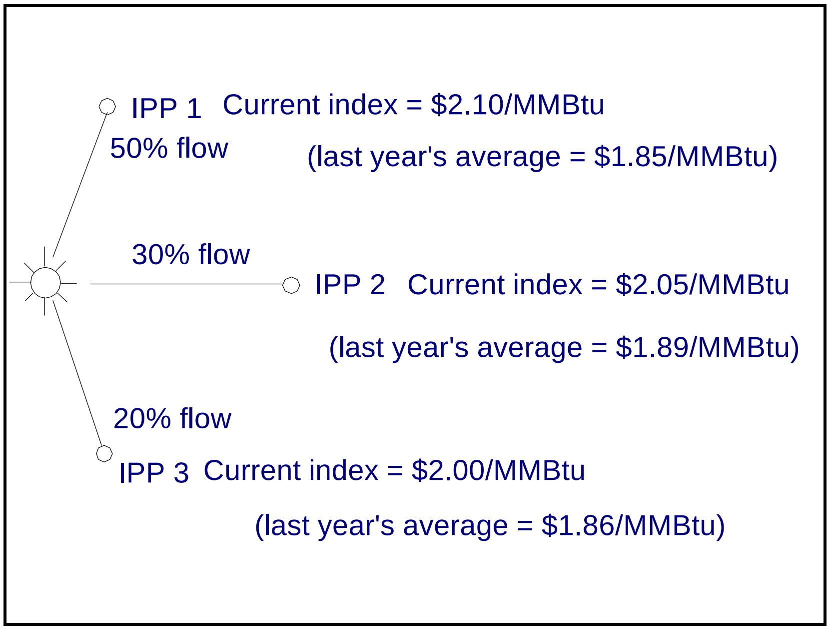








Below is an example of how to calculate both a weighted average index value and the fixed index when there are 3 IPP:



Weighted average method

(0.5 x $2.10/MMBtu) + (0.3 x $2.05/MMBtu) + (0.2 x $2.00/MMBtu) = $2.07/MMBtu.

Note that *current* index prices are used.

Fixed index method

Array the previous calendar year's average indices within the selected publication from highest to lowest as follows:

Last year's averages:

$1.89 index 2
$1.86 index 3
$1.85 index 1

Therefore, in the example above (three or more IPP), $1.86 was the second in the array of last year's average indices and therefore $2.00/MMBtu less any applicable costs to transport gas from the wellhead to that location would be used to value the lessee's entire gas stream for the current month. IPP 3 in this example is the location at which production for this calendar year will be valued.

In the case of a tie:

In the event that two or more IPP have the same price within the selected publication, the lessee must determine which one IPP must be used in order to apply the appropriate LD. The following example clarifies this circumstance:

Assume the index prices are arrayed as follows:

Last year's averages:

IPP 1 $1.50
IPP 4 $1.50
IPP 2 $1.48
IPP 3 $1.47

Because there are three or more indices, the lessee must choose the second price in the array - $1.50/MMBtu. The prices at IPP 1 and IPP 4 are both $1.50, therefore it must be determined which IPP is second in the array. In order to make this determination, individual month's prices must be averaged to determine which IPP has the largest average carried to eight decimal places. For example:

	IPP 1	IPP 4
Jan	$1.42	$1.43
Feb	$1.50	$1.52
Mar	$1.46	$1.45
Apr	$1.49	$1.50
May	$1.40	$1.38
Jun	$1.41	$1.40
Jul	$1.40	$1.45
Aug	$1.48	$1.52
Sep	$1.58	$1.58
Oct	$1.60	$1.62
Nov	$1.59	$1.60
Dec	$1.68	$1.57
	$1.50083333	$1.50166667

Based on the above annual average carried out to eight decimal points, IPP 1 has the second highest annual average. Therefore, IPP 1 would be the IPP chosen for value determination and applicable LD.

2) Negotiation:

The committee discussed in detail which index to use for value when the well was physically connected to several index pricing points. For simplicity, industry initially favored using the index at the closest index pricing point to which the well was physically connected. When several index pricing points are equally close, such as at the tailgate of a plant or at a hub, industry recommended using an arithmetic average of the indices.

In split/multiple connect situations, MMS and the States contended that using the closest index would be inappropriate when gas did not actually flow to that IPP but flowed to another IPP with a higher price. It was pointed out that this situation is common in the Rocky Mountain region where the gas typically flows to disparate markets. As a means to capture the market value of the gas in these situations, MMS and States advocated the use of a weighted average of the indices where the gas actually flowed. Alternatively, they suggested using the highest index.

Many members of industry objected strongly to being required to trace the physical flow of gas each month to various IPP in order to compute a weighted average index value. They maintained that any sort of tracing would be administratively costly to perform and arbitrary. Industry also objected to using the highest index for several reasons: (1) it is not always available for all gas supplies because of pipeline constraints and other market forces, (2) it may be anomalous, and (3) it violates statutes requiring royalty to be paid on the value of production. As a compromise, some industry members suggested using an arithmetic average of the indices at each IPP. However, this option was eventually rejected by the committee because it would complicate the calculation of the LD associated with the arithmetic average.

The committee weighed several methods for simplifying the calculation of weighted average flow. Pipeline capacity was considered, but rejected because it is difficult to determine in many cases and it may have no relationship with actual flow. The MMS and States insisted that they did not envision detailed tracing of the gas flow back to each lease. They felt that some simplified method to approximate actual flow was practicable. Many industry members contended that any sort of monthly flow determination would be impractical. They proposed an alternative which involved computing the previous year's gas flow and applying those ratios throughout the current year. They believed this would be simpler and require less administrative effort. Representatives of various companies, however, claimed that they could compute current actual flows (real time) of their gas monthly.

A subcommittee including States, industry, and MMS members assigned to examine transportation concluded that LDs could not be determined without also considering the selection of IPP (see Negotiation section of LDs). Their pricing proposal to the committee was: (1) for two IPPs, to use "the monthly posting for the highest average pipeline index price from the previous year for a single valid publication", (2) for three or more IPPs, they proposed using the monthly posting for the second highest average index from the previous year.

Under the consensus reached by the committee, the members from the States, industry, and MMS compromised by allowing lessees to elect between two options (weighted average or fixed index) for a period of two years. The committee believed that using the highest or second highest IPP was the best way to achieve simplicity and at the same time ensure a sufficient value for royalty. In other words, paying at a higher index was a cost of simplicity.

However, for those companies who can efficiently determine the flow of their gas, they are given the option to use a weighted-average of indices to determine value. Further, because marketing options are based on connections, not zones, the committee agreed that this election was to apply on a connection basis.

The MMS and States preferred the use of contemporaneous data for determining average indices and weighted average flow. However, industry preferred using previous year's data. The committee compromised that weighted average calculations using current confirmed nominations (first of month or monthly) and fixed index determinations using previous year's data would be acceptable. The requirement to use these options for a minimum of two years was intended to maintain consistency in the payment of royalties.

Location Differential ***(LD)***

A location differential shall be allowed from the well to the point where royalty value is determined if transportation costs were or would have been incurred to get the gas to that point. Where there is a direct connect to a pipeline with a valid index at that point (into pipe), no transportation should be deducted. The LD is calculated in the manner described below for both jurisdictional and non-jurisdictional lines. The lessee is not required to submit transportation allowance forms prior to claiming an allowance on Form MMS-2014; however, lessees paying on index must report their LD as a separate line-item on Form MMS-2014. Gross proceeds lessees may continue to use transportation factors in accordance with 30 CFR § 206.157(a)(5).

The LD associated with a split or multiple connection is calculated using the same method as the calculation of the index value. That is, if the lessee chooses to use the volume weighted average to calculate the index value, then the LD is also calculated using a volume weighted average of the LDs for each of the index pricing points. The LD for fixed index is based on transportation to the applicable index pricing point regardless of where the flow is occurring.

Jurisdictional lines (defined as pipelines with rates regulated and approved by FERC or state agencies):

If gas is transported by either the lessee or its affiliate through the jurisdictional line, the LD equals the actual contract rate paid.

If the lessee's gas does not flow to the index pricing point (herein-after referred to as a "gas does not flow" or "no flow" situation), the LD is equal to the maximum interruptible transportation (IT) rate.

Non-jurisdictional Lines:

Arm's-length:

If gas is transported by either the lessee or its affiliate through the non-jurisdictional line under an arm's-length contract, the LD equals the actual contract rate paid.

If gas does not flow, the LD equals 1) a lessee calculated rate that will be subject to audit, or 2) a rate calculated by MMS with the lessee reimbursing MMS in full for the administrative cost of gathering data and making the computation. Documentation that shall be considered by MMS in determining whether the lessee's calculated rate is acceptable includes but is not limited to the following, not necessarily in order:

- ***Copy of third party transportation contract***
- ***Pipeline published rate, if available***
- ***Rate applicable to lessee's last flow, provided that flow occurred for any 30 days (not necessarily consecutive) in the prior 12 months***

Non-Arm's-length:

If 30 percent or less of the gas moving through the non-jurisdictional line is moving under an arm's-length contract, the LD is based on the lessee's actual costs calculated under the 1988 valuation regulations <u>or</u> a de minimis rate. Transportation costs must have been incurred for any de minimis rate or other deductions to be allowed. The de minimis rate for Outer Continental Shelf (OCS) leases is $0.02/MMBtu. For onshore leases a de minimis rate has yet to be computed. Such rate, not to exceed $0.09/MMBtu and to include field fuel costs, will be based on a study to be conducted by MMS and published six months prior to the effective date of the final rule.

If more than 30 percent of the gas moving through the non-jurisdictional line is moving under arm's-length contracts, the LD is the 25th percentile <u>in an array of third party contracts</u> <u>or</u> the lessee's actual costs based on the 1988 gas valuation regulations. The 25th percentile is determined by arraying all the third party contracts from highest to lowest and starting from the bottom, choosing the rate closest to the 25th percentile.

For any transportation/processing facility purchased by the lessee or lessee's affiliate that does not have a previously claimed MMS depreciation schedule, the lessee may treat it as a newly installed facility for depreciation purposes.

1) Explanation

It was a consensus of the committee that an allowance representing the costs of transportation (or LD) would be allowed, when applicable, between the lease and the IPP used for value. For example, if the fixed IPP option is used, then a LD would be taken from the lease to that applicable IPP. When the weighted average IPP option is used to value production for royalty purposes, the LD would be a weighted average of the LD's associated with each IPP. The following example illustrates how to compute the weighted average LD.

	IPP 1	IPP 2
Lessee's amount of flow	30%	70%
LD	\$0.15/MMBtu	\$0.20/MMBtu

Weighted average = (0.3 x 0.15) + (0.7 x 0.2) = \$0.185/MMBtu

For any jurisdictional lines through which the lessee's gas does not flow, the lessee would use the maximum IT rate for the pipeline at the first of the month. If the maximum IT rate is subsequently revised as the result of a rate case hearing, the lessee will not be required to retroactively adjust the amount of the LD originally claimed. This rate should be available from the pipeline or from an electronic bulletin board.

For arm's-length non-jurisdictional lines through which the lessee's gas does not flow, there are two options. The lessee may use its own determined rate based on documentation that may include third-party transportation contracts, pipeline published rate, if available, and a lessee's rate applicable to its last flow. However, for that rate to be valid, the lessee must have used that rate for at least 30 days of flow during the calendar year. Such a rate will be subject to audit.

The other option available to lessees involves the lessee requesting MMS to obtain information and compute allowable LD annually, but this option involves reimbursement to MMS for the cost of that service. The MMS will charge no more than its own administrative costs to obtain and process the rate. Once established by MMS, this rate will not be subject to audit.

For non-arm's-length, non-jurisdictional lines, the LD depends on how much of the flow through the line is under arm's-length contracts. If less than 30 percent is arm's-length, the lessee must use its, or its affiliate's, actual non-arm's-length costs as currently required under 30 CFR § 206.157(c) (1994). Alternatively, for offshore leases, the lessee may use a flat rate of \$0.02/MMBtu for these lines. This includes situations where the lessee may have purchased a lateral line as part of a lease property package. For onshore leases, the lessee may use a de minimis flat rate that MMS will compute based on a study. The rate will account for fuel used for field transportation. The study will be completed by MMS and the rate published six months prior to the effective date of the final rule. This rate will not exceed \$0.09/MMBtu.

If more than 30 percent of the production is moving through the line under an arm's-length transportation contract, the lessee must use the rate at or closest to the 25th percentile of all arm's-length, third party rates as follows:

Example 1:

8 transactions	$0.02	$0.04	$0.05	$0.12	$0.12	$0.13	$0.13	$0.20
Percentile	.125	.250	.375	.50	.625	.75	.875	1.00

In this scenario, $0.04 would be the rate.

Example 2:

7 transactions	$0.05	$0.12	$0.13	$0.13	$0.20	$0.25	$0.25
Percentile	.143	.286	.429	.571	.714	.857	1.00

In this scenario, $0.12 is closest to the 25th percentile and would be the rate.

Example 3:

6 transactions	$0.05	$0.12	$0.13	$0.13	$0.20	$0.25
Percentile	.1667	.3333	.500	.6667	.8333	1.00

In this scenario, $0.05 and $0.12 are equidistant from the 25th percentile, the rate would be an average of $0.05 rate and the $0.12 rate, which would be $0.085.

