Minerals Management Service Royalty Gas Marketing Pilot

Final Report
September 1996

MINERALS MANAGEMENT SERVICE
ROYALTY GAS MARKETING PILOT

TABLE OF CONTENTS

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ROYALTY GAS MARKETING PILOT REPORT

SEPTEMBER 1996

SUMMARY

Under the terms of the standard federal oil and gas lease, the government is entitled to a share of the production saved, sold, or removed from the lease. This share of production is referred to as a royalty interest and is a stated percentage of production (normally 16 2/3 percent for offshore leases). The lease also provides that the royalty is to be paid by the lessee based upon the value of the production, unless the lessor elects to take its royalty in kind (in product instead of in value). Historically, the Federal Government has collected its gas royalties in value.

Because of the changing gas market, it has become increasingly difficult for federal lessees to accurately determine the proper value for royalty purposes. Royalty is due based on the value of the production at the lease, whereas much of today's gas sales occur well downstream of the lease or under contracts where the source of the production being sold is not lease-specific. Out of necessity, the Minerals Management Service (MMS) conducts its audits several years after the sale to determine if the lessee's royalty payment was based on the proper value. Disputes frequently occur on what the proper royalty value should be and litigation often results. The MMS decided to conduct a pilot in the Gulf of Mexico to determine if taking our royalty in kind could reduce these disputes and improve the royalty collection process.

In May 1994, MMS formed a team (Appendix 1) to develop and implement a Royalty Gas Marketing Pilot. The objectives of the pilot were 1) to find processes for streamlining royalty collections in a manner that reflects the recent changes in the gas market, and 2) to test a process of royalty collection that might provide for increased efficiency and greater certainty in royalty collection without compromising revenue collection.

The pilot was made possible by recent changes in the gas marketplace (see Appendix 2). Orders 436 and 636 of the Federal Energy Regulatory Commission (FERC) created a gas distribution system with greater access and flexibility than previously available. Because MMS lacked experience in gas marketing and transportation, the pilot was structured to take advantage of the expertise available in the private sector. Third party marketing companies were competitively chosen to purchase MMS' royalty gas.

Because MMS does not have regulations to govern the taking and sale of gas royalties in kind, a contractual agreement (volunteer agreement) was developed in collaboration with the lessees who volunteered to participate in the pilot. The volunteer agreement established the

operational procedures for taking the royalty gas in kind (see Exhibit C of Appendix 3), and also formed the foundation for the Invitation for Bids (IFB) (Appendix 3) and the sales contracts (contract) with our marketers (Appendix 4).

Volunteer lessees were used in order to minimize the disruptions that could occur. Fourteen lessees volunteered 79 leases (Appendix 5) for inclusion in the pilot. Federal leases located in the Gulf of Mexico that are not partially sharable with the states were eligible to participate in the pilot. Sharable leases were not included in this pilot to shield the states from any negative impacts that might result from this experiment.

The pilot was conducted from January 1, 1995, through December 31, 1995, during which time the MMS took approximately 45.6 billion cubic feet of gas in kind, totaling over $72.6 million, and sold it to the marketers. The MMS sold its royalty gas to the marketer at or near the lease-- the same point at which MMS received delivery of the gas from the volunteer lessee. The marketer was responsible for all costs incurred downstream of the point of delivery, and was entitled to all revenue it received for the gas. The marketer was required to pay MMS for the royalty gas on the 25th of the month following the month of delivery, and to report the royalty gas on a Form MMS-2014, the form normally used by royalty payors. The lessees were relieved of royalty reporting responsibilities on pilot leases, but continued to be responsible for normal production reporting. The lessees also provided gas allocation data and monthly gas balancing reports to the marketers and MMS.

The marketers were required, except in very limited situations, to accept all royalty gas that was made available and to arrange for transportation downstream. The contracts provided for severe penalties in the event of breach.

The pilot was an operational success, proving that the concept of MMS taking and selling non-8(g) royalty gas at or near the wellhead is feasible. However, the pilot team conducted an analysis of the royalty revenue impact of the pilot, and concluded that royalties collected during the pilot were approximately $.0974/MMBtu less than they would have been had MMS continued to collect the royalties in value (see "Revenue Impact Analysis" below). We also analyzed internal administrative savings that possibly could be realized if MMS were to take all of its Gulf of Mexico gas royalties in kind in a program similar to the pilot. This analysis showed that the potential savings would be only $.0044/MMBtu (see "Internal Administrative Savings Analysis").

These analyses are discussed in detail below. In addition, we have included discussions on the pilot's operational aspects, possible external administrative savings, pilot team activities, and lessons learned.

OPERATIONAL ASPECTS

The pilot's operations were governed by several documents: the agreement between MMS and the volunteer lessees (Exhibit C, Appendix 3); the Invitation for Bids (Appendix 3); the Sales Contract between MMS and the royalty gas purchasers (Appendix 4); and the Operation Plan for the Gas Marketing Pilot (Appendix 6), detailing the functional responsibilities of the pilot team and the Royalty Management Program (RMP) during the pilot.

The major operational aspects of the pilot were developed in conjunction with the lessees and documented in the volunteer agreement, which became the basis for the IFB and the resultant sales contracts. The major terms of the volunteer agreement were:

- The lessees made the royalty gas available at specified points of delivery to MMS, which immediately transferred title to the purchaser. The points of delivery in all cases were the Facility Measurement Points (FMP) at or near the leases. The lessees made the gas available in condition acceptable to the transporters, and performed at their own expense necessary dehydration, sweetening, and compression. By making the royalty gas available at the point of delivery, the lessees satisfied in full their royalty obligation, subject to volume verification.

- Within 8 days prior to the month of delivery, the lessees provided MMS and the purchasers estimates of the gas quantities the lessees expected to be available for delivery. They also notified the parties of any non-routine production fluctuations that occurred during the month.

- The lessees tracked imbalances that occurred (see Section 5 of the volunteer agreement) in a Royalty Gas Imbalance Account that they provided to the parties 45 days after the production month. The lessees worked directly with the purchasers to arrange for increased or decreased deliveries to eliminate the imbalances. The lessees had the option of settling final imbalances in gas or in cash, and worked with MMS on these settlements (for details on the final balancing procedures, see Section 5.5 of the volunteer agreement).

- The lessees were relieved of royalty reporting on Forms MMS-2014 for the pilot leases, but continued to provide production-related reports. The lessees also agreed to provide MMS volumetric and valuation data on the disposition of their share of production during the pilot for the sole purpose of evaluating the royalty revenue neutrality of the pilot (see Appendix 7).

The major terms of the IFB were derived from the agreement with the lessees and augmented by standard contracting procedures (see Appendix 8). The sales contract was based on the IFB, and contained the following major provisions:

- The purchaser was to accept delivery of 100 percent of the royalty gas made available by the lessee at the FMP and arrange for all necessary transportation, etc., downstream of that point. Failure to accept delivery or arrange for transportation could result in breach of contract, which carried severe penalties (see Section C.5 of Appendix 4).

- The purchaser took title to the gas at the point(s) of delivery, and was responsible for all costs, including transportation and marketing costs, downstream of that point. The purchaser also was entitled to all revenue downstream of the point(s) of delivery, and did not have to share revenues with MMS.

- The purchaser was required to pay MMS for the royalty gas at the specified bid price by the 25th day of the month following the month of delivery. The purchaser also was required to file a Form MMS-2014 to document the payment. The MMS provided model forms for the purchasers, and the purchasers were required to fill out the non-recurring fields on the forms. They were required to report in Mcf's instead of MMBtu's, which created some problems (see Appendix 9).

The major pilot team activities are discussed in the section titled "Pilot Team Activities." The RMP employees also had activities to perform during the pilot, some of which were unique to this pilot. The major RMP tasks were (for details of these duties, see Appendix 6):

- Once the marketers were selected, RMP assigned unique payor codes and entered PIF's for all selected leases (note: the pilot team prepared the PIF's for the marketers). The RMP also mailed the model Forms MMS-2014 to the marketers.

- The General Ledger Section monitored payments and notified the pilot team of receipt dates. This was necessary because of the non-standard payment due date.

- The RMP employees referred all reporting and late payment exceptions to the pilot team for review, and took corrective actions only when the team requested them.

- The RMP employees assigned all pilot lease royalty/production exceptions to the team. The team worked to resolve exceptions involving gas royalties taken in kind, but referred exceptions on payments in value back to RMP for resolution.

- The RMP auditors reviewed the data provided by the lessees on their share of production from selected pilot leases for selected months (note: the pilot team selected the samples).

There were some operational problems in the pilot, some of which are described in this report, but all of them were resolved. The fact that MMS designed and evaluated the pilot in collaboration with its customers undoubtedly was instrumental in the pilot's operational success.

PILOT RESULTS

REVENUE IMPACT ANALYSIS

Primary Method of Determining Revenue Impact

The revenue impact estimates contained in this report are based on the "primary" method developed by the pilot team. We relied on this method over other methods because it uses the greatest amount of reliable data from MMS accounting systems. We believe that this method accurately forecasts the revenues MMS would have received from our gas marketers if the pilot was to be revenue neutral with royalties paid in value.

The primary method estimates the royalties that MMS would have received for the pilot leases if these royalties had increased or decreased by the same percentage between 1994 (the year before the pilot) and 1995 (the year of the pilot) as did royalties on similar Gulf of Mexico leases that were not included in the pilot.

Because this method is partially based on unaudited 1994 and 1995 royalty data (as are other methods), we assumed that the reported royalty value would be 3 percent higher after audit.[1]

Under this method, we used data from our Auditing and Financial System (AFS) and Production Accounting and Auditing System (PAAS) to calculate volume-weighted average lease royalty values per MMBtu for each month of 1994 and 1995 for offshore Gulf of Mexico leases that were not included in the pilot. This universe included the approximately 1,000 leases and
135 units not categorized as Outer Continental Shelf Lands Act (OCSLA) Section 6 or Section 8(g). We eliminated Section 6 and 8(g) leases from the calculation to mirror the characteristics of the pilot lease universe. We eliminated the top and bottom 2 percent of the leases based on our calculated MMBtu values assuming that the data was unreliable. We used the calculated MMBtu values to establish a price relationship for each month for the 2 years. For quality assurance purposes, we also calculated a similar relationship for each month of 1994 and 1995 using the average index prices contained in the IFB.

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[1] In separate interviews, two MMS audit managers represented that an average 3 percent increase to original offshore royalty reports could be expected due to audit findings. We gathered audit statistics from MMS' 1994 Minerals Revenue Report to confirm this figure. From 1985 through 1994, audit collections as a percentage of total royalties were 3.24 percent (see Appendix 10). While this figure includes oil, gas, and other minerals from offshore, onshore, and Indian leases, and involves both volumetric and valuation issues, we concluded that audit collections for gas valuation issues in the Gulf of Mexico likely would be 3 percent or more.

We next used data from MMS systems to calculate volume-weighted average lease royalty values per MMBtu for each month of 1994 for the 79 pilot leases. We adjusted these calculated royalty values upward by 3 percent to account for future audit adjustments. We applied the 1994/1995 price relationships established for the non-pilot lease universe for each month to these adjusted pilot lease MMBtu values to arrive at an expected revenue value for the 1995 pilot leases. We then compared the expected value with the payments received from MMS' gas marketers, arriving at a $4.7 million estimated revenue loss for the pilot.[2]

We also calculated the results using the relationships established by the average index prices each month and calculated an estimated revenue loss of $4.6 million. This provided a high degree of assurance for the conclusions reached in our primary method using our 1994 and 1995 AFS and PAAS system data.

To illustrate our approach, the following example is provided using data for the month of January.

$1.6558	**January 1995 average volume-weighted price per MMBtu for leases not included in pilot**
$2.1393	**January 1994 average volume-weighted price per MMBtu for leases not included in pilot**
77.40%	**January 1995 price as a percent of January 1994 price using data on royalties paid in value**
$2.0029	**Average unaudited January 1994 volume-weighted price per MMBtu for leases that were later included in the 1995 pilot**
1.03	**Audit factor (assumes 3 percent uplift resulting from future audits)**
$2.0630	**Adjusted average January 1994 volume-weighted price per MMBtu for leases that were included in the 1995 pilot ($2.0029 x 1.03)**
$1.5967	**Average January 1995 price necessary from gas marketers to achieve revenue neutrality (calculated from above numbers ($2.0630 x 77.40 percent)**
$1.4883	**Average January 1995 volume-weighted price per MMBtu received from MMS' marketers**

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[2] Using no audit uplift, the loss would be $2.5 million. Using a 6 percent audit factor, the loss would be $7.0 million. These figures, while unrealistic, are presented to allow the reader to extrapolate a pilot loss based upon a different audit uplift assumption.

($.1084) **Calculated loss per MMBtu for January 1995 pilot ($1.4883-$1.5967)**

4,138,143 **MMBtu's sold to MMS' marketers during January 1995**

($448,575) **January 1995 estimated revenue loss for gas marketing pilot**

In addition, the following calculation was performed as an assurance test for the above data:

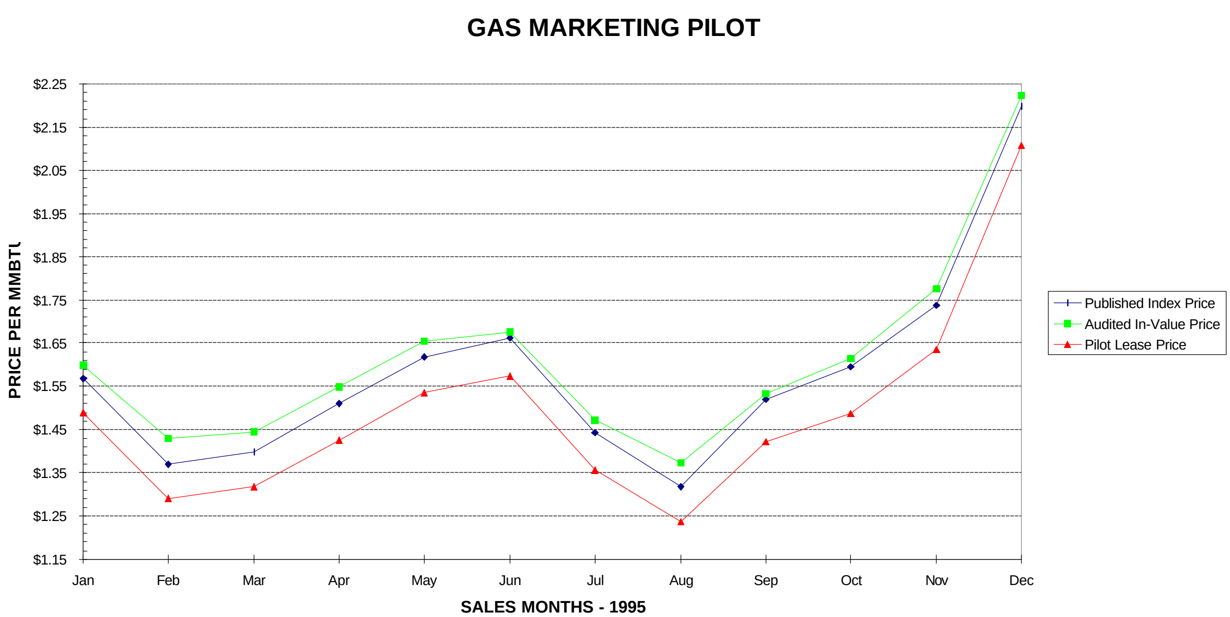
$1.5654 **Average January 1995 published index price per MMBtu**

$2.0085 **Average January 1994 published index price per MMBtu**

77.94% **January 1995 index price as a percent of January 1994 index price (compared to 77.40 percent for royalty data on leases paid in value)**

We applied this percentage in the above calculation resulting in an estimated loss for the pilot of $494,931 for January 1995 using average index price changes.

The graph below plots the average index price, the average lease price for royalties paid in value (adjusted for audit), and the average pilot lease price for each month of the pilot year. It is clear from the data that the 1,100+ similar leases/units on which royalties were paid in value tracked much closer to index (slightly above index) than did the pilot leases (below index).



Other Revenue Impact Methods

Other revenue impact estimation methods support the general trends and conclusions reached in our primary method. These two methods use other sales from the 79 pilot leases during the pilot year to project royalties that would have been received in value had MMS not taken its royalty gas in kind.

One method used only those leases that had less than 100 percent of the lease production included in the pilot (some lessees volunteered their share of production while others did not). We compared the unaudited gas royalties per MMBtu paid in value by the non-volunteer lessees during the pilot period with the price received from MMS' marketers on those same leases. Of the 36 bid packages in the IFB, 15 had royalty reports from non-volunteer lessees; these formed the basis of our projections for the entire pilot lease universe. This method resulted in an estimated $4 million dollar revenue decrease for the pilot lease universe assuming a 3 percent audit adjustment to the data reported by the non-volunteer lessees. This method was not selected to be the primary method because 1) it relies on a very small number of leases to make a projection, 2) errors to reported data (such as Btu content information) could result in skewed results, 3) there was no data for those leases where 100 percent of production was volunteered for the pilot, and 4) it relies too heavily on the marketing ability of a small number of lessees to form a projection applicable to a larger universe.Another method relied on reports submitted by the pilot volunteer lessees for the sale of their working interest share of production during the pilot period. The MMS auditors verified a sample of the volunteer reports to the lessee's records to determine what royalties would have been received by MMS had the lessees paid royalties in value based on their sales. The auditors identified significant errors in the data contained in many of the reports, concluding that the reports were inconsistent and unreliable for both royalty valuation and pilot revenue impact analysis purposes. Nevertheless, we calculated a substantial estimated revenue loss by using the audited data with the remainder of the unaudited data. This served to confirm the conclusions reached in our other methods. We determined that, because all other methods generally revealed consistent estimated revenue losses, the value of auditing the remaining leases and months would be minimal and would not justify the substantial time and effort that MMS and the volunteer lessees would have to spend on those audits.

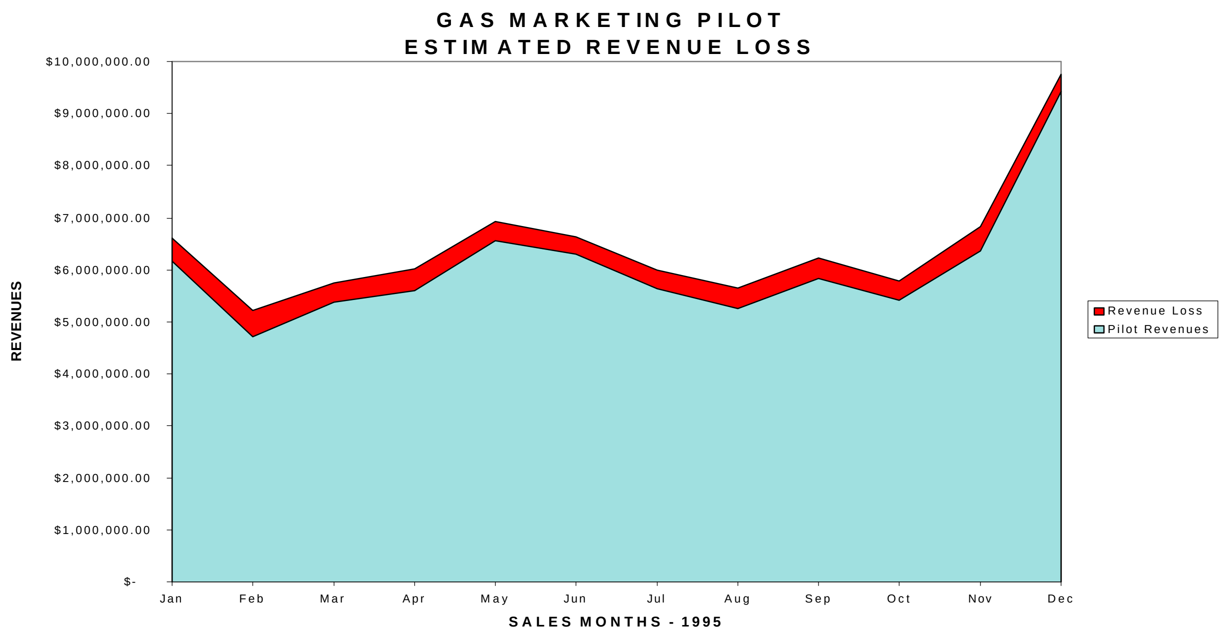
Furthermore, one volunteer lessee testified before Congress that MMS received $.14/Mcf less under our marketing contract than they received for the sale of their share of gas from the pilot leases. The testimony serves to confirm the general losses revealed in the other methods we used, although our analysis showed a loss somewhat less for this lessees' properties. We discussed the possible causes of the revenue losses and ways to alleviate them with this company and others. The results of those discussions are reflected elsewhere in this section and in the external administrative analysis and lessons learned sections.

Results

The results of our pilot analysis using the primary method are summarized in Table 1.

Table 1 - Revenue Impact Analysis Results	
Estimated revenue loss for 1995 gas marketing pilot	**$ 4.7 Million**
Estimated percentage revenue loss	**6.5 %**
Estimated revenue loss per MMBtu	**$ .0974/MMBtu**

The following chart presents the estimated revenue loss with total pilot revenues by sales month:



All revenue impact methods resulted in revenue losses. The lowest estimated revenue loss we calculated was $4 million and the highest was $5.1 million. The primary method for estimating revenue impact resulted in a $4.7 million loss and is depicted in both the table and graph above. The average estimated monthly revenue loss was $394,000; the lowest estimated revenue loss was in June 1995 ($322,000), the highest was in February 1995 ($495,000).

All estimates were calculated using the actual bid prices in effect during each month of the pilot. Estimates were not adjusted retroactively for renegotiated contract price changes. Had these price changes been applied retroactively to the beginning of the pilot (assuming the marketer's initial bid would have been lower had all necessary information been available during bid formulation), the estimated revenue loss would be greater.

Projection Based on Estimated Pilot Losses

Applying these revenue loss estimates to the entire Gulf of Mexico lease universe, we project that revenue losses could exceed $82 million annually if MMS were to take its gas in kind under conditions identical to the 1995 royalty gas marketing pilot. This projection includes Section 6 and Section 8(g) leases. While we can not predict what those losses might be if some or all of the revenue loss factors discussed below were addressed, we believe that the losses would remain substantial.

Factors Affecting Revenues

Many factors likely contributed to the decrease in revenues realized during the pilot. Several of these factors might be mitigated by improvements in future programs or pilots where MMS takes its royalty gas in kind. However, based on the results of this pilot, it is highly unlikely that future in kind programs in which the government sells its royalty gas to a third party at the lease would yield as much revenue as royalty collections in value for the reasons discussed below.

The primary unavoidable factor is the fee charged for the services rendered by MMS' marketer. This fee is not separately stated, but is included within the bid price. During a pre-pilot interview, a gas marketer represented to us that fees of $.01 to $.03 per MMBtu could be expected. While we do not have access to information that would confirm the actual marketing fees that were factored into the bid prices, it is intuitive that one does not receive the benefit of a service without paying for the service. For example, we reviewed the "Invitation to Negotiate a Marketing Contract" recently issued by the State of Texas for its gas marketing program, which indicates the Texas General Land Office (TGLO) charges a $.03 per MMBtu fee for its contract administration services. These services provided by TGLO are similar to the marketing services provided by MMS' marketers.

In addition, MMS' marketers were required to complete and submit a Form MMS-2014 each month in order to make their payments for the royalty gas. This was an additional service for which MMS likely was charged through the marketer's bid price. We view these marketing fees as barriers to revenue neutrality under any similarly-structured program since the lessee must bear all costs of marketing without cost to the federal lessor when royalties are paid in value.

Another factor that may not be avoidable is the charge for transportation through producer-owned pipelines. These pipelines are not subject to the rate jurisdiction of FERC. It is not clear whether the government could control the transportation rate charged to our marketer through producer-owner pipelines. Under the current regulations for royalties paid in value, the producer owners are limited to their actual pipeline costs as a transportation deduction from royalty. Indications are that the rates negotiated and paid by MMS' gas marketers were considerably higher than the actual cost basis allowed under the current regulations. Pilot revenues were directly affected by these higher transportation costs through lower bids. Because those costs are included within the gas marketer's bid price, we have no way to measure the effect of this factor, although we have reason to believe this was a significant revenue reduction factor based on our interviews with MMS' marketers. While we considered many possible solutions to this factor, we are not aware of any solution that would entirely mitigate the revenue implications of this factor short of implementing regulations that would control rates charged by producer-owned pipelines to levels allowed under the current regulations for off-lease delivery of royalty gas in kind.

A partially avoidable factor is the additional consideration received for the downstream processing of natural gas liquids. Under the pilot, sufficient Btu information was not contained in the IFB that would allow marketers to readily determine the potential for natural gas liquid recovery that might enhance the value of the production. In addition, some marketers were unable to arrange for processing because of the short period of time they had to formulate bids. Therefore, marketers may not have considered the potential increase to the value of the gas at the lease when formulating their bids. Because MMS has information on Btu content of the gas, this factor could be partially mitigated by inclusion of the Btu content of the wellhead gas stream in the IFB. Alternatively, MMS could structure future programs so as to retain gas processing rights.

Another partially avoidable factor is the packaging of larger aggregated volumes. Gas marketers indicated to us during our workshops that packages in excess of 5,000 MMBtu's per day would generally receive a more favorable bid price. The pilot had many packages that were less than 5,000 MMBtu's per day. However, if MMS takes 100 percent of its production in the Gulf of Mexico in kind, there will always be nuisance volumes that will not fit logically into larger packages.

Another partially avoidable factor is the lack of gas volume warranty in MMS' gas marketing contracts. With the large amount of gas at its disposal, MMS could warranty volumes of gas for many contracts. However, this function would not come without expense, since either contractors would have to monitor and manage gas supplies and storage or MMS personnel would have to obtain training and experience in these areas to perform this function.

A fully avoidable factor is the short preparation time imposed by MMS for bid submission. The IFB allowed only 30 days for marketers to perform the necessary research and formulate a bid. This likely resulted in a slightly lower price overall than would have occurred with additional time. In some cases, it was indicated to MMS that we received higher bids due to the lack of time and information, but this is more likely the exception to the rule.

The above factors raise significant doubts about whether collections of royalty gas in kind based on an approach similar to the one used in the pilot could be revenue neutral. Should MMS decide to pursue additional programs for collecting gas royalties in kind, then MMS should seek to structure the program so as to minimize the revenue losses associated with the factors above.

Contract Settlements

The potential impact on revenues if MMS elected to take its royalties in kind from leases for which royalties may be due on contract settlement proceeds warrants special mention. We are aware of one Gulf of Mexico lease that, if MMS took its gas in kind and was prevented from collecting royalties in value on the contract settlement proceeds from the lessee, revenues would have declined by an additional $16.7 million based on 1995 data.

Therefore, given the magnitude of contract settlement royalty obligations, any future gas marketing pilots or programs should be designed to avoid taking these leases in kind.

Time Value of Accelerated Payments

Under the pilot, MMS realized a time value of money benefit as payments from the marketers were due on the 25th of the month following the month of delivery versus the normal due date of the end of the month following the month of sale for royalties paid in value. Based on an average monthly payment of $6.1 million from MMS' marketers at an average of 5.2 days earlier than normal (at an average interest rate of 9.25 percent), MMS realized a time value benefit of $96,000 for the pilot year. This benefit was not included in the revenue impact estimates outlined above.

INTERNAL ADMINISTRATIVE SAVINGS ANALYSIS

The team considered different ways to estimate MMS' potential administrative cost savings if we were to take all of our Gulf of Mexico royalty gas in kind. We decided to study the functions performed by the staffs of the RMP divisions to collect royalties in value and determine to what extent staffing needs would change if royalties were collected in kind. Using this approach, we concluded that MMS could realize annual administrative cost savings of about $3.6 million. These estimated savings were based on several assumptions (see Appendix 11), and on discussions with the divisions. Most of these savings would be in audit and associated functions; we identified very low savings for those divisions that build, operate, and maintain MMS' computerized accounting systems.

We also analyzed MMS' costs as they have been allocated for Net Receipt Sharing purposes. (Net Receipt Sharing is a method legislated by Congress for MMS to deduct part of its costs from the states who receive federal royalties from leases within their state). The Net Receipt Sharing data indicate that it costs RMP approximately $13.4 million per year to collect, verify, and distribute Gulf of Mexico gas royalties. This amount does not include $7.4 million that is spent on contract settlements, which are audit costs that would not be affected if MMS were to take its gas royalties in kind in the future. The total does include costs for collection, disbursement, and other functions that would continue to be incurred at some level.

Our study of this data showed that many of these costs would not be affected if we were to take our royalty gas in kind. While it is difficult to determine exactly how much of the $13.4 million could be saved, it is clear that, even if MMS could devise a way to eliminate the entire cost associated with administering Gulf of Mexico gas royalties, the savings still would be far less than the revenue loss projected for a gas royalty-in-kind program similar to this pilot.

EXTERNAL ADMINISTRATIVE SAVINGS ANALYSIS

Throughout the pilot, from the planning to post-contract phases, we solicited comments, suggestions, and observations from the natural gas industry, especially the volunteer producers and the marketers who participated in the pilot. In addition to individual and group meetings and discussions, we conducted written surveys and held workshops to solicit input. The results of these efforts are summarized below, in the section titled "Pilot Team Activities."

The focus of these earlier efforts was on operational aspects of the pilot. However, another objective of the pilot was to determine whether an expanded program could result in administrative savings to MMS and industry. The MMS administrative savings analysis is discussed in the preceding section; this section addresses the potential external administrative savings.

To determine participants' views on potential savings, a team member interviewed several in person or by telephone after the pilot was over. For the most part, those interviewed believed that their companies could realize net administrative savings with an expanded, permanent program because of reduced complexity in royalty determination and payment. Specifically, an expanded program should result in:

- reductions in audit efforts;
- reductions in conflicts and litigation;
- simplification of pricing, coupled with certainty; and
- reductions in reporting requirements.

Of course, certain conditions would have to be present in order for these projections to hold true, such as:

- there could not be a significant "mix" of payments in value and in kind in the same area, such as the Gulf of Mexico;
- leases should not be split between in kind and in value;
- this pilot's reporting requirements should be eliminated (i.e., the Gas Imbalance Statement and the reporting on the producer's share of production. The former should be replaced by normal industry reports and the latter should be eliminated); and
- flash gas should be included in the program.

The companies also noted several administrative burdens associated with providing royalty gas in kind, including:

- increased gas control efforts because of the addition of another party with whom to deal for nominations, delivery, balancing, etc.;
- the elimination of the Form MMS-2014 data base, which several companies use as an internal check and also as a way to track royalty costs; and
- the requirement to work with marketers that are not familiar with royalty reporting to help them report correctly.