2) Negotiation

As with IPP, the committee negotiated extensively on LD. The committee agreed early in the negotiation process that the LD was dependent upon the IPP. That is, if the lessee chooses to use the volume weighted average to calculate the index value, then the LD is also calculated using a volume weighted average of the LDs for each of the index pricing points. The LD for fixed index is based on transportation to the applicable index pricing point regardless of where the flow is occurring. However, some State members initially believed that only the lessee's actual, allowable costs of transportation should be used. In other words, only the costs incurred by the lessee in moving the gas to where it actually flowed should be allowed. The States eventually agreed to allow using the costs that would be incurred to flow the gas to where the IPP was located.

The committee also discussed whether to establish a "postage stamp" LD rate to be used throughout the zone for all leases in that zone. The concept was that MMS would publish a flat rate for all index lessees in the zone based on representative transportation costs. This option would have the advantages of simplicity and certainty, and would result in administrative savings to industry. A subcommittee was formed to determine this concept. They concluded that no feasible method could be developed to determine a "postage stamp" rate that would be acceptable to all parties because the transportation costs varied on a lease by lease basis and because there was no publicly available rate. Further, it would be administratively costly to MMS, and it would be vulnerable to litigation. The committee abandoned this option.

The committee then focused on establishing LD for particular categories of pipelines. Pipelines can be classified as jurisdictional or non-jurisdictional, flow or no flow (by the lessee), and arm's-length or non-arm's-length. There was agreement that for any arm's-length flow situation (both jurisdictional and non-jurisdictional), the lessee must use the actual rate paid under its arm's-length contract.

However, in the case of a wellhead sale to an affiliate, there was some debate whether the subsequent flow by that affiliate would be considered a no flow situation for the lessee. Some industry members asserted that there is a legal question whether the affiliate's transactions are subject to audit by MMS. The committee compromised and agreed that a sale to an affiliate would be a flow situation and the lessee would use its affiliate's arm's-length rate. This compromise was reached in recognition of the principle that costs may be incurred to move production to the sales or royalty valuation point remote from the lease. The committee reached consensus that where production actually flows to an IPP the most accurate reflection of this LD is the actual transportation contract rate paid. However, for companies who sell their gas production to affiliates, it was determined by consensus of the committee that the most accurate reflection of this LD will be the costs incurred by the lessee's affiliate to actually move the gas from the lease to the IPP. Therefore, if the lessee producer applies an LD, it will be required to secure from its affiliate the necessary information to calculate the value at the well. Industry asserts that this requirement is not intended and shall not be construed to blur the corporate separateness between the lessee producer and its affiliate. The MMS and States felt strongly that they have the right to look through the affiliate to establish royalty value.

For non-arm's-length jurisdictional lines with flow, the committee agreed to using the actual rate paid.

The discussion then focused on jurisdictional lines with no flow situations and on non-jurisdictional lines. In no flow situations, access to publicly available information is the biggest problem. For jurisdictional lines where gas did not flow to the point of valuation, the subcommittee proposed the maximum IT rate for three reasons: (1) to offset the revenue impact of the fixed IPP option, (2) because this rate is publicly available and therefore, simple and certain to obtain and determine, and (3) because much of the gas transported upstream of the IPP actually moves at this rate.

Research by the subcommittee suggested that at least 90 percent of all gas through jurisdictional lines was subject to the maximum IT rate. However, MMS and State members were concerned that the maximum IT rate did not account for the discounts applied to the other 10 percent of the gas. The MMS and the States wanted to compromise at 80 or 90 percent of the maximum IT rate. Large independents, however, pointed out that using a rate less than the maximum IT rate would discriminate against them because, unlike major oil and gas companies who more than likely ship their own gas, they would more commonly be in a no flow situation. Therefore, the committee agreed to use the maximum IT rate for both arm's-length and non-arm's-length jurisdictional lines in a no flow situation. The committee agreed that the maximum IT rate was appropriate for non-arm's-length jurisdictional lines, because 90 percent of the gas flowing through jurisdictional lines is subject to the maximum IT rates and this rate is readily available to lessees.

For arm's-length non-jurisdictional lines with no flow, access to information is a larger problem. There is no publicly available IT rate because non-jurisdictional lines are not required to publish such a rate. The only rates directly available to lessees are idle contract rates. The MMS maintained that under Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA), it could obtain non-jurisdictional rates from pipeline companies. The committee agreed that MMS-computation of a transportation rate should be an option for lessees. However, MMS would have to charge the lessees to whom service was being provided an administrative fee to cover the costs of obtaining, processing, and providing these rates.

For non-arm's-length, non-jurisdictional lines with either flow or no flow, the main issue discussed by the committee was whether to require a lessee to use its actual non-arm's-length costs as currently required under 30 CFR § 206.157(c) (1994). The MMS and States favored this method. Industry, particularly large independents, objected, citing a situation common in purchasing producing properties in today's business environment. Typically, such purchases are made on an aggregated basis where the purchase price may include the gas reserves, equipment, plants, gathering systems, lateral lines, etc. The purchase price does not assign individual costs to each of these individual components. Therefore, actual costs associated with non-jurisdictional lines cannot be determined by the lessee. The MMS and States acknowledged that this is a problem under the current regulations.

The subcommittee proposed that if 10 percent or more of the gas flowing through the line is arm's-length, lessees could use an average of those arm's-length rates. If less than 10 percent of the gas flowing through the line is arm's-length, lessees should be allowed to choose either a postage-stamp rate or non-arm's-length actual costs under the 1988 regulations. There was no support for the postage-stamp concept because there was no way of anticipating on which non-jurisdictional lines rates would have to be calculated. Therefore, they could potentially have to be calculated on all non-jurisdictional lines, creating an administrative burden for MMS. The MMS and States favored using third-party rates only if 50 percent or more of the gas flowing through the line was arm's-length. Eventually a compromise was reached at 30 percent.

In addition, to recognize the problems of producers that purchase lateral lines as part of a producing property, the committee debated and ultimately agreed to allow for a de minimis rate to reflect at least some of the transportation costs through these lines. Some committee members had information indicating that at least offshore, these costs ranged up to $0.05/MMBtu. Further discussion centered on setting a rate that would not exceed lessees actual costs. The committee compromised at setting the offshore rate at $0.02/MMBtu. Industry agreed to this rate in consideration of the diminishing depreciated capital investment. However, at a lessee's election, actual costs may be calculated pursuant to the 1988 regulations. For onshore leases a de minimis rate has yet to be computed. Such rate, not to exceed $0.09/MMBtu including field fuel costs, will be based on a study to be conducted by MMS and published 6 months prior to the effective date of the final rule.

In addition to the de minimis rate, the committee agreed to allow transportation or processing facilities purchased by the lessee or lessee's affiliate that did not have a previously claimed MMS depreciation schedule to be treated as a newly installed facility for depreciation purposes. Such facilities may have been previously subject to a FERC tariff and not an MMS depreciation schedule.

Industry supported the subcommittee proposal of using an average of third party contract rates where more than 30% of the gas flowing through the line is under third party arm's-length transportation contracts. The MMS and States, however, preferred using the lowest rate. They were concerned that, because of the captive nature of the pipeline, the arm's-length rates may be excessive. The committee settled on allowing the rate closest to the 25th percentile of the array of arm's-length rates. Alternatively, lessees may use their actual costs computed in accordance with the current valuation regulations.

Choice of Index Publication

If more than one publication publishes an index price at the index pricing point, then the lessee must elect a valid publication to use during a calendar year. The MMS will publish the index pricing points that it considers to be overlapping among publications. The MMS will also publish a list of valid publications, referencing which tables are to be used. Criteria which determine valid publications include:

1. ***Publications frequently used by buyers and sellers.***
2. ***Publications frequently referenced in purchase/sales contracts.***
3. ***Publications which use adequate survey techniques including gathering information from a substantial number of sales.***
4. ***Publications independent from lessees and MMS.***

Any publication may petition MMS to be added to the list of valid publications provided the publication can meet these and other possible criteria.

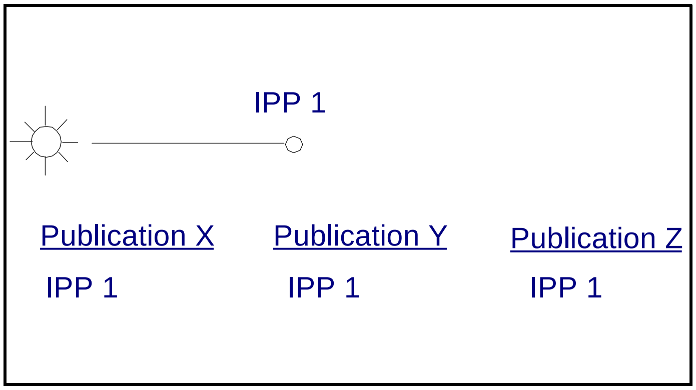
For split or multiple connects, if the lessee has chosen the weighted average method and a publication has added a new index pricing point, the lessee must immediately begin using that new index pricing point (add or substitute whichever is appropriate). If the lessee has chosen the fixed index method, the lessee must make its selection of the publication at the beginning of every year. However, if the lessee's selected publication has dropped an index pricing point the lessee must choose another publication.

If the publication the lessee subscribes to does not publish a pertinent index pricing point at the first pipeline interconnect to which the well is physically connected, then the lessee must obtain the information regarding the index pricing point from another valid publication.

1) Explanation:

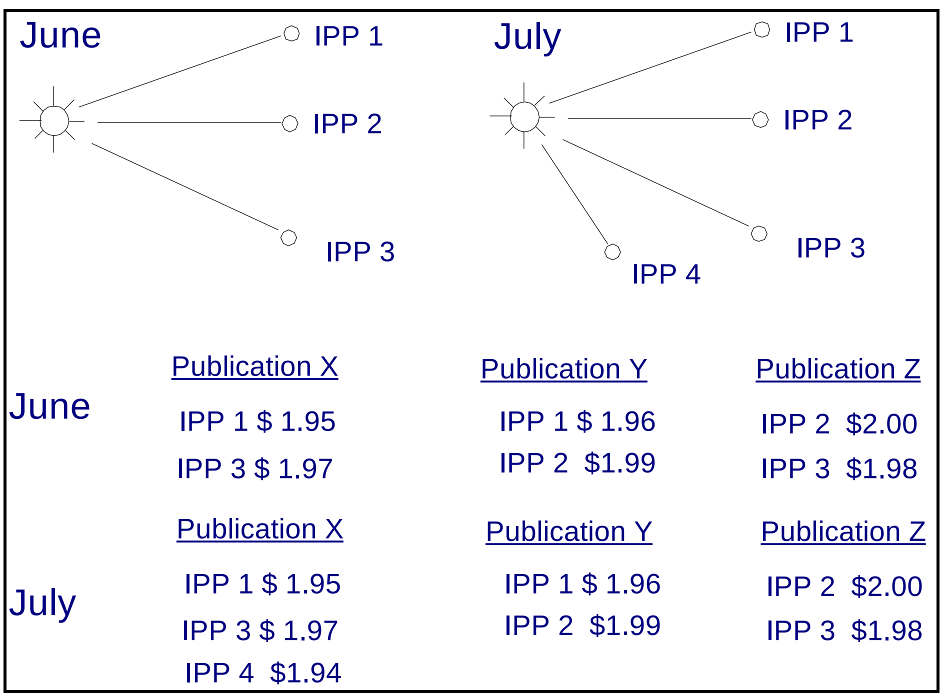
The following are examples of selecting a publication and the IPP published by that publication:

Example 1:



In Example 1, at the beginning of the calendar year, the lessee may chose any of publications X, Y, or Z, because each publishes an index price at IPP 1.

Example 2:



In Example 2, the lessee chooses a particular publication at the beginning of the year, for each IPP. However, in July, Publication X began publishing a price at IPP 4. Here are the results:

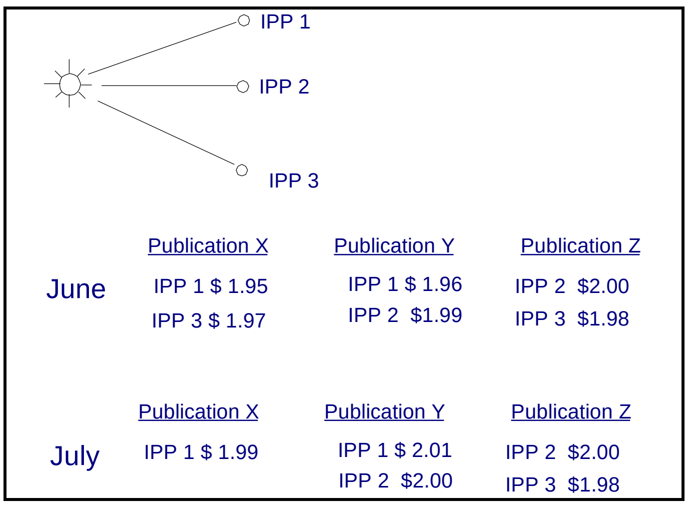
Weighted-Average

· The lessee must begin including IPP 4 in July in the weighted average calculation.

Fixed Index

· The lessee must wait until the following January to select a publication that publishes an index for IPP 4. If, in January, the lessee continues using Publication X, then it would consider Publication X's average index price for IPP 4 for the previous year in determining the IPP with the second highest index to be used for the current year. However, if another publication publishes indices for IPP 1, 3, and 4 for the previous year, the lessee may, in January, select that other publication.