Most companies stated that these burdens would lessen over time and would not be as significant as the potential benefits. However, several companies did note potential problems that, for them, could offset any administrative benefits. Foremost among these was the concern with the effect a large-scale program would have on the existing market and on their abilities to market gas. Specifically, an expanded program could:

- disrupt contracts and inconvenience customers;

- create a competitive disadvantage for producers that have traditionally marketed their gas themselves by taking away a significant portion of their volumes; and

- cause problems when gas plant ownership is based on throughput.

Of course, each company's situation, coupled with the design of the program, would dictate whether and to what extent it realized administrative benefits because of an expanded program. However, for the most part, companies felt that the concept is workable and should result in mutual administrative benefits through streamlining and reduced costs if designed properly. (Note: several companies volunteered to help design the next pilot or program, if there is one. In fact, there was considerable support for a negotiated rulemaking, if one is necessary.)

PILOT TEAM ACTIVITIES

One of the actions the Director, MMS, took in response to the changing environment in the gas industry discussed in Appendix 2 was to direct a study to determine the feasibility of taking the Federal Government's offshore gas royalties in kind. The study, conducted by MMS employees in early 1994, showed that the concept was worthy of consideration (see Appendix 12). Accordingly, the Director, in May 1994, tasked the Associate Director for Policy and Management Improvement (PMI) to design and implement a pilot program by November 1, 1994.

The first step in implementing the pilot was to establish an administrative process to complete the necessary work. The Associate Director, PMI, formed a team of MMS employees, of which she was the sponsor, to design and conduct the pilot. The six-person team consisted of one representative from Administration & Budget (A&B), one from RMP, one from the Offshore Minerals Management Gulf of Mexico Region (GOMR) and three from PMI (see Appendix 1). Another PMI employee was added in November 1994. Only three of the original team members remained on the team throughout the pilot, but all of them were on the team until at least March 1995.

Prior to the formation of the team, MMS decided to retain consulting assistance for the drafting of the IFB. The MMS did not have the expertise to draft an IFB that adequately reflected the changes that had occurred in the U.S. gas market. Moreover, the institutions of the gas market had become complex and still were changing as a result of FERC Order 636 (see Appendix 2). The MMS faced a very tight time schedule because the initial plan called for commencing the pilot by early November 1994. Under such a plan, the marketing company(ies) would need to be competitively selected by the end of August 1994. In order to complete the selection of marketing companies by the end of August, we would have had to issue the IFB in the July 15 to August 25 period. The IFB would have needed to be ready for issuance by July 1, 1994.

To assist in the preparation of the IFB, MMS retained the services of Benjamin Schlesinger and Associates (BSA) located in Bethesda, Maryland. The BSA had performed a 1992 study of the U.S. gas market for the Minerals Management Service and also had done highly regarded studies of the U.S. gas market for FERC and the American Gas Association. The BSA's involvement in the pilot design and IFB development is discussed in the detailed chronology of events below.

The pilot team designed and implemented the pilot, with the following key dates:

June 1, 1994	First team meeting
October 21, 1994	IFB issued
November 21, 1994	Bid opening
December 1994	Contracts let
January 1, 1995	Pilot began
December 31, 1995	Pilot ended
September 1996	Pilot report completed

Following is a detailed pilot chronology, including discussions of the team's activities and decisions, operational aspects of the pilot, and significant pilot events.

May 1994

Two team members met with A&B's Chief Procurement Officer to brief him about the preliminary plans and timelines, and to request assistance, when required, to award contracts. It was as a result of this meeting that the team sponsor decided to add a contracting officer from A&B to the team.

June 1994

The team met for the first time in June 1994 in Houston, Texas. The reason for meeting in Texas was to visit with representatives of two natural gas marketing companies, who briefed us about the gas market. We met as a team after these briefings, with the following results:

- Decided to ask for an extension of the target pilot start date to at least January 1, 1995, because of the complexity of the task at hand (subsequently, the sponsor asked for and received an extension to January 1 from the Director).

- Decided, again as a result of the complexity of the task and the limited time available, to take the royalty gas in kind as close as possible to the wellhead and sell it by competitive bid to gas marketing companies chosen through a competitive process. Other options considered were to provide the gas to federal installations for their use or take the gas further from the leases. The latter option would have required MMS to perform some marketing functions, such as arranging for transportation, either itself or with an agent.

- Developed a preliminary revenue impact analysis plan.

- Held preliminary discussions about the pilot's operational aspects.

We published notices about the upcoming pilot in major industry publications and sent letters to Gulf of Mexico lessees soliciting their interest in participating in the pilot (Appendix 13). In response, over 20 companies initially volunteered to provide royalties in kind from selected leases.

In late June, team members held the first meeting with RMP managers and employees to discuss how to design the pilot so that there would be no adverse impacts on RMP's financial and reporting systems and as little disruption to normal RMP operations as possible. These meetings, which continued throughout the pilot, resulted in agreements that were spelled out in the RMP Operational Plan (Appendix 6). Some of the major elements of this plan were discussed above. The plan worked well, and there were very few problems associated with the pilot's operations within the parameters of RMP's systems. The main problems were related to the requirement that gas purchasers convert MMBtu's to Mcf's and report the well-head Btu content for Form MMS-2014 reporting. This is discussed in detail in Appendix 9.

July 1994

During July, we continued discussions to determine the approach to take. For example, in mid-July, we met with a representative of the Department of the Interior's Office of the Solicitor (SOL) to discuss legal aspects of the pilot. The SOL was involved actively from that point forward in the pilot's design, especially during development of the agreement with the lessees in September and October 1994.

We also met with our consultant to discuss his perception of the workings of the gas marketplace and how best to design a pilot that would work within the parameters of the marketplace as much as possible. One of the major topics of discussion was how to offer the royalty gas so as to try to achieve revenue neutrality. This included discussions on how to price the gas.

August 1994

We held several meetings to discuss preliminary pilot design and issues that needed to be addressed prior to issuing the IFB. Some of these issues were:

- how to account for royalties taken in kind and collect payments while staying within RMP's existing royalty and production systems;

- how to design the pilot so as to minimize risk for all parties;

- how to arrange for the taking and selling of gas royalties in a manner that would closely parallel industry practices while not compromising MMS' royalty collection responsibilities; and

- how to gather the necessary information on volunteered leases.

We developed a preliminary approach and held an informational meeting with industry representatives on August 30, 1994, in Houston, Texas. The open meeting was attended by over 85 industry representatives, and the information exchange was valuable to both sides. In addition to the industry meeting, we met individually with some prospective volunteers to discuss the development of an operational agreement. We then met briefly as a team to discuss the results of the meetings.

During August, team members continued to meet with RMP representatives to discuss the RMP operation plan. The team leader also briefed the State and Tribal Royalty Audit Committee (STRAC) about the plans for the pilot. This was the first of several courtesy STRAC briefings, designed to keep them apprised of developments even though they were not directly involved in or affected by the pilot because no onshore, OCSLA Section 8(g), or Indian leases were included in the pilot.

September 1994

This was a critical month in the pilot's development, because we finalized the list of pilot leases and the GOMR began working with the volunteers' technical representatives. In addition, two team members began negotiating the terms of the agreement with the volunteer lessees.

In addition, the team's GOMR representative, with help from two other GOMR employees, did the following to prepare for the IFB.

- Determined where the volunteered leases' production was measured for royalty purposes and how production flowed to that point by:

  Reviewing the measurement data base;
  Reviewing measurement approval letters;

Reviewing pipeline maps;
Obtaining data from lessees; and
Verifying findings with lessees.

- Verified the percent ownership, type of royalty, royalty rate, and volumes and MMBtu's volunteered, as they appeared on the volunteer form, by reviewing the measurement and lease data bases, contacting lessees, and performing the necessary calculations.

- Identified pipelines carrying volunteered production for the purpose of determining jurisdictional and non-jurisdictional[3] (lateral) pipelines.

- Prepared maps showing volunteered leases and pipelines carrying that production from the lease to shore for the purpose of lease bid grouping and index determinations.

- Prepared the tables for inclusion in Section B of the IFB.

The members of the team that were working on the volunteer agreement met with most of the volunteer lessees to develop the volunteer agreement, which originally was drafted by the lessee that had volunteered the most production for the pilot. In addition, team members met several times with SOL and RMP representatives to apprise them of the procedures being developed and obtain their input. There were a lot of negotiations involved before the terms of the agreement were set (see "Operational Aspects" above for the agreement's major terms).

The agreements were signed by the Director, MMS, and the volunteers in mid-October, just prior to the issuance of the IFB. We could not issue the IFB until the agreements were signed, because the terms of the IFB mirrored those of the agreements.

During September, the team's contracting officer drafted the IFB, not including the portions that were going to be derived from the volunteer agreement and GOMR's work. These were added in mid October, once the agreement terms were finalized.

October 1994

As stated above, the agreements with the lessees were finalized and signed in mid-October.

The GOMR completed reviewing the technical data for the volunteered leases. In addition, several team members had teleconferences with the consultant to aggregate the leases into 36 bid groups and to select price indices to use in the IFB.

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[3] The term "non-jurisdictional" refers to those pipelines that are not regulated by FERC. Pipelines that fall under FERC jurisdiction are those used to transport gas in inter-state commerce. Inter-state commerce includes gas produced in one state that is transported across state boundaries to be sold in another state; also included in this category is gas produced from federal offshore lands and transported across the federal-state offshore boundary for sale in one of the states. "Non-jurisdictional" pipelines do not fall in the above category and refer to those smaller lines used for gathering gas within a field or as connectors to jurisdictional lines.

We issued the open IFB on October 21, 1994 (Appendix 3). The IFB instructed bidders to prepare bids by group, based on specified published price indices. Bids were to be stated in terms of the published index prices plus or minus a differential chosen by the bidders. The bidder's differential adjustments from the published index price were to cover all costs, including transportation, from the point of delivery at or near the lease to the index point interconnect.

Shortly after issuing the IFB, we received suggestions that the indices should be changed for 17 of the 36 groups of leases. The original designations contained in the IFB were challenged as inappropriate or incorrect. In response, we made most of the suggested changes and issued an amendment to the IFB on November 8th. (For a discussion of the concerns, see Appendix 14).

Team members met with RMP representatives several times in October, especially to discuss royalty/production exception reconciliation procedures.

November 1994

We analyzed royalties received on the pilot leases for the period November 1993 (FERC Order 636 effective date) through July 1994 to establish an historical record for use in evaluating bids. We then developed a bid evaluation procedure to use in reviewing bids. The procedure established a method for evaluating bids so that bids that clearly would result in significant lost revenue could be identified and rejected. (Note: The first test was how much the bids, in the aggregate, were above or below what we expected to receive based on our analysis of historical receipts. The MMS management had decided that all bids would be accepted if the aggregate projected loss was less than 5 percent, because the pilot was an important test. The bids passed this test, so all were initially accepted. Later, a bid group was eliminated when the first bidder withdrew and subsequent bids were deemed to be too low.)

We opened 23 bids from 22 companies on November 21, selected the initial winning bids, and contacted the companies to tell them the bid groups on which they were successful. As we contacted bidders, it became apparent that many of them had not researched the leases adequately, particularly the transportation requirements, and others had misinterpreted where the royalty gas would be made available. As a result, their bids were in many cases substantially higher than other bids. Therefore, we ensured that all winning bidders were aware of the particulars of the groups; when they were so informed, many requested that they be allowed to withdraw their bids.

The MMS required winning bidders seeking to be relieved of their obligations to demonstrate that they were unaware of the existence of previously unidentified pipelines and that they would incur additional costs that were unanticipated at the time that they formulated their bids. These bidders had to certify that they had erred in their bidding because of misunderstandings regarding the flow of gas. However, no bidders were allowed to withdraw a bid because they miscalculated the cost of gas flow.

In some instances, relieving the winning bidder of its obligation resulted in bid groups being removed from the pilot. We removed two bid groups from the pilot because all qualified bidders withdrew after discovering that additional transportation costs would be incurred in moving the gas through non-jurisdictional lines. In addition, we dropped another group from the pilot after the initial winning bidder was allowed to withdraw its bid. The group was removed from the pilot because we found the next highest bid to be unacceptably low.

The MMS then stipulated that, as of January 1, 1995, the following conditions would be enforced:

- a purchaser could not be relieved of liability for failure to identify pipeline segments; and

- a purchaser's failure to take gas from an individual group would be considered breach of contract and could result in a termination of the purchaser's contract with MMS for that particular group. The MMS then could offer the contract to the next highest bidder from the original list of bidders, or re-advertise the terminated group.

A purchaser held in breach would have its contract terminated for default. A purchaser in breach would be required to pay MMS the difference between its winning bid price and the new contract price. This obligation would be in effect for the life of the pilot, and MMS would not remove leases from the pilot once gas began to flow.

One purchaser was found to be in breach on January 1, 1995, as a result of failing to take the gas. However, the purchaser was able to document that, prior to January 1, it discovered that the flow of gas involved an additional segment of pipeline. The costs of using this additional pipeline were not addressed in bid formulation. To reduce administrative burden and financial harm to the Federal Government, the MMS and the affected volunteer lessee mutually agreed to remove the lease from the pilot. The volunteer continued to pay royalties in value on this lease.

December 1994

The MMS entered into 14 sales contracts, notified the lessees, and instructed the purchasers to contact the lessees to begin taking gas on January 1, 1995. However, during the period immediately preceding January 1, a purchaser encountered difficulty with a non-jurisdictional pipeline. The purchaser had purchased gas from the volunteer lessee during 1994 without paying for the services of an upstream pipeline. In formulating its bid, the purchaser assumed that a similar arrangement would apply in the taking of the gas in kind. While making arrangements for the commencement of the pilot, the purchaser discovered that a fee would be charged for the use of the pipeline.

The purchaser contacted the team’s contracting officer during the last week of December. The purchaser explained that the additional transportation cost would result in a substantial loss for the year and asked to be relieved of its contractual responsibility after the last day in January. To be consistent with the policy of relieving bidders that didn't identify pipeline segments required for movement during the bidding process, but did identify them prior to January 1, MMS granted the request. The contract for the remaining 11 months of the pilot was awarded to the next highest bidder.

Also during December, pilot team members worked with RMP employees to set up the purchasers as payors and to complete all necessary system preparations. We also met with audit managers to discuss the pilot's audit requirements.

January 1995

The pilot began on January 1, and the transition from in value to in kind went smoothly, with the exception of the situation mentioned above. In fact, very few operational problems occurred over the life of the pilot.

In January, we began to develop the instruction letter to the lessees outlining the agreement that had been reached for them to provide the data on their share of production for use in the pilot evaluation. We issued the letter (Appendix 7) on February 27, 1995. The letter included a form for use in reporting the data. The lessees provided the data throughout the pilot, a team member ensured that all reports were received, and RMP auditors reviewed the data for selected leases and months after the pilot ended.

We also met in mid-January to discuss several issues, including the agreement mentioned in the above paragraph, the initial pilot occurrences mentioned above, and operational issues.

February 1995

The purchasers submitted their first payments and reports at the end of February. For the most part they were timely, although two payments were 1 day late.

March 1995

We published an interim report in March 1995 that documented pilot operations and results through January 1, 1995.[4]

In order to verify the accuracy of the marketers' payments, we began the process of entering monthly Form MMS-2014 data into a spreadsheet program to determine the price reported per MMBtu for each lease. These prices were compared to the expected contract prices for each month. There were numerous reporting errors due to the MMBtu pricing requirement (incorrect volumes or Btu contents). We contacted the marketers to resolve the pricing exceptions and all material exceptions (some exceptions were due to rounding and involved large sales quantities) were resolved. In fact, on an aggregate basis, the approximate $72.6

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[4] You may request a copy of this or other documents mentioned in this report, but not included as appendices, from Jim McNamee, PO Box 25165, MS 9130, Denver, CO 80225, FAX No. 303 275-7124.

million reported and collected for the pilot year was within $1,909 of being 100 percent accurate.

We also conducted volume reconciliations throughout the pilot and post-pilot balancing periods (see Appendix 9). We compared the data on the Forms MMS-2014 to that on the Gas Imbalance Statements provided by the lessees and the production reports provided by the operators. Overall, the volume and value reconciliation efforts resulted in additional royalties totaling about $159,000.

Team members in Washington, D.C. held a series of meetings with representatives of industry and government interested in having small business set asides included in future pilots or programs (see Appendix 15).

April 1995

Team members met with representatives of SMD to discuss the revenue impact analysis data needs. The SMD started to design the reports we would need.

June 1995

We mailed survey questionnaires in June 1995 that were tailored to three groups of companies to gauge the experience with, or perceptions of, the pilot. The surveys were mailed to the volunteer lessees, the companies that were purchasing royalty gas in the pilot, and companies in the natural gas industry in the Gulf of Mexico that did not participate in the pilot.

For the most part, the responses were favorable to the pilot; they also contained several comments and recommendations. Some of the more prevalent comments concerned:

- Non-jurisdictional pipelines ("lateral lines");
- Extent of information provided in the IFB;
- The lack of flexibility in certain areas such as balancing arrangements and surety requirements;
- The lack of protection for the purchaser regarding fluctuating transportation costs and gas volumes;
- The "must-take" requirements combined with non-guaranteed volumes; and
- Record-keeping and reporting requirements.

July 1995

We received a request from a purchaser to modify the terms of its contract because of a changed condition outside the scope of the original competition. The contractor had bid on an estimated volume, supplied in the IFB, of 4,493 MMBtu/day, which was approximately the volume delivered through May 1995. In June, the volume increased to as much as 27,000 MMBtu/day because of new wells.

To respond to this increase, MMS reached a negotiated agreement with the contractor to adjust the contract price. The agreement provided for the contractor to pay the contract price for royalty gas through September 1, 1995, and for the first 5,000 MMBtu/day of royalty gas for the remaining life of the contract. The agreement further provided that the contractor would pay a different price for all volumes over 5,000 MMBtu/day.

The price agreed to for the additional volumes was one proposed by the contractor. Before accepting the proposed price, MMS solicited price proposals from the next three highest bidders off the original bid abstract to validate the contractor's offer. The MMS found the price offered by the incumbent contractor to be the most favorable, and modified the contract accordingly, effective September 1, 1995.

August 1995

The MMS conducted three workshops in August and September 1995 to inform the industry about the current pilot, discuss opportunities for improvement, and explore future options. The workshops were held in Houston, Texas (about 85 industry members attended), Denver, Colorado (20 attendees), and New Orleans, Louisiana (40 attendees). Again, the overall perception of the pilot was favorable, but there were several recommendations for improvement (see Appendix 16 for a detailed discussion).

Many of the recommendations mirrored those received on the surveys. Some of the major topics of conversation included:

- The information contained in the IFB concerning gas flow, delivery location, existence of lateral lines, and gas quality;
- The amount of time allowed to respond to the IFB;
- The lack of flexibility in pricing mechanisms, especially concerning transportation costs and volume fluctuations;
- Procedures for establishing access to and rates for lateral lines;
- Payment due dates;
- The effect of a permanent program on gas processing arrangements; and
- Financial qualifying criteria in the IFB.

October 1995

The Office of the Inspector General (OIG), Department of the Interior, began a review of the pilot at MMS' request. The purpose of the review was to provide assistance in the evaluation of the concept and the pilot itself. The OIG issued its report on May 31, 1996 (Appendix 17), concluding that MMS ". . . had established effective administrative procedures over the pilot project and demonstrated that the royalty-in-kind concept holds promise." The report also offered several suggestions, most of which validated our findings in our own reviews and surveys. Some of the OIG suggestions were:

- Future pilots should encompass a (broader range) of producing companies, lease types, and lease ownership situations;

- The MMS should offer bid packages with larger volumes of gas and warrant volumes;

- The MMS should package lease groups along logical transportation routes;

- The MMS could attempt to negotiate reasonable transportation fees for non-jurisdictional pipelines;

- The MMS should include more information in the IFB and spend more time validating it; and;

- The MMS should explore the concept of taking royalty gas in kind and using it in federal facilities.

December 1995

The pilot ended on December 31, 1995, although final contract reporting, payment, and balancing continued after that date. There were two post-contract incidents, neither of which was significant. They were:

- A lessee invoiced a purchaser for dehydration fees on royalty gas. The invoice was an error and the lessee withdrew it.

- One of the lessees failed to terminate deliveries on January 1, 1996, and the purchaser continued to nominate and take gas after the contract expired. We noticed what was happening and contacted the lessee. The lessee corrected the situation prior to February and settled directly with the purchaser for the erroneous deliveries.

January to June 1996

The pilot team and RMP employees worked on various administrative aspects of the pilot, such as completion of the 5/6 evaluation reviews by the auditors, completing value and volume reconciliations, executing contract balancing procedures, gathering and analyzing data for the revenue impact analysis, completing the internal and external administrative analyses, and preparing the pilot report.

SUMMARY OF MAIN LESSONS LEARNED

Although this limited test was an operational success, we learned many things that should be considered before MMS conducts another pilot or institutes a permanent program. Foremost among these were:

- There should be sufficient lead time allowed to prepare the IFB. Additional preparation time would allow MMS to avoid many of the problems that can arise between the date on which contracts are awarded and the scheduled commencement of the pilot. For example, additional time would allow MMS to verify information on physical gas flow for all the leases and determine the appropriate gas price indices. We estimate that at least 6 months are needed to prepare an IFB.

- Contracts should be awarded between seasons, preferably well in advance of the winter season. In addition, MMS should explore ways to package leases for sale that provides for volume aggregation but does not create problems with gas flow or indices.

- Future IFB's should include as much information that may be helpful to the bidders as possible. Examples include gas analysis information (including Btu content), and the names of producer contacts for information on transportation costs and gas flow. Including this type of information may result in higher bids and prevent problems that can arise after bid opening.

- The IFB and contracts should contain better definitions and mutual understanding of key contract terms, provisions, and procedures between MMS, lessees, and marketers for:
  1) changed conditions; 2) royalty gas entitlements; 3) royalty gas allocated volumes; and 4) final balancing.

- The MMS must find a way to alleviate the problems associated with the flow of royalty gas through non-jurisdictional pipelines after the point of delivery.

- In future royalty gas sales, prospective bidders must be given ample time to study the IFB, gather information and prepare bid responses. For example, prospective bidders may require considerable time to obtain information on non-jurisdictional pipelines and secure reasonable access. We estimate that bidders should be given at least 3 months to respond to an IFB.

- The MMS should examine ways to alleviate purchasers' risk associated with submitting a bid for an extended period of time that includes a "fixed" transportation cost.

- The MMS needs experience with the non-voluntary taking of royalty gas. A pilot effort based on the non-voluntary taking of royalty gas in kind would give a more accurate view of the challenges involved in dealing with operational problems. As stated above, some of the problems the volunteers and marketers encountered during the pilot were resolved without involving MMS.

- In future pilots or rulemakings, MMS should ensure that the IFB contains enough information on entrained liquids, so that their value, if any, is reflected in the bids.

- Net Profit Share leases probably should not be included in future pilots or programs because MMS is limited under terms of the leases to taking no more than 1/3 of the royalty value in kind. In addition, there are no provisions specified for how to grant credit for royalties taken in kind against royalty payments made in value. If such leases are included in the future, the regulations governing the pilot or program would have to address this issue.

- The SOL has advised MMS that we may need to promulgate regulations before we can institute a permanent program to take our gas royalties in kind. In addition, it has stated that OCSLA "fair market value" provisions may preclude us from proceeding with a new pilot or program without a change in the OCSLA or a regulatory clarification of this provision's meaning (see page 5, Appendix 2).

Appendix 1

Royalty Gas Marketing Pilot Team Members

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ADM = Administration and Budget, Herndon, Virginia

OMM = Offshore Minerals Management, Gulf of Mexico Region, New Orleans, Louisiana

PMI = Office of Policy and Management Improvement, Washington, D.C. and Lakewood, Colorado

RMP = Royalty Management Program, Lakewood, Colorado

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[1] Has been involved actively since June 1995, and was the team leader for early MMS activities in late 1995 and early 1996 to prepare for additional RIK pilots. This activity was postponed pending completion of the final evaluation report.

[2] On team from inception through March 1995.

[3] On team from inception through March 1996.

[4] On team from inception through August 1995.

[5] Joined team in November 1994.

[6] Joined team in August 1995.

[7] Joined team in October 1995.

[8] Joined team in January 1996.

MINERALS MANAGEMENT SERVICE
ROYALTY GAS MARKETING PILOT

BACKGROUND DISCUSSION[1]

The Department of the Interior's Minerals Management Service (MMS), is responsible for collecting royalties on approximately 4.3 trillion cubic feet of natural gas produced from the Gulf of Mexico each year. Current royalty collection efforts are based on the 1988 valuation regulations, 30 C.F.R. 206, which require valuation of gas for royalty purposes based on the arm's-length gross proceeds received from the sale of the gas. However, the repeal of regulated gas prices, and the policies of the Federal Energy Regulatory Commission (FERC) as implemented in various orders such as Orders 436 and 636, have transformed the U.S. gas market, creating an array of marketing options for lessees, marketers and purchasers. Source specific contracts have largely been replaced with contracts sourced from large "pools" of gas aggregated from many leases and traded through market centers. Consequently, tracing the gross proceeds from such sales of gas back to any particular lease is very difficult, and determining the royalty value of gas produced from federal leases has become increasingly complex and burdensome.

Accordingly, MMS has undertaken several reinvention efforts to design a federal gas royalty determination and collection system that will complement today's gas market while reducing administrative and audit costs. One such effort was the Royalty Gas Marketing Pilot (pilot), in which MMS took in kind its royalty share of gas produced from leases in the Gulf of Mexico and sold it to competitively selected natural gas purchasers.

The objective of the pilot was to identify processes that would radically alter royalty collections in a manner reflecting changes that have occurred in the natural gas marketing environment. This objective promised increased efficiency and greater certainty in valuation.

Sections of the March 1, 1988, federal valuation regulations for oil and gas (30 C.F.R. 206) have been subject to numerous appeals and litigation since their inception. The controversy centers around the differences between the lessor's and lessee's definition of gross proceeds.

[1] This appendix is an edited excerpt from a Rocky Mountain Mineral Law Foundation (RMMLF) paper entitled “Testing the Waters, a Cooperative Effort to Design the MMS’ Royalty-in-Kind Pilot Program for Natural Gas.” The paper was co-written by employees of Chevron U.S.A. Inc., OXY USA INC, and MMS, and was presented at the RMMLF’s Annual Institute on July 21, 1996. The edited portion presented here originally was written by the MMS employees. For a complete copy of the paper, contact RMMLF at 7039 East 18th Avenue, Denver, CO 80220.

One suggestion to avoid this contentious issue has been that MMS take its gas in kind. The MMS no longer would have to trace sales and transportation transactions to determine gross proceeds.
Prior to the deregulation of the gas market, the concept of MMS taking its royalty gas in kind had limited practicality because MMS' gas was held captive on individual pipelines. Also, natural gas typically was being sold to the pipeline company by the lessee under long term contracts at the wellhead. For these reasons, MMS would have had a more difficult time offering its gas for sale at competitive prices, as compared to the lessee.

In the post-FERC Order 636 gas marketing environment, the concept of taking gas in kind became more realistic because natural gas pipelines were required to unbundle their sales services from their transportation services. As a result, the pipeline's traditional customers, local distribution companies (LDC) and end-users, began purchasing gas directly from lessees and gas marketers. This open market enabled MMS to offer its gas competitively to willing purchasers under more flexible contract terms.

Another effect of deregulation was that valuing federal gas under the 1988 regulations for the purpose of paying royalties became even more complex. When lessees sold directly to natural gas pipelines at the wellhead or outlet of a processing plant, gross proceeds were easier to determine because, generally, MMS' royalty value was based on the price paid to the lessee. However, with the advent of deregulation and open access, some 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.

In this marketing environment, it is more difficult to value federal gas for royalty purposes. Federal gas is now subject to a myriad of gas marketing transactions such as firm and interruptible transportation, storage, swing supply, capacity release, market hub services, pipeline imbalance resolution, and transportation refunds and penalties. The royalty implications of these transactions have yet to be determined under the 1988 regulations.

In an attempt to respond to these changes, MMS also formed the Federal Gas Valuation Negotiated Rulemaking Committee. This Committee explored alternative valuation methodologies that would reduce the need to trace federal gas molecules through a myriad of complex marketing transactions in an attempt to determine gross proceeds.

There were several concerns raised by various parties during the formulation of the pilot. These are discussed below.

No prior experience. Prior to the pilot, the only experience MMS and industry had with federal royalties being taken in kind was the oil royalty-in-kind (RIK) program, administered under the regulations at 30 C.F.R. 208. Concerns were expressed that a gas RIK pilot program would be similar to the existing oil RIK program, which is viewed as not being lessee-friendly because delivery of royalty oil does not necessarily satisfy the lessee's royalty obligation.

The MMS and its predecessor have been administering the oil RIK program continuously since the early 1980's. The objective of the oil RIK program is to provide royalty oil to "eligible refiners" that may not be able to procure oil supplies regularly on the open market.

The royalties under the oil RIK program are valued in accordance with the 1988 valuation regulations at 30 C.F.R. 206. The royalty oil is allocated to eligible refiners through a lottery rather than by competitive bid, and the refiners pay MMS based on the value of the lessee's share of its production. Because of these and other design factors, the gas marketing pilot bore virtually no significant resemblance to the oil RIK program except that lessees deliver the royalties to the purchasers at designated points of delivery. The valuation of royalties that is done in the oil RIK program was not occurring in the gas RIK pilot.

Because of the fundamental differences in intent and objectives between the oil RIK program and the gas RIK pilot, MMS decided not to use the framework of the oil RIK program to design the gas pilot. Instead, MMS teamed with volunteer lessees to design the gas pilot. No aspects of the oil in-kind program were adopted in the gas pilot. In this way, the gas pilot would better mirror the current gas marketing environment.

MMS performing marketing activities. Questions arose regarding the federal government's ability to assume risk and perform complex marketing transactions. The MMS currently relies on the lessee's duty to market its royalty gas. By taking its gas in kind, MMS assumes the inherent risks and costs associated with marketing natural gas. Critics claimed that the federal government has no legitimate role in the gas market, and, further, does not have the expertise to market its own gas.

Alternatives were considered to address these concerns: (1) selling MMS' gas at the wellhead; (2) developing in-house expertise to perform marketing activities; or (3) contracting with a third party to market MMS' gas.

The MMS decided to take title to its gas at a designated point and simultaneously sell the gas to a competitively selected purchaser. The purchaser, and not MMS, was responsible for all downstream marketing activity. However, the pilot provided MMS direct experience in the gas market, which will assist in its analysis and formulation of future valuation policy.

The question most often asked was whether the federal government, with 2 Bcf/d of royalty gas in the Gulf of Mexico, would have a detrimental influence in the marketplace. To address this concern, MMS decided to limit the volumes taken in the pilot to no more than 10 percent of the federal gas in the Gulf of Mexico. In addition, MMS encouraged volunteer lessees to offer gas from a diverse cross section of the Gulf of Mexico, with limited aggregation, to attract a variety of potential purchasers.