Example 3:



In Example 3, the lessee chooses a particular publication at the beginning of the year, for each IPP. However, in July Publication X stopped publishing a price at IPP 3. Here are the results:

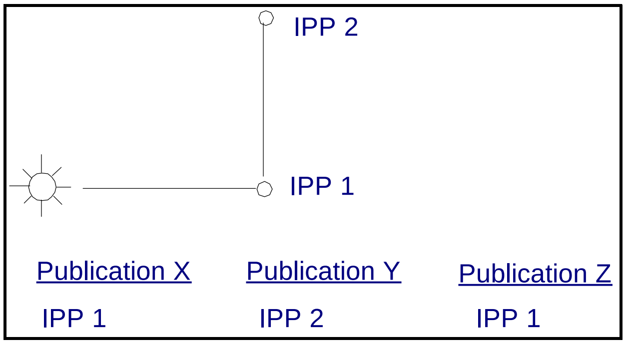
Weighted-Average

· If the lessee was using Publication X for IPP 3, in July it must begin including Publication Z for IPP 3.

Fixed Index

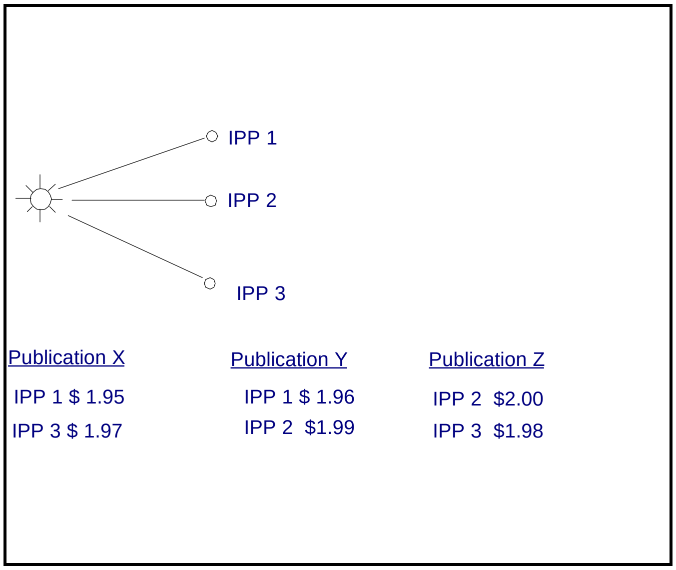
· Assuming that IPP 3 was the required IPP based on the fixed index method, the lessee must use Publication Z for IPP 3 beginning with July production month. The lessee is not required to re-array the previous year's average index prices because a publication has dropped an index price in the current year.

Example 4:



In Example 4, a single connect, there are two index pricing points to which the well is physically connected. Publications X and Z publish at IPP 1 and Publication Y publishes at IPP 2. If the lessee uses or subscribes to only Publication Y, it must choose either Publication X or Publication Z because IPP 1 is the first IPP to which the well is physically connected.

Example 5:



Example 5 summarizes how the lessee chooses the publication when there are overlapping publications prices at each IPP.

Weighted-Average

- If the lessee uses or subscribes to only Publication X, it must select either Publication Y or Z to obtain a current index price for IPP 2. It would then calculate the weighted average index value for IPP 1, 2, and 3.

Fixed Index

- If the lessee uses or subscribes to only Publication X, it must select either Publication Y or Z for IPP 2 and use the previous year's data to determine the IPP with the second highest average index.

- If the lessee chose Publication Y for IPP 2 and the previous year's second highest index was IPP 1, the current month's index value is $1.95. If IPP 2 was the second highest, the current month's index value is $1.99. If IPP 3 was the second highest, the current month's index value is $1.97.

2) Negotiation:

This aspect of the recommendation did not require significant negotiation. The discussions centered around the most simplistic method, given the complexity of various publications publishing indices for various IPP. The selection of any valid publication was necessary because MMS cannot legally endorse one publication over another.

Safety Net Calculation

For lessees whose payment methods are subject to the safety net the following applies:

On an annual zone-wide basis, the lessee's weighted average value will be compared to the median value of the arm's-length gross proceeds-based royalty values net of allowances paid for all Federal leases geographically located in the zone where the lease is located in the following situations:

For arm's-length non-dedicated gas sales in qualified zones (where the lessee has elected the index methodology) and non-arm's-length gas sales in a zone eligible for index valuation, the payor has the option to:

1) ***Pay index on unprocessed gas, or***
2) ***For processed gas, pay index on residue gas and gross proceeds on natural gas liquids (NGL's), or***
3) ***For processed gas, pay index on a wellhead MMBtu, or***
4) ***Pay on the net back from the affiliate's arm's-length gross proceeds (this option does not require a safety-net comparison).***

For arm's-length non-dedicated gas sales in qualified zones (where the lessee has elected to pay on gross proceeds), and non-arm's-length gas sales (where the lessee has elected option 4 above) the payor may elect to:

5) ***For processed gas, pay the gross proceeds residue gas price on a wellhead MMBtu.***

The following data reported to MMS will be used to calculate the median value:

a. *arm's-length dedicated gross proceeds less allowances,*
b. *arm's-length non-dedicated gross proceeds less allowances, for those lessees who have elected to stay on gross proceeds, and*
c. *Federal Royalty-in-Kind (RIK) gas sales for the applicable zone.*

The safety net will include the following Form MMS-2014 codes:

- *product codes 03 (processed gas) excluding the processed gas reported and paid using a gross proceeds residue gas price on a wellhead MMBtu , 04 (unprocessed gas), 05 (drip condensate), 07 (natural gas liquids), and 19 (sulfur from Federal oil and gas leases).*

- *transaction codes 01 (royalty due), 11 (transportation), and 15 (processing) associated with the above product codes.*

Median value is calculated by arraying the prices imputed from the three data sources listed above from highest price to lowest price (at the bottom). The median value is that price at which 50 percent (by volume) plus one MMBtu of the gas (starting from the bottom) is sold.

The median value calculated by the above procedures will be hereinafter referred to as "safety net median value."

The safety net median value must be based on a representative sample of sales from Federal leases in the zone and calculated on an MMBtu basis.

The MMS will publish a "snapshot" of the safety net median value 6 months following the end of each index year. The snapshot means the initial safety net median value calculation based on unaudited Form MMS-2014 data. On or before that time, MMS will initiate a zone-wide audit of the gross proceeds payors. After the rule is proposed but prior to final publication, MMS and States commit to work with API, COPAS, RMOGA, IPAA/IPAMS, and NGSA to develop the audit method for the zones. The committee recommends very strongly that members of this committee be included on the audit method team.

The MMS will notify lessees within two years following the end of each index year, of the final safety net median value. The final safety net median value calculation will be based on Form MMS-2014 data and will include the following data related to gross-proceeds based payors and gas RIK reporters:

a. *unappealed claims,*
b. *unappealed Director's decisions,*
c. *refunds from Section 10 requests, and*
d. *claims from appealed Director's decisions to IBLA/Court.*

The final safety net median value calculation will not include:

a. pipeline buyout/buydown settlements,
b. unpaid issue letters, (preliminary determination letters)
c. appealed claims not yet decided by the MMS Director.

The MMS will continue to streamline the appeals process and use alternative dispute resolution (ADR) techniques to assure that appeals by gross proceeds lessees are decided/resolved by the Director within the two year period following the end of the index year.

Lessees may request a technical procedural review of the MMS-calculated final safety net median value published two years following the end of the index year. The results of the technical review will be a final departmental action and will be completed in an expeditious manner.

For lessees who elected to pay on an index-based method, MMS will calculate the lessee's weighted average index price paid net of allowances for the index year by zone. For lessees who elected to pay on a gross proceeds based method and value their processed gas (i.e. NGL's) on a residue gas price applied to the wellhead MMBtu's (including arm's-length sales situations and non-arm's-length sales situations where the lessee elects to net back from the affiliate's arm's-length gross proceeds), MMS will calculate the weighted average price paid net of allowances for the index year by zone. These values will be compared to the MMS calculated safety net median value net of allowances for the index year for the same zone.

If the lessee's weighted average price paid for the index year for the zone is less than the safety net median value, then the lessee must pay additional royalty as described below. Any additional royalties due may be paid by the lessee as a one-line entry on Form MMS-2014 for the zone. Late payment interest will accrue effective with the date that MMS publishes the snapshot of the safety net median value. If at the time of the snapshot the lessee pays additional royalties as an estimated payment, the lessee will receive a credit/refund adjustment (without being subject to section 10 of the OCS Lands Act) if the estimated payment is greater than the actual additional royalties due subject to the final safety net median value and applicable caps as described below.

For any lessee's weighted average values subject to the safety net, as explained above, the following caps will apply.

105 percent/50 percent Cap

For gas:

a) *never processed, and the lessee elects to pay index on unprocessed gas (arm's-length or non-arm's-length) or*

b) *sold arm's-length prior to processing with no processing rights retained, and the lessee elects to pay index on unprocessed gas or*

c) *sold non-arm's-length prior to processing and the affiliate subsequently processes or retains the right to process the gas and the lessee elects to pay index on residue gas and gross proceeds NGL's, or*

d) *processed by the lessee and the lessee elects to pay index on residue gas and gross proceeds on NGL's,*

the lessee will not be required to pay total royalties of more than 105 percent of the index-based price or the lessee's final safety net median value, whichever is less, for the first year the regulations are in effect. For subsequent years, the cap will be 50 percent of the difference between the lessee's weighted-average index-based value and the final safety net median value.

105 percent/65 percent Cap

For gas:

a) *sold subsequent to processing or*

b) *sold prior to processing but the processing rights have been retained by the lessee, or*

c) *sold non-arm's-length prior to processing and the affiliate subsequently processes or retains the right to process the gas, or*

d) *processed by the lessee*

and the lessee elects to pay index on a wellhead MMBtu, the lessee will not be required to pay total royalties of more than 105 percent of the lessee's index price or the final safety net median value, whichever is less, for the first year the regulations are in effect. For subsequent years, the cap will be 65 percent of the difference between the lessee's weighted-average index-based value and the final safety net median value.

105 percent/30 percent Cap

For gas:

a) ***sold subsequent to processing or***

b) ***sold prior to processing but the processing rights have been retained by the lessee, or***

c) ***sold non-arm's-length prior to processing and the affiliate subsequently processes or retains the right to process the gas, or***

d) ***processed by the lessee***

and the lessee elects to pay the gross proceeds residue gas price on a wellhead MMBtu, the lessee will not be required to pay total royalties of more than 105 percent of the lessee's residue gas price or the final safety net median value, whichever is less, for the first year the regulations are in effect. For subsequent years, the cap will be 30 percent of the difference between the lessee's residue gas price and the final safety net median value.

Conversion of NGL gallons to MMBtu's

In order to calculate the safety net median value, gross proceeds lessees reporting NGL's (product code 07) must convert gallons currently reported to MMBtu's. For POP contracts, this conversion must be reported as follows:

1) ***100 percent residue value with 100 percent residue volume (reported as product code 03)***
2) ***If gross proceeds is greater than the 100 percent residue value, then report gross proceeds under product code 03.***

For all other contracts, this conversion must be reported as follows:

1) ***Volume will be calculated by subtracting the residue MMBtu from the wellhead MMBtu. This volume will be reported as the royalty quantity on the product code 07 line.***

Other Aspects of Safety Net Calculation

Any additional royalties due may be paid by the lessee as a one-line entry on the Form MMS-2014 for the zone. Late payment interest will accrue effective with the date that MMS publishes the snapshot of the safety net median value.

If the lessee's value is greater than or equal to the final safety net median value, royalty will be based on the lessee's value.

If market conditions change, for example, the spot market shrinks so that the index-based method is no longer an appropriate measure of market value, theregulations will provide for zone disqualification. However, a zone will not bedisqualified prior to the end of an index year. The MMS will hold a technical conference and notify payors by September 1 of the year prior to disqualification.

1) Explanation:

For each index-based lessee in each zone, MMS will compute the weighted average value net of allowances for the year based on lease volumes and values they reported and paid on the Form MMS-2014's. The MMS will compare this value to the safety net median value for the zone, also net of allowances to reflect value at the lease. The following is an illustrated example of the safety net median value calculation:

Volume (MMBtu)	Price	Cumulative Volume(MMBtu)	Percentage
1,000	$3.00	36,500	100%
2,500	$2.75	5,500	96%
5,000	$2.60	33,000	90%
4,000	$2.35	28,000	77%
4,500	$2.10	24,000	66%
6,000	$1.90	19,500	53%
5,000	$1.85	13,500	37%
3,500	$1.50	8,500	23%
5,000	$1.20	5,000	14%
36,500			

Fifty percent of 36,500 is 18,250. The price at which 18,250 plus 1 MMBtu was sold is $1.90; therefore, the safety net median value to which the index based lessee's will be compared is $1.90.

If the weighted average index-based value is greater than or equal to the final safety net median value, no additional royalty is due. However, if the weighted-average index value is less than the final safety net median value, the lessee must pay additional royalties. The additional royalty compensates for the difference between the final safety net median value and lessee's weighted-average index value. For the first year the regulations are in effect, a lessee's total royalty obligation on a MMBtu basis will not exceed 105 percent of the lessee's weighted-average index value. For subsequent years, a lessee's additional royalty obligation on a MMBtu basis will not exceed 30, 50, or 65 percent of the difference between the final safety net median value and the lessee's weighted-average index price depending on how the lessee elects to report NGL's. The following is an example:

Example 1 (105 percent/50 percent cap)

Current Year

Suppose the final safety net median value for a particular zone is $1.95/MMBtu.