Transportation penalties. There was concern that MMS and lessees would be exposed to transportation penalties if a purchaser failed to take royalty gas. To reduce this risk of penalty, the purchaser was required to secure transportation beyond the facility measurement point (FMP) for all gas delivered each day by the lessee. In all cases, the FMP was the designated point of delivery. Failure to take away all delivered volumes would have been considered a breach of contract by the purchaser and the purchaser would have remained responsible for payment of delivered volumes to MMS whether it took the gas or not, except under very limited circumstances.

If the purchaser had become insolvent, the lessee would have been required to remit payment to MMS for its royalty gas until MMS was able to secure a replacement purchaser. The assumption was that, if MMS didn't have a purchaser accepting delivery of the gas, the lessee would market such gas with its share of production. To mitigate the impacts of breach or insolvency, MMS would have attempted to obtain a replacement purchaser as soon as practicably possible. This situation never arose.

Shifting costs associated with marketing activities from the lessee to the purchaser. Currently, the lessee is required to perform marketing activities at no cost to the lessor under the "marketable condition rule." A shift of these costs could result in a loss of revenue for the federal government because these costs would be reflected in the bid price.

The MMS decided to continue to require the lessee to place the gas into marketable condition at or near the lease at no cost to the lessor. The most consistent way to adhere to this view was to have the lessee deliver the gas to MMS at the FMP as approved by MMS' Offshore Minerals Management, Gulf of Mexico Region.

Loss of revenue to the government. Congressional and administration requirements dictate that changes to existing regulations or statutes cannot result in a reduction in the revenues being collected by the federal government. Relative to federal royalty payments, the 1988 regulations are the baseline for revenue neutrality and any changes to these regulations must result in an equivalent amount of collections. (Note: this issue is addressed in the body of the report.)

The pilot would be constrained by existing royalty requirements. To measure the administrative benefits of a pilot, the best case scenario would have been to take gas in kind without being subject to existing royalty accounting requirements. However, this was impractical for several reasons, including the limited scope of the pilot and time constraints during the design phase. Therefore, MMS attempted to design the pilot to minimize royalty accounting procedures while still working within existing systems and maintaining appropriate financial controls.

Specifically, the royalty requirements that were addressed for the pilot included:

> **Lease terms require that royalties must be paid the month following the month of production.** This payment requirement significantly impacted the design of the pilot. In response to this requirement, it was decided that, in order for MMS to be whole by the end of the month following the month of production, the purchaser must accept delivery of all volumes made available by the lessee. However, similar to estimated payments, there were provisions in the pilot for the resolution of volume imbalances that occurred in the normal course of business (see the volunteer agreement and the sales contracts).
>
> **Disbursement of proceeds to appropriate federal accounts.** To properly account for such disbursement, the existing financial system was used, which meant that the Form MMS-2014 was required. However, the party responsible for filing the report was changed from the lessee to the purchaser, since the purchaser was the one remitting payment to MMS for volumes taken. Even though MMS continued to require Form MMS-2014 reporting, much of the exception processing and related assessments related to these reports were waived for the pilot.
>
> **Production reporting.** Although the lessees were not required to prepare royalty reports for the pilot leases, they were required to continue filing production reports.

Legal restraints in the Outer Continental Shelf Lands Act (OCSLA) 43 U.S.C. 1351, et seq.

There were concerns that the OCSLA provision regarding fair market value would preclude MMS from taking its offshore royalty gas in kind in a manner envisioned in the pilot. Specifically, Section 27 of the OCSLA requires that, if the Secretary exercises the right to take royalty gas in kind, it must be done in such a manner that the price received is not more than the regulated price, or, if no regulated price applies, not less than its fair market value. Because of the way the OCSLA defines fair market value, this could be interpreted to mean that the Department, on a lease-by-lease basis, must make some sort of comparison to lessees' sales to determine if fair market value has been received for royalty volumes taken in kind. The basis for valuing lessees' sales would be as defined by the 1988 valuation regulations.

Because the pilot was a test and overall "fair market" impacts could be considered prior to awarding contracts, MMS was able to move forward with the pilot while researching legislative and regulatory alternatives.

INVITATION FOR BIDS

U.S. Department of the Interior
Minerals Management Service
Washington, D.C.

Department of the Interior
Minerals Management Service
Procurement and Property Management Division
Procurement Operations Branch
387 Elden Street, MS 2500
Herndon, Virginia 22070-4817

COVER SHEET

The Minerals Management Service (MMS) (also referred to as the Government) invites bids for contracts to purchase natural gas located in the Gulf of Mexico for 12 months and to be available to purchase final balancing natural gas, if applicable (see Section C.4) after the 12-month period. MMS will award no more than one contract for the entire amount offered for each group of Leases. This Invitation for Bid (IFB) is being issued with the understanding that if, for whatever reasons, bids for any given item are so low that it is not economically feasible for MMS to accept such a bid, then the group of Leases affected by such bid will be removed from the Pilot. In each contract month, Contractor must take 100 percent of the Government's MMBtu's made available for sale at the Point(s) of Delivery, and Contractor must pay the Government for all MMBtu's made available regardless of whether Contractor actually takes such MMBtu's. If Contractor fails to take all MMBtu's made available at the Point(s) of Delivery, the Government may declare breach of contract (See Section C.5).

AUTHORITY. This Notice is published pursuant to the Outer Continental Shelf Lands Act (OCSLA) (43 U.S.C. 1331, et seq.).

IFB Issued: October 21, 1994

Bid Opening: November 21, 1994
U.S. Department of the Interior
Minerals Management Service
381 Elden Street
Herndon, Virginia 22070-4817
Rooms 2114-2118

Contracts are for purchasing natural gas for 12 consecutive months, commencing on January 1, 1995, and terminating on through December 31, 1995. (See E.1.) Contractor may have to be available for purchase of final balancing natural gas after this time (see Section C.4.5).

Address any questions regarding this IFB to James E. MacKay, the Contracting Officer for this IFB, at (703) 787-1351. MMS will not accept collect telephone calls.

DOCUMENTS TO ACCOMPANY BID: Bidders must submit the following documents with their bids. MMS may reject, as nonresponsive, bids not accompanied by these documents:

1. **Executed Bidder's Signature Page, Section A;**
2. **Schedule of Items and Prices (Your BID), Completed Table in Section B;**
3. **Contractors Representative, F.5;**
4. **Representations, Certifications, and Acknowledgements, Section J;**
5. **Acknowledgement of IFB Amendments, if any, K.5;**
6. **Bid Guarantee, K.7;**
7. **Financial Statement, K.10;**
8. **Certification of Qualification, Exhibit B**

TABLE OF CONTENTS

SECTION A
BIDDER'S SIGNATURE PAGE

This bid is submitted in response to IFB No. 3768. By my signature below, I agree, if this offer is accepted within 35 calendar days from the date for receipt of offers specified in the IFB, to perform in accordance with the terms and conditions of the IFB and this offer, under the contract which results therefrom.

I certify that the information, representations, and certifications included herein are full, accurate, and complete.

BIDDER'S BUSINESS NAME:

ADDRESS:

AUTHORIZED SIGNATURE: ______________________________

TYPED NAME AND TITLE:

DATE:

Bids by corporations must be executed over the corporate seal. Self-certification as to one's authority is not acceptable. Therefore, the signatures above and below must be by different persons.

CORPORATE OR PARTNERSHIP CERTIFICATION

I, ______________________________, certify that I am the ____________________ of the above bidder, that ______________________________, who signed this bid on behalf of that bidder then held the office or position of ______________________________ of said bidder, that said individual duly signed said bid on behalf of said bidder by authority of its governing body or his position of employment with said bidder, and his/her signature of this bid is within the scope of that person's authority.

Seal[1] ______________________________

Signature **Corporate or Partnership Officer**

The making of false statements to the Government is punishable by a fine of not more than $10,000 and/or not more than 5 years imprisonment. See 18 U.S.C. §1001.

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[1] If bidder has no seal, the signatory or the corporate or partnership certifying official shall write "No Seal" by hand and initial in the space provided for the seal.

SECTION B
BIDS AND INSTRUCTIONS

B.1. BIDDER QUALIFICATIONS

Bids will be accepted only from qualified Bidders. Bidders must complete the certification as to Qualifications contained in Exhibit B to this IFB No. 3768.

B.2. INSTRUCTIONS TO BIDDERS

B.2.1. The table in this Section, entitled Table of OCS Lease Groups Offered for Bid, contains a listing of groups of leases for which Royalty Gas is available for purchase by qualified Bidders. Each offered group contains one or more leases for bid. For each such Group, the table identifies:

- Offered group number
- Lease(s)
- Block(s)
- Percent ownership
- Point of Delivery, i.e., receipt point for such natural gas
- FMP No., i.e., MMS assigned measurement location identification number of the Point of Delivery
- Facility operator, by name of company, i.e., operator
- Volumes of Royalty Gas available for bid, in estimated MMBtu's per day
- Applicable Index
- Bid (intentionally left blank).

B.2.1.a The Lessees, as defined in Section C.1., are operating rights owners of certain oil and natural gas leases the Government issued, as reflected in Section B. Said leases are hereinafter called "said leases," whether one or more. This contract applies only to Royalty Gas made available to Contractor by the Government's Lessees by virtue of the Government's Lessees ownership in said leases on the effective date of this contract. If Government's Lessees assign all or a portion of said leases, this contract shall apply to the assigned portion thereof. If Government's Lessees obtain additional interest in said leases, such additional interest shall be subject to this contract only if the parties mutually agree in writing.

B.2.1.b Volumes of Royalty Gas shown in the table B.3 are estimates for planning purposes only. Each volume is a percentage of the lease production owned by the Lessees (as determined by percentage ownership) multiplied by the royalty rate. The volume represents the Royalty Gas expected to be available and must be taken by the Contractor each month. These are only estimates and are subject to change depending on actual natural gas availability information provided each month to the Contractor by Government's Lessees (see Section C.3 on natural gas availability).

B.2.2. Bidder may submit a bid for any or all of the groups (or combination of groups) contained in the table (see B.3 below) by expressing its bid in the column labeled "Bid" in the space provided in the row for that group. All bids must be in the form of a

numerical adjustment to the Applicable Index for that group in B.3. The Bidder's adjustment may be either additive or subtractive or zero. No percentages nor multiplier adjustments will be accepted. Bidders are hereby notified that the Government will select winning bids only from qualified bidders (i. e., bidders having credit worthiness to pay the Government in full each month for all available MMBtu's, and the performance capability to take away all volumes made available by Government's Lessees each month) strictly on the basis of maximum revenue return to the Government.

B.2.3. Bidder must provide a bid price for all natural gas offered in each group which the Bidder seeks to purchase. Bidders may not ungroup Leases, but must submit one single bid for all the Royalty Gas in any offered group as a whole. If the Bidder is not bidding on a line item in the table in B.3, the line for the bid should be left blank.

B.2.4. In addition, the Bidder may submit an alternative bid; the Bidder may arrange aggregations of its own choosing, each of which may consist of any number of the Government's offered groups. For such aggregations, Bidder may submit an alternative bid for the Royalty Gas in each offered group, under the stipulation that the Government will not break up Bidder's self-defined aggregation if it is to award Bidder's alternative price for all the offered groups in its aggregation. In other words, acceptance by the Government of Bidder's alternative bid will mean that Bidder's aggregation will not be broken up. If a bid for an aggregation of groups maximizes revenue for the Government, this bid will be accepted even though an individual bid for an individual group within the aggregation may be greater than the bid submitted for the aggregation.

However, any Bidder who bids on a such a self-defined aggregation of offered groups as an indivisible whole <u>must</u> also provide individual bids for each of the offered groups within its aggregation. In other words, while the Government's offered groups of Leases may not be broken up, Bidder-defined aggregations may not be accepted by the Government if the bid for such aggregations fail(s) to maximize the Government's revenues (see the example in B.2.5 below). Thus, the highest bid on any individual offered group in B.3 is not necessarily a guarantee of an award.

B.2.5. <u>Examples:</u>

(a) Assume Bidder wishes to bid on the group of leases in the B.3 table which includes G02632, G02812 and G03301, whose total estimated volume of Royalty Gas equals 4,456 MMBtu/day, as shown on Page 3 of the attached table in B.3. Note that the Applicable Index for the group is the Southern Natural Gas Company, Louisiana Index. If the Bidder wishes to bid the amount of $.023/MMBtu over the Index, then Bidder writes or types "+0.023" in the Bid column, in the row for that group.

(b) Assume Bidder wishes to bid on that foregoing group, as well as the group above it in the table, i.e., Lease G06359, containing an estimated 14,333 MMBtu/day of Royalty Gas. Moreover, Bidder is willing to pay an additional $0.010 per MMBtu (above the index) only if he is awarded an aggregation including <u>both</u> groups. Again, note that if this bid for the aggregation maximizes revenue for the Government, it will be accepted even though an individual bid for either of the two groups may be greater than $0.010 per MMBtu. In this example, Bidder must still provide an offer for each of the two offered groups individually in the space provided in B.3. In addition, however, Bidder must indicate its alternative bid in the space provided at the end of the table, by typing or

printing the Offered Group Numbers and its bids for each group under the presumption that the Bidder will be awarded all of the groups in its aggregation, without exception. Again, all bids must be in the form of a numerical adjustment to the Applicable Index for each group.

B.3. [BID TABLE FOLLOWS]

SECTION B

OFFRD GRP. NO.	LEASE	AREA/ BLOCK	% OWNERSHIP	POINT OF DELIVERY	FMP NUMBER	FACILITY OPERATOR	ROY. GAS	APPLICABLE INDEX	BID $/MMBTU
1	G03011	MUA16	50% OXY	MU A16 A	3042702MP08	OXY	**1530**	Northern Natural - Texas, Oklahoma, Kansas	
	G04064	MU739	45%OXY	MU 739 A	3042702MP00	OXY			
2	G04536	MUA22	100% CHEVRON	MU A31 B	3042702PN01	CHEVRON	**7907**	Transco - Zone 1	
	G04537	MUA31	100% CHEVRON	MU A31 B	3042702PN01	CHEVRON			
	G04537	MUA31	100% CHEVRON	MU A31 A	3042702PN00	CHEVRON			
3	G03932	MI527P	61% ENRON	MI 555 C	3042703SS04	ENRON	**4162**	Northern Natural - Texas, Oklahoma, Kansas	
	G03079	MI555	63% ENRON	MI 555 C	3042703SS04	ENRON			
	G03080	MI556	61% ENRON	MI 555 C	3042703SS04	ENRON			
	G03080	MI556	61% ENRON	MI 527 A	3042703SS03	ENRON			
	G03932	MI527P	61% ENRON	MI 527 A	3042703SS03	ENRON			
	G03080	MI556	61% ENRON	MI 527 B	3042703SS0F	ENRON			
4	G03087	MI620	89% ENRON	MI 638 B	3042703SS0B	ENRON	**6914**	Northern Natural - Texas, Oklahoma, Kansas	
	G06044	MI638	85% ENRON	MI 638 B	3042703SS0B	ENRON			
5	G02663	BAA70	25% OXY	BA A70 A	3042705CC01	OXY	**834**	Transco - Zone 1	
6	G02665	BAA133	25% OXY	BA A133 A	3042705CC08	OXY	**5731**	Transco - Zone 1	
	G02665	BAA133	25% OXY	BA A133 B	3042705CC08	OXY			

ROY GAS (MMBTU/day)

SECTION B

OFFRD GRP. NO.	LEASE	AREA/ BLOCK	% OWNERSHIP	POINT OF DELIVERY	FMP NUMBER	FACILITY OPERATOR	ROY. GAS	APPLICABLE INDEX	BID $/MMBTU
7	G06167	HI195	32.61% APACHE	HI 176 A	3042708OO0G	APACHE	365	Transco - Zone 2	
8	754393023	HIA384	100% ORYX	HI A384 A	3142711HI00	ORYX	1298	Transco - Zone 2	
9	G02414 G02746 G02745	HIA323 HIA356 HIA355	19.4% OXY 45% OXY 40% OXY	HI A323 A HI A356 A HI A355 B	3142711HI0F 3142711HI0R 3142711HI0Q	OXY OXY OXY	1840	Transco - Zone 2	
10	G13553	WC55	100% ZILKHA	WC 53 A	3017700SA00	ZILKHA	1016	Transco - Zone 2	
11	G05377 G00971 G01880 G04433	EC185 EC261 EC264 SM160	100% AMOCO 100% AMOCO 100% AMOCO 50% CHEVRON	EC 185 A EC 261 A EC 261 A SM 160 A	3117703BB02 3017704BB01 3017704BB01 3017708BB05	AMOCO AMOCO AMOCO CHEVRON	3608	Southern Natural - Louisiana	
12	G00974 G00974 G00972	EC278 EC278 EC265	50% TEXACO 50% AMOCO 50% TEXACO 50% AMOCO	EC 278 C EC 278 B EC 278 B	3017704BB0A 3117704BB00 3117704BB00	TEXACO TEXACO TEXACO	14130	Southern Natural - Louisiana	

ROY GAS (MMBTU/day)

OFFRD GRP. NO.	LEASE	AREA/ BLOCK	% OWNERSHIP	POINT OF DELIVERY	FMP NUMBER	FACILITY OPERATOR	ROY. GAS	APPLICABLE INDEX	BID $/MMBTU
13	G02051	EC286	50% MOBIL	EC 286 A	3017704FF07	MOBIL	11718	Texas Eastern - East Louisiana Zone	
			50% CHEVRON		3017704Y002	MOBIL			
	G02063	EC338	48.7% ORYX	EC 338 A	3017704Y004	ORYX			
14	G06358	GB189	50% TEXACO	GB 189 A	3060807BW01	TEXACO	12450	Southern Natural - Louisiana	
			50% UNOCAL						
15	G06359	GB191	50% CHEVRON	GB 191 A	3060807Y000	CHEVRON	14333	Transco - Zone 2	
16	G02632	GB236	37% CHEVRON	GB 236 A	3060807BW00	CHEVRON	4456	Southern Natural - Louisiana	
	G02812	GB237	37% CHEVRON	GB 236 A	3060807BW00	CHEVRON			
	G03301	GB192	37% CHEVRON	GB 236 A	3060807BW00	CHEVRON			
17	G01146	VR245	100% CHEVRON	VR 245 F	3017705BW0Q	CHEVRON	4416	Southern Natural - Louisiana	
	G01146	VR245	100% CHEVRON	VR 245 B	3017705BW0J	CHEVRON			
	G01146	VR245	100% CHEVRON	VR 245 E	3017705BW0J	CHEVRON			
	G01146	VR245	100% CHEVRON	VR 246 D	3017705BW0L	CHEVRON			
	G01147	VR246	100% CHEVRON	VR 246 D	3017705BW0L	CHEVRON			
18	G02873	VR251	100% CHEVRON	VR 251 D	3017705BW00	CHEVRON	2383	Southern Natural - Louisiana	
	G05431	VR252	100% CHEVRON	VR 252 F	3017706BW09	CHEVRON			
	G01149	VR250	100% CHEVRON	VR 250 C	3017705BW0N	CHEVRON			
	G05031	VR253	100% CHEVRON	VR 250 C	3017705BW0N	CHEVRON			

ROY GAS (MMBTU/day)

SECTION B

OFFRD GRP. NO.	LEASE	AREA/ BLOCK	% OWNERSHIP	POINT OF DELIVERY	FMP NUMBER	FACILITY OPERATOR	ROY. GAS	APPLICABLE INDEX	BID $/MMBTU
19	G01196	SM61	100% CHEVRON	SM 61 D	3017707BW0E	CHEVRON	**16953**	Southern Natural - Louisiana	
	G01196	SM61	100% CHEVRON	SM 61 B	3017707BW0C	CHEVRON			
	G01196	SM61	100% CHEVRON	SM 61 C	3017707BW0D	CHEVRON			
	G03145	SM60	100% CHEVRON	SM 61 C	3017707BW0D	CHEVRON			
20	G02892	EI10	75% A. HESS 25% FREEPORT	EI 10 A	3017709TT00	A. HESS	**1807**	Koch Gateway - Louisiana	
	317	EI47	100% MURPHY	EI 47 A	3117709QQ00	MURPHY			
21	G10735	EI186	50% AMOCO 50% TEXACO	EI 193 A	3017709K00F	AMOCO	**5458**	Transco - Zone 3	
	572	EI193	50% AMOCO 50% TEXACO	EI 193 A	3017709K00F	AMOCO			
	572	EI193		EI 215 B	3017709K00F	AMOCO			
	578	EI215P	50% AMOCO 50% TEXACO	EI 215 B	3017709K00F	AMOCO			
22	G04453	EI240	100% MOBIL	EI 240 A	3017709BB0B	MOBIL	**4493**	Southern Natural - Louisiana	
23	G05040	EI316	100% PENNZOIL	EI 315 A	3017710BW0U	PENNZOIL	**1145**	Southern Natural - Louisiana	
	G05040	EI316	100% PENNZOIL	EI 316 A	3017710BW0V	PENNZOIL			
24	G02914	EI341	100% CHEVRON	EI 341 A	3017710XW0E	CHEVRON	**1144**	ANR Pipeline - Louisiana	
	G04864 *	EI164	100% DEVON	EI 164 #1	3017709XW0N	DEVON			

* NET PROFIT SHARE LEASE

ROY GAS (MMBTU/day)

SECTION B

OFFRD GRP. NO.	LEASE	AREA/ BLOCK	% OWNERSHIP	POINT OF DELIVERY	FMP NUMBER	FACILITY OPERATOR	ROY. GAS	APPLICABLE INDEX	BID $/MMBTU
25	G02323	EI360	91% CHEVRON	EI 361 A	3017710XE03	CHEVRON	**4888**	Trunkline -	
	G02324	EI361	91% CHEVRON	EI 361 A	3017710XE03	CHEVRON		Field Zone	
	G03410	EI352	91% CHEVRON	EI 361 A	3017710XE03	CHEVRON			
	G03783	EI353	91% CHEVRON	EI 361 A	3017710XE03	CHEVRON			
26	819	SS168	100% CHEVRON	SS 168 D	3017711BW0B	CHEVRON	**6337**	Southern Natural -	
	821	SS183	80% CHEVRON	SS 182 C	3017711BW0F	CHEVRON		Louisiana	
	G01019	SS182P	80% CHEVRON	SS 182 C	3017711BW0F	CHEVRON			
	G03584	SS170	100% CHEVRON	SS 170 A	3017711BW0C	CHEVRON			
	G03584	SS170	100% CHEVRON	SS 181 B	3017711BW0E	CHEVRON			
	G04231	SS181	50% CHEVRON	SS 181 B	3017711BW0E	CHEVRON			
27	820	SS169	33.4% CHEVRON	SS 169 A	3017711K00E	CHEVRON	**1040**	Transco -	
								Zone 3	
28	G01240	ST51P	100% CHEVRON	ST 35 E	3017715Q003	CHEVRON	**883**	Trunkline -	
	G01241	ST52	100% CHEVRON	ST 35 E	3017715Q003	CHEVRON		Field Zone	
	G06766	ST51P	100% CHEVRON	ST 35 E	3017715Q003	CHEVRON			
	G01240	ST51P	100% CHEVRON	ST 52 A	3017715XE00	CHEVRON			
	G01241	ST52	100% CHEVRON	ST 52 A	3017715XE00	CHEVRON			
29	G05599	ST100	100% CHEVRON	ST 100 A	3017715XE0K	CHEVRON	**1869**	Trunkline -	
	G05602	ST111	100% CHEVRON	ST 100 A	3017715XE0K			Field Zone	
30	891006669	ST135	100% CHEVRON	ST 151	3017715Q008	CHEVRON	**4016**	Trunkline -	
								Field Zone	

ROY GAS (MMBTU/day)

SECTION B

OFFRD GRP. NO.	LEASE	AREA/ BLOCK	% OWNERSHIP	POINT OF DELIVERY	FMP NUMBER	FACILITY OPERATOR	ROY. GAS	APPLICABLE INDEX	BID $/MMBTU
31	G01259	ST176	100% CHEVRON	ST 177 E	3017715Q00F	CHEVRON	**6737**	Tennessee Gas - Louisiana + Offshore, Zone 1	
	G01260	ST177	100% CHEVRON	ST 177 E	3017715Q00F	CHEVRON			
	G01572	ST189	100% CHEVRON	ST 177 E	3017715Q00F	CHEVRON			
	G01899	ST188P	100% CHEVRON	ST 177 E	3017715Q00F	CHEVRON			
32	G04464	ST200	80% TEXACO 20% WHITING	ST 200 A	3017715XE0I	TEXACO	**1926**	Trunkline - Field Zone	
33	G05224	ST225	100% A. HESS	ST 206 A	3017715XE0R	A. HESS	**525**	Trunkline -	
34	G09651	PL6	65% WALTER	PL 6 A	3017713Q000	WALTER	**2926**	Tennessee Gas - Louisiana + Offshore, Zone 1	
35	G01606	SP54P	100% TEXACO	SP 54 A	3017721E002	TEXACO	**8563**	Tennessee Gas - Louisiana + Offshore, Zone 1	
	G04479	SP45	89% OXY	SP 45 A	3017721E006	OXY			
36	G12087	MP107P	66.68% A. HESS 16.66% BROOKLYN UNION 16.66% SMITH	MP 108 A	3017725Z00J	A. HESS	**741**	Southern Natural - Louisiana	
	G01633	MP133	31.5% MOBIL	MP 133 C	3017725Z006	CHEVRON			
	G01649	MP237	15.75% MOBIL	MP 133 C	3017725Z006				

ROY GAS (MMBTU/day)

SECTION B

ALTERNATE BID GROUPING	BID $/MMBTU

SECTION C
TERMS AND CONDITIONS OF GAS SALES AND PURCHASE

C.I. DEFINITIONS

C.1.1. Applicable Index means the Index published in Inside F.E.R.C.'s Gas Market Report or "GMR" (for the first-of-the-month price) under the table entitled "Prices of Spot Gas Delivered to Pipelines" specified in the table in Section B.3 of this IFB No. 3768 for each item included in that table.

C.1.2. Audit refers to any review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Federal and Indian leases, and, as used herein, refers to such review of Contractor's compliance with the provisions of this Contract.

C.1.3. Btu means British thermal unit, and is the quantity of heat required to raise the temperature of 1 pound of water from 58.5 to 59.5 degrees Fahrenheit. MMBtu means one million Btu's.

C.1.4. Commodity Charge means the fee which Contractor shall pay the Government for each MMBtu of Gas that the Government through its Lessees delivers to the Point(s) of Delivery for Contractors account.

C.1.5. Contract means this IFB No. 3768, immediately after it has been fully executed and accepted by Bidder and the Government, and includes any amendments or revisions thereto, between the Parties, and constitutes an obligation which, with due consideration, is enforceable by law.

C.1.6. Contracting Officer (CO) is a person with the authority to enter into, administer, and/or terminate contracts and make related determinations and findings. The term includes the authorized representative of a CO acting within the limits of his or her authority, as delegated by the CO, except as otherwise provided in this contract.

C.1.7. Contracting Officer's Technical Representative (COTR) is that person named to administer day-to-day technical contracting matters.

C.1.8. Contractor means the bidder to this IFB No. 3768 whose offer is accepted by the Government and who is a purchaser of Royalty Gas subject to the provisions of this IFB No. 3768. The Contractor is also referred to herein as Government's Contractor.

C.1.9. Day means a period of twenty-four (24) hours beginning at 8:00 a.m. on any calendar day and ending at 8:00 a.m. on the following day.

C.1.1O. Force Majeure

(a) Force majeure means acts of God, strikes, lockouts, or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, hurricanes or storms, hurricane or storm warnings which require the

precautionary shut-down or evacuation of production facilities, earthquakes, fires, floods, washouts, arrest and restraints of governments and people, civil disturbances, explosions, breakage or accidents to machinery, equipment, or lines of pipe, freezing of wells or lines of pipe, partial or entire failure of wells or pipelines, and any other cause beyond the reasonable control of the party affected which renders that party unable to carry out its obligations under this Agreement. Contractors failure to market, failure of markets, and failure of interruptible transportation, are not force majeure events. The settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty, and any Force Majeure shall be remedied with all reasonable dispatch but shall not require the settlement of strikes or lockouts by acceding to the demands of opposing party when such course is inadvisable in the discretion of the party having the difficulty.

(b) The loss of markets to other natural gas supplies or fuels, whether or not caused by regulatory determinations or regarding applicable transportation rates, shall not constitute an event of force majeure. The Parties agree that a lack of funds, economic hardship, or other financial cause shall not in any circumstance be an event of force majeure. Failure of interruptible transportation is not force majeure.

(c) In the event of any Party being rendered unable, wholly or in part by force majeure to carry out its obligations under this Gas Purchase Agreement, other than the obligation to make payment of amounts accrued and due at the time thereof, it is agreed that on such Party's giving notice and full particulars of such force majeure in writing or by telefax to the other Party within a reasonable time after the occurrence of the cause relied on, the obligations of all Parties, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused, but for no longer period, and such cause shall so far as possible be remedied with all reasonable dispatch.

C.1.11. Government, as used in this document, means the United States Department of the Interior, Minerals Management Service.

C.1.12. Inside F.E.R.C.'s Gas Market Report or "GMR" shall mean the journal by that name which is published on a weekly basis by McGraw-Hill Corporation.

C.1.13. Lease refers herein to any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the Government under the Outer Continental Shelf Act (43 U.S.C. 1331 et seq.) which authorizes exploration for development or extraction of, or removal of natural gas from Federal lands in the Gulf of Mexico.

C.1.14. Lessee is that party through Federal lease ownership which has entered into a Lease with the Government, or which owns operating rights in such a Lease, as defined herein, and which has entered into an agreement with the Government to participate in the Royalty Gas Marketing Pilot and has agreed to the terms outlined in Exhibit C.

C.1.15. Government's Contractor means a company, corporation, partnership, association, person or other entity with whom the Government has contracted to receive, handle, deliver, and/or market Royalty Gas taken by the Government as its royalty on production from or attributable to said Leases. The Contractor does not necessarily perform the functions performed by Transporter, although nothing prohibits Government's Contractor and Transporter from being the same entity.

C.1.16. Month means a calendar month.

C.1.17. Operating Rights (working interest) means the interest created out of a lease authorizing the holder of that right to enter upon the leased lands to conduct drilling and related operations, including production of oil or natural gas from such lands in accordance with the terms of the lease. 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.

C.1.18. Outer Continental Shelf, or "OCS", as used herein, refers to all submerged lands lying seaward and outside of the area of land beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

C.1.19. Parties mean the Government and the Contractor.

C.1.20. Point(s) of Delivery means the point or points identified at which Government's Lessee is to make available to the Contractor, and Contractor is required to take Royalty Gas from or attributable to said Leases.

C.1.21. Royalty Gas means that portion of natural gas and entrained liquids, produced from or attributable to said Leases for taking in kind at the Point(s) of Delivery, to which the Government is entitled as the royalty percentage of the production from or attributable to said Leases. Royalty Gas includes flash gas which is commingled and delivered with other gas at the Point(s) of Delivery, but does not include the following:

(a) The volumes of natural gas beneficially used (used on lease) or unavoidably lost, as approved by the Government, upstream of the Point(s) of Delivery;

(b) Naturally occurring condensate, retrograde condensate, drip condensate or other liquid hydrocarbons which move separately from the natural gas stream downstream of the Point(s) of Delivery; and

(c) Flash gas which separates from liquid hydrocarbons downstream of the Point(s) of Delivery.

C.1.22. Royalty Gas Balance Account shall have the meaning ascribed to it in Section C.4.4. of this IFB No. 3768.

C.1.23. Royalty-In-Kind Pilot means the one-year trial, beginning January 1, 1995, being undertaken by the Government in which Royalty Gas will be sold in the marketplace by the Government.

C.1.24. Secretary is the Secretary of the United States Department of the Interior or any person, persons, or board (other than the Contracting Officer) authorized to act for the Department or the Secretary.

C.1.25. Transporter means principally the pipeline company receiving delivery or Royalty Gas at the Point(s) of Delivery, but may mean any upstream or downstream Pipeline transporter, as dictated by context.

C.2. GENERAL TERMS

C.2.1. Contractor and the Government agree that 100 percent of the Royalty Gas made available by Government's Lessees at the Point(s) of Delivery will purchased and taken by Contractor at the Point(s) of Delivery. Title to the Royalty Gas delivered hereunder and taken by the Contractor shall pass to and vest in the Contractor at the inlet flange of the Point(s) of Delivery. Lessees shall be deemed to be in exclusive control and possession of said Royalty Gas prior to the time of delivery to the Contractor at the inlet flange of the Point(s) of Delivery, and, if taken at the Point(s) of Delivery, the Contractor shall be deemed to be in exclusive control and possession of said Royalty Gas thereafter.

C.2.2. The Government's Lessees shall be responsible for delivery of its Royalty Gas to Contractor at the Point(s) of Delivery. Contractor shall be responsible for transportation of volumes from the Point(s) of Delivery to Contractor's markets. Contractor represents and warrants that it has obtained transportation rights necessary to satisfy its obligations under this Gas Sales and Purchase Agreement. Contractor shall maintain appropriate contracts with Transporting Pipelines, including all interstate, intrastate, private or other pipelines, laterals, feeder lines and any and all other carriers, so that Contractor can receive and deliver all volumes pursuant to this Gas Sales and Purchase Agreement. Contractor shall take all necessary steps to properly arrange for the nomination, dispatch, and removal from the Point(s) of Delivery of all volumes of Royalty Gas tendered by the Government, and to arrange for required transportation in order to carry out the intent of and obligations of this Gas Sales and Purchase Agreement.

C.2.3. The party deemed to be in control and possession of the Royalty Gas shall be responsible for and shall indemnify, defend and hold the other party harmless with respect to any losses, claims, liabilities or damages arising therefrom when such Royalty Gas is deemed to be in that party's control and possession. The Government shall not be liable for consequential, incidental, special or punitive damages or losses which may be suffered as a result of the failure to make available or take the Royalty Gas hereunder.

C.2.4. Contractor shall hold the Government and the Government's Lessees harmless for all costs and penalties, including any and all scheduling and imbalance penalties, which may be assessed or imposed by a Transporter against Contractor at or after the Point(s) of Delivery, including without limitation purchases or sales of imbalance quantities of natural gas at unfavorable prices. The Government shall not hold the Contractor responsible for any costs and penalties which may be assessed against the Government prior to the Point(s) of Delivery. Only when Government's Lessees, through gross negligence or willful misconduct, fail to perform duties described in Section C.3.1 and C.3.2 may the Government's Lessees be required to pay for such penalties, as set forth above, after the Point(s) of Delivery.

If any costs or penalties associated with transportation of natural gas are anticipated, the Contrator or Government's Lessees shall inform the other in writing as soon as the Government's Contractor or the Government's Lessees becomes aware. The Contractor and the Government's Lessees shall immediately work with the other to minimize or eliminate, if possible, such costs or penalties. The Contractor and the Government's Lessees shall work with each other and with the Transporter to verify delivery and receipt of nominated volumes on a timely basis.

C.2.5. It is specifically agreed that there are no third party beneficiaries to this contract, and that the contract shall not impart any rights enforceable by any person, firm, organization, or corporation not a party hereto.

C.2.6. The Contractor shall enter into agreements with Transporter, such as operational balancing agreements and predetermined allocations, which agreements have the effect of reducing scheduling and delivery imbalances with Transporter, and which therefore assist in mitigating possible allocation of Royalty Gas to Lessees or other Operating Rights owners.

C.2.7 Notwithstanding any other provision herein to the contrary, it is agreed and understood that the Government's Lessees shall be in sole control of any well drilled under the terms of the said Leases and nothing herein will operate by implication to enlarge or decrease any right which the Government's Lessees would have in the absence of the Government's Agreement with the Lessees (Exhibit C) with respect to the operation and maintenance of any well drilled hereunder or to impair any right the Government's Lessees would otherwise have to repair, rework, plug and abandon, produce or schedule the production of any well or wells drilled under the terms of the said Leases. During any period of time a gas well is shut in for any reason, The Government's Lessees shall not be obligated to deliver any Royalty Gas from that well and shall not be responsible for any loss to the Government or the Government's Contractor for failure to so deliver Royalty Gas.

C.3. NOTIFICATION OF ROYALTY GAS AVAILABILITY AND CONTRACTOR ACKNOWLEDGEMENT

C.3.1. Estimated Gas Available. No later than (8) working days before the first day of the applicable month of delivery or the twentieth (20th) day of the calendar month before the first day of the applicable month of delivery, whichever is earlier, Government's Lessees have agreed to communicate by facsimile transmission to the Government COTR and the Contractor the Lessees's good faith estimate of the daily quantity of Royalty Gas, stated in MMBtu's, that Lessee expects to be available for delivery from or attributable to said Leases during such month. The parties understand and agree that Lessees's estimates of deliverability from said leases are not a warranty of deliverable quantities, but are given to facilitate planning for necessary transportation and marketing of the Royalty Gas.

C.3.2. Changes in Availability. The Government's Lessees have agreed to use reasonable efforts, customary in the industry, to communicate by facsimile transmission to the Government COTR and the Contractor circumstances beyond routine production fluctuations that affect natural gas deliverability from said Leases, so that the Contractor may adjust its transportation and marketing arrangements on a continuous basis in order to take the full quantity of Royalty Gas available each day. The Government's Lessees have agreed to issue such communication to the Contractor as soon as practicable.

C.3.3. Acknowledgement from the Contractor. No later than twenty-four (24) hours, excluding weekends and holidays, prior to Transporter's first-of-the-month nomination deadline, the Contractor shall confirm by facsimile transmission to the Government's Lessees and the Government COTR the daily quantity of Royalty Gas, stated in MMBtu's, that the Contractor must take from Government's Lessees during the upcoming month. The Contractor shall communicate changes in such transportation nominations related to any changes made by Governments' Lessees by facsimile transmission to Government's Lessees and Government's COTR in the same manner throughout each month of delivery, and with adequate notice to allow confirmation of nomination changes before applicable deadlines. The Contractor shall work in good faith with the Government's Lessees and Transporter(s) to arrange for delivery of 100 percent of the quantities of Royalty Gas made available at the Point(s) of Delivery.

C.3.4. The responsibilities and obligations of Lessees set forth under this Section shall be performed by the Operator, if the Operator has agreed and is a volunteer in the Pilot, for the applicable Leases to the extent practicable.

C.4. IMBALANCES

C.4.1 Contractor Obligation to Take or Nominate. Notwithstanding Lessees's maintenance of a balancing account, the parties understand and agree that this contract does not permit the Contractor to delay timely takes of 100 percent of the Royalty Gas delivered by Lessees. The Contractor shall use reasonable efforts in accordance with industry standards to avail itself of any third-party agreements available to it with the Transporter to minimize the incurrence of any imbalance with the Lessees. Such agreements may include, for example, operational balancing agreements or pipeline allocations.

C.4.2. Conditions Warranting Balancing. The balancing mechanism described in this Section C.4 is designed for a Contractor to correct only those imbalances resulting from the following:

C.4.2.a Differences between the Government's monthly Royalty Gas entitlements and allocated volumes.

C.4.2.b Typical scheduling imprecision that result in differences between Transporters receipts and Lessees's deliveries.

C.4.2.c Failure by the Government's Contractor during any given month to nominate all quantities made available by Lessees, not to exceed three consecutive days during any month period.

C.4.2.d Operational changes that can occur between the Transporters first-of-the-month nomination deadline and the first day of a calendar month.

This balancing arrangement does not include Royalty Gas subject to Section C.5.1 and does not relieve the Contractor of its responsibility to take 100 percent of the Government's Royalty Gas, whether the actual amount thereof is more or less than Lessees's previous estimate.

C.4.3. Managing imbalances during term of Contract. For any Contractor imbalance occurring under Section C.4.2, during any calendar month, the Contractor shall work with the

Government's Lessees to arrange for increased or decreased deliveries of Royalty Gas in the subsequent month or months, in order to eliminate such imbalance as soon as is reasonably practicable. Such differences shall be maintained by the Government's Lessees in a Royalty Gas Imbalance Account, as defined in Section C.4.4 of this IFB No. 3768.

C.4.4. <u>Royalty Gas Imbalance Accoun</u>t. The Government's Lessees will be required to maintain a Report of Royalty Gas Imbalance Account which shall include: (1) actual Royalty Gas quantities produced from or attributable to said Leases, (2) actual takes of Royalty Gas by the Contractor, and (3) the overtakes or undertakes of Royalty Gas by the Contractor. The Royalty Gas Imbalance Account report will be submitted to the Government COTR and the Contractor no later than 45 days following the month of production. If adjustments or corrections of actual quantities delivered have not been received by such date, the Lessees will be required to file an estimated Royalty Gas Imbalance Account for the applicable month and must issue a corrected Royalty Gas Imbalance Account promptly after all such adjustments or corrections are received.

C.4.5. <u>Final Balancin</u>g. After December 31,1995, the contractual relationship with the Contractor shall continue to allow for purchase of any imbalance which may exist, either in the Royalty Gas Imbalance Account or by virtue of any subsequent Transporter adjustments. Such final imbalances shall be communicated to the Government and the Contractor within thirty (30) days after December 31, 1995, or when Lessees come into possession of all necessary information for the last delivery month, whichever is later. The parties shall settle such imbalance as follows:

C.4.5.a <u>Contractor has taken less natural gas than the Government's entitlement</u>. The Government's Lessees, at its sole option, may settle the imbalance in either of the following ways. The Lessees must notify the Government of its election and the Government shall notify the Contractor as to method of settlement within (15) after Lessees issues the final Royalty Gas lmbalance Account. (1) The Lessees may pay the Government for the amount of undertaken Royalty Gas with the natural gas being valued at the Contractors bid price at the time that the imbalance accrued. If Government's Lessees elects this method, Contractor shall have no obligation with respect to such Royalty Gas. (2) The Lessees may settle the imbalance by making available natural gas from or attributable to the Leases to the Contractor at the Point(s) of Delivery. If Lessees elects to settle in natural gas, and if natural gas production is no longer available from the Leases at the Point(s) of Delivery, or if natural gas production is not of sufficient quantity to allow recovery of the imbalance within 30 days, then to settle such imbalance, Lessees must make available equivalent quantities of natural gas, of similar quality and equivalent value, at agreed-upon alternative Point(s) of Delivery as soon as practically possible to the Contractor to reconcile undertakes on an in kind basis.

C.4.5.b <u>Contractor has taken more than the Government's entitlement</u>. Subject to final audit, the Contractor's obligations under final balancing will be satisfied once It has submitted payment for the overtake equal to the final imbalance quantity valued at the Contractors bid price per MMBtu at the time said imbalance was accrued.

C.4.6. The responsibilities and obligations of Lessees set forth under Sections C.4.1 through C.4.4. shall be performed by the Operator, if the Operator agrees and is a volunteer in the Pilot. However, Lessees shall be responsible for any final balancing as provided by Section C.4.5.

C.5 FAILURE BY THE CONTRACTOR (BREACH) AND CONTRACTOR LIABILITY

C.5.1. Breach of Contract by Failure to Take. If, for reasons other than a Force Majeure occurrence or those occurrences described in Section C.4.2 subject to the Royalty Gas Imbalance Account, the Contractor does not satisfy its contractual obligations to the Government by failing to take the Government's entire share of Royalty Gas made available to it during any month, the Government may terminate the contract. Circumstances, not of a force majeure nature, constituting a breach of contract with the Government by the Contractor include, but are not limited to the following circumstances:

C.5.1.a Once during any month, more than three consecutive working days pass in which the Contractor fails to provide nominations in response to Royalty Gas made available by the Government's Lessees.

C.5.1.b If, due to a curtailment of interruptible transportation by Transporter or a non Force Majeure curtailment of firm transportation by Transporter, more than three consecutive working days pass in which the Contractor fails to take Royalty Gas made available by the Government's Lessees.

C.5.1.c Within a given month, the Contractor allows a repeated sequence of delays in nominating or taking Royalty Gas. If it appears that during any month Contractor is swinging Royalty Gas by not taking for 3 consecutive days or less but repeating a non-taking pattern throughout the month (e.g., no taking for 2 days, then taking for a day, and then not taking for another 2 days), this may be considered a breach of contract.

The disposition of any quantities of Royalty Gas, delivered by the Government's Lessees but not taken by the Contractor which is considered a breach of the Contractors contract with the Government shall be accomplished in accordance with Transporter's applicable tariff provisions and/or existing balancing agreements among Transporters and other entities party to such pipeline balancing arrangements (which may include the Contractor if it has entered into an operational balancing agreement or predetermined allocation). The distribution of breach Royalty Gas causing the imbalance will be accomplished without the necessity of any additional documentation from the Government as the Government is not impacted by such allocations.

If the Government's Lessees (either as Lessees hereunder or as an Operating Rights owner in any oil and natural gas lease in which a third party is participating in the Government's royalty-in-kind pilot project) incur any scheduling or imbalance penalties assessed by Transporter as established by applicable tariffs because of Contractors failure to take Royalty Gas for any oil or gas lease subject to the royalty-in-kind pilot project under the circumstances covered in Section C.5.1, the Government shall hold Contractor responsible for such penalties.

C.5.2. Contractor Liability for Bid Value of Royalty Gas Notwithstanding contract termination pursuant to C.5.1, the Contractor shall be liable for the bid value of 100 percent of the Royalty Gas made available to it by the Government's Lessees including gas made available but not taken by the Contractor. In the event that the Government is able to sell the breach gas to a third party (other than the Lessee) at a price below the Contractor's bid price, the Contractor will be liable for the difference between the price received by the Government and the Contractors bid price. If the Government is unable to sell the breach gas, the Contractor will be liable for the full bid value of the gas.

C.5.3. <u>Breach of Contract by Failure to Pay</u>. Contractor shall be in breach of the contract by failure to pay for any Royalty Gas made available by the Government's Lessees.

C.5.4. <u>Liability for Transporter Penalties</u>. The Contractor shall be liable for any pipeline penalties imposed as a result of the Contractors breach.

C.6. COMMODITY PRICES

C.6.1. For each MMBtu of Gas delivered to Contractor by the Government at the Point(s) of Delivery, Contractor shall pay the Government a Commodity Charge which will be equal to the price which the Contractor, in Section B of this IFB No. 3768, has bid to be paid to the Government for the Royalty Gas purchased subject to the provisions of this IFB No. 3768.

C.6.2. In the event that the Applicable Index ceases to be published by GMR, or the categories change, or the CO determines that GMR has indefinitely suspended reporting the Applicable Index, then the last billing price will remain in effect until the Parties mutually agree on a substitute index or pricing mechanism upon which to base the Commodity Charge. If the Parties are unable to agree upon an alternate index or pricing mechanism, then the matter will be submitted to the dispute resolution procedures of the U.S. Department of the Interior, as authorized in the Administrative Dispute Resolution Act, Public Law No. 101-102, U.S.C. 581-583 and as implemented by U.S. Department of Interior in 59 Federal Register notice 30368, June 13, 1994.

C.7. EVALUATION OF PILOT PROJECT

The Contractor agrees to work in good faith with the Government and with Lessees to evaluate the Royalty-in-Kind Pilot Project, and shall upon request offer suggestions to enable the Government to improve the procedures used therein. This evaluation shall be completed by June 30, 1996.

SECTION D
INSPECTION AND ACCEPTANCE

D.1. GENERAL

Royalty Gas is sold under this IFB in U.S. dollars per MMBtu. The natural gas will be measured by the Transporter in accordance with the Terms and Conditions of the Transporters approved tariff, or in accordance with standard industry practice.

D.2. PRESSURE, MEASUREMENT AND PIPELINE CONDITION

D.2.1. Pressure. Royalty Gas shall be delivered to the Contractor at the Point(s) of Delivery, as listed in the contract, at the pressure maintained in the facilities of the Transporter in accordance with the provisions of the tariff(s) of the Transporter, insofar as such tariff(s) apply at the Point(s) of Delivery. However, in no event shall the Government's Lessees be required to install additional compression equipment over and above what Lessees install for their own gas.

D.2.2. Measurement. For purposes of this Agreement, the unit of measure for all Royalty Gas produced from or attributable to said Leases shall be 1 MMBtu, determined on an unsaturated basis. All measurements of Royalty Gas delivered and sold hereunder shall be in accordance with the provisions of the tariff(s) of the Transporter, insofar as such tariff(s) apply at the Point(s) of Delivery.

D.2.3. Pipeline Condition. The Government's Lessees will make the Royalty Gas available to contractor at the Point(s) of Delivery in condition acceptable for transportation at Point(s) of Delivery. The Government's Lessees will continue to perform, at its own expense, any necessary dehydration, sweetening or compression currently required under the terms of said Leases and required to meet the delivery requirements at the Point(s) of Delivery.

D.2.3. Transporters Meter. Contractor will arrange to have the appropriate measurements taken by Transporter, and to pay Transporter for all necessary transportation services. Contractor will pay the Government for all Royalty Gas received, based on Transporter's physical flow measurement, and will enclose a copy of Transporter's meter-based invoice along with its payment to the Government for Royalty Gas received. At its own expense, Contractor may have a third party gas chart reading service integrate meter charts for natural gas delivered and shall provide chart copies to the Director, MMS.

D.3.3. Operator's Meter. The Government will monitor individual well production to verify royalty gas entitlements. The Government will also determine volumes of Royalty Gas based on the Operator's meter, and will bring any discrepancies to the attention of the Contractor. The Parties will work diligently and reasonably to resolve any such discrepancies

SECTION E
DELIVERY AND TERM OF PERFORMANCE

E.1. CONTRACT TERM

Deliveries will begin January 1, 1995, and end December 31, 1995, subject to the provisions of Section B of this IFB No. 3768. The contract shall remain in force until all final balancing has been concluded, amounts due have been paid, and the Government releases Contractor.

E.2. PRODUCT DELIVERY AND ACCEPTANCE

Subject to the provisions of Sections B and D of this IFB No. 3768, Contractor at its own expense shall make all necessary arrangements to accept delivery, and shall take Royalty Gas at the Point(s) of Delivery, title passing at the inlet flange of the measurement device identified by the FMP number in the B.3 table.

SECTION F
CONTRACT ADMINISTRATION DATA

F.1. PAYMENT AND REPORTING

F.1.1. Responsibilities of Contractor. The following reporting and payment requirements are the monthly responsibility of the Contractor during the term of this Gas Sales and Purchase Contract:

(a) Contractor shall render payment to the Government in accordance with the procedures at F.1.1.(b) for all Royalty Gas made available to it at the Point(s) of Delivery. The Contractor is required to pay to the Government for all Royalty Gas made available to it whether or not it accepts delivery of such gas. The Contractor will calculate the amount due each month based on the contract bid price and the Royalty Gas volumes recorded at the Point of Delivery identified in the B.3. Table.

(b) The Contractor will remit the total amount due to the Government by electronic funds transfer (EFT). Payment must be credited to the Government's account by close of business on the 25th day of the month following the month of delivery. The Contractor must also complete and submit a Form MMS-2014. (See Exhibit D for a sample Form MMS-2014.) Data requirements in the Form 2014 will be limited to information related to Lease designation, quantity of gas taken and the total payment to be submitted. The Government will provide the Contractor Form MMS-2014 reporting instructions; instructions for EFT reporting are at Exhibit A.

In addition, the Government will provide Contractor monthly a Model Form MMS-2014 with recurring data fields completed. The Contractor will be responsible for completing non-recurring data fields for each Lease under this contract. The Government will provide training and be available to answer questions over the telephone for the Contractor in Form MMS-2014 procedures. The Government does not anticipate that the reporting requirement will be an excessive administrative burden on Contractor.

(c) If Contractor has not received Transporters invoice by the 20th day of the month following the month for which payment is due, then Contractor will make payment to the Government based on a diligent and reasonable estimate of Royalty Gas volumes received in the prior month, such as an estimate based on the Operator's records. The Contractor will submit the Form MMS-2014 as required by F.1.1.(b) with the estimated data and will submit an adjusted Form MMS-2014, and payment, if applicable, as soon as it receives the Transporter's invoice. The Government will provide instructions for submitting revised Forms MMS-2014's.

(d) If Contractor fails to remit payment in full to the Government as provided in paragraph (c) by the 25th day of the month, the Government will calculate the interest due and will request a billing action through the Minerals Management Service's Royalty Management Program, with interest based on the underpayment rate established in 30 U.S.C. 1721. In addition, the Government may withhold all or any part of future deliveries of Royalty Gas, and may terminate the contract for default in whole or in part. In any event, if payment from the Contractor is late, Contractor will owe interest from the due date until the date payment is credited to the Government's account. The Government will invoice Contractor for the amount due, and may assess applicable penalties.

F.2. PAYMENT DISPUTES

The Contractor's disagreement with any invoice is a dispute under Section H.5 of this IFB No. 3768. The Government's Contractor must immediately pay the invoiced amount by the bill due date and may submit a claim for alleged overcharges within 30 calendar days of the date of the disputed invoice. Payment claims not filed within 30 days are forever barred.

F.3. SET-OFF

The Government's Contractor shall not reduce payments due hereunder because of any claim against the Government arising outside of this contract.

F.4. GOVERNMENT REPRESENTATIVES

James McNamee is the Contracting Officer's Technical Representative (COTR) and Frank Pausina is the MMS Gulf of Mexico Region representative.

F.5. PURCHASER'S REPRESENTATIVES

Purchasers shall provide the following information:

Bidder's Business Number: Fax Number:
Accounts Payable Rep: Telephone:
Alternate Accounts Payable Rep: Telephone:
Purchasers Field Rep: Telephone:

F.6. RIGHT TO AUDIT

The Government shall have the right to audit contractor's records for the Royalty Gas taken; these audits will be during normal business hours, at reasonable times, to verify the accuracy of any statements related to Royalty Gas and payments required under or pursuant any of the provisions of this Contract. Upon request, the Government and Contractor also shall make available to Lessees for audit purposes any relevant records of the Transporter to which the Government or Contractor has access. The Contractor must maintain and make accessible to the Government all records pertaining to this contract for a period of 1 year following the term of this contract.

SECTION G
SPECIAL PROVISIONS

G.1. DEFINITIONS

(a) Secretary is the Secretary of the United States Department of the Interior or any person, persons, or board (other than the Contracting Officer) authorized to act for the Department or the Secretary.

(b) Contracting Officer (CO) is a person with the authority to enter into, administer, and/or terminate contracts and make related determinations and findings. The term includes the authorized representative of a CO acting within the limits of his or her authority, as delegated by the CO, except as otherwise provided in this contract.

(c) Contracting Officers Technical Representative (COTR) is that person named to administer day-to-day technical contracting matters.

G.2. NOTICES

(a) Any notices shall be in writing, shall include the contract number, and shall be forwarded, prepaid, to the address in (c) below. In addition, notices shall be sent by facsimile transmission immediately to the COTR at the telephone number in G.2.c.2.

(b) Notices to the Contractor shall be to the J.6. address.

(c) Notices to MMS shall be to:

(1) For the CO:

Mr. James E. MacKay, Contracting Officer
U.S. Department of the Interior
Minerals Management Service
381 Elden Street, MS 2500
Herndon, Virginia 22070-4817

(2) For the COTR:

Mr. James McNamee
Contracting Officer's Technical Representative
U.S. Department of the Interior
Minerals Management Service
12600 West Colfax Avenue, Suite B 440
Lakewood, Colorado 80215
PHONE (303) 275-7126
FAX (303) 275-7124

G.3. INDEMNIFICATION

Contractor shall indemnify and save the Government and Lessees harmless from and against any loss, expense, liability, or claim of any kind for damage to property of, or for injury to or death of persons which Contractor, its agents, employees, or personnel intentionally or negligently cause, arising in any way from or connected with performance of this contract.

G.4. GOVERNING LAWS AND REGULATIONS

The sale of MMS natural gas hereunder is governed solely by the Outer Continental Shelf Lands Act (OCSLA) (43 U.S.C. 1331 et seq.) and this IFB. The Federal Acquisition Regulations (FAR), 48 CFR, Ch. 1, Pts. 1-53 do not apply to this sale; however, MMS may use the FAR as guidance in bid solicitation and contract award.

SECTION H
GENERAL PROVISIONS

H.1. WITHHOLDING OF DELIVERIES AND TERMINATION FOR CONTRACTOR DEFAULT

(a) The Contracting Officer may, without liability to the Government, withhold deliveries hereunder if payment is not made in accordance with this contract.

(b) The Contracting Officer, without liability to the Government, may terminate this contract in whole or in part by written notice to the Contractor effective upon such notice being delivered personally to any authorized representative of the Contractor, being deposited in the United States Postal System, or with an overnight delivery service addressed to the Contractor as provided in G.2. in the event:

(1) Contractor breaches any warranty made herein;

(2) Contractor fails to take delivery in accordance with the terms of this contract;

(3) Contractor no longer meets the financial qualifying criteria specified in this IFB No. 3768, as determined by the Government;

(4) There are instituted by or against Contractor proceedings in bankruptcy *or* other insolvency law; or

(5) Contractor fails to comply with any other term or condition of this contract within 48 hours after the Government, through the Contracting Officer or his designee, gives telephonic or other oral notice. The Government will confirm any oral notification in writing.

(c) Notwithstanding other provisions of this Article, Contractor shall not be charged with any liability to the Government under circumstances which prevent Contractors acceptance of delivery hereunder due to causes beyond the control and without the fault or negligence of Contractor, as deemed by the Contracting Officer.

(d) Nothing herein will limit the Government in the enforcement of any legal or equitable remedy which it might otherwise have, and a waiver of any particular cause for termination will not prevent termination for the same cause occurring at any other time or for any other cause.

(e) Upon termination of a contract for Contractor's default, the Contracting Officer may sell or otherwise dispose of the remaining natural gas in an appropriate manner.

H.2. PAYMENTS UPON TERMINATION FOR DEFAULT

If this contract is terminated under H.1., the Contractor shall:

(a) Make final payment under Section F;

(b) Be liable to the Government for other damages including, but not limited to, administrative costs and expenses associated with solicitation and award of a replacement contract; and

(c) Pay all amounts due the Government and private parties under this provision by the bill due date. Disagreements on the amounts due the Government are H.5. disputes.

H.3. TERMINATION FOR CONVENIENCE OF THE GOVERNMENT

Without liability to the Government, the Contracting Officer may terminate this contract in whole or in part for the convenience of the Government. Such provision will not be unreasonably exercised. Effective 10 calendar days after dispatching written termination, unless the Contracting Officer otherwise designates, Contractor shall pay under Section F for natural gas delivered.

H.4. LIMITATION OF THE GOVERNMENT'S LIABILITY

The Government is not liable for nonperformance if due to causes beyond its control and without its fault or negligence, including, but not limited to, the provisions of Section C.5 of this Contract.

H.5. DISPUTES

(a) This contract is subject to the Contract Disputes Act of 1978 (41 U.S.C. §601 et seq., PL 95-563). If a dispute arises, the Contractor may submit a claim to the Contracting Officer who will issue a written decision on the dispute. A "claim" is a written request submitted to the Contracting Officer for payment of money, adjustment of contract terms, or other relief requiring a Contracting Officer's decision.

(b) In the case of disputed requests or any amendments to such requests for payments exceeding $50,000, the Contractor shall certify, at the time of the submission of a claim.

> I certify that the claim is made in good faith, that the supporting data is accurate and complete to the best of my knowledge and belief, and that the amount requested accurately reflects the contract adjustment for which Contractor believes the Government is liable.
>
> Contractors Name:
> Signature of Certifying Official:
> Title:

(c) The Contractor shall pay the Government interest on the amount found due from the date the amount is due until the Contractor makes payment at the underpayment rate in 30 U.S.C. 1721.

(d) The decision of the Contracting Officer will be final and conclusive and not subject to review by any forum, tribunal, or Government agency unless an appeal or action is timely commenced as specified by the Contract Disputes Act of 1978.

(e) Contractor shall comply with any Contracting Officer decision, and at the Contracting Officer's direction will diligently perform under this contract pending final resolution of any claim, appeal, or action related to this contract.

H.6. OFFICIALS NOT TO BENEFIT

No member or delegate to Congress, officers, or employee of the Government will be admitted to any share or part of this contract or to any benefit that may arise herefrom except if made with a corporation for its general benefit.

H.7. ASSIGNMENT

Contractor shall not make or attempt to make any assignment of this contract or any interest herein contrary to the Assignment of Claims Act of 1940, as amended (31 U.S.C. §3727, 41 U.S.C. §15).

H.8. GRATUITIES

(a) the Government may terminate Contractor's contract by written notice if, after notice and hearing, the agency head or designee determines that the Contractor, its agent, or another representative offered or gave a gratuity (e.g., entertainment or gift) to an officer, official, or employee of the Government and intended to obtain a contract or favorable treatment under a contract.

(b) The facts supporting this determination may be reviewed by any court having lawful jurisdiction.

(c) If this contract is terminated under (a) above, the Government is entitled to pursue the same remedies as in a breach of contract.

(d) The rights and remedies of the Government provided in this Article are in addition to any other rights and remedies provided by law or under this contract.

H.9. ORDER OF PRECEDENCE

In the event of an inconsistency in this contract, unless otherwise provided herein, the inconsistency shall be resolved by giving precedence in the following order:

(a) Schedule, Sections A through F;
(b) General Provisions, Section H;
(c) Other provisions of the IFB, Sections G, J, K, and L;
(d) Attachments and Exhibits, Section I; and
(e) Cover Sheet.