Suppose also that the lessee's weighted-average index price for **unprocessed gas** in the same zone is $1.85/MMBtu.

Result: For the first year the regulations are in effect, the lessee's price for royalty purposes would be $1.94/MMBtu because the cap of 105 percent would come into effect: ($1.85 * 105 percent). Because the lessee had initially remitted royalties based on a price of $1.85, the lessee would be required to pay an additional $0.09/MMBtu for production in that zone.

However, if the final safety net median value in the first year was determined to be $1.88/MMBtu, the lessee's price for royalty purposes would be the full safety net median value of $1.88/MMBtu because the cap ($1.94/MMBtu) exceeds the safety net median value.

Assume the same facts for all subsequent years

Result: The lessee's price for royalty purposes would be $1.90/MMBtu because of the applicable cap of 50 percent of the difference between the final safety net median value and the lessee's weighted-average index price as follows:

($1.95 - $1.85) * 50 percent = $0.05/MMBtu
$0.05 + $1.85 = $1.90/MMBtu

Example 2 (105 percent/65 percent cap)

Current Year

Suppose the final safety net median value for a particular zone is $2.00/MMBtu.

Suppose also that the lessee's weighted-average index price for **processed** gas in the same zone is $1.85/MMBtu.

Result: For the first year the regulations are in effect, the lessee's price for royalty purposes would be $1.94/MMBtu because the cap of 105 percent would come into effect: ($1.85 * 105 percent). Because the lessee had initially remitted royalties based on a price of $1.85, the lessee would be required to pay an additional $0.09/MMBtu for that zone.

However, if the final safety net median value in the first year was determined to be $1.90/MMBtu, the lessee's price for royalty purposes would be the full safety net median value of $1.90/MMBtu because the cap ($1.94/MMBtu) exceeds the safety net median value.

Assume the same facts for all subsequent years

Result: The lessee's price for royalty purposes would be $1.95/MMBtu because of the applicable cap of 65 percent of the difference between the final safety net median value and the lessee's weighted-average index price as follows:

($2.00 - $1.85) * 65 percent = $0.0975/MMBtu
$0.0975 + $1.85 = $1.9475/MMBtu

Example 3 (105 percent/30 percent cap)

Current Year

Suppose the final safety net median value for a particular zone is $2.00/MMBtu.

Suppose also that the lessee's weighted-average residue price for **processed** gas in the same zone is $1.85/MMBtu.

Result: For the first year the regulations are in effect, the lessee's price for royalty purposes would be $1.9425/MMBtu because the cap of 105 percent would come into effect: ($1.85 * 105 percent). Because the lessee had initially remitted royalties based on a price of $1.85, the lessee would be required to pay an additional $0.0925/MMBtu for production in that zone.

However, if the final safety net median value in the first year was determined to be $1.90/MMBtu, the lessee's price for royalty purposes would be the full safety net median value of $1.90/MMBtu because the cap ($1.9425/MMBtu) exceeds the safety net median value.

Assume the same facts for all subsequent years

Result: The lessee's price for royalty purposes would be $1.90/MMBtu because of the applicable cap of 30 percent of the difference between the final safety net median value and the lessee's weighted-average index price as follows:

($2.00 - $1.85) * 30 percent = $0.045/MMBtu
$0.045 + $1.85 = $1.8945/MMBtu (applied to all volumes in the zone)

Late-payment interest associated with any additional royalties due under the safety net calculation would accrue effective with the date MMS publishes the "snapshot" of the safety net median value approximately 6 months after the end of the index year. A lessee may eliminate or minimize interest by making an additional royalty payment based on the "snapshot." The snapshot is the initial safety net median value calculation performed by MMS based on unaudited MMS-2014 data. The following is a time-line reflecting the "snapshot" and the period of time in which the safety net median value will be determined.

1/97 index Year	12/97	6/98	Potential Interest Period	12/99
		"Snapshot"		Publication of final safety net median value for 1997 index year.

1997 -	First index year
June 1998 -	MMS to publish "snapshot" and interest to begin to accrue.
December 31, 1999 -	Zone audit to be completed, final safety net median value to be determined.

As a condition of accepting the index proposal, MMS insisted if market conditions change, for example, the spot market shrinks so that the index-based method is no longer an appropriate measure of market value, the regulations will provide for zone disqualification. However, a zone will not be disqualified during an index year. The MMS will hold a technical conference and notify payors by September 1 of the year prior to a zone being disqualified.

2) Negotiation:

<u>Summary</u>

The safety net was a critical component for MMS and the States in adopting alternative valuation recommendation. The MMS and States were concerned that: 1) indices represent the spot market value of gas and do not reflect premiums associated with long term contracts, and 2) approximately 30 percent of the gas is currently sold on the spot market. In essence, the "safety net" provided MMS and the States assurance that index-based values would not result in substantially lower revenues than those received under gross proceeds while allowing industry the option to report and pay on index. The safety net helped to alleviate some of MMS concerns regarding revenue neutrality associated with an index-based method.

The independent producers expressed concern that because the safety net calculation is based on audited gross proceeds data, there will be a new burden for gross proceeds based payors. Some independent producers believe that this will create an additional administrative expense.

Industry representatives who favored an index-based method disputed the necessity for a safety net, maintaining that index prices net of LD reflected market value at the lease.

When the MMS and States' acceptance of an index-based method was conditioned upon a safety net, industry's main concerns became the method of calculating the safety net and the necessity for including a safety net cap. Industry maintained that a safety net adjustment based solely on gross proceeds payments would not properly reflect the opposing views on the proper measure of market value at the lease. Industry insisted on a safety net cap because: 1) it ensured that gross proceeds and indexes were afforded equal weight in measuring market value at the lease, and 2) no downward adjustment of index payments would be allowed in the event they exceeded the safety net.

In calculating the safety net median value, the committee agreed to use the median value method currently used for determining major portion for Indian gas. This median value method was chosen primarily to eliminate the effect of pricing anomalies in the gross proceeds reported to MMS. Further, because reported gross proceeds values used in the safety net median value calculation may be net of transportation; i.e., transportation factors, the committee agreed that all comparisons between the safety net median value and indices must be adjusted for transportation, as applicable. In effect, the comparison should be between gross proceeds values net of transportation at the wellhead and index values net of transportation at the wellhead. For this reason lessees paying on index must report their LD as a separate line item on Form MMS-2014.

<u>Background of Safety Net Issues</u>

Initially, the committee agreed on a safety-net tolerance factor of 97 percent. That is, if the index-based value was at least 97 percent of the safety net median value, the index-based lessee would owe no additional royalties. However, the committee modified the 97 percent tolerance factor in favor of a 100 percent factor as a result of the agreement to include a cap on the safety net median value and the fact that it is already at the 50th percentile of the gross proceeds values reported to MMS.

When the committee was considering a tolerance factor of 97 percent, industry proposed a corresponding cap of 103 percent. That is, index-based payments would be limited to 103 percent of the index value, if the final safety net median value were greater than that. The MMS and the States strongly opposed a cap. However, industry was adamant about including a cap, if MMS was going to charge interest on any additional royalty payment attributable to the safety net calculation. Industry was also concerned about unforeseen liability when the safety net median value far exceeded the index value, particularly in the first year of the rule.

The parties compromised and agreed that the safety net would include both a cap and an interest assessment. The concept of a cap on the safety net calculation was developed by the committee for several reasons, which included: 1) the risk of litigation by both parties would be split equally, 2) disputes regarding inclusion of Order No. 636 components in gross proceeds valuation, and 3) if no cap, index valuation would be equivalent to gross proceeds.

The MMS and the States countered industry's proposal by raising the 97 percent tolerance to 100 percent and the cap to 105 percent of lessee's index value, but only for the first year. For following years the cap would be 50 percent of the difference between lessee's weighted-average index value and the final safety net median value. In addition, once the committee discussed the proposal for NGL's, they determined there would need to be different caps on the safety net calculation for different valuation methods. (See "Valuation of Natural Gas Liquids").

Another key issue in the resolution of the safety net was the assessment of late payment interest on any additional royalty payments required to be paid by the lessee. The MMS and States said interest should be assessed because (1) the royalty obligation accrues at the time of production and (2) interest equals the time value of money.

Industry objected to paying interest on any additional royalty payment associated with the safety net for several key reasons including: (1) interest is not owed until the additional royalty value is established, (2) they cannot know what the safety net median value is at the time of production in order to correctly pay royalties, and (3) if index is greater than the safety net median value, the lessee is deprived of the time value of money.

The MMS and States agreed that lessees cannot know at the time of production what the safety net median value will be. As a compromise, the committee reached consensus to assess interest beginning with the "snapshot." If at the time of the snapshot the lessee pays additional royalties as an estimated payment, the lessee will receive a credit/refund adjustment (without being subject to section 10 of the OCS Lands Act) if the estimated payment is greater than the actual additional royalties due subject to the final safety net median value and applicable caps as described below.

Industry recommended MMS compute a safety net median value as soon as possible so they could determine if there was an obligation. However, because the "snapshot" data is "un-audited," MMS and States favored a second safety net median value after audits were completed. Industry conceded to a second computation of safety net median value if it was completed quickly. The MMS, sensitive to industry's concerns, committed to completing gross proceeds audits, resolving associated disputes, and issuing a final safety net median value within 2 years after the end of the index year.

The MMS members said resources would be allocated so that a team of State and MMS auditors, valuation personnel, and AFS/PAAS personnel would be available to perform the zone audits within the 2-year period. Industry accepted the use of audited gross proceeds provided they could participate in the process of developing MMS' audit method. With affirmation by the Deputy Associate Director for Compliance, MMS committed to work with the various industry trade associations to develop audit methodologies for the zones.

<u>Representative Sample</u>

The safety net median value must be computed using a sufficient amount of gas from Federal leases in the zone to represent market value. Representative sample is defined as either a minimum of 10 percent of the total Federal zone production paid and reported to MMS on gross proceeds or a minimum of 20 percent of total Form MMS-2014 lines reported as "royalty due" in a zone are based on gross proceeds.

At the time of the snapshot, MMS will determine if there is a representative sample for the zone. If there is not a representative sample for the zone then the following procedure will be used to obtain the deficient arm's-length data:

1) ***The MMS will ask for volunteers from index-based lessees to provide access to their records (including affiliate resale values) to obtain volume and value information to develop a representative sample. The MMS will take a stratified sample of this information to be added to the values as reported by the gross proceeds payors to reach the 10 percent/20 percent threshold. <u>All the companies</u> who volunteer to provide access to their records shall pay additional royalties, as required, up to the lesser of a negotiated value based on the snapshot or $0.005/MMBtu less than the final safety net calculation, but never less than the original index price required. For those companies that do not volunteer to provide access to their records, MMS will use the gross proceeds data obtained from volunteers and all other data available to calculate the safety net median value.***

2) ***If there are no volunteers, or not enough volunteers to reach the 10 percent/20 percent threshold, MMS will establish value, which would include, but not be limited to, issuing orders to lessees within the zone as required to obtain sufficient gross proceeds data to develop the safety net median value.***

1) Background

In order to calculate a representative safety net median value by zone to be used to determine any additional royalty payments due from index-based lessees, the committee agreed that there had to be a certain number of transactions or volumes reported by gross proceeds payors in each zone. Original discussions surrounding the issue of how the safety net median value would be determined if there were no representative volumes in a particular zone centered on sampling transactions based on all gross proceeds transactions in the zone. Industry representatives stated that their position was if there is no representative volume in a zone, then index equals market value and index should be acceptable for royalty purposes. However, MMS and States disagreed and suggested sampling first arm's-length transactions of index payors in the zone that does not have a representative volume to determine the safety net median value. Some industry representatives strongly objected to this suggestion because it involved use of an affiliate's proceeds rather than the lessee's proceeds. The MMS and States felt strongly that the safety net median value should include bona fide arm's-length sales and sales from producers to their affiliates would not be indicative of market value.

2) Explanation

If less than 10 percent of the total Federal zone production is paid and reported to MMS on gross proceeds or less than 20 percent of total Form MMS-2014 lines are reported as "royalty due" in a zone then the gross proceeds reported to MMS by arm's-length payors would not be acceptable for determination of the safety net median value. At the time of the snapshot (roughly 6 months after the end of the index year), if MMS determines that there are not enough volumes to meet the 10 percent/20 percent requirement, then MMS will request volunteers to come forward to provide access to their records in order to meet the 10 percent/20 percent requirement. For example, if the snapshot indicates that only 3 percent of the volumes in the zone were reported by gross proceeds payors, MMS will ask for volunteers to come forward and provide access to their records.

For any lessee that offers access to their records, at a minimum that lessee will receive $.005/MMBtu less than the final safety net calculation as modified by the applicable cap. Such volunteers could begin settlement negotiations with MMS to determine that individual lessee's additional royalty obligation, if any, applicable to their value at that time. If the lessee enters into negotiations with MMS, any additional royalty obligation would be the lesser of the lessee's negotiated value or $0.005/MMBtu less than the final safety net calculation, subject to the applicable cap. However, value can never be less than the lessee's weighted-average index value for the year. Volunteers must provide access to appropriate sales/transportation/processing related records for that zone

.

For example, if the snapshot indicated that the safety net median value calculated based on 3 percent of the volumes for the zone was $1.95, the index-based lessees who volunteered to provide access to their records would reach a settlement with MMS using the $1.95 as a starting point for the settlement. Once settlement is reached, the lessee will never be required to pay additional royalty above the settlement amount provided it is not less than the lessee's weighted average value as reported during the index year.

Example 1

Assume the following example for **unprocessed** gas (50 percent cap) for the second and all subsequent years:

	Price per MMBtu
Snapshot median value	$1.95
Volunteer lessee's weighted-average value (as originally reported during the index year)	$1.93
Negotiated Settlement Price	$1.95
Final Safety Net Median Value (including all volunteer lessees' data)	$1.99
Cap calculation:	($1.99 - $1.93) * 50% = $0.03
Lessee's final safety net calculation price:	$1.93 + $0.03 = $1.96
Lessee's final safety net calculation less $0.005:	$1.96 - $0.005 - $1.955
Lessee's negotiated settlement price:	$1.95
Lessee's final safety net calculation less $0.005:	$1.955
Lesser of negotiated settlement price or lessee's final safety net calculation:	$1.95

Result: The volunteer lessee's final royalty obligation would be based on a price of $1.95/MMBtu which is $0.02/MMBtu above their originally reported weighted-average value of $1.93/MMBtu. This final royalty obligation is not known until the lessee's final safety net calculation is determined (2 years after the index/year).

However, if the lessee's final safety net calculation, subject to the applicable cap (as calculated by MMS 2 years after the index year), is less than the lessee's negotiated settlement price, the lessee may be due a credit equal to the settlement price less the final safety net calculation less $0.005/MMBtu.

Example 2

Assume the following example for **unprocessed** gas (50 percent cap) for the second and subsequent years:

	Price per MMBtu
Snapshot median value	$1.98
Volunteer lessee's weighted-average value (as originally reported during the index year)	$1.93
Negotiated Settlement Price	$1.98
Final Safety Net Median Value (including all volunteer lessees' data)	$2.03
Cap calculation:	($2.03 - $1.93) * 50% = $0.05
Lessee's final safety net calculation price:	$1.93 + $0.05 = $1.98
Lessee's final safety net calculation less $0.005:	$1.98 - $0.005 - $1.975
Lessee's negotiated settlement price:	$1.98
Lessee's final safety net calculation less $0.005:	$1.975
Lesser of negotiated settlement price or lessee's final safety net calculation:	$1.975

Result: The volunteer lessee's final royalty obligation would be based on a price of $1.975/MMBtu which is $0.005/MMBtu below the lessee's final safety net calculation price. Therefore, because this lessee had paid a negotiated settlement price of $1.98/MMBtu at the snapshot, the lessee would be entitled to a credit of $0.005/MMBtu at the time the final safety net calculation is determined (2 years after the index year)

For lessees that did not volunteer records and did not reach settlement, MMS will calculate a final safety net median value based on its original gross proceeds data plus the additional information obtained from the volunteer lessees. For example, if the snapshot indicates that only 3 percent of the volumes in the zone were reported by gross proceeds payors, MMS will ask for volunteers to come forward and provide access to their records. The MMS will select a stratified sample of records from volunteers which would represent at least an additional 7 percent of the volume in the zone. Based on the combined information of the 3 percent reported by the gross proceeds payors and the 7 percent sampled from the volunteer index-based lessees, the final safety net median value would be calculated. This final safety net median value would be used to determine any additional royalties due from the index-based lessees who did not volunteer to provide access to information.

If there are no volunteers, or not enough volunteers to reach the 10 percent/20 percent threshold, MMS will establish value by methods, which would include, but not be limited to, issuing orders to lessees within the zone as required to obtain sufficient gross proceeds data to develop the final safety net median value.

3) Negotiation

Industry representatives proposed using the lessee's average percentage difference between the safety net median value and the lessee's weighted-average index price for all zones with a representative sample for the zone in which there was no representative volume. The MMS and States could not accept that proposal because they felt the difference between index and gross proceeds in one zone is not indicative of the difference in another zone based on markets served. The MMS and States initially proposed conducting an audit of index payors including affiliate resale prices in order to obtain a representative sample. Some industry members could not agree with the issue of including affiliate's gross proceeds in the sample. The MMS and States then suggested that in those instances where there was not a representative sample, MMS would ask for volunteers to come forward and provide access to their records (including affiliates resale values) to obtain enough gross proceeds volume and value data to develop a representative sample. The committee reached consensus on this proposal.

<u>Zone Determination</u>

MMS will publish the zones that are eligible for index-based valuation method. As stated above, the safety net median value calculation will be based on gross proceeds paid to MMS for Federal leases geographically located in a zone. For index-based lessees and arm's-length non-dedicated gross proceeds lessees applying their residue price to a wellhead MMBtu, the amount of any additional royalties due will be based on the safety net median value for the zone where the lease is geographically located.

Factors/conditions for zone determination:

- ***Common markets served***
- ***Common pipeline systems***
- ***Simplification***
- ***Easily identifiable in MMS' system; e.g. block/area***
- ***Deepwater blocks would go into their respective zones based on first shelf tie-in with appropriate additional LD.***

The committee agreed to the following initial list of zones that are eligible for index-based valuation.

Offshore Zone Determinations

Zone 1 includes the following areas and additions:

- ***South Padre Island Area with the East Addition***
- ***North Padre Island Area with the East Addition***
- ***Mustang Island Area with the East Addition***
- ***Matagorda Island Area***
- ***Brazos Area with the South Addition***

Zone 2 includes the following areas and additions

- ***Galveston Area with the South Addition***
- ***High Island Area with the South Addition, East Addition, and East Addition South extension***
- ***Sabine Pass Area***
- ***West Cameron Area West Addition***
- ***West Cameron Area South Addition***
- ***West Cameron Area Blocks 8-14, 16-23, 42-49, 53-59, 78-83, 90-95, 114-18, 128-131, 150-153, 165-167, 186-189, 208, and 209***

Zone 3 includes the following areas and additions

- ***West Cameron Area excluding the blocks listed in Zone 2***
- ***East Cameron Area with the South Addition***
- ***Vermillion Area with the South Addition***
- ***South Marsh Island Area with the South Addition***
- ***Bay Marchand Area***
- ***Eugene Island Area with the South Addition***
- ***Ship Shoal Area with the South Addition***
- ***South Pelto Area***
- ***South Timbalier Area with the South Addition***
- ***Grand Isle Area South Addition***
- ***Ewing Bank Area***

Zone 4 includes the following areas and additions

- ***Grand Isle Area***
- ***West Delta Area with the South Addition***
- ***Chandeleur Area***
- ***Main Pass Area with the East and South Additions***
- ***South Pass Area with the East and South Additions***
- ***Viosca Knoll Area***
- ***Breton Sound Area***

Zone 5 includes the following area

- ***Mobile Area***

Probable Zones for Deepwater areas

- ***Zone 1 Corpus Christi and Port Isabel Areas***
- ***Zone 2 East Breaks and Alaminos Canyon Areas***
- ***Zone 3 Green Canyon, Walker Ridge, Garden Banks, and Kealthy Canyon Areas***
- ***Zone 4 Mississippi Canyon, Atwater, and Lund Areas***
- ***Zone 5 None***

Note: The Zones associated with the various deepwater areas, as listed above, represent the Zone in which the first shelf pipeline tie-in is most likely to occur for blocks in those areas. Such a tie-in, as stated in the Factors/conditions for zone determination section of the proposal, solely determines the actual zone for any block in a deepwater area. Deepwater blocks would go into their respective zones based on first shelf tie-in with appropriate additional LD adjustment to the safety-net median value.

Onshore Zone Determinations

Oklahoma Zone 1:	***Guymon - Hugoton***
Oklahoma Zone 2:	***Anadarko Basin, Southern Oklahoma, and Arbuckle Upthrust***
Oklahoma Zone 3:	***Arkoma Basin***

Northern Zone

- ***Green River Basin***
- ***Red Desert Basin***
- ***Washakie Basin***
- ***Wind River Basin***
- ***Northern Utah***
- ***North West Colorado***

Central Zone

- ***Uinta Basin***
- ***Piceance Basin***
- ***Paradox Basin***

Denver Basin Zone

San Juan Basin Zone

Permian Basin Zone

Zones with no active spot market as of December 1994

- ***San Luis***
- ***Williston***
- ***Bighorn***
- ***Hogeland***
- ***Powder River***
- ***Raton***
- ***West Coast- California/Alaska***
- ***All other areas with Federal gas production that have not been previously identified***

At least 90 days prior to the effective date of the rule, MMS will hold a technical conference with the States, industry, and the appropriate technical personnel in the Department to make the final determination of the zones that are eligible for index-based valuation based on the factors and conditions established in the final rule. The results will be published by MMS at least 60 days prior to the effective date of the rule. The results are subject to technical review which will be considered a final departmental action.

On a routine basis, MMS will monitor the zone determinations and announce a technical conference, if necessary, to add, delete or modify a particular zone. A technical conference may also be called at the request of a lessee or State.

1) Background

As the committee began developing the index-based valuation proposal, they recognized that the index-based valuation method would not be appropriate for certain geographical regions of the country. That is, certain parts of the country, such as the Rocky Mountain region, do not have active spot markets or valid published indices and index prices. Therefore, the committee developed the concept of zones to identify geographical regions that would be eligible for the index-based valuation method.

In addition, zones were established to require lessees with arm's-length non-dedicated sales to elect the index-based method on a scale broader than lease-by-lease. The primary reason for this zone-wide requirement was to prevent lessees from electing to use index versus gross proceeds in order to reduce their royalty obligations.

Further, royalty payments from lessees who report and pay royalties based on the index-based method will be compared against the gross proceeds lessees in the zone in which the lessee's lease is geographically located and may be subject to additional royalty payments based on the applicable safety net calculation. The same is true for arm's-length non-dedicated lessees who chose to report and pay by applying their residue price to a wellhead MMBtu. The zone concept ensures that any difference between the index based lessees and gross proceeds lessees will be based on a true representation of market value for the geographical area in which the lease is located as well as recognition of the gas markets served by that lease. The factors and conditions contained in the committee's recommendations were key in the committee's initial zone determinations and will be used by MMS in any future technical determinations to redefine zones. To test the factors and conditions the committee was developing, the committee identified an initial list of zones that qualify for the index-based method as of December 1994. This initial list is subject to the MMS technical conference after which MMS will publish the final list of qualified zones. By reaching consensus on the initial list of zones, the committee prevented delay and lessened uncertainty as to what the eligible zones would be.

2) Explanation/Negotiation

The committee formed a subcommittee to determine how best to divide the Gulf OCS into zones. The subcommittee presented the full committee two options on for breaking-up the Gulf into zones (1) strictly geographic with no exceptions for production being produced in one zone but sold in another zone and (2) geographic but with a cross zone comparison, that is, if a lease is in one zone but the production is sold in an adjacent zone, the comparison would be based on the adjacent zone. The subcommittee presented the pros and cons for both options. Based on this information, the committee agreed: (1) the safety net median value calculation should be based on gross proceeds for all leases geographically located in a zone and (2) for index-based lessees, the comparison to the safety net median value should be based on the zone where the lease is geographically located; that is, safety net median values should not cross zones.

The committee also developed the factors and conditions that would be used to determine zones. The committee recognized that this list of factors and conditions is not necessarily all inclusive when determining zones but represents a list of significant considerations in making this determination.

The committee discussed exceptions to zones for deepwater gas. The subcommittee proposed that deepwater blocks be associated with the zone where the shelf tie-in occurs. An additional LD would be allowed, where appropriate, to be deducted from the safety net median value for the applicable shelf tie-in zone. That is, the first zone where the deepwater production ties into the shelf would be the zone used for that zone's comparison. The full committee adopted the subcommittee's proposal.

The committee voted on the initial list of all zones as a single package. The committee reached consensus on the initial list of zones and the factors and conditions in determining zones. The committee sought to develop a procedure that could be consistently applied to all zones. Therefore, the committee agreed that there would be one safety net per zone with no exceptions. Final zone boundaries will be determined by MMS technical conference.

B. VALUATION OF GAS SOLD UNDER NON-ARM'S-LENGTH SALES CONTRACTS IN AREAS WITH NO ACTIVE SPOT MARKET

1. Background

The original charter of this committee was to revise the current non-arm's-length benchmark system. The majority of the problems associated with the current benchmark system have been solved through the committee development of the index method and the associated safety net. Based on royalty data, the committee estimated that at least 95 percent of all Federal gas is produced in zones where, under the committee recommendation, non-arm's-length production must be valued on the index method. However, lessees always have the option of paying royalties for non-arm's-length production based on the affiliate's arm's-length resales.

The majority of the problems surrounding the current benchmark system centered around the definition of comparable contracts and the lessees inability to access such information. For those non-arm's-length sales from leases that fall outside of a qualified zone, an alternate valuation method must be determined.

2. Discussion of Alternative Proposals

The MMS and States formulated a proposal for consideration by the committee which involved applying these following benchmarks in the following order:

a. The weighted average of gross proceeds paid under comparable arm's-length contracts (without any deductions for marketing or placing production in marketable condition) in the field or area between third parties and the lessee or its affiliate; i.e. arm's-length contracts to which the lessee or its affiliate have access. In order to assure that the arm's-length contracts are arrived at in a free and open market, at least 50 percent of the lessee's or affiliate's purchases in the field or area must be under arm's-length contracts in order for this benchmark to be used.