H.10. INTEREST

All amounts due and payable, including interest assessed on late payments, must be paid by the bill due date. Amounts not so paid shall bear interest, computed on a daily basis, from the date due (i. e., date of deemed receipt of invoice) until the Government receives payment at the underpayment rate under 30 U.S.C. 1721.

H.11. EXPORT LIMITATIONS AND LICENSING

Contractors are subject to all the limitations and licensing requirements of the Export Administration Act of 1969 (83 Stat. 841) in accordance with 10 U.S.C. §7430(e).

H.12 CONTRACTOR'S RELEASE OF CLAIMS

Contractor hereby releases the Government from all claims arising in connection with this contract, except those claims meeting the requirements of the Contract Disputes Act which the Contracting Officer receives prior to the date upon which final payment is due hereunder. Claims not received before such date are forever barred. Supplemental billings and credits issued after the final invoice will not extend the date for submission of claims beyond the final payment date shown on the final invoice.

SECTION I
LIST OF DOCUMENTS AND ATTACHMENTS

Exhibit A:	**Instructions for Wire Transfer of Funds**
Exhibit B:	**Bidder Qualification Certification**
Exhibit C:	**Sample Royalty-In-Kind Pilot Program Agreement**
Exhibit D:	**Sample of the Form MMS-2014**

SECTION J
REPRESENTATIONS, CERTIFICATIONS, AND ACKNOWLEDGEMENTS

J.1. SMALL BUSINESS CONCERN REPRESENTATION

(a) Representation: The Bidder represents and certifies as part of its offer that it___ is, ___is not a small business concern.

(b) Definition: "Small business concern," as used in this provision, means a concern, including its affiliates, that is independently owned and operated, not dominant in the field of operation in which it is bidding on Government contracts, and qualified as a small business under the criteria and size standards in 13 CFR 121.

J.2. SMALL DISADVANTAGED BUSINESS CONCERN REPRESENTATION

(a) Representation: The Bidder represents that it ___is, ___is not a small disadvantaged business concern.

(b) Definitions:

(1) "Asian-Indian American," as used in this provision, means a United States citizen whose origins are in India, Pakistan, or Bangladesh.

(2) "Asian Pacific Americans," as used in this provision, means a United States citizen whose origins are in Japan, China, the Philippines, Vietnam, Korea, Samoa, Guam, the U.S. Trust Territory of the Pacific Islands (Republic of Palau), the Northern Mariana Islands, Laos, Cambodia, or Taiwan.

(3) "Native Americans," as used in this provision, means American Indians, Eskimos, Aleuts, and native Hawaiians.

(4) "Small Business concern," as used in this provision, means a concern, including its affiliates, that is independently owned and operated, not dominant in the field of operation in which it is bidding on Government contracts, and qualified as a small business under the criteria and size standards in 13 CFR 121.

(5) "Small disadvantaged business concern," as used in this provision, means a small business concern that (a) is at least 51 percent unconditionally owned by one or more individuals who are both socially and economically disadvantaged individuals, and (b) has its management and daily business controlled by one or more such individuals.

(c) Qualified Groups: The Bidder shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian-Pacific Americans, Asian-Indian Americans, and other individuals found to be qualified by the SBA under 13 CFR 124.1.

J.3. WOMEN-OWNED SMALL BUSINESS REPRESENTATION

(a) <u>Representation:</u> The Bidder represents that it ___is, ___is not a woman-owned small business concern.

(b) <u>Definitions:</u>

(1) "Small business concern" means a concern, including its affiliates, that is independently owned and operated, not dominant in the field of operation in which it is bidding *on* Government contracts, and qualified as a small business under the criteria and size standards in 13 CFR 121.

(2) "Women-owned" means a small business that is at least 51 percent owned by a woman or women who are U.S. citizens and who control and operate the business.

J.4. TYPE OF BUSINESS ORGANIZATION

Bidder operates as ___an individual, ___a partnership, ___a nonprofit organization, ___a corporation incorporated under the laws of the State of ________________________________.

J.5. AFFILIATION AND IDENTIFYING DATA

A "parent" company, for the purpose of this bid, is a company which either owns or controls the activities and basic business policies of the Bidder. To own another company means the parent company must own at least a majority (more than 50 percent) of the voting rights in that company. To control another company, such ownership is not required. If another company is able to formulate, determine, or veto basic business policy decisions of the Bidder, such other company is considered the parent company of the Bidder. This control may be exercised through the use of dominant minority voting rights, use of proxy voting, contractual arrangements, or otherwise. Therefore, each Bidder shall complete the following, to the extent applicable:

(a) Bidder ___is ___is not owned or controlled by a parent company.

Bidders owned or controlled by a parent company shall provide the parent Company's name and address in the space below.

Bidder's Name:

Name of Parent Company:

Main Office Address:

(b) Bidder's parent company ___is ___is not owned by a parent company. Bidder's parent company owned or controlled by a parent company shall provide the parent company's name and address in the space below

Name of Parent Company:

Main Office Address:

(c) Bidder ___owns ___does not own or control other companies. Bidders owning or controlling other companies shall provide the names and addresses of the companies it controls below. (Attach additional pages if needed.)

J.6. BIDDER'S DESIGNATED CONTACTS

________________________________ and ________________________________ are authorized to handle all details in connection with this bid and any resulting contracts, and to arrange for all deliveries.

Name:
Title:
Office Address:

Telephone Number:
Fax Number:

Name:
Title:
Office Address:

Telephone Number:
Fax Number:

J.7. CERTIFICATION OF INDEPENDENT PRICE DETERMINATION

(a) By submission of this bid, the Bidder certifies that in connection with this solicitation:

(1) The prices in this bid have been arrived at independently, without consultation, communication, or agreement for the purpose of restriction competition as to any matter relating to such prices with other Bidders or with any competitor;

(2) Unless otherwise required by law, the prices which have been quoted in this bid have not been knowingly disclosed by the Bidder and will not knowingly be disclosed by the Bidder prior to bid opening; and

(3) No attempt has been made or will be made by the Bidder to induce any other person or firm to submit or not to submit a bid for the purpose of restricting competition.

(b) Each person signing this bid certifies that:

(1) The signer is the person in the Bidder's organization responsible within that organization for the decision as to the prices being offered herein and that the signer has not participated, and will <u>not</u> participate, in any action contrary to (a)(1) through (a)(3) above; or

(2) The signer is not the person in the Bidder's organization responsible within that organization for the decision as to the prices being offered herein but that the signer has been authorized in writing to act as agent for the persons responsible for such decision in certifying that such persons have not participated, and will not participate, in any action contrary to (a)(1) through (a)(3) above, and as their agent does hereby so certify that the signer has not participated, and will not participate, in any action contrary to (a)(1) through (a)(3) above.

(c) A bid will not be considered for award where (a)(1), (a)(3), or (b) above has been deleted or modified. Where (a)(2) above has been deleted or modified, the bid will not be considered for award unless the Bidder furnishes with the bid a signed statement which sets forth in detail circumstances of the disclosure and unless it is determined that such disclosure was not made for the purpose of restricting competition.

SECTION K
INSTRUCTIONS TO BIDDERS

K.1. PREPARATION OF BIDS

(a) Bidders must examine the complete IFB package, including the specifications, schedule, special and general provisions, and must comply with all instructions. Failure to do so may result in a non-responsive bid.

(b) Bidders must ensure that bid packages are complete (See Cover Sheet) and that all required supplemental data and the bid guarantee are attached. Failure to submit material information will result in rejection of the bid as nonresponsive. Original signatures and fill-in information must be provided in Sections A, F, and J, and in Exhibit B. Section K requires the submission of the following:

(c) The Bidder must sign and affix its corporate seal to the "Bidder's Signature Page" in Section A. Any erasures or other changes must be initialed by the person signing the bid and bids signed by an agent must be accompanied by evidence of his or her authority. If a corporation has no corporate seal, the words "NO CORPORATE SEAL" must be hand-written in the space reserved for the seal, and the person signing the corporate certification must initial that statement.

K.2. SUBMISSION OF BIDS

(a) Bids submitted to the Government by telegram, mailgram, or telecopier will not be considered.

(b) Bids may be modified or withdrawn by mail, telegram, or mailgram provided the modification or withdrawal is received at the office designated in (c) below prior to the hour and date specified for receipt of bids.

(c) Bids sent by mail or hand-carried bids, including bids delivered by a delivery service, and modifications sent by mail, telegram, or mailgram must be received at the following address no later than the date and time of bid opening, November 21, 1994, 2:00 PM, EST.

U.S. Department of the Interior
Minerals Management Service
Procurement Operations Branch
381 Elden Street, MS 2500
Herndon, Virginia 22070-4817

ATTN: James E. MacKay, Contracting Officer
TELEPHONE: (703) 787-1351
FAX (703) 787-1009

(d) Due to MMS' official days/hours of operation, the Contracting Officer cannot accept mail, telegrams, mailgrams, or hand-carried items on Saturdays, Sundays, or Federal Government holidays, or any time prior to 7:30 a.m. or after 4:00 p.m., local time.

(e) Bidders shall affix an appropriate label (samples below) to the bid envelope. The outside of the envelope shall be plainly marked with the Bidder's full name and return address.

_____(Bidder's Name)______

_____(Return Address)_____

____

TO: U.S. DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
PROCUREMENT OPERATIONS BRANCH
381 ELDEN STREET, MS 2500
HERNDON, VIRGINIA 22070-4817

ATTENTION: JAMES E. MACKAY, CONTRACTING OFFICER

RE: MMS NATURAL GAS IFB 3768

DO NOT OPEN BEFORE 2:00 PM, LOCAL TIME ON:
NOVEMBER 21, 1994

NOTE: The MMS Procurement Office is located in a secure building; therefore if you wish to hand-carry your proposal to this office, please comply with the following:

When you arrive at the Atrium Building located at 381 Elden Street, Herndon, Virginia, park at the rear of the building. Upon entering the rear lobby, you will be facing a bank of elevators with a courtesy telephone to the right of the elevators. Dial extension 1354 and notify the person who answers the telephone that you have a bid to deliver.

K.3. AWARD PROCEDURE

If a bid is successful, the Government will make award by means of an award sheet, signed by the Contracting Officer which identifies the items, quantities, and prices which the Government is accepting. A contract will consist of an "Award Sheet," the "Bidder's Signature Page," "Corporate Certificate," Sections A through J, and the Exhibits of the IFB. Sections K and L are incorporated into the contract by reference.

K.4 LATE BIDS, MODIFICATIONS OF BIDS, AND WITHDRAWAL OF BIDS

(a) Any bid received at the office designated in K.2(c) of the IFB after the exact time specified for receipt will not be considered unless it is received before award is made and it:

(1) Was sent by registered or certified mail not later than the fifth calendar day prior to the date specified for the receipt of bids (e. g., a bid submitted in response to a solicitation requiring receipt of bids by the 20th of the month must have been mailed by the 15th or earlier); or

(2) Was sent by U.S. Postal Service Express Mail Next Day Service-Post Office to Addressee not later than 5:00 p.m. at the place of mailing two (2) working days prior to the date specified for receipt of bids. The term "working days" excludes weekends and Federal holidays.

(b) Any modification or withdrawal of a bid is subject to the same conditions as in (a) above.

(c) The only acceptable evidence to establish the mailing date of a late bid, modification, or withdrawal sent by registered or certified mail is the U.S. or Canadian Postal Service postmark on the envelope or wrapper or the original receipt from the U.S. or Canadian Postal Service. If neither postmark shows a legible date, the bid, modification, or withdrawal shall be deemed to have been mailed late. "Postmark" means a printed, stamped, or otherwise placed impression, exclusive of a postage meter impression, that is readily identifiable without further action as having been supplied and affixed on the date of mailing by employees of the U.S. or Canadian Postal Service. Therefore, Bidders should request the postal clerk to place a hand cancellation bull's-eye postmark on both the receipt and the envelope or wrapper.

(d) The only acceptable evidence to establish the time of receipt at the Government installation for a bid, modification to a bid, or a bid guarantee, in the form of an LOC submitted by a bank, is the time/date stamp provided by the Contracting Officer at the address specified in K.2(c).

(e) The only acceptable evidence to establish the date of mailing of a late bid, modification, or withdrawal sent by U.S. Postal Service Express Mail Next Day Service-Post Office to Addressee is the date entered by the post office clerk on the "Express Mail Next Day Service-Post Office to Addressee" label and the postmark on the envelope or wrapper and on the original receipt from the U.S. Postal Service. "Postmark" has the same meaning as in paragraph (c) above.

(f) A bid may be withdrawn in person by a Bidder or its authorized representative if, before the exact time set for receipt of bids, the identity of the person requesting withdrawal is established and that person signs a receipt for the bid.

K.5. ACKNOWLEDGEMENT OF AMENDMENTS TO SOLICITATIONS

Bidders must acknowledge receipt of any amendment to this IFB by (a) signing and returning the amendment, or by (b) letter, mailgram, or telegram to the address for mailed bids specified in K.2(c). The Government must receive the acknowledgement by the time and at the place specified for receipt of bids.

K.6. JOINT BIDDING

No joint bidding of any type will be accepted.

K.7. BID GUARANTEE

(1) As a bid guarantee, each Bidder must submit a $2,500 certified or cashier’s check or an Irrevocable Standby Letter of credit (LOC), payable to the U.S. Department of the

Interior, Minerals Management Service, with its bid. Bid guarantees must be issued by a depository institution located and authorized to do business and to issue such checks or LOC's by United States, State, or District of Columbia law. LOC's must be in effect for 35 days after the bid submission date, and will be returned to Bidder upon request. Checks will be returned to all Bidders not awarded a contract within 35 days after the bid opening date, and to all Bidders awarded a contract upon receipt of a satisfactory performance guarantee. If Bidder's bank is to send the LOC directly to MMS, the Contracting Officer must receive the original of the LOC before bid opening. The forwarding bank must provide the following information on the face of the LOC's forwarding envelope:

Bidder's Business Name:
Return Address:

To: U.S. Department of the Interior
Minerals Management Service
Procurement Operations Branch
381 Elden Street, MS 2500
Herndon, Virginia 22070-4817

ATTN: Contracting Officer
RE: Natural Gas Sale - IFB No. 3768

(2) Bid guarantees are forfeited if Bidder withdraws its bid within 35 days of bid opening. Forfeiture will not preclude the United States' recovering damages over the bid guarantee amount due to Bidder's failure to keep its bid open for 35 days.

K.8. FAILURE TO SUBMIT A BID

If no bid is submitted, do not return the IFB.

K.9. CLARIFICATIONS OF IFB TERMS

Any prospective Bidder must request explanations or clarification of the IFB, specifications, etc., in writing soon enough to allow a reply to reach all prospective Bidders before bid submission. Oral explanation or instructions given before contract award are not binding on MMS. MMS will provide such information as an amendment to the IFB if that information is necessary in submitting bids, or if its lack disadvantages prospective Bidders.

K.10. FINANCIAL STATEMENT

(a) With its bid, each Bidder shall submit its latest published financial statement showing its financial condition and profit and loss statement for the period covered thereby. Bidder's principal accounting officer must certify no material changes in the Bidder's financial condition since the date of the statement, and that it presents the true financial condition as of the date of the bid. If changed, then Bidder must explain its amount and nature.

(b) If Bidder does not submit financial information adequate for the Contracting Officer to determine if it is financially responsible, the Contracting Officer may reject its bid as nonresponsive.

K.11. PROPRIETARY AND CONFIDENTIAL DATA

If Bidder submits any proprietary information, it must so mark that information and explain its proprietary nature. All applicable Department of Interior regulations governing proprietary data shall apply.

K.12. ACCEPTANCE PERIOD

Bids will remain valid for 35 days after the bid opening date.

SECTION L
EVALUATION PROCEDURES FOR AWARD

L.1. METHOD OF AWARD

(a) The Contracting Officer is the sole judge as to whether the bids conform to this IFB, and as to the qualifications of the Bidders. The Contracting Officer will award contracts for each line item or combination of line items to the highest responsive, responsible Bidder meeting the certification criterion specified in Exhibit B.

(b) The Government reserves the right to reject any or all bids and to waive minor informalities and irregularities, and to reject any bid offering prices which the Contracting Officer, in his or her sole discretion, determines to be below fair market value, and/or not in the best interests of the Government.

L.2. BID EVALUATION PROCEDURES

(a) Bidders may submit bids in accordance with Section B of this IFB No. 3768.

(b) Tie bids will be broken by drawing lots.

EXHIBIT A
INSTRUCTIONS FOR WIRE TRANSFER OF FUNDS

Contractor must pay by wire transfer over the Fedwire Deposit System Network (FDS). Contractor will provide the information in items 5, 7, 8, 9, and 10 to the sending bank and the sending bank will provide the information in items 2, 3, and 4. All items MUST appear on all transfers as they appear below:

Item 1 Receiver Depository Financial Institution (DFI) Number: 021030004.
Item 2 Type Code: Sending bank will provide.
Item 3 Sending Bank DFI: Sending bank will provide this nine digit number.
Item 4 Sender Reference Number: Sixteen character number provided by the sending bank at its option.
Item 5 Amount: Depositor will provide the amount, which will include the dollar sign and the appropriate punctuation, including commas and decimal points.
Item 6 Sending Bank Name: Automatically inserted by the Federal Reserve Bank.
Item 7 Receiver DFI Name: "TREAS NYC/" entered by the sending bank.
Item 8 Product Code: "CTR/" entered by the sending bank.
Item 9 Agency Location Code: BNF=\AC-14170001
Item 10 Third Party Information: "OBI= "; enter payor code and numbers of invoices/Forms MMS-2014 paid by this funds transfer.

Questions should be referred to Chief, General Ledger, at 303-231-3574.

EXHIBIT B

BIDDER QUALIFICATION CERTIFICATION

All Bidders must complete the following certification:

I, ______________________________ (please print), certify that I am the ______________________________ of the Bidder named below, and that Bidder's total revenue derived from the marketing of natural gas to non-affiliated entities, has not been less than the sum of $20,000,000 (U.S. dollars) during any calendar year from 1990 through 1994, inclusively or alternatively, that I was principally responsible for marketing not less than the sum of $20,000,000 (U.S. dollars) of natural gas during any calendar year from 1990 through 1994 and that Bidder's total revenues derived from the marketing of natural gas to non-affiliated entities, has not been less than the sum of $20,000,000 (U.S. dollars) during any calendar year from 1992 through 1994, inclusively.

BIDDER'S BUSINESS NAME:

ADDRESS:

AUTHORIZED SIGNATURE: ______________________________

TYPED NAME AND TITLE:

DATE:

EXHIBIT C

SAMPLE ROYALTY-IN-KIND PILOT PROGRAM AGREEMENT

THIS AGREEMENT is made effective as of January 1, 1995, between the MINERALS MANAGEMENT SERVICE, United States Department of the Interior, hereinafter called "Lessor", and ____ , hereinafter called "Lessee".

RECITALS

A. Lessee is an operating rights owner of certain Oil and Gas Leases the Lessor issued, as reflected on _______________. Lessee acknowledges that operating ownership reflected on ___________________ is accurate as of the effective date of this Agreement. Said leases are incorporated in this Agreement for all purposes by reference, and are hereinafter called "said Leases" whether one or more.

B. Pursuant to the Outer Continental Shelf Lands Act (OCSLA), 43 U.S.C. § 1331 et seq., Lessor has the right to take in kind and separately dispose of its royalty interest in the gas produced from said Leases (the "Royalty Gas").

C. Lessor may contract with a marketer or purchaser to receive delivery of the Royalty Gas on behalf of Lessor.

D. The parties hereto desire to establish the terms and conditions under which Lessor shall take in kind and Lessee shall make available the Royalty Gas.

AGREEMENT

For and in consideration of the premises and the mutual benefits and advantages accruing to the parties, Lessor and Lessee hereby agree as follows:

7. APPLICABILITY

This Agreement applies only to Royalty Gas made available to Lessor by Lessee by virtue of Lessee's ownership of Operating Rights in said Leases on the effective date of this Agreement. If during the term of this Agreement, Lessee acquires additional Operating Rights or assigns Operating Rights, such ownership changes will be managed in accordance with Section 13 of this Agreement.

2. DEFINITIONS

Terms used in this Agreement shall have the meanings given them in this Agreement.

3. COVENANTS OF SUPPLY AND TAKES

3.1. Lessor

Lessor agrees to take in kind 100 percent of the Royalty Gas made available to Lessor by Lessee at the Point(s) of Delivery identified in Exhibit "B" attached hereto and made part hereof. The taking of Royalty Gas shall be in accordance with the terms and conditions of this Agreement.

3.2. Lessee

Lessee agrees to make the Royalty Gas available to Lessor at the Point(s) of Delivery in accordance with the terms and conditions of this Agreement. Lessee will make the Royalty Gas available to Lessor at the Point(s) of Delivery in condition acceptable for transportation at such Point(s) of Delivery, and will continue to perform at its own expense any necessary dehydration, sweetening or compression currently required under the terms of said Leases to meet the delivery requirements at the Point(s) of Delivery.

3.3. Fulfillment Of Royalty Obligation

Lessor and Lessee agree that Lessee's actions to make Royalty Gas available to Lessor at the Point(s) of Delivery in accordance with the terms and conditions of this Agreement shall satisfy in full Lessee's gas royalty obligation to Lessor under said Leases with respect to the quantity of production for which the Royalty Gas represents the royalty share. However, delivery of Royalty Gas under this Agreement does not alter:

3.3.1 <u>Contract Settlement Proceeds</u>

The obligations, if any, that Lessee has to pay Lessor on proceeds from gas contract settlements with third parties (relating to production occurring prior to the effective date of this Agreement) and attributable to production from said Leases during the term of this Agreement;

3.3.2 <u>Gas Avoidably Lost</u>

The rights, duties, and/or obligations that currently exist between the parties with respect to the royalty obligation of Lessee under said Leases for gas avoidably lost prior to the Point(s) of Delivery pursuant to 30 CFR Part 202.150.

4. LESSEE'S NOTIFICATION OF ROYALTY GAS AVAILABILITY

4.1. Estimated Gas Available

No later than eight (8) working days before the first day of the applicable month of delivery or the twentieth (20th) day of the calendar month before the first day of the applicable month of delivery, whichever is earlier, Lessee shall communicate by facsimile transmission to Lessor and Lessor's Agent, Lessee's good faith estimate of the daily quantity of Royalty Gas, stated in MMBtu's, that Lessee expects to be available for delivery from or attributable to said Leases during such month. The parties understand and agree that Lessee's estimates of deliverability from said Leases are not a warranty of deliverable quantities, but are given to facilitate planning for necessary transportation and marketing of the Royalty Gas.

4.2. Changes in Availability

Lessee agrees to use reasonable efforts, customary in the industry, to communicate by facsimile transmission to Lessor and Lessor's Agent circumstances beyond routine production fluctuations that affect gas deliverability from said Leases, so that Lessor or Lessor’s Agent may adjust its transportation and marketing arrangements on a continuous basis in order to take the full quantity of Royalty Gas available each day. Lessee shall issue such communication to Lessor and to Lessor’s Agent as soon as practicable.

4.3. Acknowledgement from Lessor’s Agent

No later than twenty-four (24) hours, excluding weekends and holidays, prior to Transporters first-of-the-month nomination deadline, Lessor or Lessor's Agent shall confirm by facsimile transmission to Lessee the daily quantity of Royalty Gas, stated in MMBtu’s, that Lessor or Lessor's Agent must take from Lessee during the upcoming month. Lessor or Lessor's Agent shall communicate changes in nominations as related to any changes made by Lessee by facsimile transmission to Lessee in the same manner throughout each month of delivery, and with adequate notice to allow confirmation of nomination changes before applicable deadlines. Lessee shall work in good faith with Lessor, Lessor's Agent and Transporter to arrange for delivery of 100 percent of the quantities of Royalty Gas made available at the Point(s) of Delivery.

5. IMBALANCES

5.1. Lessor's or Lessor’s Agent Obligation to Take or Nominate

Notwithstanding Lessee’s maintenance of a balancing account, the parties understand and agree that this agreement does not permit Lessor or Lessor's Agent to delay timely takes of 100 percent of the Royalty Gas delivered by Lessee. Lessor or Lessor’s Agent shall use reasonable efforts in accord with industry standards to avail itself of any third-party agreements available to it with the Transporter to minimize the incurrence of any imbalance with the Lessee. Such agreements may include, for example, operational balancing agreement or predetermined allocations.

5.2. Conditions Warranting Balancing

The balancing mechanism described in this Section 5 is designed to correct only those imbalances resulting from the following:

5.2.1 Differences between Lessor's monthly Royalty Gas entitlements and allocated volumes

5.2.2 Typical scheduling imprecisions that result in differences between Transporter's receipts and Lessee’s deliveries.

5.2.3 Failure by Lessor's Agent during any given month to nominate all quantities made available by Lessee, not to exceed three consecutive days.

5.2.4 Operational changes that can occur between the Transporters first-of-the-month nomination deadline and the first day of a calendar month.

This balancing arrangement does not include Royalty Gas subject to Section 6.2 and does not relieve the Lessor or Lessor's Agent of its responsibility to take 100 percent of Lessor's Royalty Gas, whether the actual amount thereof is more or less than Lessee's previous estimate.

5.3. Managing Imbalances during Term

For any Imbalance occurring under Section 5.2, during any calendar month, the Lessee shall work with Lessor or Lessor's Agent to arrange for increased or decreased deliveries of Royalty Gas in the subsequent month or months, in order to eliminate such imbalance as soon as is reasonably practicable. Such differences shall be maintained by Lessee in a Royalty Gas Imbalance Account as described in Section 5.4.

5.4. Royalty Gas Imbalance Account

Lessee shall maintain a Royalty Gas Imbalance Account which shall include: (1) actual Royalty Gas quantities produced from or attributable to said Leases, (2) actual takes of Royalty Gas by Lessor or Lessor's Agent, and (3) the overtakes or undertakes of Royalty Gas by Lessor or Lessor's Agent. The Royalty Gas Imbalance Account report will be submitted to Lessor and Lessor's Agent no later than forty-five (45) days following the month of production. If adjustments or corrections of actual quantities delivered have not been received by such date, Lessee shall file an estimated Royalty Gas Imbalance Account report for the applicable month, and shall issue a corrected Royalty Gas Imbalance Account report promptly after all such adjustments or corrections are received.

5.5. Final Balancing

After the term of this Agreement, any imbalance which may exist, either in the Royalty Gas Imbalance Account or by virtue of any subsequent Transporter adjustments, shall be communicated to the Lessor and Lessor's Agent within thirty (30) days after the term, or within fifteen (15) days after Lessee comes into possession of all necessary information for the last delivery month, whichever is later. The parties shall settle such imbalance as follows:

5.5.1 <u>Lessee Owes Gas to Lessor</u>

Lessee, at its sole option, may settle the imbalance in either of the following ways. Lessee shall notify Lessor of its election as to method of settlement within fifteen (15) days after Lessee issues the final Royalty Gas Imbalance Account.

5.5.1.1 <u>Settlement in Cash</u>

Lessee may pay Lessor the value of the final imbalance quantity, based on the Lessor's Agent's bid price per MMBtu at each Point(s) of Delivery at the time said imbalance was accrued.

5.5.1.2 <u>Settlement in Gas</u>

Lessee may settle the imbalance by making available gas from or attributable to said Leases at the Point(s) of Delivery. If Lessee elects to settle in gas, and if gas production is no longer available from said Leases at the Point(s) of Delivery, or if gas

production is not of sufficient quantity to allow recovery of the imbalance within 30 days, then to settle such imbalance, Lessee shall make available equivalent quantities of gas, of similar quality and equivalent value, at agreed-upon alternative Point(s) of Delivery as soon as practically possible.

In either event, Lessee shall submit a settlement in cash to Lessor within 30 days following its election under 5.5.1.1 and not owe Lessor late payment interest because of this settlement obligation, nor will Lessee be required to file lease-specific or point-of-delivery-specific MMS Forms 2014. An MMS Form 2014 will be required to be filed by Lessee only indicating the total quantity delivered to settle such imbalance with Lessor.

5.5.2 Lessor Owes Gas to Lessee

Pursuant to Section 10 of OCSLA (43 USC §1339), the Lessee shall request a refund or credit from the Lessor equal to the value of the final imbalance quantity based on the Lessor's Agent's bid price per MMBtu at the time said imbalance was accrued. Once receiving such refund request, Lessor agrees to submit to Congress valid requests within thirty (30) days from receipt, and to issue such refund or authorize a credit to Lessee thirty (30) days after receiving Congressional approval, without offsetting such refund or credit against any other obligation due from Lessee other than any outstanding obligations under this Agreement.

6. FAILURE TO TAKE GAS BY LESSOR'S AGENT (BREACH)

6.1. Transporter Balancing Mechanisms

Where available, and where doing so would not be impracticable or disadvantageous in Lessor or Lessor's Agent reasonable opinion, Lessor or Lessor's Agent shall enter into agreements with Transporter, such as operational balancing agreements and predetermined allocations, which agreements have the effect of reducing scheduling and delivery imbalances with Transporter, and which therefore assist in mitigating possible allocation of Royalty Gas to Lessee or other Operating Rights owners.

6.2. Breach of Lessor's Agent's Contract with Lessor

6.2.1 Breach Defined

If, for reasons other than a Force Majeure occurrence or those occurrences described in Section 5.2 subject to the Royalty Gas Imbalance Account, Lessor's Agent does not satisfy its contractual obligations to Lessor by failing to take in kind Lessor's entire share of Royalty Gas made available during any month, the Lessee will have fulfilled its royalty obligations to the Lessor since the Lessee shall have made available to Lessor or Lessor's Agent the Royalty Gas under said Leases. Circumstances constituting a breach of contract with Lessor by Lessor's Agent include, but are not limited to:

6.2.1.1 During any month, Lessor's Agent fails to provide nominations in excess of three consecutive days in response to Royalty Gas made available by Lessee.

6.2.1.2 Lessor's Agent fails to take Royalty Gas made available by Lessee in excess of three consecutive days due to a curtailment of interruptible transportation by

Transporter, or a curtailment of firm transportation by Transporter if such curtailment is not the result of a Force Majeure condition.

6.2.2 Gas Disposition

The disposition of any quantities of Royalty Gas, delivered by Lessee but not taken by Lessor's Agent which is considered a breach of Lessor's Agent's contract with Lessor, shall be accomplished in accordance with Transporter's applicable tariff provisions and/or existing balancing agreements among Transporters and other entities party to such pipeline balancing arrangements (which may include Lessor's Agent if it has entered into an operational balancing agreement or predetermined allocation). The distribution of breach Royalty Gas causing the imbalance will be accomplished without the necessity of any additional documentation from the Lessor as the Lessor is not impacted by such allocations.

6.2.3 Penalties Resulting from Breach

If Lessee (either as Lessee hereunder or as an Operating Rights owner in any oil and gas lease in which a third party is participating in Lessor's royalty-in-kind pilot project) incurs any scheduling or imbalancing penalties assessed by Transporter as established by applicable tariffs because of Lessor's Agent's failure to take Royalty Gas for any oil or gas lease subject to the royalty-in-kind pilot project under the circumstances covered by this Section 6.2, the Lessor will hold Lessor's Agent responsible for such penalties by contract. However, the Lessor acknowledges that it is liable for such penalties, subject to the availability of a general appropriation to the Minerals Management Service at the time such penalties are assessed. If such an appropriation is not available, then Lessor agrees to attempt in good faith to secure such appropriation.

6.2.4 Bankruptcy of Lessor's Agent

If Lessor's Agent becomes insolvent or bankrupt and is unable to compensate Lessor for losses incurred by Lessor by Lessor's Agent's breach as described in this Section 6.2, then Lessor shall request and Lessee shall remit payment to Lessor for gas made available by and allocated to Lessee but not received by Lessor's Agent. Only under the circumstances set forth in this Section 6.2.4, Lessee shall pay Lessor for such gas at the price per MMBtu (unsaturated) published in *Inside F.E.R.C.'s Gas Market Report* for the first-of-the-month price for the applicable pipeline at the Point(s) of Delivery, less any transportation costs incurred in moving gas to the applicable pricing point listed in noted publication. If there is more than one pipeline connection at the point(s) of delivery, then Lessee shall pay Lessor for such gas at the arithmetic average at the price per MMBTU (unsaturated) published in Inside F.E.R.C. for the first-of-the-month price for the applicable pipelines less any transportation costs incurred in moving gas to the applicable pricing points listed in the noted publication.

6.3. Transportation Imbalances

Except where through gross negligence or willful misconduct Lessee fails to perform the duties described in Sections 4.1, 4.2, and 4.3, Lessor or Lessor's Agent shall bear and pay any scheduling or imbalance penalties imposed by Transporter, including without limitation purchases or sales of imbalance quantities of gas at unfavorable prices. Lessee shall pay such penalties where its gross negligence or willful misconduct results in the incurrence of the same, as set forth in the preceding sentence. Nothing in this paragraph, however, shall

prevent Lessor from seeking indemnification from Lessor's Agent for Lessor's liability. If any costs or penalties associated with the transportation of gas are anticipated, when the Lessee or Lessor's Agent becomes aware that such costs or penalties may be assessed or incurred shall inform the other as soon as the Lessee or Lessor's Agent becomes aware, followed by notice in writing. The Lessee and the Lessor's Agent shall then immediately cooperate in good faith with the other party to minimize or eliminate, if possible, such costs or penalties. The parties shall cooperate with each other and with the Transporter to verify delivery and receipt of monthly nominated quantities on a timely basis.

7. REPORTING

During the term of this Agreement, Lessee shall continue to provide all production-related reports required under said Leases, but shall be relieved of the obligation of providing any and all royalty-related reports required pursuant to 30 CFR §210.10 as it applies to gas production from said Leases. Lessor shall conduct manual reconciliation of its AFS and PAAS systems in light of this Agreement. However, as to adjustments affecting gas production from or attributable to said Leases prior to the effective date hereof, Lessee shall file all such reports irrespective of this paragraph.

8. TITLE, RISK OF LOSS AND LIABILITY

8.1. Title And Control

Title to the Royalty Gas delivered hereunder shall pass to and vest in Lessor at the inlet flange of the Point(s) of Delivery. Lessee shall be deemed to be in exclusive control and possession of said Royalty Gas prior to the time of delivery to Lessor at the Point(s) of Delivery through the meter(s), and Lessor shall be deemed to be in exclusive control and possession of said Royalty Gas thereafter.

8.2. Liability

The party deemed to be in control and possession of the Royalty Gas shall be responsible for and shall indemnify, defend and hold the other party harmless with respect to any losses, claims, liabilities or damages arising therefrom when such Royalty Gas is deemed to be in that party's control and possession.

8.3. No Special Damages

Neither party shall be liable in any event for consequential, incidental, special or punitive damages or losses which may be suffered by the other as a result of the failure to make available or take the Royalty Gas hereunder.

8.4. No Third Party Beneficiaries

It is specifically agreed that there are no third party beneficiaries to this Agreement, and that this Agreement shall not impart any rights enforceable by any person, firm, organizatlon, or corporation not a party hereto.

9. PRESSURE AND MEASUREMENT

9.1. Pressure

All Royalty Gas shall be delivered to Lessor at the Point(s) of Delivery, as listed in at the pressure maintained in the facilities of the Transporter in accordance with the provisions of the tariff(s) of the Transporter, insofar as such tariff(s) apply at the Point(s) of Delivery.

9.2. Measurement

For purposes of this Agreement, the unit of measure for all Royalty Gas produced from or attributable to said Leases shall be 1 MMBtu, determined on an unsaturated basis. All measurements of Royalty Gas delivered and sold hereunder shall be in accordance with the provisions of the tariff(s) of the Transporter, insofar as such tariff(s) apply at the Point(s) of Delivery.

10. RIGHT TO AUDIT

Lessor shall have the right to audit Lessee’s records for said leases during normal business hours, at reasonable times, to verify the accuracy of any statements or charges made under or pursuant to any of the provisions of this Agreement. Upon request, Lessor and Lessor’s Agent shall also make available to Lessee for audit purposes any relevant records of the Transporter to which Lessor or Lessor's Agent has access. This Agreement neither increases or reduces Lessee’s obligations to furnish records or other information to Lessor in accordance with said Leases, the Federal Oil and Gas Royalty Management Act of 1982 (30 U.S.C. 1701 et seq.), and with any other applicable laws, rules, regulations or orders of any governmental authority having jurisdiction.

11. FORCE MAJEURE

If either the Lessee or the Lessor is rendered unable, wholly or in part, by Force Majeure to carry out its obligations under this Agreement, other than to make payments owed to the other party, then upon such party’s giving notice and full particulars of such Force Majeure in writing to the other party as soon as practicable after the occurrence of the case relied on, the obligations of the party giving such notice, so far as they are affected by such Force Majeure, shall be suspended during the continuance of any inability so caused but for no longer period, and such cause shall as far as possible be remedied with all reasonable dispatch.

12. TERM

This Agreement shall be effective for production months as of January 1, 1995, through December 31, 1995; however, this Agreement may terminate earlier under the following circumstances:

12.1 Termination of said Leases, in which case this Agreement shall terminate at the same time as the last of said Leases to terminate; or

12.2 Termination by Lessor of the entire royalty-in-kind pilot project, in which case this Agreement shall terminate on a date sixty (60) days after Lessee’s receipt of written notice from Lessor of the termination of said pilot project.

Notwithstanding the foregoing, the terms and provisions of this Agreement shall apply to all Royalty Gas made available and/or taken hereunder until settlement of final imbalances of such Royalty Gas pursuant to Section 5.5.

13. ASSIGNABILITY

If Lessee assigns all or a portion of said Leases, this Agreement shall apply to the assigned portion thereof. If Lessee obtains additional interest in said Leases, such additional interest will be subject to this Agreement only if the parties mutually agree in witing.

14. NOTICES

Any notice, direction, request, statement or other communication provided for in this Agreement (including notifying Lessee of Lessor's Agent), or any notice which either party may desire to give the other, shall be in writing (including first class, postage prepaid mail, overnight express mail or courier, telegram, telex or facsimile) and shall be considered as duly given when delivered to and received by the other party at the following addresses:

LESSOR
Minerals Management Service
P. O. Box 25165, M.S. 9130
Denver, Colorado 80225
Attn: Mr. James A. McNamee
Fax: (303) 275-7124
Telephone: (303) 275-7126

LESSEE
Notices and Correspondence:

Attention:
Fax:
Telephone:

Statements and Invoices:

Attention:

15. MISCELLANEOUS

15.1. Amendments

This Agreement may be amended at any time and from time to time, but any amendment must be in writing and signed by the parties hereto before such amendment shall be given effect.

15.2. Binding Effect

Each party represents to the other that it has read this Agreement, that it has joined in the drafting thereof, that no oral representations or promises have been made to it as an inducement of executing said Agreement, that the sole and only consideration expected by it or promised to it is found expressed within this Agreement, and that all parties hereto are bound only in the manner and to the extent herein stipulated. This Agreement and the covenants, obligations, undertakings, rights and benefits hereunder shall be binding on and inure to the benefit of the respective successors and assigns of the parties hereto, except to the extent of any contrary provision in this Agreement.

15.3. Entirety

This Agreement contains the entire agreement between Lessor and Lessee relating to the rights granted and obligations assumed in this Agreement. Any oral representations or modifications concerning this Agreement shall be of no force or effect unless and until executed in accordance with Section 15.1.

15.4. Laws And Regulations

This Agreement is subject to all present and future valid orders, roles and regulations of any regulatory body having jurisdiction and to the laws of the United States or any State having jurisdiction. This Agreement shall be deemed modified to the extent necessary to comply with such order, rule, regulation or law for such time as the order, rule, regulation or law is in effect.

15.5. Captions Or Headings

The headings appearing at the beginning of each Section of this Agreement and at the beginning of various paragraphs and subparagraphs hereof are all inserted and included solely for convenience and shall not be considered or given any effect in construing this Agreement.

15.6. Conflicts Between Agreement And Leases

In the event of a conflict between this Agreement and the Leases, the terms and provisions of the Leases shall control.

16. EVALUATION OF PILOT PROJECT

Lessee agrees to work in good faith with Lessor and Lessor's Agent to evaluate Lessor's royalty-in-kind pilot project, and shall upon request offer suggestions to enable Lessor's improvement of the procedures used therein. Lessee will provide to Lessor (not Lessor's Agent) raw data sufficient to calculate the value of production sold by the Lessee from said Leases for the sole purpose of evaluating the royalty revenue neutrality of this pilot. The data requirements will be agreed to by Lessor and Lessee prior to the commencement of the pilot, and all data will be treated as confidential. This evaluation shall be completed by June 30, 1996.

IN WITNESS WHEREOF, this Agreement is executed by the parties as of the effective date first above written.

Dated the 17th day of October, 1994.

LESSOR: MINERALS MANAGEMENT SERVICE, UNITED STATES OF AMERICA DEAPARTMENT OF THE INTERIOR	LESSEE:
By	By
Title: Acting Director	Title:

Form MMS-2014 Revised 5/94

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service - Royalty Management Program

REPORT OF SALES AND ROYALTY REMITTANCE

REPORT MO./YR. ______

1 PAYOR'S NAME ______

ADDRESS ______

CITY/STATE ______

2 PAYOR CODE ______

3 FEDERAL ☐ OR INDIAN ☐

3a PAYOR-ASSIGNED DOCUMENT NUMBER ______

4	5 RESERVED FOR PREPARER'S USE	6 ACCOUNTING IDENTIFICATION (AID) NUMBER	7 PRODUCT CODE	8 RID PRICE CODE	9 SELLING ARR CODE	10 SALES MONTH YEAR	11 TRANS CODE	12 ADJ REAS CODE	13 SALES QUANTITY	14 QUALITY MEASURE-MENT	15 CALC METH	16 SALES VALUE	17 ROYALTY QUANTITY
1													
2													
3													
4													
5													
6													
7													
8													
9													
10													
11													
12													
13													

REPORT CONTROL BLOCK

	Payment	(Method Code)	Amount
22	Checks to MMS	(01)	
23	Payments to Others	(02)	
24	EFT to MMS	(03)	
25	Royalty-In-Kind	(04)	
26	Checks to MMS for BIA	(05)	
27	EFT to BIA	(06)	
28	Payments to Lockboxes	(07)	
29	TOTAL OF ITEMS 22-28		

WARNING: This is to inform you that failure to report accurately and timely in accordance with the statutes, regulations, or terms of the lease, permit, or contract may result in late payment charges, civil penalties, or liquidated damages being assessed without further notification. Intentional false or inaccurate reporting is subject to criminal prosecution in accordance with applicable Federal law(s).

20 PAGE T

21 REPORT

The Paperwork Reduction Act of 1980 (44 U.S.C. 3501 et seq.) requires us to inform you that this information is being collected to document details of royalty payments on sales of minerals from leases on Federal and Indian lands. MMS will use this information to maintain and audit lease accounts.

PROPRIETARY-FOR U.S. GOVERNMENT USE ONLY

I have read and examined the statements in this report and agree they are accurate and complete.

30 ______
Name (typed or printed) and authorized signature

31 ______
Name of preparer

INSTRUCTIONS

REPORT OF SALES AND ROYALTY REMITTANCE

(Form MMS-2014 Revised 3/91)

Please refer to the Payor Handbook for detailed instructions and for the codes you will use to complete some of the items, or contact the Minerals Management Service (MMS) for further information.

REPORT MO. / YR. - Enter the month and year you prepare the report (for example [0|4|9|2]).

1. PAYOR'S NAME AND ADDRESS - Enter the name and address of the company or person remitting the payment.
2. PAYOR CODE - Enter the 5-digit code number assigned to the Payor (Item 1) by MMS. Contact MMS if you do not know your Payor Code.
3. FEDERAL or INDIAN - Check one of the boxes to indicate whether you are reporting Federal or Indian royalty. If you need to report both, use separate forms and make separate payments.

3A. PAYOR-ASSIGNED DOCUMENT NUMBER (PADN) - This number must be entered in block 3A and on the check or contained in the electronic funds transfer transmittal message. The PADN may consist of any combination of alphanumeric characters selected by the payor limited to six characters. This number must be unique, and used only one time for any royalty report(s) and payment(s) combination.

4. LINE number - Use separate lines to report the royalty remittance for each different product, price code, selling arrangement, etc. for each Accounting Identification (AID) number. Also use separate lines to report different transactions or adjustments, rental or minimum royalty payments, etc., or to report royalty taken in kind.
5. RESERVED FOR PREPARER'S USE - Use this space, if you wish, for your own identification of a line item.
6. ACCOUNTING IDENTIFICATION (AID) NUMBER - Enter the 13-digit AID code number assigned by MMS for a lease or property. For unit or communitization agreement sales, royalty payments must be allocated to an AID number. Contact MMS if you do not have an AID number for the lease transactions you are reporting.
7. PRODUCT CODE - Enter the appropriate code from the list in the Payor Handbook.
8. REGULATED PRICE CODE - Not used.
9. SELLING ARRANGEMENT CODE - Enter the code provided by MMS in your Payor's Confirmation Report. Contact MMS if you do not have a Selling Arrangement Code for the transaction you are reporting.
10. SALES MONTH/YEAR - Enter the month and year the sales were made.
11. TRANSACTION CODE - Enter the appropriate code from the Payor Handbook for the line item.
12. ADJUSTMENT REASON CODE - Enter the appropriate code from the Payor Handbook to identify an adjustment to a previous report and the reason for the adjustment.
13. SALES QUANTITY - Enter the amount of the product sold or removed using the appropriate units for product code used in Item 7. For example, barrels for oil, MCF's for gas, or gallons for plant products.
14. QUALITY MEASUREMENT - Enter average Btu's per Mcf for gas or average gravity per barrel for oil or plant products. This column is left blank for alphabetical product codes.
15. CALCULATION METHOD - This code, listed in the Oil and Gas Payor Handbook, describes the method used to calculate royalty due for gas product codes 03, 04, 07 and 12. For all other product codes this column is left blank.
16. SALES VALUE - Enter the total value of the Sales Quantity (Item 13) from which the royalty will be computed. For leases with other than ad valorem royalty rates, this column is left blank.
17. ROYALTY QUANTITY - Multiply the Sales Quantity (Item 13) by the royalty rate stated in your lease using the same units as stated in Item 13. For leases with other than ad valorem royalty rates, this column is left blank.
18. ROYALTY VALUE - Multiply the Sales Value (Item 16) by the royalty rate and enter the result, or use the calculation method required by lease terms and/or applicable regulations.
19. PAYMENT METHOD CODE - Enter the code from the Payor Handbook that identifies how you are paying the royalty for this line item.
20. PAGE TOTAL - Add the total royalties in Item 18 for each page.
21. REPORT TOTAL - Add the Page Totals of all the pages of the report and enter the result on Page 1 of the completed report.

Fill in the REPORT CONTROL BLOCK only on Page 1 of the report. Numbers in parentheses are Payment Method Codes (Item 19).

22. CHECKS TO MMS - Enter the total amount of the check for Federal royalties submitted with this report.
23. PAYMENTS TO OTHERS - Enter the total rentals and royalties reported on this form but paid directly to Indian Tribes or allottees, to Alaska Natives, etc.
24. ELECTRONIC FUNDS TRANSFER (EFT) TO MMS - Enter the total amount paid by electronic transfer of funds directly from Payor's bank to the Minerals Management Service's Treasury account.
25. ROYALTY-IN-KIND - Enter the total royalty value that will be paid by the contractor who takes the product in kind.
26. CHECKS TO MMS for BIA - Enter the total amount of the checks submitted to MMS with this report to be paid to specific Indian Tribes or allottees.
27. ELECTRONIC FUNDS TRANSFER (EFT) TO BIA - Enter the total amount paid by electronic transfer of funds directly from Payor's bank to the Bureau of Indian Affairs' Treasury account.
28. PAYMENTS TO LOCKBOXES - Enter the total amounts paid directly to an Indian Tribe's or allottee's account at a bank.
29. TOTAL OF ITEMS 22-28 - Enter the sum of the above, which must agree with the Report Total (Item 21).
30. NAME (TYPED OR PRINTED) AND AUTHORIZED SIGNATURE; DATE - Enter the legible name and provide the signature of a person authorized by the Payor to certify the accuracy of the report, on Page 1. Enter the date signed.
31. NAME OF PREPARER; TELEPHONE - Enter the name and telephone number of the person who prepared the report, on Page 1.

Public reporting burden for this form is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining data, and completing and reviewing the form. Direct comments regarding the burden estimate or any other aspect of this form including suggestions for reducing the burden to the Information Collection Clearance Officer, Mail Stop 2300, Minerals Management Service, 381 Elden Street, Herndon, Va 22070, and the Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project (1010-0022) Washington, DC 20503.

Mail completed report and remittance to:

Minerals Management Service
Royalty Management Program
P.O. Box 5810, T.A.
Denver, CO. 80217

For MMS Use Only

AMENDMENT OF SOLICITATION/MODIFICATION OF CONTRACT

1. CONTRACT ID CODE	PAGE OF PAGES
	1 | 2

2. AMENDMENT/MODIFICATION NO.	3. EFFECTIVE DATE	4. REQUISITION/PURCHASE REQ. NO.	5. PROJECT NO. (If applicable)
1	11/8/94	N/A	

6. ISSUED BY CODE

Minerals Management Service
Procurement Operations Branch
381 Elden Street, MS-2510
Herndon, Virginia 22070-4817

7. ADMINISTERED BY (If other than Item 6) CODE

James E. MacKay
Address same as Block 6

8. NAME AND ADDRESS OF CONTRACTOR (No., street, county, State and ZIP Code)

CODE | FACILITY CODE

(√)	
XX	9A. AMENDMENT OF SOLICITATION NO. IFB 3768
	9B. DATED (SEE ITEM 11) 10/21/94
	10A. MODIFICATION OF CONTRACT/ORDER NO.
	10B. DATED (SEE ITEM 13)

11. THIS ITEM ONLY APPLIES TO AMENDMENTS OF SOLICITATIONS

[X] The above numbered solicitation is amended as set forth in Item 14. The hour and date specified for receipt of Offers [ ] is extended, [X] is not extended.

Offers must acknowledge receipt of this amendment prior to the hour and date specified in the solicitation or as amended, by one of the following methods: (a) By completing Items 8 and 15, and returning 1 copies of the amendment; (b) By acknowledging receipt of this amendment on each copy of the offer submitted; or (c) By separate letter or telegram which includes a reference to the solicitation and amendment numbers. FAILURE OF YOUR ACKNOWLEDGMENT TO BE RECEIVED AT THE PLACE DESIGNATED FOR THE RECEIPT OF OFFERS PRIOR TO THE HOUR AND DATE SPECIFIED MAY RESULT IN REJECTION OF YOUR OFFER. If by virtue of this amendment you desire to change an offer already submitted, such change may be made by telegram or letter, provided each telegram or letter makes reference to the solicitation and this amendment, and is received prior to the opening hour and date specified.

12. ACCOUNTING AND APPROPRIATION DATA (If required)

13. THIS ITEM APPLIES ONLY TO MODIFICATIONS OF CONTRACTS/ORDERS, IT MODIFIES THE CONTRACT/ORDER NO. AS DESCRIBED IN ITEM 14.

(√) A. THIS CHANGE ORDER IS ISSUED PURSUANT TO: (Specify authority) THE CHANGES SET FORTH IN ITEM 14 ARE MADE IN THE CONTRACT ORDER NO. IN ITEM 10A.

B. THE ABOVE NUMBERED CONTRACT/ORDER IS MODIFIED TO REFLECT THE ADMINISTRATIVE CHANGES (such as changes in paying office, appropriation date, etc.) SET FORTH IN ITEM 14, PURSUANT TO THE AUTHORITY OF FAR 43.103(b).

C. THIS SUPPLEMENTAL AGREEMENT IS ENTERED INTO PURSUANT TO AUTHORITY OF:

D. OTHER (Specify type of modification and authority)

E. IMPORTANT: Contractor [ ] is not, [ ] is required to sign this document and return ______ copies to the issuing office.

14. DESCRIPTION OF AMENDMENT/MODIFICATION (Organized by UCF section headings, including solicitation/contract subject matter where feasible.)

Section B.2.4. Change the first sentence of this Section to read, "In addition, the Bidder may submit up to five (5) alternative bids; the Bidder may arrange aggregations of its own choosing, each of which may consist of any number of the Government's offered groups."

Section B.3. Bid Table

Change the applicable Index for the following offered groups to read:

Except as provided herein, all terms and conditions of the document referenced in Item 9A or 10A, as heretofore changed, remains unchanged and in full force and effect.

15A. NAME AND TITLE OF SIGNER (Type or print)		16A. NAME AND TITLE OF CONTRACTING OFFICER (Type or print)	
		James E. MacKay, Contract Specialist	
15B. CONTRACTOR/OFFEROR (Signature of person authorized to sign)	15C. DATE SIGNED	16B. UNITED STATES OF AMERICA BY James E. MacKay (Signature of Contracting Officer)	16C. DATE SIGNED 11/8/94

NSN 7540-01-152-8070 30-105 STANDARD FORM 30

OFFERED GROUP NO.	INDEX IN IFB	NEW INDEX
1	NNG - TX, OK, KANSAS	HOUSTON SHIP CHANNEL (HSC)
3	NNG - TX, OK, KANSAS	HSC
4	NNG - TX, OK, KANSAS	HSC
11	SOUTHERN NATURAL-LA	COLUMBIA GULF-LA
12	SOUTHERN NATURAL-LA	COLUMBIA GULF-LA
13	TEXAS EASTERN EAST LA ZONE	TEXAS EASTERN WEST LA ZONE
14	SOUTHERN NATURAL-LA	COLUMBIA GULF-LA
15	TRANSCO-ZONE 2	NGPL-LA
16	SOUTHERN NATURAL-LA	COLUMBIA GULF-LA
17	SOUTHERN NATURAL-LA	TENN-LA ZONE 1
18	SOUTHERN NATURAL-LA	TENN-LA ZONE 1
19	SOUTHERN NATURAL-LA	TENN-LA ZONE 1
22	SOUTHERN NATURAL-LA	TENN-LA ZONE 1
23	SOUTHERN NATURAL-LA	TENN-LA ZONE 1
26	SOUTHERN NATURAL-LA	TENN-LA ZONE 1
30	TRUNKLINE-FIELD ZONE	TEXAS EASTERN - EAST LA
31	TENNESSEE GAS-LA & OFFSHORE ZONE 1	TEXAS EASTERN - EAST LA

--End of Amendment--

Appendix 4

ROYALTY GAS MARKETING PILOT
SAMPLE SALES CONTRACT

TABLE OF CONTENTS

SECTION A
BIDDER'S SIGNATURE PAGE

This bid is submitted in response to IFB No. 3768. By my signature below, I agree, if this offer is accepted within 35 calendar days from the date for receipt of offers specified in the IFB, to perform in accordance with the terms and conditions of the IFB and this offer, under the contract which results therefrom.

I certify that the information, representations, and certifications included herein are full, accurate, and complete.

BIDDER'S BUSINESS NAME:

ADDRESS:

AUTHORIZED SIGNATURE:

TYPED NAME AND TITLE:

DATE: November 16, 1994

Bids by corporations must be executed over the corporate seal. Self-certification as to one's authority is not acceptable. Therefore, the signatures above and below must be by different persons.

CORPORATE OR PARTNERSHIP CERTIFICATION
I, ___________________________________, certify that I am the ___________________ of the above bidder, that _________________________________,who signed this bid on behalf of that bidder then held the office or position of ____________________________________ of said bidder, that said individual duly signed said bid on behalf of said bidder by authority of its governing body or his position of employment with said bidder, and his/her signature of this bid is within the scope of that person's authority.

Seal[1]

____
Signature Corporate or Partnership Officer

The making of false statements to the Government is punishable by a fine of not more than $10,000 and/or not more than 5 years imprisonment. See 18 U.S.C. §1001.

[1] If bidder has no seal, the signatory or the corporate or partnership certifying official shall write "No Seal" by hand and initial in the space provided for the seal.

SECTION B
INSTRUCTIONS AND CONTRACT TABLE

B.1. INSTRUCTIONS TO CONTRACTOR

B.1.1. The table in this Section contains a listing of groups of leases for Royalty Gas covered by this contract. For each such Group, the table identifies:

- Offered group number
- Lease(s)
- Block(s)
- Percent ownership
- Point of Delivery, i.e., receipt point for such natural gas
- FMP No., i.e., MMS assigned measurement location identification number of the Point of Delivery
- Facility operator, by name of company, i.e., operator
- Volumes of Royalty Gas available for bid, in estimated MMBtu's per day
- Applicable Index
- Contract Price.

B.l.l.a The Lessees, as defined in Section C.l., are operating rights owners of certain oil and natural gas leases the Government issued, as reflected in Section B. Said leases are hereinafter called "said leases," whether one or more. This contract applies only to Royalty Gas made available to Contractor by the Government's Lessees by virtue of the Government's Lessees ownership in said leases on the effective date of this contract. If Government's Lessees assign all or a portion of said leases, this contract shall apply to the assigned portion thereof. If Government's Lessees obtain additional interest in said leases, such additional interest shall be subject to this contract only if the parties mutually agree in writing.

B.1.1.b Volumes of Royalty Gas shown in the contract table are estimates for planning purposes only. Each volume is a percentage of the lease production owned by the Lessees (as determined by percentage ownership) multiplied by the royalty rate. The volume represents the Royalty Gas expected to be available and must be taken by the Contractor each month. These are only estimates and are subject to change depending on actual natural gas availability information provided each month to the Contractor by Government's Lessees (see Section C.3 on natural gas availability).

B.2. CONTRACT TABLE (including price(s))

SECTION C
TERMS AND CONDITIONS OF GAS SALES AND PURCHASE

C.l. DEFINITIONS

C.1.1. Applicable Index means the Index published in Inside F.E.R.C.'s Gas Market Report or "GMR" (for the first-of-the-month price) under the table entitled "Prices of Spot Gas Delivered to Pipelines" specified in Section B of this contract.

C.1.2. Audit refers to any review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Federal and Indian leases, and, as used herein, refers to such review of Contractor's compliance with the provisions of this contract.

C.1.3. Btu means British thermal unit, and is the quantity of heat required to raise the temperature of 1 pound of water from 58.5 to 59.5 degrees Fahrenheit. MMBtu means one million Btu's.

C.1.4. Commodity Charge means the fee which Contractor shall pay the Government for each MMBtu of Gas that the Government through its Lessees delivers to the Point(s) of Delivery for Contractor's account.

C.1.5. Contract includes this document and any amendments or revisions thereto, between the Parties, and constitutes an obligation which, with due consideration, is enforceable by law.

C.1.6. Contracting Officer (CO) is a person with the authority to enter into, administer, and/or terminate contracts and make related determinations and findings. The term includes the authorized representative of a CO acting within the limits of his or her authority, as delegated by the CO, except as otherwise provided in this contract.

C.1.7. Contracting Officer's Technical Representative (COTR) is that person named to administer day-to-day technical contracting matters.

C.1.8. Contractor means the bidder to IFB No. 3768 whose offer is accepted by the Government and who is a purchaser of Royalty Gas subject to the provisions of this contract. The Contractor is also referred to herein as Government's Contractor.

C.1.9. Day means a period of twenty-four (24) hours beginning at 8:00 a.m. on any calendar day and ending at 8:00 a.m. on the following day.

C.1.10. Force Majeure

(a) Force majeure means acts of God, strikes, lockouts, or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, hurricanes or storms, hurricane or storm warnings which require the precautionary shut-down or evacuation of production facilities, earthquakes, fires, floods, washouts, arrest and restraints of governments and people, civil disturbances, explosions, breakage or accidents to machinery, equipment, or lines of pipe, freezing of wells or lines of pipe, partial or entire failure of wells or pipelines, and any other cause beyond the reasonable control of the party affected which renders that party unable to carry out its obligations under this Agreement. Contractor’s failure to market, failure of markets, and failure of interruptible transportation, are not force majeure events. The settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty, and any Force Majeure shall be remedied with all reasonable dispatch but shall not require the settlement of strikes or lockouts by acceding to the demands of opposing party when such course is inadvisable in the discretion of the party having the difficulty.

(b) The loss of markets to other natural gas supplies or fuels, whether or not caused by regulatory determinations or regarding applicable transportation rates, shall not constitute an event of force majeure. The Parties agree that a lack of funds, economic hardship, or other financial cause shall not in any circumstance be an event of force majeure. Failure of interruptible transportation is not force majeure.

(c) In the event of any Party being rendered unable, wholly or in part by force majeure to carry out its obligations under this Gas Purchase Agreement, other than the obligation to make payment of amounts accrued and due at the time thereof, it is agreed that on such Party's giving notice and full particulars of such force majeure in writing or by telefax to the other Party within a reasonable time after the occurrence of the cause relied on, the obligations of all Parties, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused, but for no longer period, and such cause shall so far as possible be remedied with all reasonable dispatch.

C.1.11. Government, as used in this document, means the United States Department of the Interior, Minerals Management Service.

C.1.12. Inside F.E.R.C.'s Gas Market Report or “GMR” shall mean the journal by that name which is published on a weekly basis by McGraw-Hill Corporation.

C.1.13. Lease refers herein to any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the Government under the Outer Continental Shelf Act (43 U.S.C. 1331 et seq.) which authorizes exploration for development or extraction of, or removal of natural gas from Federal lands in the Gulf of Mexico.

C.1.14. Lessee is that party through Federal lease ownership which has entered into a Lease with the Government, or which owns operating rights in such a Lease, as defined herein, and which has entered into an agreement with the Government to participate in the Royalty Gas Marketing Pilot.