   In evaluating the comparability of arm's-length contracts the following factors will be considered:

   - place of sales
   - time of sale
   - duration of contract
   - volume

   A comparable arm's-length contract by volume will be one whose volume is within plus or minus 20 percent of the volume sold pursuant to the non-arm's-length sales being evaluated.

   b. The first bona fide arm's-length sale of the production by the affiliate.

c. Other relevant matters including, in the following order:

   i. gross proceeds paid under comparable arm's-length contracts in the same field or nearby fields,
   ii. prices reported to FERC or the relevant public utility commission,
   iii. netback method, or
   iv. any other reasonable method to determine value.

Members of industry opposed this proposal for several reasons which included the following: 1) the 50 percent requirement in benchmark a., 2) using the weighted-average of prices, and 3) benchmark b. The fundamental disagreement focused on the use of affiliate's arm's-length sales to establish value.

Industry members proposed calculating a safety net for non-arm's-length lessees in those non-index zones based on gross proceeds reported to MMS for the same area. Some MMS and State representatives expressed concern about this proposal because of the additional administrative costs associated with defining additional zones, calculating safety net median values, and verifying additional MMS-2014 lines. Further, the committee could not agree upon criteria to establish these new zones. An industry representative then modified the MMS and State proposal as follows:

<u>An Industry Proposal</u>

The value of production sold pursuant to a non-arm-'s-length contract or no sale situation from leases located in an area with no active spot market shall be valued in accordance with the first applicable benchmark:

1. The weighted average of gross proceeds paid under comparable arm's-length purchase contracts (without any deductions for marketing or placing production in marketable condition) in the field or area between third parties and the lessee or its affiliate; i.e, arm's-length contracts to which the lessee or its affiliate have access. In order to assure that the arm's-length contracts have been arrived at in a free and open market, they must meet the following criteria:

   1) the third party(s) must not be a "captive market," i.e., they must have alternative options in marketing their gas;

   2) the price paid by the affiliate must be "essentially equal" to the price paid by the affiliate under its non-arm's-length contracts for similar quality gas in the same field or area;

   3) the volume sold under the contract must be "material, " i.e., the third party would be adversely affected if the price specified in the purchase contract were substantially below market value.

In evaluating the comparability of arm's-length contracts any of the following factors will be considered, but not all are necessarily required:

- place of sale
- time of sale
- duration of contract
- volume

A comparable arm's-length contract by place of sale will be one whose delivery point is within 50 miles of the delivery point specified in the non-arm's-length contract being evaluated, or if both contracts specify "into pipe" delivery points.

For "short term" agreements, (1-5 mo. in duration), a comparable arm's-length contract by time of sale will be one whose effective date is within 2 months of the effective date of the non-arm's-length contract being evaluated.

For "medium term" agreements, (6-23 mo. in duration), a comparable arm's-length contract by time of sale will be one whose effective date is within 5 months of the effective date of the non-arm's-length contract being evaluated.

For "long term" agreements, (24 mo. or longer), a comparable arm's-length contract by time of sale will be one whose effective date is within 23 months of the effective date of the non-arm's-length contract being evaluated.

A comparable arm's-length contract by duration of contract will be one within the same category of duration, i.e., short, medium or long, as the non-arm's-length contract being evaluated.

A comparable arm's-length contract by volume will be one whose volume is within plus or minus 50 percent of the volume sold pursuant to the non-arm's-length sale being evaluated.

2. Other relevant matters including, in the following order:

   a. gross proceeds paid under comparable arm's-length contracts in the same field or nearby fields; or,

   b. prices reported to FERC or the relevant public utility commission,

3. A negotiated (via ADR) valuation method established by mutual agreement between lessor and lessee.

4. Any other reasonable method to determine value.

The MMS and States then modified their original proposal by benchmarking the following:

a. Other arm's-length sales by the lessee in the field/area.
b. Other arm's-length purchases by the lessee's affiliate in the field/area.
c. Affiliate's arm's-length resale values (excluding direct sales to residential customers).
d. Other relevant matters.

Arguments regarding affiliates were raised by both sides. The MMS and States could not yield the use of the affiliate's resale value as a means for establishing royalty values. Industry stated that they could not agree to any model that included affiliate's resales. Industry suggested using the average percentage difference between the safety net median value and lessee's weighted-average index price for surrounding zones instead of calculating an additional safety net. The MMS and States opposed this suggestion because zones are defined based on market circumstances.

3. Discussion of Final Recommendation

Because of the committee's opposing views regarding affiliate's sales, the committee did not take a vote on this issue. The MMS will write a proposed rule for valuing non-arm's-length sales in zones that do not qualify for index. In these areas, the issue of marketing affiliate was not addressed by the committee.

C. VALUATION OF NATURAL GAS LIQUIDS

Summary of Recommendation

Value of natural gas liquids derived from non-dedicated gas produced in areas where there is an active spot market and valid published indices may be based on an index or a residue gas price, as applicable, applied to a wellhead MMBtu, subject to the safety net.

1. Background

Throughout the negotiation process for the index method, the issue arose regarding simplifying the valuation and reporting of NGL's. Currently, when gas is processed, the lessee must determine residue gas values, NGL values and associated processing allowances, and file separate reporting lines and forms. A majority of committee members felt it was in the best interests of all parties to pursue alternative valuation and reporting methods for NGL's.

Final Recommendation

The following recommendation applies to processed gas produced in qualified zones only:

> ***For arm's-length non-dedicated gas sales (where the lessee has elected the index method) and non-arm's-length gas sales in a zone eligible for index valuation, the lessee has the option to:***
>
> ***1) Pay index on residue and gross proceeds on liquids, or***
> ***2) Pay index on a wellhead MMBtu, or***
> ***3) Pay on the net back from the affiliate's arm's-length gross proceeds***
>
> ***For arm's-length non-dedicated gas sales (where the lessee has elected to pay on gross proceeds), and non-arm's length gas sales (where the lessee elects to pay on the netback from the affiliate's arm's-length gross proceeds) the lessee may elect to:***
>
> ***4) Pay the gross proceeds residue gas price on a wellhead MMBtu.***
>
> ***(Note: All the above elections must be made for a two year period for all residue and NGL's in the zone. Gas is considered processed or unprocessed as provided under the current regulations.)***

Royalty-free residue gas returned to the lease will not be included in the wellhead MMBtu's.

Federal lessees are not required to submit processing allowance forms, including those situations where the lessee reports and values NGL's separately and claims a processing allowance on Form MMS-2014.

Dual accounting for Federal gas is no longer required for all lessees.

Reporting Requirements for Options 1 and 2

- ***Arm's-length POP contracts are required to be reported as processed gas (product code 03) and valued on gross proceeds, if the contract is dedicated.***

- ***Keepwhole contracts with a processing plant are to be reported as processed gas (product code 03)***

- ***In order to calculate the safety net, gross proceeds lessees reporting NGL's (product code 07) must convert gallons currently reported to MMBtu's. For POP contracts, this conversion must be reported as follows:***

    1) 100 percent residue value with 100 percent residue volume (reported as product code 03)

2) ***If gross proceeds is greater than the 100 percent residue value, then report gross proceeds under product code 03.***

For all other contracts, this conversion must be reported as follows:

1) ***Volume will be calculated by subtracting the residue MMBtu from the wellhead MMBtu. This volume will reported as the royalty quantity on the product code 07 line.***

Reporting Requirements for Option 4

- ***100 percent of the wellhead MMBtu will be reported as the royalty quantity under product code 03.***

- ***To determine the royalty value, the lessee must multiply the 100 percent wellhead MMBtu by their gross proceeds residue gas price.***

2. Explanation

Example 1

Assume the following facts:

Royalty Rate	12.5%
Wellhead Mcf	10,000
Wellhead Btu/cf	1.102
Residue Mcf	9,000
Residue Btu/cf	1.038
Total NGL Gallons	8,000
Average NGL Price	$0.25
Index Price	$1.80
Processing Cost	$500
Safety Net Median Value	$1.90

If an index lessee elects option 1 (index on residue and gross proceeds on liquids), the lessee (or payor) would report the following:

Product Code	Tran Code	Sales Quantity	Sales Value	Royalty Quantity	Royalty Value
03	01	9,000	$16,815.60	1,125	$2,101.95
07	01	1,678	$ 2,000.00	210	$ 250.00
07	15				($ 62.50)

Note: The Sales Quantity (MMBtu) for Product Code 07 was calculated as follows:

Wellhead MMBtu - residue gas MMBtu = (10,000 * 1.102) - (9,000 * 1.038) = 1,678 MMBtu.

This lessee would be subject to the final safety net median value limited to a cap of 50 percent of the difference between the index price and the final safety net median value price: 50 percent * ($1.90 - $1.80) = $0.05, $0.05 + $1.80 = $1.85

Example 2

Alternatively, if an index lessee elects option 2 (index on a wellhead MMBtu), the lessee (or payor) would report the following:

Product Code	Tran Code	Sales Quantity	Sales Value	Royalty Quantity	Royalty Value
03	01	11,020	$19,836.00	1,377.50	$2,479.50

This lessee would be subject to the final safety net median value limited to a cap of 65 percent of the difference between the lessee's weighted-average index price and the final safety net median value: 65 percent * ($1.90 - $1.80) = $0.065, $0.065 + $1.80 = $1.865

Example 3

Assume the same facts as above but assume the lessee is a gross proceeds lessee and elects Option 4, and the residue gas price is $1.88, the lessee (or payor) would report the following:

Product Code	Tran Code	Sales Quantity	Sales Value	Royalty Quantity	Royalty Value
03	01	11,020	$20,717.60	1,377.50	$2,589.70

This lessee would be subject to the final safety net median value subject to a cap of 30 percent of the difference between the residue gas price and the final safety net median value: 30 percent * ($1.90 - $1.88) = $0.006, $0.006 + $1.88 = $1.886.

Example 4

Assume the same facts as under example 1 except that the lessee pays on gross proceeds (and the residue gas price is $1.80), because the gas is dedicated under an arm's-length contract. Assume also that the gas contains seven percent hydrogen sulfide, from which 50 long tons of elemental sulfur are recovered and sold for $50/long ton. Assume a sulfur processing cost of $2,200. The lessee (or payor) would report the following:

Product Code	Tran Code	Sales Quantity	Sales Value	Royalty Quantity	Royalty Value
03	01	9,000	$16,815.60	1,125.00	$2,101.95
07	01	1,678	2,000.00	209.75	250.00
07	15				(62.50)
19	01	50	2,500.00	6.25	312.50
19	15				(275.00)

While the lessee (or payor) would not be subject to the safety net median value calculated by MMS, MMS would use the lessee's reported data in calculating the safety net median value in $/MMBtu as follows:

Product Code	Quantity MMBtu's	Value $$	Processing Costs $$
03	9,342	16,815.60	-
07	1,678	2,000.00	(500.00)
19	-	2,500.00	(2,200.00)
Totals	11,020	21,315.60	(2,700.00)

Value used in the array for the safety net median value calculation = ($21,315.60 - $2,700) ÷ 11,020 MMBtu = $1.69

3. Negotiation

In association with the index-based valuation alternative, much of industry advocated using indices applied to a wellhead MMBtu as an alternative to processed gas valuation. The MMS and States agreed in principle with this concept. However, as evidenced by a sample study limited to an offshore plant, MMS and States believed that there should be an uplift in the index price to reflect the value of entrained liquids. After much discussion, a subcommittee was formed to examine the issue and report back to the committee with any feasible NGL valuation alternatives.

The subcommittee considered the following potential alternatives:

1) NGL Option - include the NGL's gross proceeds values in the safety net calculation with a 62.5 percent cap for processed gas. Additionally, an index-based lessee that elected to value their processed gas on a wellhead MMBtu basis would be comparing their weighted-average index-based value to a second safety net median value that included NGL's values from gross proceeds lessees.

2) Step-scale - add an uplift to the index price based on a step-scale of the btu content of the gas.

3) Liquid Published Prices - continue using current NGL reporting requirements but use NGL published prices to value the NGL's.

4) Plant/Lessee Specific Valuation - determine yearly the NGL uplift for each plant and each lessee and convert that uplift in the subsequent year to their index-based value at the wellhead.

Based on criteria of simplicity, certainty, practicality, and revenue neutrality, the majority of the subcommittee members believed that the NGL option, with an increased safety net cap of 62.5 percent, was the best potential alternative to recommend to the committee. The 62.5 percent cap was calculated as follows: Assume a typical wellhead stream is comprised 75 percent of residue gas and 25 percent entrained liquids. Apply the 50 percent safety net cap previously agreed to on residue gas, plus a 100 percent safety net cap on NGL's: (75 percent x 50 percent) + (25 percent x 100 percent) = 62.5 percent.

An important issue considered by the subcommittee was how gas under POP contracts and keep-whole agreements would be treated under a wellhead MMBtu valuation method and their impact on the safety net median value. In its recommendation to the committee, the subcommittee included several options for valuing and reporting this gas. In essence, the proposal provided for two safety net calculations based on whether the gas was processed, unprocessed, under a POP contract, under a keep-whole agreement, and whether the lessee elected a gross proceeds or index-based valuation method. The proposal also included a reporting change for gross proceeds lessees whereby NGL gallons, as currently reported, would need to be converted to an MMBtu basis.

The committee's consideration of the proposal focused on the following key issues:

(a) How can the proposal be simplified and yet retain options affording equal treatment among lessees?

(b) What would be the administrative cost impact on MMS and the States?

(c) What would be the audit and reporting impact on gross proceeds lessees, particularly small independents?

(d) How would wellhead MMBtu reporting affect the representative sample?