C.1.15. Government's Contractor means a company, Corporation, partnership, association, person or other entity with whom the Government has contracted to receive, handle, deliver, and/or market Royalty Gas taken by the Government as its royalty on production from or attributable to said Leases. The Contractor does not necessarily perform the functions performed by Transporter, although nothing prohibits Government's Contractor and Transporter from being the same entity.

C.1.16. Month means a calendar month.

C.1.17. Operating Rights (working interest) means the interest created out of a lease authorizing the holder of that right to enter upon the leased lands to conduct drilling and related operations, including production of oil or natural gas from such lands in accordance with the terms of the lease. 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.

C.1.18. Outer Continental Shelf, or “OCS”, as used herein, refers to all submerged lands lying seaward and outside of the area of land beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

C.1.19. Parties mean the Government and the Contractor.

C.1.20. Point(s) of Delivery means the point or points identified at which Government's Lessee is to make available to the Contractor, and Contractor is required to take Royalty Gas from or attributable to said Leases.

C.1.21. Royalty Gas means that portion of natural gas and entrained liquids, produced from or attributable to said Leases for taking in kind at the Point(s) of Delivery, to which the Government is entitled as the royalty percentage of the production from or attributable to said Leases. Royalty Gas includes flash gas which is commingled and delivered with other gas at the Point(s) of Delivery, but does not include the following:

(a) The volumes of natural gas beneficially used (used on lease) or unavoidably lost, as approved by the Government, upstream of the Point(s) of Delivery;

(b) Naturally occurring condensate, retrograde condensate, drip condensate or other liquid hydrocarbons which move separately from the natural gas stream downstream of the Point(s) of Delivery; and

(c) Flash gas which separates from liquid hydrocarbons downstream of the Point(s) of Delivery.

C.1.22. Royalty Gas Balance Account shall have the meaning ascribed to it in Section C.4.4. of this contract.

C.1.23. Royalty-In-Kind Pilot means the one-year trial, beginning January 1, 1995, being undertaken by the Government in which Royalty Gas will be sold in the marketplace by the Government.

C.1.24. Secretary is the Secretary of the United States Department of the Interior or any person, persons, or board (other than the Contracting Officer) authorized to act for the Department or the Secretary.

C.1.25. Transporter means principally the pipeline company receiving delivery of Royalty Gas at the Point(s) of Delivery, but may mean any upstream or downstream pipeline transporter, as dictated by context.

C.2. GENERAL TERMS

C.2.1. Contractor and the Government agree that 100 percent of the Royalty Gas made available by Government's Lessees at the Point(s) of Delivery will purchased and taken by Contractor at the Point(s) of Delivery. Title to the Royalty Gas delivered hereunder and taken by the Contractor shall pass to and vest in the Contractor at the inlet flange of the Point(s) of Delivery. Lessees shall be deemed to be in exclusive control and possession of said Royalty Gas prior to the time of delivery to the Contractor at the inlet flange of the Point(s) of Delivery, and, if taken at the Point(s) of Delivery, the Contractor shall be deemed to be in exclusive control and possession of said Royalty Gas thereafter.

C.2.2. The Government's Lessees shall be responsible for delivery of its Royalty Gas to Contractor at the Point(s) of Delivery. Contractor shall be responsible for transportation of volumes from the Point(s) of Delivery to Contractors markets. Contractor represents and warrants that it has obtained transportation rights necessary to satisfy its obligations under this Gas Sales and Purchase Agreement. Contractor shall maintain appropriate contracts with Transporting Pipelines, including all interstate, intrastate, private or other pipelines, laterals, feeder lines and any and all other carriers, so that Contractor can receive and deliver all volumes pursuant to this Gas Sales and Purchase Agreement. Contractor shall take all necessary steps to property arrange for the nomination, dispatch, and removal from the Point(s) of Delivery of all volumes of Royalty Gas tendered by the Government, and to arrange for required transportation in order to carry out the intent of and obligations of this Gas Sales and Purchase Agreement.

C.2.3. The party deemed to be in control and possession of the Royalty Gas shall be responsible for and shall indemnify, defend and hold the other party harmless with respect to any losses, claims, liabilities or damages arising therefrom when such Royalty Gas is deemed to be in that party's control and possession. The Government shall not be liable for consequential, incidental, special or punitive damages or losses which may be suffered as a result of the failure to make available or take the Royalty Gas hereunder.

C.2.4. Contractor shall hold the Government and the Government's Lessees harmless for all costs and penalties, including any and all scheduling and imbalance penalties, which may be assessed or imposed by a Transporter against Contractor at or after the Point(s) of Delivery, including without limitation purchases or sales of imbalance quantities of natural gas at unfavorable prices. The Government shall not hold the Contractor responsible for any costs and penalties which may be assessed against the Government prior to the Point(s) of Delivery. Only when Government's Lessees, through gross negligence or willful misconduct, fail to perform duties described in Section C.3.1 and C.3.2 may the Government's Lessees be required to pay for such penalties, as set forth above, after the Point(s) of Delivery.

If any costs or penalties associated with transportation of natural gas are anticipated, the Contractor or Government's Lessees shall inform the other in writing as soon as the Government's Contractor or the Government's Lessees becomes aware. The Contractor and the Government's Lessees shall immediately work with the other to minimize or eliminate, if possible, such costs or penalties. The Contractor and the Government's Lessees shall work with each other and with the Transporter to verify delivery and receipt of nominated volumes on a timely basis.

C.2.5. It is specifically agreed that there are no third party beneficiaries to this contract, and that the contract shall not impart any rights enforceable by any person, firm, organization, or corporation not a party hereto.

C.2.6. The Contractor shall enter into agreements with Transporter, such as operational balancing agreements and predetermined allocations, which agreements have the effect of reducing scheduling and delivery imbalances with Transporter, and which therefore assist in mitigating possible allocation of Royalty Gas to Lessees or other Operating Rights owners.

C.2.7. Notwithstanding any other provision herein to the contrary, it is agreed and understood that the Government's Lessees shall be in sole control of any well drilled under the terms of the said Leases and nothing herein will operate by implication to enlarge or decrease any right which the Government's Lessees would have in the absence of the Government's Agreement with the Lessees with respect to the operation and maintenance of any well drilled hereunder or to impair any right the Government's Lessees would otherwise have to repair, rework, plug and abandon, produce or schedule the production of any well or wells drilled under the terms of the said Leases. During any period of time a gas well is shut in for any reason, The Government's Lessees shall not be obligated to deliver any Royalty Gas from that well and shall not be responsible for any loss to the Government or the Government's Contractor for failure to so deliver Royalty Gas.

C.3. NOTIFICATION OF ROYALTY GAS AVAILABILITY AND CONTRACTOR ACKNOWLEDGMENT

C.3.l. Estimated Gas Available. No later than (8) working days before the first day of the applicable month of delivery or the twentieth (20th) day of the calendar month before the first day of the applicable month of delivery, whichever is earlier, Government’s Lessees have agreed to communicate by facsimile transmission to the Government COTR and the Contractor the Lessees's good faith estimate of the daily quantity of Royalty Gas, stated in MMBtu's, that Lessee expects to be available for delivery from or attributable to said Leases during such month. The parties understand and agree that Lessees's estimates of deliverability from said Leases are not a warranty of deliverable quantities, but are given to facilitate planning for necessary transportation and marketing of the Royalty Gas.

C.3.2. Changes in Availability. The Government's Lessees have agreed to use reasonable efforts, customary in the industry, to communicate by facsimile transmission to the Government COTR and the Contractor circumstances beyond routine production fluctuations that affect natural gas deliverability from said Leases, so that the Contractor may adjust its transportation and marketing arrangements on a continuous basis in order to take the full quantity of Royalty Gas available each day. The Government's Lessees have agreed to issue such communication to the Contractor as soon as practicable.

C.3.3. Acknowledgment from the Contractor. No later than twenty-four (24) hours, excluding weekends and holidays, prior to Transporter’s first-of-the-month nomination deadline, the Contractor shall confirm by facsimile transmission to the Government's Lessees and the Government COTR the daily quantity of Royalty Gas, stated in MMBtu's, that the Contractor must take from Government's Lessees during the upcoming month. The Contractor shall communicate changes in such transportation nominations related to any changes made by Governments' Lessees by facsimile transmission to Government's Lessees and Government's COTR in the same manner throughout each month of delivery, and with adequate notice to allow confirmation of nomination changes before applicable deadlines. The Contractor shall work in good faith with the Government's Lessees and Transporter(s) to arrange for delivery of 100 percent of the quantities of Royalty Gas made available at the Point(s) of Delivery.

C.3.4. The responsibilities and obligations of Lessees set forth under this Section shall be performed by the Operator, if the Operator has agreed and is a volunteer in the Pilot, for the applicable Leases to the extent practicable.

C.4. IMBALANCES

C.4.1 Contractor Obligation to Take or Nominate. Notwithstanding Lessees's maintenance of a balancing account, the parties understand and agree that this contract does not permit the Contractor to delay timely takes of 100 percent of the Royalty Gas delivered by Lessees. The Contractor shall use reasonable efforts in accordance with industry standards to avail itself of any third-party agreements available to it with the Transporter to minimize the incurrence of any imbalance with the Lessees. Such agreements may include, for example, operational balancing agreements or pipeline allocations.

C.4.2. Conditions Warranting Balancing. The balancing mechanism described in this Section C.4 is designed for a Contractor to correct only those imbalances resulting from the following:

C.4.2.a Differences between the Government's monthly Royalty Gas entitlements and allocated volumes.

C.4.2.b Typical scheduling imprecisions that result in differences between Transporter's receipts and Lessees's deliveries.

C.4.2.c Failure by the Government's Contractor during any given month to nominate all quantities made available by Lessees, not to exceed three consecutive days during any month period.

C.4.2.d Operational changes that can occur between the Transporter's first-of-the-month nomination deadline and the first day of a calendar month.

This balancing arrangement does not include Royalty Gas subject to Section C.5.1 and does not relieve the Contractor of its responsibility to take 100 percent of the Government's Royalty Gas, whether the actual amount thereof is more or less than Lessees's previous estimate.

C.4.3. Managing imbalances during term of Contract. For any Contractor imbalance occurring under Section C.4.2, during any calendar month, the Contractor shall work with the Government's Lessees to arrange for increased or decreased deliveries of Royalty Gas in the subsequent month or months, in order to eliminate such imbalance as soon as is reasonably practicable. Such differences shall be maintained by the Government's Lessees in a Royalty Gas Imbalance Account, as defined in Section C.4.4 of this contract.

C.4.4. Royalty Gas Imbalance Account. The Government's Lessees will be required to maintain a Report of Royalty Gas Imbalance Account which shall include: (1) actual Royalty Gas quantities produced from or attributable to said Leases, (2) actual takes of Royalty Gas by the Contractor, and (3) the overtakes or undertakes of Royalty Gas by the Contractor. The Royalty Gas Imbalance Account report will be submitted to the Government COTR and the Contractor no later than 45 days following the month of production. If adjustments or corrections of actual quantities delivered have not been received by such date, the Lessees will be required to file an estimated Royalty Gas Imbalance Account for the applicable month and must issue a corrected Royalty Gas Imbalance Account promptly after all such adjustments or corrections are received.

C.4.5. Final Balancing. After December 31,1995, the contractual relationship with the Contractor shall continue to allow for purchase of any imbalance which may exist, either in the Royalty Gas Imbalance Account or by virtue of any subsequent Transporter adjustments. Such final imbalances shall be communicated to the Government and the Contractor within thirty (30) days after December 31, 1995, or when Lessees come into possession of all necessary information for the last delivery month, whichever is later. The parties shall settle such imbalance as follows:

C.4.5.a Contractor has taken less natural gas than the Government's entitlement. The Government's Lessees, at its sole option, may settle the imbalance in either of the following ways. The Lessees must notify the Government of its election and the Government shall notify the Contractor as to method of settlement within (15) after Lessees issues the final Royalty Gas Imbalance Account. (1) The Lessees may pay the Government for the amount of undertaken Royalty Gas with the natural gas being valued at the Contractors bid price at the time that the imbalance accrued. If Government's Lessees elects this method, Contractor shall have no obligation with respect to such Royalty Gas. (2) The Lessees may settle the imbalance by making available natural gas from or attributable to the Leases to the Contractor at the Point(s) of Delivery. If Lessees elects to settle in natural gas, and if natural gas production is no longer available from the Leases at the Point(s) of Delivery, or if natural gas production is not of sufficient quantity to allow recovery of the imbalance within 30 days, then to settle such imbalance, Lessees must make available equivalent quantities of natural gas, of similar quality and equivalent value, at agreed-upon alternative Point(s) of Delivery as soon as practically possible to the Contractor to reconcile undertakes on an in kind basis.

C.4.5.b Contractor has taken more than the Government's entitlement. Subject to final audit, the Contractor’s obligations under final balancing will be satisfied once it has submitted payment for the overtake equal to the final imbalance quantity valued at the Contractor’s bid price per MMBtu at the time said imbalance was accrued.

C.4.6. The responsibilities and obligations of Lessees set forth under Sections C.4.1 through C.4.4. shall be performed by the Operator, if the Operator agrees and is a volunteer in the Pilot. However, Lessees shall be responsible for any final balancing as provided by Section C.4.5.

C.5. FAILURE BY THE CONTRACTOR (BREACH) AND CONTRACTOR LIABILITY

C.5.1. Breach of Contract by Failure to Take. If, for reasons other than a Force Majeure occurrence or those occurrences described in Section C.4.2 subject to the Royalty Gas Imbalance Account, the Contractor does not satisfy its contractual obligations to the Government by failing to take the Government's entire share of Royalty Gas made available to it during any month, the Government may terminate the contract. Circumstances, not of a force majeure nature, constituting a breach of contract with the Government by the Contractor include, but are not limited to the following circumstances:

C.5.1.a Once during any month, more than three consecutive working days pass in which the Contractor fails to provide nominations in response to Royalty Gas made available by the Government's Lessees.

C.5.1.b If, due to a curtailment of interruptible transportation by Transporter or a non Force Majeure curtailment of firm transportation by Transporter, more than three consecutive working days pass in which the Contractor fails to take Royalty Gas made available by the Government's Lessees.

C.5.1.c Within a given month, the Contractor allows a repeated sequence of delays in nominating or taking Royalty Gas. If it appears that during any month Contractor is swinging Royalty Gas by not taking for 3 consecutive days or less but repeating a non-taking pattern throughout the month (e.g., no taking for 2 days, then taking for a day, and then not taking for another 2 days), this may be considered a breach of contract.

The disposition of any quantities of Royalty Gas, delivered by the Government's Lessees but not taken by the Contractor which is considered a breach of the Contractor's contract with the Government shall be accomplished in accordance with Transporter's applicable tariff provisions and/or existing balancing agreements among Transporters and other entities party to such pipeline balancing arrangements (which may include the Contractor if it has entered into an operational balancing agreement or predetermined allocation). The distribution of breach Royalty Gas causing the imbalance will be accomplished without the necessity of any additional documentation from the Government as the Government is not impacted by such allocations.

If the Government's Lessees (either as Lessees hereunder or as an Operating Rights owner in any oil and natural gas lease in which a third party is participating in the Government's royalty-in-kind pilot project) incur any scheduling or imbalance penalties assessed by Transporter as established by applicable tariffs because of Contractor's failure to take Royalty Gas for any oil or gas lease subject to the royalty-in-kind pilot project under the circumstances covered in Section C.5.1, the Government shall hold Contractor responsible for such penalties.

C.5.2. Contractor Liability for Bid Value of Royalty Gas. Notwithstanding contract termination pursuant to C.5.1, the Contractor shall be liable for the bid value of 100 percent of the Royalty Gas made available to it by the Government's Lessees including gas made available but not taken by the Contractor. In the event that the Government is able to sell the breach gas to a third party (other than the Lessee) at a price below the Contractors bid price, the Contractor will be liable for the difference between the price received by the Government and the Contractor's bid price. If the Government is unable to sell the breach gas, the Contractor will be liable for the full bid value of the gas.

C.5.3. Breach of Contract by Failure to Pay. Contractor shall be in breach of the contract by failure to pay for any Royalty Gas made available by the Government's Lessees.

C.5.4. Liability for Transporter Penalties. The Contractor shall be liable for any pipeline penalties imposed as a result of the Contractor's breach.

C.6. COMMODITY PRICES

C.6.1. For each MMBtu of Gas delivered to Contractor by the Government at the Point(s) of Delivery, Contractor shall pay the Government a Commodity Charge-which will be equal to the price which the Contractor, in Section B of this contract, has bid to be paid to the Government for the Royalty Gas purchased subject to the provisions of this contract.

C.6.2. In the event that the Applicable Index ceases to be published by GMR, or the categories change, or the CO determines that GMR has indefinitely suspended reporting the Applicable Index, then the last billing price will remain in effect until the Parties mutually agree on a substitute index or pricing mechanism upon which to base the Commodity Charge. If the Parties are unable to agree upon an alternate index or pricing mechanism, then the matter will be submitted to the dispute resolution procedures of the U.S. Department of the Interior, as authorized in the Administrative Dispute Resolution Act, Public Law No. 101-102, U.S.C. 581-583 and as implemented by U.S. Department of Interior in 59 Federal Register notice 30368, June 13, 1994.

C.7. EVALUATION OF PILOT PROJECT

The Contractor agrees to work in good faith with the Government and with Lessees to evaluate the Royalty-in-Kind Pilot Project, and shall upon request offer suggestions to enable the Government to improve the procedures used therein. This evaluation shall be completed by June 30, 1996.

SECTION D
INSPECTION AND ACCEPTANCE

D.l. GENERAL

Royalty Gas is sold under this contract in U.S. dollars per MMBtu. The natural gas will be measured by the Transporter in accordance with the Terms and Conditions of the Transporter's approved tariff, or in accordance with standard industry practice.

D.2. PRESSURE, MEASUREMENT AND PIPELINE CONDITION

D.2.1. Pressure. Royalty Gas shall be delivered to the Contractor at the Point(s) of Delivery, as listed in the contract, at the pressure maintained in the facilities of the Transporter in accordance with the provisions of the tariff(s) of the Transporter, insofar as such tariff(s) apply at the Point(s) of Delivery. However, in no event shall the Government's Lessees be required to install additional compression equipment over and above what Lessees install for their own gas.

D.2.2. Measurement. For purposes of this Agreement, the unit of measure for all Royalty Gas produced from or attributable to said Leases shall be 1 MMBtu, determined on an unsaturated basis. All measurements of Royalty Gas delivered and sold hereunder shall be in accordance with the provisions of the tariff(s) of the Transporter, insofar as such tariff(s) apply at the Point(s) of Delivery.

D.2.3. Pipeline Condition. The Government's Lessees will make the Royalty Gas available to Contractor at the Point(s) of Delivery in condition acceptable for transportation at Point(s) of Delivery. The Government's Lessees will continue to perform, at its own expense, any necessary dehydration, sweetening or compression currently required under the terms of said Leases and required to meet the delivery requirements at the Point(s) of Delivery.

D.2.4. Transporter's Meter. Contractor will arrange to have the appropriate measurements taken by Transporter, and to pay Transporter for all necessary transportation services. Contractor will pay the Government for all Royalty Gas received, based on

Transporter's physical flow measurement, and will enclose a copy of Transporter's meter-based invoice along with its payment to the Government for Royalty Gas received. At its own expense, Contractor may have a third party gas chart reading service integrate meter charts for natural gas delivered and shall provide chart copies to the Director, MMS.

D.2.5. Operator's Meter. The Government will monitor individual well production to verify royalty gas entitlements. The Government will also determine volumes of Royalty Gas based on the Operator's meter, and will bring any discrepancies to the attention of the Contractor. The Parties will work diligently and reasonably to resolve any such discrepancies.

SECTION E
DELIVERY AND TERM OF PERFORMANCE

E.l. CONTRACT TERM

Deliveries will begin January 1, 1995, and end December 31, 1995, subject to the provisions of Section B of this contract. The contract shall remain in force until all final balancing has been concluded, amounts due have been paid, and the Government releases Contractor.

E.2. PRODUCT DELIVERY AND ACCEPTANCE

Subject to the provisions of Sections B and D of this contract, Contractor at its own expense shall make all necessary arrangements to accept delivery, and shall take Royalty Gas at the Point(s) of Delivery, title passing at the inlet flange of the measurement device identified by the FMP number in the contract table.

SECTION F
CONTRACT ADMINISTRATION DATA

F.1. PAYMENT AND REPORTING

F.1.1. Responsibilities of Contractor. The following reporting and payment requirements are the monthly responsibility of the Contractor during the term of this Gas Sales and Purchase Contract

(a) Contractor shall render payment to the Government in accordance with the procedures at F.1.1.(b) for all Royalty Gas made available to it at the Point(s) of Delivery. The Contractor is required to pay to the Government for all Royalty Gas made available to it whether or not it accepts delivery of such gas. The Contractor will calculate the amount due each month based on the contract bid price and the Royalty Gas volumes recorded at the Point of Delivery identified in the Contract Table.

(b) The Contractor will remit the total amount due to the Government by electronic funds transfer (EFT). Payment must be credited to the Government's account by close of business on the 25th day of the month following the month of delivery. The Contractor must also complete and submit a Form MMS-2014. Data requirements in the Form 2014 will be limited to information related to Lease designation, quantity of gas taken and the total payment to be submitted. The Government will provide the Contractor Form MMS-2014 reporting instructions; instructions for EFT reporting are at Exhibit A.

In addition, the Government will provide Contractor monthly a Model Form MMS-2014 with recurring data fields completed. The Contractor will be responsible for completing nonrecurring data fields for each Lease under this contract. The Government will provide training and be available to answer questions over the telephone for the Contractor in Form MMS-2014 procedures. The Government does not anticipate that the reporting requirement will be an excessive administrative burden on Contractor.

(c) If Contractor has not received Transporter's invoice by the 20th day of the month following the month for which payment is due, then Contractor will make payment to the Government based on a diligent and reasonable estimate of Royalty Gas volumes received in the prior month, such as an estimate based on the Operator's records. The Contractor will submit the Form MMS-2014 as required by F.1.1.(b) with the estimated data, and will submit an adjusted Form MMS-2014, and payment, if applicable, as soon as it receives the Transporter's invoice. The Government will provide instructions for submitting revised Forms MMS-2014's.

(d) If Contractor fails to remit payment in full to the Government as provided in paragraph (c) by the 25th day of the month, the Government will calculate the interest due and will request a billing action through the Minerals Management Service's Royalty Management

Program, with interest based on the underpayment rate established in 30 U.S.C. 1721. In addition, the Government may withhold all or any part of future deliveries of Royalty Gas, and may terminate the contract for default in whole or in part. In any event, if payment from the Contractor is late, Contractor will owe interest from the due date until the date payment is credited to the Government's account. The Government will invoice Contractor for the amount due, and may assess applicable penalties.

F.2. PAYMENT DISPUTES

The Contractor's disagreement with any invoice is a dispute under Section H.5 of this contract. The Government's Contractor must immediately pay the invoiced amount by the bill due date and may submit a claim for alleged overcharges within 30 calendar days of the date of the disputed invoice. Payment claims not filed within 30 days are forever barred.

F.3. SET-OFF

The Government's Contractor shall not reduce payments due hereunder because of any claim against the Government arising outside of this contract.

F.4. GOVERNMENT REPRESENTATIVES

James McNamee is the Contracting Officer's Technical Representative (COTR) and Frank Pausina is the MMS Gulf of Mexico Region representative.

F.5. RIGHT TO AUDIT

The Government shall have the right to audit Contractor's records for the Royalty Gas taken; these audits will be during normal business hours, at reasonable times, to verify the accuracy of any statements related to Royalty Gas and payments required under or pursuant to any of the provisions of this Contract. Upon request, the Government and Contractor also shall make available to Lessees for audit purposes any relevant records of the Transporter to which the Government or Contractor has access. The Contractor must maintain and make accessible to the Government all records pertaining to this contract for a period of 1 year following the term of this contract.

SECTION G
SPECIAL PROVISIONS

G.l. DEFINITIONS

(a) Secretary is the Secretary of the United States Department of the Interior or any person, persons, or board (other than the Contracting Officer) authorized to act for the Department or the Secretary.

(b) Contracting Officer (CO) is a person with the authority to enter into, administer, and/or terminate contracts and make related determinations and findings. The term includes the authorized representative of a CO acting within the limits of his or her authority, as delegated by the CO, except as otherwise provided in this contract.

(c) Contracting Officer's Technical Representative (COTR) is that person named to administer day-to-day technical contracting matters.

G.2. NOTICES

(a) Any notices shall be in writing, shall include the contract number, and shall be forwarded, prepaid, to the address in © below. In addition, notices shall be sent by facsimile transmission immediately to the COTR at the telephone number in G.2.c.2.

(b) Notices to the Contractor shall be to the address provided on the Contract Award Sheet (SF-26).

(c) Notices to MMS shall be to:

(1) For the CO:
Mr. James E. MacKay, Contracting Officer
U.S. Department of the Interior
Minerals Management Service
381 Elden Street, MS 2500
Herndon, Virginia 22070-4817

(2) For the COTR:
Mr. James McNamee
Contracting Officer's Technical Representative
U.S. Department of the Interior
Minerals Management Service
12600 West Colfax Avenue, Suite B 440
Lakewood, Colorado 80215
PHONE (303) 275-7126
FAX (303) 275-7124

G.3. INDEMNIFICATION

Contractor shall indemnify and save the Government and Lessees harmless from and against any loss, expense, liability, or claim of any kind for damage to property of, or for injury to or death of persons which Contractor, its agents, employees, or personnel intentionally or negligently cause, arising in any way from or connected with performance of this contract.

G.4. GOVERNING LAWS AND REGULATIONS

The sale of MMS natural gas hereunder is governed solely by the Outer Continental Shelf Lands Act **(**OCSLA) (43 U.S.C. 1331 et seq**.**) and this contract.

SECTION H
GENERAL PROVISIONS

H.l. WITHHOLDING OF DELIVERIES AND TERMINATION FOR CONTRACTOR DEFAULT

(a) The Contracting Officer may, without liability to the Government, withhold deliveries hereunder if payment is not made in accordance with this contract.

(b) The Contracting Officer, without liability to the Government, may terminate this contract in whole or in part by written notice to the Contractor effective upon such notice being delivered personally to any authorized representative of the Contractor, being deposited in the United States Postal System, or with an overnight delivery service addressed to the Contractor as provided in G.2. in the event:

(1) Contractor breaches any warranty made herein;

(2) Contractor fails to take delivery in accordance with the terms **of** this contract;

(3) Contractor no longer meets the financial qualifying criteria specified in the IFB, as determined by the Government;

(4) There are instituted by or against Contractor proceedings in bankruptcy or other insolvency law; or

(5) Contractor fails to comply with any other term or condition of this contract within 48 hours after the Government, through the Contracting Officer or his designee, gives telephonic or other oral notice. The Government will confirm any oral notification in writing.

(c) Notwithstanding other provisions of this Article, Contractor shall not be charged with any liability to the Government under circumstances which prevent Contractor's acceptance of delivery hereunder due to causes beyond the control and without the fault or negligence of Contractor, as deemed by the Contracting Officer.

(d) Nothing herein will limit the Government in the enforcement of any legal or equitable remedy which it might otherwise have, and a waiver of any particular cause for termination will not prevent termination for the same cause occurring at any other time or for any other cause.

(e) Upon termination of a contract for Contractor's default, the Contracting Officer may sell or otherwise dispose of the remaining natural gas in an appropriate manner.

H.2. PAYMENTS UPON TERMINATION FOR DEFAULT

If this contract is terminated under H.1., the Contractor shall:

(a) Make final payment under Section F;

(b) Be liable to the Government for other damages including, but not limited to, administrative costs and expenses associated with solicitation and award of a replacement contract; and

(c) Pay all amounts due the Government and private parties under this provision by the bill due date**.** Disagreements on the amounts due the Government are H.5. disputes.

H.3. TERMINATION FOR CONVENIENCE OF THE GOVERNMENT

Without liability to the Government, the Contracting Officer may terminate this contract in whole or in part for the convenience of the Government. Such provision will not be unreasonably exercised. Effective 10 calendar days after dispatching written termination, unless the Contracting Officer otherwise designates, Contractor shall pay under Section F for natural gas delivered.

H.4. LIMITATION OF THE GOVERNMENT'S LIABILITY

The Government is not liable for nonperformance if due to causes beyond its control and without its fault or negligence, including, but not limited to, the provisions of Section C.5 of this Contract.

H.5. DISPUTES

(a) This contract is subject to the Contract Disputes Act of 1978 (41 U.S.C. §601 et seq., PL 95-563). If a dispute arises, the Contractor may submit a claim to the Contracting Officer who will issue a written decision on the dispute. A "claim" is a written request submitted to the Contracting Officer for payment of money, adjustment of contract terms, or other relief requiring a Contracting Officer's decision.

(b) In the case of disputed requests or any amendments to such requests for payments exceeding $50,000, the Contractor shall certify, at the time of the submission of a claim:

> I certify that the claim is made in good faith, that the supporting data is accurate and complete to the best of my knowledge and belief, and that the amount requested accurately reflects the contract adjustment for which Contractor believes the Government is liable.
>
> Contractor's Name:
> Signature of Certifying Official:
> Title:

(c) The Contractor shall pay the Government interest on the amount found due from the date the amount is due until the Contractor makes payment at the underpayment rate in 30 U.S.C. 1721.

(d) The decision of the Contracting Officer will be final and conclusive and not subject to review by any forum, tribunal, or Government agency unless an appeal or action is timely commenced as specified by the Contract Disputes Act of 1978.

(e) Contractor shall comply with any Contracting Officer decision, and at the Contracting Officer's direction will diligently perform under this contract pending final resolution of any claim, appeal, or action related to this contract.

H.6. OFFICIALS NOT TO BENEFIT

No member or delegate to Congress, officers, or employee of the Government will be admitted to any share or part of this contract or to any benefit that may arise herefrom except if made with a corporation for its general benefit.

H.7. ASSIGNMENT

Contractor shall not make or attempt to make any assignment of this contract or any interest herein contrary to the Assignment of Claims Act of 1940, as amended (31 U.S.C. §3727, 41 U.S.C. §15).

H.8. GRATUITIES

(a) The Government may terminate Contractor's contract by written notice if, after notice and hearing, the agency head or designee determines that the Contractor, its agent, or another representative offered or gave a gratuity (e.g., entertainment or gift) to an officer, official, or employee of the Government and intended to obtain a contract or favorable treatment under a contract.

(b) The facts supporting this determination may be reviewed by any court having lawful jurisdiction.

(c) If this contract is terminated under (a) above, the Government is entitled to pursue the same remedies as in a breach of contract.

(d) The rights and remedies of the Government provided in this Article are in addition to any other rights and remedies provided by law or under this contract.