After considerable discussion, the committee decided not to adopt the subcommittee recommendation as proposed. Independents paying on gross proceeds were concerned about increased audits, additional reporting burdens, and not having the same options as index-based lessees to use simplified wellhead MMBtu reporting. The MMS and States were particularly concerned about administrative costs and achieving simplicity, particularly with two safety net calculations. The MMS and States also did not want to open up a new category of options based on whether any lessee processes its gas or not. Some larger companies, while generally supporting a modification to the subcommittee's proposal, were concerned about a new proposal that would result in applying an index price to those wellhead MMBtu's that have no value. Industry maintained that diamonoids, etc., contained in a wellhead gas stream have a Btu content, but no commercial value.

Another option then evaluated by the committee was retaining the status quo, (that is, current valuation procedures) but with simplified reporting resulting from no allowance form filing and no Federal dual accounting. The committee eventually rejected this option on the grounds that the administrative cost savings to all parties would be insignificant.

Using the objectives of simplicity, fairness, and reduced administrative cost, the committee agreed that there should be only one safety net calculation. In addition, the committee agreed that gross proceeds lessees should have the option to value their processed gas on a wellhead MMBtu basis. However, in order to limit lessee's options, the committee agreed that gross proceeds-based lessees must remain on a gross proceeds valuation basis. Therefore, under this option, gross proceeds based lessees must use their gross proceeds residue gas price applied to the wellhead MMBtu's.

The committee concluded that the single safety net should include values associated with the arm's-length gross proceeds for unprocessed gas, residue gas, and NGL's. They also recognized that different caps should apply depending on the valuation method selected by the lessee as noted in the above explanation.

For unprocessed gas valued on index prices, the cap for index years subsequent to year one would remain at the 50 percent limit agreed to earlier. For processed gas (including all gas considered processed under the current regulations) valued on index prices applied to the wellhead MMBtu's, the cap for index years subsequent to year one would be 65 percent. The committee agreed to the uplift from 62.5 percent with the understanding that MMS and the States could not audit all gas plants.

For processed gas valued on gross proceeds but under the wellhead MMBtu option, the cap for index years subsequent to year one would be 30 percent. Because the residue gas portion is valued on gross proceeds, the committee agreed it should not be subject to the safety net calculation; only the NGL portion of the wellhead stream should be subject to the safety net calculation.

The committee agreed to allow transportation or processing facilities purchased by the lessee or lessee's affiliate that did not have a previously claimed MMS depreciation schedule to be treated as a newly installed facility for depreciation purposes. Such facilities may have been subject to a FERC tariff and not an MMS depreciation schedule.

In addition, the committee agreed on other simplification factors: 1) eliminate Federal dual accounting requirements, and 2) eliminate processing allowance forms.

D. VALUATION OF GAS PRODUCED FROM UNIT AND COMMUNITIZATION AGREEMENTS

<u>**Summary of Recommendation**</u>

The committee concurred with the MMS proposal that for gas produced from Agreements which contain only Federal leases with the same royalty rate and funds distribution, and from leases not in an Agreement (stand-alone leases), volume and value must be reported and paid on a takes method. The proposal provided for an exception for lessees to request approval to pay on entitlements.

For gas produced from mixed Agreements which contain leases with different lessors, royalty rates, or funds distribution, volume and value must be reported and paid on an entitlements method. Federal lessees who meet certain production criteria will be granted an exception to this requirement and will be allowed to report and pay on takes, subject to an annual adjustment to an entitlements basis. In addition, all lessees may contractually agree to assign reporting and payment responsibility among themselves in any manner which ensures that entitled royalty volumes allocable to Federal leases are reported and paid each month.

1. Background

The current regulations for gas production in Agreements can be found at 30 CFR § 202.150(e) (1994). In general, the regulations require that royalties are paid on the full share of production allocated to each Federal lease in the Agreement. If the lessee does not actually take its entitled share of production, royalties are nonetheless due on the full share of that production. That portion of the allocated production which the lessee did not take shall be valued based on the circumstances controlling the actual disposition of the gas. In other words, a lessee must trace the production to determine who took the gas and how it was disposed in order to determine the correct royalty value. If a lessee takes more than its proportionate share of the production, that lessee must allocate those overages to the other leases in the Agreement. Lessees have difficulty in complying with the tracing method due to the problems in determining the disposition of the gas by other Agreement participants and the value at which the gas was sold.

The difficulty lessees have in complying with the tracing method results in exceptions generated by the AFS/PAAS comparison. The operator reports production under the Agreement number; the system then allocates the production to each lease based on the Agreement allocation schedule. The system compares the allocated production to the sales reported for the lease on the Form MMS-2014. If differences are noted, an exception is sent to the payor. Each month the system detects about 8,400 exceptions. Of that total, 2,200 are strictly allocation exceptions with correct unit totals and 6,200 are differences between sales and production. The vast majority of exceptions result from companies within the same Agreement paying on different methods.

In addition, the tracing method has led to problems in the area of payor liability. The key issue is that although the lessee may have paid properly according to the tracing method, MMS may still hold the lessee liable for their proportionate share of production from the lease in the event another party has failed to pay according to the tracing method.

The committee was briefed by representatives of the MMS and the Office of the Solicitor on a proposed rule currently being developed by the MMS regarding payor liability. The Solicitor said that when MMS determines that royalties are underpaid for a Federal or Indian lease, MMS generally bills the person who filed a Payor Information Form (PIF) for that lease, and that payor usually resolves the matter with MMS. However, sometimes that royalty payor can no longer pay (for example., it is bankrupt or otherwise out of business), or it asserts that someone else is responsible for the royalty payment. In such event, the current payor often does not agree to pay the deficiency, requiring MMS to determine liability and assess accordingly. The Solicitor explained that MMS is considering publishing a proposed rule that would clarify all of the parties that could be liable in this situation. He explained that under a takes reporting method, the MMS would still maintain the right to hold the lessee liable for their allocated share of production from the Agreement.

The Solicitor also explained that this proposed rule would amend the requirement to report and pay royalties on production from, or attributable to individual leases (leases not committed to Federal Agreements) or leases in 100 percent Federal Agreements. Because these leases and Agreements only include Federal leases, MMS is considering a takes method for these situations.

The MMS asked the committee for their input on a takes method for stand alone leases and leases in 100 percent Federal Agreements. The committee agreed with the MMS proposal. Although MMS explained that the lessee could still be held liable for undertakes in these situations, industry favored a takes reporting method for stand-alone leases and leases in 100 percent Federal Agreements because of simplicity and the fact it eliminates out-of-pocket royalties. Industry did not agree with MMS' position that the lessee would be liable for undertakes in these situations; however, industry did not perceive the issue associated with liability in these situations as problematic because the parties are Federal lessees and are more likely familiar with Federal royalty payment requirements.

2. Discussion of Alternative Proposals

The discussions of the alternative proposals considered by the committee focused on various versions of takes which included "pure takes," or entitlements. While the committee considered many options, five of those were given extensive evaluation by the committee. The pure takes option was eliminated by the committee, because it did not comply with the principles set out in the committee charter. The following is a brief summary of the five final proposed options.

a. SB-X (Senate Bill 168 example)

This would be a modified version of Oklahoma Senate Bill No. 168 where all selling parties would pay royalties to a single entity (Operator or MMS) and that entity would disburse royalties to all royalty owners. This option was eliminated from discussion because it would require legislation, would be administratively burdensome to the single entity (operator or MMS), and royalties would be paid based on a weighted average price which may be lower or higher than the price to which the lessor is entitled.

b. Modified Takes

This method would be similar to SB-X in computing royalty payment. That is, each sales volume would be attributable to each tract based on the tract's unit decimal or participation factor. However, each taking party would pay each royalty owner directly. This option was eliminated for many of the same reasons as the SB-X option including the administrative burden placed on each lessee to maintain up to date payee data on every lessor in the entire Agreement.

c. Entitlements

This method would require each lessee/working interest owner/operating rights owner to pay or cause to be paid royalties on their entitled share of volume allocated to the lease using the valuation criteria established by this committee. This "pure" entitlements method was favored by MMS and the States and some industry members. However, representatives of independent producers strongly opposed this option because it would force some producers to pay royalties on production allocated to a lease but not actually taken and sold by the lessee. Some independents stated they have difficulty in obtaining information regarding production allocable to their leases from the operator creating additional administrative burden and associated costs.

d. Entitlements with Marketing Requirement/Option

This would be based on the same philosophy as Option 3; however, if the lessee cannot or chooses not to market its share of production, it could market sufficient gas to generate income to cover royalties due on its entitled share of production. The small independents presented a similar option where the operator takes the working interest owners' gas volumes, sells the gas on behalf of the working interest owners, and reports and pays the working interest owners' royalty share. The States and MMS rejected both of these proposals because of the low volumes being marketed only to avoid out-of-pocket royalties. Further, there was concern that the producer would have neither the negotiating power nor the incentive to obtain good prices.

e. Exception to Entitlements

This would also be an entitlements-based option, but with provisions to obtain MMS approval for an exception to pay on other methods. This option was rejected by the committee because it was believed to be too broad, administratively burdensome and uncertain. Another method would be where the lessee pays only when production is sold, and MMS is temporarily out-of-balance from its entitled share, subject to conditions. A version of this option was ultimately adopted that did not involve an application process and was limited to certain producers.

In its discussions, the committee considered an MMS gas RIK option as a means to alleviate the problems with valuing production from unit and communitization Agreements. However, the committee recognized that the MMS was already conducting a RIK pilot program for OCS Gulf leases. The committee recommends that royalty-in-kind for onshore gas sales be considered in the future based on the findings of the pilot.

The committee discussed all proposals and agreed on the following:

a. Any option which does not keep the government whole on a monthly basis should be eliminated.

b. The Federal lessee is liable for royalty due on its entitled share of production.

c. The royalty rate used must be that specified in the lease.

d. Value must be determined at the time of production.

3. Final Recommendation

For natural gas produced from Federal leases in mixed Agreements, royalties must be paid on each working interest owner's (WIO) entitled share of the produced volume from the Agreement. Value for entitled production actually taken must be based on the acceptable method for the company and area -- that is, gross proceeds, index-based value (subject to the safety net), or gross proceeds residue gas price on a wellhead MMBtu for arm's-length sales, or the improved benchmarks, index (subject to safety net), or net-back from the affiliate's arm's-length gross proceeds for non-arm's-length sales. Value for entitled production not taken (including no takes) must be based on the appropriate valuation method for the company and area.

For gross proceeds lessees who take entitled production, the value of the entitled share of production attributable to the lessee will be based on the gross proceeds (including weighted average gross proceeds) received for the portion that was taken.

For gross proceeds lessees who do not take any of their entitled share of their production, the value of the entitled share not taken shall be valued in accordance with the first applicable benchmark:

a. The weighted average arm's-length gross proceeds from the previous three months.

b. The weighted average of the lessee's arm's-length sales in the field/area.

c. If gross proceeds comparable information is unavailable to the lessee, the lessee will pay royalty on the first applicable index with transportation allowance. If the lessee is in a non-index area, value will be based on the improved benchmarks.

For lessees who elect or are required to pay on an index-based method, the value of the entitled production must be at index.

Two Exceptions:

In an effort to accommodate the needs of small independents, the committee worked diligently to develop an exception to allow those independents adequate time to take and sell their entitled share of production to cover out-of-pocket royalty payments.

Exception 1.

For Federal producers that produce less than 6,000 Mcf/day total U.S. natural gas production <u>and</u> less than 1,000 bbls./day of oil, royalties may be paid each month on the volume actually taken subject to the following criteria:

- *Takes reporting must be indicated on Form MMS-2014 using a special indicator.*

- *Annually, and within six months after the calendar year in which it reported takes, the producer must pay additional royalties based on its entitled share if the producer is net undertaken for the year.*

- *The MMS will not be expected to provide data specifying the producer's entitled share. Producers may obtain production information from the operator, BLM, State, or other sources.*

- *If producer is net even or overtaken at the end of the calendar year-- that is, it has taken equal to or more than its entitled share -- MMS will:*

    1. Assess interest for any month during the calendar year in which the producer took less than its entitled share, and

2. ***Allow a credit, if overtaken, to be applied to future undertaken amounts. (Credit also applied if overtaken at six months after the end of the calendar year of production.)***

- ***If producer is net undertaken at the end of the calendar year, it must:***

  a. ***Pay additional royalties based on its entitled share of volume and value any deficient volumes based on weighted-average gross proceeds from other sales for the year or, if no other sales, the improved benchmarks, and***

  b. ***Pay interest accruing for each month in which it is undertaken. (Same assessment procedure as currently practiced for audit.)***

Exception 2.

All lessees may contractually agree to assign reporting and payment responsibility among themselves in any manner which ensures that entitled royalty volumes allocable to Federal leases are reported and paid each month.

a. Explanation

Assume the following facts:

1997	Lessee Entitled Volume	Lessee Taken Volume	Cumulative Over/Under Balance
January	1,000	900	-100
February	1,500	1,700	+100
March	1,000	1,500	+600
April	1,000	1,500	+1,100
May	1,500	1,000	+600
June	1,000	800	+400
July	1,500	0	-1,100
August	1,000	1,000	-1,100
September	1,000	0	-2,100
October	1,000	0	-3,100
November	1,500	1,000	-3,600
December	1,500	2,000	-3,100
	14,500	11,400	

Within 6 months of the end of the calendar year of production (that is, June 30, 1998), the qualified producer electing a takes method must pay royalties on the deficient 3,100 mcf. Interest on 100 mcf of the total 3,100 would begin accruing in January and end in February and interest would begin accruing again in July.

Alternatively, if the total taken volumes for the year were 16,000 instead of 11,400, the producer would not owe any interest or any additional royalties and would be allowed a credit of 1,500 mcf to be applied against the next calendar year reporting.

b. Negotiation

Most of industry expressed preference for entitlements-based reporting, but only because of MMS' interpretation of payor liability. Many MMS and State committee members also preferred entitlements-based reporting because they believed there should be a connection between payors and parties responsible. Some committee members raised a concern with the legal authority for holding fee/States lessees responsible and liable for Federal royalty payments. Small independents were opposed to entitlement-based reporting because royalties would be due on values exceeding the lessee's actual proceeds when they do not sell their allocable share of the production. One independent suggested allowing an exception for those producers qualifying for "independent producer" status pursuant to the Internal Revenue Service (IRS) regulations. This exception was worked into the final consensus on this topic.

The States were concerned about treating producers from the same properties or fields differently with some paying on takes and others on entitlements. They asserted that the lease terms, Agreement terms, and court cases require entitlements for all lessees. A small independent representative conceded that some sort of reconciliation is warranted, but it must be practical. It was suggested that any additional royalty due as a result of the reconciliation be calculated without interest as a compromise similar to the compromise reached on the index-based safety net calculation. One State representative said that you could not equate this situation to the interest decision made in the index recommendation. In the case of the index-based method, MMS would be receiving royalties on the full volume on a monthly basis; that is not the case with this proposal. The final compromise grants a royalty holiday by not assessing interest for undertaken months if at the end of the year the lessee is even or overtaken.

The committee reached consensus on an entitlements-based proposal with two exceptions: for lessees who meet certain production criteria and for producers/working interest owners from the same producing area who contractually agree to pay on takes. However, as a condition of consensus by the committee, qualifying statements were given by a member representing IPAMS/IPAA.

IPAMS/IPAA: "IPAMS/IPAA will vote sideways on the proposal for valuing and reporting royalties for agreement production. IPAMS/IPAA will vote sideways in an effort to continue the negotiated rulemaking process. IPAMS/IPAA are, however, opposed to an entitlements based reporting/valuation method. An entitlements method will significantly penalize and discriminate against the independent producer. It will force the independent to pay royalties on "phantom income". In addition, the MMS' intention of going back to 1988 to true-up from takes to entitlements will significantly impact the independents and will most likely force many independents out of business. IPAMS/IPAA refers you to the many comments by independents which have already been recorded in previous meetings' minutes. In order for IPAMS/IPAA to vote sideways, the MMS agrees to guarantee that our true position is reflected in meeting minutes, reports issued by the committee, the proposed rule and all other materials associated with the writings and recordings of this committee."

Given the legal restraints of holding fee/State lessees liable for Federal payments and given MMS' position on payor liability, entitlements with limited exceptions seemed to be the only feasible option under existing agreement terms.

Regarding clean-up of past periods and transition from the 1988 regulations to the proposed rule, the committee concluded that it could not resolve those issues. These will be resolved on a case-by-case basis.

E. TRANSPORTATION VS. GATHERING

<u>Final Recommendation</u>

The lessee may deduct from value, as a transportation allowance, the cost of moving royalty bearing substances (identifiable, measurable oil and gas, including gas that is not in need of initial separation) from the point at which it is first identifiable and measurable to the sales point or other point where value is established. The lessee may not deduct from value the cost of gathering. Gathering is defined as the movement of an unseparated, bulk production stream to a point, on or off the lease, where the production stream undergoes initial separation into identifiable oil, gas, or free water.

1. Background

The current regulations distinguish between transportation, movement of gas which is deductible, and gathering, movement that is not deductible. This distinction is dependent upon the location to which the lease production is moved. The MMS has incorporated the facility (or royalty) measurement point into subsequent interpretations of the regulations. Gathering is defined in 30 CFR § 206.151 (1994):

> *Gathering* means the movement of lease production to a central accumulation and/or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or MMS OCS operations personnel for onshore and OCS leases, respectively.

While the term *transportation* is not defined under MMS's regulations, 30 CFR § 206.156 (1994) provide that MMS shall allow a deduction for the reasonable actual costs incurred by the lessee to transport unprocessed gas, residue gas, and gas plant products from a lease to a point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant.

2. Discussion of Final Recommendation

The committee recommended that the definition of gathering be changed to the movement of an unseparated, bulk production stream to a point, on or off the lease,where the production stream undergoes initial separation into identifiable oil, gas, or free water.

Industry representatives stated:

(1) pipelines that serve the same function should not be treated differently,
(2) the use of marketable condition as a determination between gathering and transportation is arbitrary, and
(3) the correlation between marketable condition and gathering is not logical.

The States recommended that the "field" be factored back in to the gathering determination. They expressed additional concern that non-deductible costs, such as compression, could be bundled with deductible costs. This could result in even greater negative revenue impact. Independents were concerned that gas may not be in marketable condition and that there would continue to be problems in defining terms.

The revenue impact of the new definition was not analyzed. However, the States expressed concern over the loss of revenues, that is, gathering that was not deductible under the current regulations would be reclassified transportation and thus be deductible for royalty purposes.

In reaching consensus, the committee agreed that for movement to be considered transportation, the gas must be an identifiable and measurable substance and that the current marketable condition requirement should not be the basis for determining between gathering and transportation.

Clarifying criteria:

- Identifiable products mean oil, gas, or water. Gas may include liquefiables, inerts, CO_2, etc.

- "Gas plant products" is covered under definition of gas.

- Gas from the reservoir that is free of impurities such as oil, water, condensate, etc. such that no separation is required is included under the transportation definition.

- Lease, drip, and scrubber condensate is oil for valuation purposes.

- Movement of deep water bulk production would be considered for transportation but only as an exception, on a case-by-case basis.

- A transportation allowance may not be used to reduce the minimum value of gas sold under an arm's-length percentage-of-proceeds contract below 100 percent of the value of the residue gas at the tailgate of the plant.

- Transportation allowances are subject to the limits in the current regulations--50 percent unless exceptions are granted by MMS.

F. COMPRESSION

Final Recommendation

Any compression downstream of the facility measurement point (FMP) is deductible as a component of the transportation allowance or the LD.

1. Background

In determining allowable and non-allowable deductions from royalty value, the committee identified compression as a key issue. The MMS stated that the current definition of compression is not consistently applied. Consequently, the committee felt a need to define compression in a manner that would add simplicity and clarity for both the lessee and lessor.

2. Explanation

The FMP is the point where royalty volume is determined by Bureau of Land Management (BLM) (onshore), and MMS (offshore). The lessee will not be able to apply for an exception to which compression is allowable and non-allowable.

3. Negotiation

There were several proposals developed by both industry and MMS and the States that were presented to each side. Industry proposed that deductibility of compression be based on the function of the compressor as follows:

Industry Proposal

Compression is deductible:

1. on a transportation line;

2. for internal plant compression, integral to processing;

3. for tailgate compression;

4. for hub compression;

5. to buck mainline pressure; (boosting to get into any line)

6. when located at or near an OCS lease.

Any compression deductions not described above shall be applied for as an exception.

MMS/States Proposal

Any compression occurring upstream of the point of royalty settlement/facility measurement point (the normal point at which the royalty would be taken in-kind) should be performed at no costs to the lessor.

To prevent "gaming", the costs of any compression occurring downstream of this point would be non-deductible if the production is not first commingled with production from other sources prior to that compression, unless the compression is being performed for the second time.

After deliberation by both sides on these proposals and follow-up discussion relative to the function and location of compressors, the committee developed criteria from which to develop a joint proposal. The criteria centered around simplicity, certainty, avoidance of litigation, operational considerations, and economics. The MMS made it clear that for simplicity and certainty, any compression proposal would need to pass a "bright" line test, while recognizing there would be winners and losers in individual production situations.

The committee adopted the MMS-based proposal, but modified it to rely solely on the FMP and not the commingling point. This proposal establishes a "bright" line test based on the FMP. Many committee members believed that use of the FMP provided the most certainty and simplicity in distinguishing between deductible and non-deductible compression. This proposal upholds long-standing departmental policy of not allowing compression upstream of initial measurement.

G. TRANSPORTATION AND PROCESSING ALLOWANCE FORMS

Final Recommendation

Transportation and processing allowance forms are no longer required for both gross proceeds and index-based lessees.

H. DUAL ACCOUNTING

Final Recommendation

Dual accounting for Federal gas is no longer required for all lessees.

LIST OF ACRONYMS

AFS/PAAS	Auditing and Financial System/Production Accounting and Auditing System
ADR	Alternative Dispute Resolution
APA	Administrative Procedures Act
API	American Petroleum Institute
BLM	Bureau of Land Management
COPAS	Council of Petroleum Accountants Societies
FACA	Federal Advisory Committee Act
FERC	Federal Energy Regulatory Commission
FMP	Facility Measurement Point
FOGRMA	Federal Oil and Gas Royalty Management Act of 1982
Form MMS-2014	Report of Sales and Royalty Remittance
IBLA	Interior Board of Land Appeals
IPAA	Independent Petroleum Association of America
IPAMS	Independent Petroleum Association of Mountain States
IPP	Index Pricing Point
IT	Interruptible Transportation
LD	Location Differential
LDC	Local Distribution Company
MMBtu	Million British Thermal Units
MMS	Minerals Management Service
NGL's	Natural Gas Liquids
NGSA	Natural Gas Supply Association

NPR	National Performance Review
NRA	Negotiated Rulemaking Act
OCS	Outer Continental Shelf
POP	Percentage-of-Proceeds
RIK	Royalty-in-Kind
RMAC	Royalty Management Advisory Committee
RMOGA	Rocky Mountain Oil and Gas Association
RMP	Royalty Management Program
STRAC	State and Tribal Royalty Audit Committee

LIST OF DEFINITIONS

Active spot market means one or more valid publications, publishing bidweek prices(or if bidweek prices are not available, first of the month prices) with at least one index pricing point in the zone.

Agreement means approved Federal unit or communitization agreement.

Cap means the limit of additional lessee royalties due on the difference between the safety net median value and the lessee's weighted-average index price or residue price, as applicable.

Committee means Federal Gas Valuation Negotiated Rulemaking Committee.

Dedicated means production (or a specified portion) from a lease or well is dedicated when production from that lease/well is specified in a sales contract and that production must be sold pursuant to that contract to the extent that production occurs from that lease/well.

De minimis means concerning trifles; i.e. so small as to be relatively insignificant when compared to the whole.

Department means Department of the Interior.

Direct connect means a wellhead connection to a pipeline.

Entitlements means royalties are due on the gas production attributable to each operating rights owner in the Federal or Indian lease under the terms of the agreement (including the unit operating agreement).

Facility Measurement Point means the point at which the measurement device is located that was approved by MMS or BLM for determining the volume of gas removed from the lease.

Gathering means the movement of an unseparated, bulk production stream to a point, on or off the lease, where the production stream undergoes initial separation into identifiable oil, gas, or free water.

Index means the price ($/MMBtu) published by a valid publication at specific locations.

Index Pricing Point means the first pipeline interconnect for which there is a valid published index

Index Year means a calendar year of production for which the lessee uses the index-based method to value its gas.

Jurisdictional pipeline means a pipeline with a rate regulated and approved by Federal Energy Regulatory Commission (FERC) or a state agency.

Lessee, for the purpose of this report, means operating rights owner, including those who pay their own royalties.

Location differential (LD) means the transportation costs incurred or which would be incurred to get the gas from the well to the index pricing point.

Multiple connection means one pipeline connected to the well, but that pipeline splits prior to an index point.

Natural gas means a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exist either in the gaseous phase or in solution with crude oil in natural underground reservoirs.

Non-dedicated means production from a lease or well that is not dedicated.

Non-jurisdictional pipeline means not regulated by Federal Energy Regulatory Commission (FERC) or a state agency.

Operating rights owner(working interest owner) means a person who owns operating rights in a lease subject to this part. A record title owner is the owner of operating rights under a lease except to the extent that the operating rights or a portion thereof have been transferred from record title.

Order No. 636 means FERC Order No. 636.

Percentage-of-Proceeds (POP) contract means a contract for the sale of gas prior to processing that provides for the value to be determined on the basis of a percentage of the purchaser's proceeds resulting from processing the gas.

Representative Sample means 10 percent of the total zone production paid and reported to MMS on gross proceeds or 20 percent of transactions in a zone paid and reported to MMS on gross proceeds.

Safety net median value means the median value of the gross proceeds-based royalty values paid for all Federal leases geographically located in a zone as computed by MMS.

Safety net calculation means the comparison between the safety net median value and the lessee's weighted-average index price for that index year with the application of the appropriate cap (30%, 50%, or 65%).

Snapshot means the initial safety net median value calculation performed by MMS based on unaudited MMS-2014 data.

Split connect means more than one pipeline connected directly to the well.

Takes means when the operating rights owner sells or removes production from or allocated to a lease, or when such sale or removal occurs for the benefit of an operating rights owner.

Transportation means the cost of moving royalty bearing substances (identifiable, measurable oil and gas, including dry gas) from the point at which it is first identifiable and measurable to the sales point or other point where value is established.

Wellhead means the production that leaves the lease. Production used royalty free is not included in the wellhead volumes.

Zone means a geographic area containing blocks or fields as defined by MMS based on criteria established in this rule.