H.9. ORDER OF PRECEDENCE

In the event of an inconsistency in this contract, unless otherwise provided herein, the inconsistency shall be resolved by giving precedence in the following order:

(a) Contract Table;
(b) General Provisions, Section H;
(c) Other provisions of the contract

H.10. INTEREST

All amounts due and payable, including interest assessed on late payments, must be paid by the bill due date. Amounts not so paid shall bear interest, computed on a daily basis, from the date due (i.e., date of deemed receipt of invoice) until the Government receives payment, at the underpayment rate under 30 U.S.C. 1721.

H.11. EXPORT LIMITATIONS AND LICENSING

Contractors are subject to all the limitations and licensing requirements of the Export Administration Act of 1969 (83 Stat. 841) in accordance with 10 U.S.C. §7430(e).

H.12. CONTRACTOR'S RELEASE OF CLAIMS

Contractor hereby releases the Government from all claims arising in connection with this contract, except those claims meeting the requirements of the Contract Disputes Act which the Contracting Officer receives prior to the date upon which final payment is due hereunder. Claims not received before such date are forever barred. Supplemental billings and credits issued after the final invoice will not extend the date for submission of claims beyond the final payment date shown on the final invoice.

Appendix 5

Royalty Gas Marketing Pilot
Pilot Volunteer Lessees, Contractors, and Operators by Bid Group

Bid Group	Royalty Gas MMBtu/D (per IFB)	Lease No.	Volunteer Lessee	Operator	Contractor	Percent Lessee Interest In Lease
1	1,055	054-003011-0	OXY	OXY		50.000%
1	475	054-004064-0	OXY	Sonat Exploration		43.600%
1 Total	1,530				CNG	
2	7,907	054-004536-0	Chevron	Chevron		100.000%
2	incl. above	054-004537-0	Chevron	Chevron		100.000%
2	1,600	054-011243-0	Chevron	Chevron		100.000%
2 Total	9,507				Chevron	
3	1,512	054-003079-0	Enron O&G	Enron O&G		64.000%
3	2,056	054-003080-0	Enron O&G	Enron O&G		61.200%
3	594	054-003932-0	Enron O&G	Enron O&G		61.100%
3 Total	4,162				Enron O&G Mktg	
4	2,492	054-003087-0	Enron O&G	Enron O&G		90.200%
4	4,422	054-006044-0	Enron O&G	Enron O&G		80.600%
4	incl. above	054-008996-0	Enron O&G	Enron O&G		78.378%
4 Total	6,914				Enron O&G Mktg	
5	834	054-002663-0	OXY	OXY		25.000%
5 Total	834				Oryx	
6	5,731	054-002665-0	OXY	OXY		25.000%
6 Total	5,731				Oryx	
8	1,298	754-393023-0	Oryx	Oryx		100.000%
8 Total	1,298				Coastal	
9	895	054-002414-0	OXY	OXY		19.375%
9	381	054-002745-0	OXY	OXY		35.600%
9	584	054-002746-0	OXY	OXY		45.000%
9 Total	1,860				Anadarko	
11	819	054-001880-0	Amoco	Amoco		100.000%
11	95	054-004433-0	Chevron	Chevron		50.000%
11	1,039	054-005377-0	Amoco	Amoco		100.000%
11	1,655	055-000971-0	Amoco	Amoco		100.000%
11 Total	3,608				Coastal	
12	1,698	054-000972-0	Amoco	Texaco		50.000%
12	1,698	054-000972-0	Texaco	Texaco		50.000%
12	5,367	054-000974-0	Amoco	Texaco		50.000%
12	5,367	054-000974-0	Texaco	Texaco		50.000%
12 Total	14,130				Coastal	
13	5,723	054-002051-0	Chevron	Mobil		50.000%
13	5,723	054-002051-0	Mobil	Mobil		50.000%
13	272	054-002063-0	Oryx	Oryx		48.742%
13 Total	11,718				Chevron	
15	7,167	054-006359-0	Chevron	Chevron		50.000%
15 Total	7,167				Texaco	

Royalty Gas Marketing Pilot
Pilot Volunteer Lessees, Contractors, and Operators by Bid Group

Bid Group	Royalty Gas MMBtu/D (per IFB)	Lease No.	Volunteer Lessee	Operator	Contractor	Percent Lessee Interest In Lease
16	4,456	054-002632-0	Chevron	Chevron		37.000%
16	incl. above	054-002812-0	Chevron	Chevron		37.000%
16	incl. above	054-003301-0	Chevron	Chevron		37.000%
16 Total	4,456				Conoco	
17	12,451	054-001146-0	Chevron	Chevron		100.000%
17	incl. above	054-001147-0	Chevron	Chevron		100.000%
17 Total	12,451				Chevron	
18	2,383	054-002873-0	Chevron	Chevron		100.000%
18	incl. above	054-001149-0	Chevron	Chevron		100.000%
18	incl. above	054-005031-0	Chevron	Chevron		100.000%
18	incl. above	054-005431-0	Chevron	Chevron		100.000%
18 Total	2,383				Chevron	
19	16,953	054-001196-0	Chevron	Chevron		100.000%
19	incl. above	054-003145-0	Chevron	Chevron		100.000%
19 Total	16,953				Chevron	
21	740	054-010735-0	Amoco	Amoco		50.000%
21	740	054-010735-0	Texaco	Amoco		50.000%
21	1,572	055-000572-0	Amoco	Amoco		50.000%
21	1,573	055-000572-0	Texaco	Amoco		50.000%
21	417	055-000578-0	Amoco	Amoco		50.000%
21	416	055-000578-0	Texaco	Amoco		50.000%
21 Total	5,458				Mobil	
22	4,493	054-004453-0	Mobil	Mobil		100.000%
22 Total	4,493				Coastal	
23	1,145	054-005040-0	Pennzoil	Pennzoil		100.000%
23 Total	1,145				Enron Gas Mktg	
24	950	054-002914-0	Chevron	Chevron		100.000%
24	194	054-004864-0	Devon	Devon	(Net Profit Share Lease)	100.000%
24 Total	1,144				Coastal	
25	4,888	054-002323-0	Chevron	Chevron		91.000%
25	incl. above	054-002324-0	Chevron	Chevron		91.000%
25	incl. above	054-003410-0	Chevron	Chevron		91.000%
25	incl. above	054-003783-0	Chevron	Chevron		91.000%
25 Total	4,888				Chevron	
26	200	054-003584-0	Chevron	Chevron		100.000%
26	2,082	054-004231-0	Chevron	Chevron		50.000%
26	1,253	055-000819-0	Chevron	Chevron		100.000%
26	721	055-000821-0	Chevron	Chevron		80.000%
26	incl. above	054-001019-0	Chevron	Chevron		80.000%
26 Total	4,256				Chevron	
27	1,040	055-000820-0	Chevron	Chevron		33.400%
27 Total	1,040				Mobil	

Royalty Gas Marketing Pilot
Pilot Volunteer Lessees, Contractors, and Operators by Bid Group

Bid Group	Royalty Gas MMBtu/D (per IFB)	Lease No.	Volunteer Lessee	Operator	Contractor	Percent Lessee Interest In Lease

28	883	054-001240-0	Chevron	Chevron		100.000%
28	incl. above	054-001241-0	Chevron	Chevron		100.000%
28	incl. above	054-006766-0	Chevron	Chevron		100.000%
28 Total	883				Chevron	
29	1,869	054-005599-0	Chevron	Chevron		100.000%
29	incl. above	054-005602-0	Chevron	Chevron		100.000%
29 Total	1,869				Conoco	
30	4,016	891-006669-0	Chevron	Chevron		100.000%
30 Total	4,016				Chevron	
31	480	054-001259-0	Chevron	Chevron		100.000%
31	incl. above	054-001260-0	Chevron	Chevron		100.000%
31	6,257	054-001572-0	Chevron	Chevron		100.000%
31	incl. above	054-001899-0	Chevron	Chevron		100.000%
31 Total	6,737				Chevron	
32	1,541	054-004464-0	Texaco	Texaco		80.000%
32	385	054-004464-0	Whiting	Texaco		20.000%
32 Total	1,926				Conoco	
33	525	054-005224-0	Amerada Hess	Amerada Hess		100.000%
33 Total	525				Amerada Hess	
34	2,926	054-009651-0	Walter O&G	Walter O&G		65.000%
34 Total	2,926				Superior	
35	6,029	054-001606-0	Texaco	Texaco		100.000%
35	741	054-001606-0	OXY	OXY		88.528%
35	1,793	054-004479-0	OXY	OXY		88.528%
35 Total	8,563				Coastal	
36	509	054-001633-0	Mobil	Chevron		31.500%
36	17	054-001649-0	Mobil	Chevron		15.750%
36	143	054-012087-0	Amerada Hess	Amerada Hess		66.680%
36	36	054-012087-0	Brooklyn Union Expl.	Brooklyn Union Expl.		16.660%
36	36	054-012087-0	Smith Offshore Expl.	Smith Offshore Expl.		16.660%
36 Total	741				Vastar	
Grand Total	155,312					

Note: Bid Groups 7, 10, 14, and 20 were eliminated from the pilot.

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Policy and Management Improvement
Box 25165
Denver, Colorado 80225-0165

IN REPLY REFER TO

MAR 9 1995

PMI/RMAD/MIB
Mail Stop 9130

Memorandum

To: Deputy Associate Director for Compliance
Chief, Data Management Division
Chief, Reports and Payments Division
Chief, Royalty Accounting Division
Chief, Compliance Verification Division

From: Gas Marketing Pilot Team

Subject: Operation Plan for Gas Marketing Pilot

We appreciate the cooperation and assistance we received from your staffs during the past several months. This memo outlines the procedures we agreed to follow during the Royalty Gas Marketing Pilot in the Gulf of Mexico. Although we have discussed these procedures at length and currently are following many of them, we would appreciate it if you would forward a copy of this memorandum to the appropriate employees.

DATA MANAGEMENT DIVISION

The DMD will establish unique payor codes for each of the selected gas marketers. These payor codes will begin with the letters "PLT" to distinguish gas marketers from other payors. The pilot team will complete PIF's for each of the pilot leases with advice from DMD as required; gas marketers will not be responsible for completing or signing PIF's. The pilot team will notify the current in-value payors of the requirements to end-date their current PIF's with assistance from DMD. The decision whether or not to end-date the in-value PIF's will be at the sole discretion of the volunteer. At the end of the pilot, the pilot team will remind those pilot lease volunteers who end-dated their in-value PIF's of the necessity to re-establish them.

Questions within DMD regarding the pilot may be directed to Larry Gratz, Lynette Schneider, or any pilot team member.

REPORTS AND PAYMENTS DIVISION

The RPD will make routine or obvious error corrections on gas marketer's 2014 lines. Gas marketers can be readily identified by the letters "PLT" as the first three characters in the payor code. The RPD also will respond to routine reporting questions from gas marketers. Questions concerning reporting matters unique to the gas marketing pilot may be referred to Nick Fadely of the pilot team, if necessary.

The RPD will send report ARO430 to the pilot team, showing how rejected lines were corrected by RPD. Any late reporting invoices generated for gas marketers will be forwarded to the pilot team.

The RPD will assist the pilot team in providing any necessary training or outreach to gas marketers, similar to the payor training outreach sessions currently conducted for in-value payors.

Questions within RPD regarding the pilot may be directed to Don Gilman, Paula Neuroth, Rose Mary Larimore, or any pilot team member.

ROYALTY ACCOUNTING DIVISION

Requests for billing action involving gas marketers will only be processed if approved by Jim McNamee (or acting) for the pilot team. Gas marketers can be readily identified by the letters "PLT" as the first three characters in the payor code. The RAD will forward any billing requests involving gas marketers that do not have the necessary approval to the pilot team for disposition.

The RAD will coordinate any follow-up actions concerning delinquent invoices to gas marketers with Nick Fadely prior to initiation of the follow-up action.

The General Ledger Branch (GLB) will handle questions and provide advice from marketers concerning electronic funds transfers. The GLB will provide a listing of the monthly payments received from gas marketers to the pilot team as soon as is practicable after the 25th of each month.

Questions within RAD regarding the pilot may be directed to Jim Mikelson, Dave Menard, or any pilot team member.

COMPLIANCE VERIFICATION DIVISION

The CVD will forward exceptions identified by the AFS/PAAS comparison involving leases in the gas marketing pilot during the pilot period to the pilot team for resolution of production problems that may involve MMS' gas marketer. Gas marketers can be readily identified by the letters "PLT" as the first three characters in the payor code.

The pilot team will forward a list of all gas marketing pilot leases to CVD by March 15, 1995. The gas marketing pilot includes the sales/production months of January 1995 through December 1995.

The gas balancing agreements with pilot volunteers are expected to cause minor variances between reports submitted by the gas marketers and the reports submitted by lease operators. The pilot team will have access to gas balancing schedules that should explain any exceptions. Any contact with gas marketers to explain discrepancies will be done by the pilot team.

Any potential royalty rate exceptions should be forwarded to Nick Fadely of the pilot team for resolution.

Any interest prebills generated for a gas marketer should be forwarded to Nick Fadely of the pilot team for resolution.

Because the gas is taken at the wellhead by MMS' gas marketers, there should be no allowances deducted. Any royalty report lines claiming allowances or allowance forms submitted by a gas marketer should be immediately referred to the pilot team.

Questions within CVD regarding the pilot may be directed to Randall Drake, Mike Miller, Paul Knueven, Dale Petersen, Carol Shelby, or any pilot team member.

AUDIT

The appropriate Compliance Division will perform audits of the volunteer producer's 5/6 share of gas sales for the pilot period for the purpose of determining what royalty the producer would have paid had royalties been paid in-value. This will be used by the pilot team during the evaluation phase at the conclusion of the pilot.

The audit sample will consist of no more than eight leases per volunteer and no more than 1 month per calendar quarter. The auditors will work with the pilot team to determine the appropriate sample. The volunteer producer will have up to 90 days from the end of the calendar quarter to supply the requested documents. These quarterly audits will be completed within 5 months of the end of each quarter. The audit will consist of a verification of the amounts reported on the Gas Marketing Pilot Evaluation Report Form by the volunteer. The auditors will review source documents such as gas sales contracts, transportation and processing agreements, invoices, etc. The standards for valuation purposes will be the regulations contained at 30 CFR Part 206. The audit reports will be forwarded to Jim McNamee of the pilot team; reports will not be supplied to the volunteer producer.

For additional information concerning this audit requirement, please refer to the Gas Marketing Pilot Evaluation Report Form and the February 27, 1995, transmittal letter.

In addition to the above audit requirements, the appropriate Compliance Division will conduct a sample of the pilot universe for the purpose of ensuring the proper delivery of royalty gas volumes during the pilot. The audit will consist of a review of the records of the lease operator, the volunteer producer, and the gas marketer. The results also will be used in the evaluation of the results of the pilot. The size and extent of the pilot sample will be at the sole discretion of the audit managers. The audit reports should be forwarded to the pilot team by May 31, 1996, for results to be considered in the final evaluation of the pilot. However, this does not suggest that any audits conducted after that time should ignore the potential for determining the correctness of the delivered pilot volumes by the volunteer producers.

Questions in Compliance regarding the pilot may be directed to Jimmy Mayberry, Ken Moyers, or any pilot team member.

GENERAL

In general, contact with, or sanctions against, our gas marketers or volunteer producers should only take place under the conditions specifically outlined above. If other situations arise that require communications between RMP and the volunteer producers or gas marketers, please contact Jim McNamee for advice.

A list of the pilot team members is attached. Please feel free to contact any member for any questions or assistance concerning the pilot.

Attachment

Gas Marketing Team Pilot Members

Jim McNamee, Team Leader	**PMI**	**(303) 275-7126**
Nick Fadely	**RMP**	**(303) 275-7244**
Ben Dillon	**PMI**	**(202) 208-4869**
Bob Kronebusch	**PMI**	**(303) 275-7113**
John Bratland	**PMI**	**(202) 208-3979**
Frank Pausina	**OMM**	**(504) 736-2560**
Jim MacKay	**ADM**	**(703) 787-1354**

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Washington, DC 20240

PMI/RMAD/MIB
Mail Stop 9130

FEB 27 1995

Dear

Enclosed is the Gas Marketing Pilot Evaluation Report Form for your use in submitting reports in accordance with Section 16 of the Royalty-in-Kind Pilot Program Agreement (Agreement). Your submittal of this report fulfills your Section 16 obligations to provide us raw data for calculating the value of production sold by you for the sole purpose of evaluating the revenue implications of the pilot; it is not intended to reflect a legal position with regard to submitting such data to Minerals Management Service (MMS) under any gas in-kind program beyond this pilot.

The MMS may choose to verify the accuracy of data reported on the evaluation form by reviewing a sample of back-up documents (such as gas sales contracts, transportation and processing agreements, and invoices) that support your reported values (see Section 10 of the Agreement). If MMS chooses to sample, we will limit the sample to no more than 20 percent of Chevron's leases in any given quarter.

The MMS will sample no more than 1 month per quarter and will notify you of the sample month and lease(s) at the end of each calendar quarter. You will be asked to make the back-up documents available to MMS at your location no later than 90 days following the end of the quarter. The MMS will close its review of the back-up documents by May 31, 1996. However, as agreed in Section 10 of the Agreement, this review closure neither increases or reduces any obligation to furnish records or other information in accordance with the lease terms, the Federal Oil and Gas Royalty Management Act of 1982 (30 U.S.C. 1701 et seq.), or any other applicable laws, rules, regulations, or orders of any governmental authority having jurisdiction.

We appreciate your cooperation in this matter. Because you are a volunteer in the pilot, you will not be subjected to penalties or assessments related to the report form that normally are associated with customary exception processing routines or audits.

Please mail the completed forms (capturing all prior period adjustments) within 90 days after the end of each <u>month</u> during the pilot period to:

Mr. James McNamee
Minerals Management Service/PMI
P.O. Box 25165, MS 9130
Denver, CO 80225

Please submit a summary report that captures all data for the year, including all known prior period adjustments, by March 31, 1996.

In addition to submitting this evaluation form, you are requested to submit an estimate of what your administrative cost savings were under this pilot by March 31, 1996.

If you have any questions, please call Ben Dillon at (202) 208-4869 or Jim McNamee at (303) 275-7126.

Sincerely,

Original Signed by
Lucy R. Querques

Lucy R. Querques
Associate Director for Policy and Management Improvement

Enclosure

MINERALS MANAGEMENT SERVICE
GAS MARKETING PILOT EVALUATION REPORT

MMS LEASE NUMBER (AS REPORTED ON FORM MMS-2014, TO REVENUE SOURCE LEVEL)	PRODUCTION MONTH	5/6 VOLUME (MMBtu's) (INCL. FLASH GAS)	GROSS VALUE RECEIVED BY PRODUCER (Note 1)	TRANSPORTATION COSTS (Note 2)	PROCESSING COSTS (Note 2)

Note 1: The total proceeds (including proceeds from NGL's and any consideration for PVR) received by the producer for the 5/6 share of the produced gas.
Note 2: Use actual costs incurred for arms-length transactions upstream of the point of sale but downstream of the FMP. For non-arm's-length transactions, use rates reported in 1994.

MINERALS MANAGEMENT SERVICE
ROYALTY GAS MARKETING PILOT

EVOLUTION OF THE SALES CONTRACT [1]

The relationship between the Minerals Management Service (MMS) and the royalty gas purchasers was governed by the terms of the Sales Contracts. These contracts were based on the terms contained in the Invitation for Bids (IFB). Therefore, this appendix will discuss the development of the IFB terms.

IFB, General.

The sale of natural gas under the pilot was governed solely by the Outer Continental Shelf Lands Act. The Federal Acquisition Regulations (48 C.F.R., Ch.1, Pts. 1-53) did not apply. Therefore, MMS was able to design an IFB and sales contracts that contained provisions unique to the sale. Of course, certain aspects of the contracts follow general contracting procedures, such as the provisions for dispute resolution, termination for the convenience of the government, and interest payments (Section H, General Provisions, of the IFB and sales contract).

The MMS had a choice between requesting proposals for negotiation or soliciting firm bids. The MMS decided on the latter approach, opting to solicit bids that were based on published price indices. The IFB instructed bidders to prepare bids by bid group, based on the published price indices specified in Section B of the IFB. The bids were to be stated in terms of the published index prices plus or minus differentials chosen by the bidders. The bidder's differential adjustments from the published index prices were to cover all costs incurred by the bidder, including transportation costs, from the facility measurement point to the point where the index was located. This bidding method allowed for pricing certainty from month to month, thereby lessening the administrative burden on both MMS and purchasers, while allowing the prices to move in relation to the market.

The MMS issued the IFB on October 21, 1994, and gave bidders 30 days to respond. A bid

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[1] This appendix is an edited excerpt from a Rocky Mountain Mineral Law Foundation (RMMLF) paper entitled “Testing the Waters, a Cooperative Effort to Design the MMS’ Royalty-in-Kind Pilot Program for Natural Gas.” The paper was co-written by employees of Chevron U.S.A. Inc., OXY USA INC, and MMS, and was presented at the RMMLF’s Annual Institute on July 21, 1996. The edited portion presented here originally was written by the MMS employees. For a complete copy of the paper, contact RMMLF at 7039 East 18th Avenue, Denver, CO 80220.

review team opened the 23 bids submitted by 22 companies on November 21, 1994, and notified the winning bidders within 2 days. The notifications were commitments by MMS to sell the applicable royalty gas to the winning bidders, with the promise that contracts would follow. The MMS entered into 14 contracts to start the pilot on January 1, 1995.

IFB terms.

The major IFB provisions governing sales of royalty gas (Section C of the IFB) were imported directly from the operating agreement that MMS entered into with the lessees; therefore, much of the IFB development was driven by the agreement. However, there were several issues unique to the IFB, including:

- Grouping of leases and selection of pricing indices
- Bid evaluation procedures
- Bidder qualifications and financial guarantees
- Default (breach of contract) provisions
- Reporting and payment instructions

A brief discussion of these issues follows:

Grouping of leases and selection of pricing indices.

The MMS decided to "bundle" leases into bid groups to provide bidders larger volumes with which to work and also to attempt to ensure that smaller-volume leases would not be left out in the bidding process. The MMS bundled the 75 individual leases and 2 units into 36 groups that were determined by lease location and common indices.

Bid evaluation procedures.

During the early planning phases, several "oversight" organizations asked MMS for briefings about the pilot concepts and methodology. One of the more prevalent topics of discussion raised by these organizations was the issue of the pilot's revenue neutrality. The MMS felt that it could take precautions to alleviate concerns that the pilot would cause the government to lose considerable amounts of revenue.

To that end, MMS analyzed each lease's royalty history from November 1993 through July 1994 and determined its weighted average per unit revenue in relation to the index stated in Section B of the IFB. The MMS then calculated the aggregate amount the government could expect to receive for November 1994 royalties using the historic averages, the applicable

November 1994 price indices, and the estimated volumes from the IFB. The MMS used this aggregate amount as a baseline to test overall bid adequacy. The MMS also had tests to evaluate individual bid group bids during the bid evaluation process, but they were not necessary because the bids, in the aggregate, exceeded the baseline.

The historical data are unaudited, so the revenue may be slightly lower than what the government would have received had the royalties been paid in value. In any case, the test was merely to provide a comfort level prior to beginning the pilot.

Bidder qualifications and financial guarantees.

The MMS had considerable discussion as to whether or not to require successful bidders to post surety guaranteeing performance under the contract. On the one hand, protecting the government's interests was a concern. However, MMS also was concerned that requiring surety would result in downward adjustments to the bid prices. As a compromise between these two primary concerns, MMS decided that it could forego sureties (other than the bid guarantee under IFB Section K.7.) if it was assured that bidders were experienced and financially sound.

To accomplish this, the bidders were required to submit "...financial information adequate for the Contracting officer to determine that it is financially responsible..." (Section K.10. of the IFB). The bidders also were required to execute a "Bidder Qualification Certification" attesting that they had marketed not less than $20 million of natural gas during each of the last 5 calendar years (Exhibit B of the IFB). The MMS' consultant advised that these two requirements would ensure that only experienced, financially responsible natural gas purchaser/marketers would be awarded contracts.

In addition, MMS wrote specific provisions for payment in the event of breach into the IFB and resultant contracts (Section C.5. of the IFB). These provisions required the purchaser to pay for all of the royalty gas made available during the term of the contract, whether taken or not, until such time as MMS was able to sell the breach gas to a third party. If MMS would have been able to sell the gas to a third party, the original purchaser would be liable for the difference between the price received by MMS under the new contract and the original purchaser's bid price. In some cases, this difference could be several cents per MMBtu.

Default (breach of contract) provisions.

Because of the severe penalties for breach (discussed in the paragraph immediately above), it was important that the IFB and contract be explicit as to what constitutes breach. The definitions and sanctions appear in C.5., H.1., and H.2. of the IFB. Briefly, MMS could have declared breach if the purchaser:

- Failed to provide nominations for all the royalty gas made available for

3 consecutive days;

- Failed to take the royalty gas made available because of a curtailment of interruptible transportation or a non force majeure curtailment of firm transportation;

- Had a repeated sequence of delays in nominating or taking royalty gas; or

- Failed to pay for any royalty gas made available.

In addition to the liability for the bid value of royalty gas, a purchaser declared to be in breach would have been liable for any pipeline penalties imposed as a result of the breach.

Reporting and payment instructions.

During the volunteer agreement negotiations, MMS decided to make reporting for royalty gas on Forms MMS-2014 the purchasers' responsibility. There were several reasons for this, the main one being that it was consistent with the fact that the purchasers would be the ones submitting payments for the royalty gas. Another reason was the fact that this would provide built-in cross checks that would ensure that the purchasers were paying for the correct volumes.

The reports and payments were to be based on statements the purchasers received from the operators and the pipelines, thereby providing the purchasers a degree of comfort. The MMS, in turn, verified the volumes to the operators' production reports. As a further cross-check, the lessees agreed to provide monthly imbalance reports to MMS and the purchasers.

Another reason to have the purchasers report rather than the lessees was to determine if it would significantly reduce the lessees' administrative burden without adversely affecting bid prices or reducing accuracy. The MMS felt that it would be more logical and efficient, especially in the event MMS made the RIK program permanent, for a purchaser to report royalties in conjunction with payments rather than requiring the lessees that were providing the royalty gas to report it separately.

The MMS decided to adopt the industry standard for payments and have them due on the 25th of the month following the delivery month. This is a few days earlier than royalty payments generally are due, thereby providing the government with time value of money; this uplift was considered in the revenue impact analysis.

VOLUME RECONCILIATION AND SUMMARY OF PROBLEMS

Reports Submitted to MMS

Gas volumes were reported on three different monthly reports: 1) Sales Quantity and Royalty Quantity on Form MMS-2014 (2014) by the gas marketer, 2) Gas Volumes Sold/Transferred to Facility on the Oil and Gas Operations Report (OGOR) by the operator, and 3) Entitlement and Delivered gas volumes on the Gas Imbalance Statement (GIS) by the lessee. The GIS report was unique to the pilot and included: 1) actual royalty gas quantities produced from or attributable to the pilot leases/agreements, 2) actual takes of royalty gas by the Contractor, and 3) the overtakes or undertakes of royalty gas by the Contractor.

All three reports contained the gas Btu content, except for the OGOR when the gas was reported as “Transferred to Facility”. The Btu content is a critical element of the reconciliation process as contractor’s payments were to be made on an MMBtu basis (MCF volume times the Btu content).

Volume Reconciliation Procedures

1) Form MMS-2014 Royalty Quantity vs. GIS Delivered Quantity

We compared the Royalty Quantity (Mcf) and Btu content from the 2014 with the Delivered Volume (Mcf) and Btu content from the GIS to ensure that the contractors paid royalties on the correct MMBtu volume. The contractor’s reported volumes were correct 80 percent of the time using a ±50 MMBtu tolerance and 92 percent of the time using a ±1000 MMBtu tolerance.

The majority of the misreporting was due to the contractors and/or lessees not allocating correctly between leases whose production was measured at the same facility measurement point; therefore, many exceptions canceled each other out. There were also instances where the Mcf volumes and Btu contents did not match each other individually, but the MMBtu’s did. This was due to contractors and/or lessees not reporting the Mcf volumes and/or Btu content at the required 15.025 pressure base.

Based on this volume reconciliation, on an aggregate basis, contractors at year-end under reported 51,998 MMBtu to MMS with an approximate value of $64,000. However, 51,367 MMBtu is attributable to two leases for one sales month and the contractor has been asked to review its records and make any necessary adjustments. Final reconciliation of any monthly contractor reported lease volumes will occur after all lessees have finished their year-end balancing, as we will assume that all adjustments have been made and the GIS Delivered Volume is correct.

2) OGOR Entitlement Volume vs. GIS Entitlement Volume

We compared the MMS calculated OGOR Entitlement Volume (volume times 1/6) to the Entitlement Volume from the GIS for sales months January - June 1995 to determine if the operator's OGOR volume equaled the lessee's GIS volume. For leases and agreements where 100 percent of production was dedicated to the pilot (48 of 79) the volumes generally equaled except for the differences caused by misallocation between leases or problems caused by using an incorrect pressure base.

On properties with less than 100 percent Working-Interest-Ownership (WIO) percentage dedicated to the pilot (31 of 79), the GIS Entitlement Volume generally did not equal the calculated OGOR Entitlement Volume. The GIS Entitlement Volume is the lessee's take, which will not equal the lessee's entitled allocation as calculated from the OGOR. MMS/contractor gas volumes are allocated and paid proportionate to the lessee's partner's deliveries. Other WIO partners not involved in the RIK pilot were continuing to allocate and pay MMS in-value royalties based on their deliveries. To ensure that MMS was kept whole, the lessee allocated MMS royalty volumes on the same basis as its partners.

There appears to have been some confusion between the pilot team and the volunteer lessees over some of the language of the Royalty-In-Kind Pilot Program Agreement concerning entitled volumes. The lessees indicated that the intent of the parties was that the lessee's obligation to deliver gas to the MMS gas marketer would be determined and satisfied based on an actual takes basis rather than an entitlement basis.

For example, if a lease had multiple WIO's and only one lessee volunteered its share of production, the marketer would only receive 1/6 of what the volunteer lessee actually took, not what it was legally entitled to. One lessee volunteered its 65 percent WIO share of the lease's production, but throughout the pilot year took anywhere from 64-75 percent of the gas and made 1/6 of it available to our marketer.

The Compliance Verification Division will need to follow up on any pilot leases where there were also in-value payors after the RIK volumes are reconciled. Since the RIK contractor's volume is based on their actual takes, regardless of their WIO percentage, whatever volumes they reported on the 2014 are assumed to be correct. Therefore, any over or under reporting of volumes will to be attributed to the in-value payor(s), not the RIK contractor.

Final Year-End Balancing

Section 5.5 of the Royalty In-Kind Pilot Program Agreement stipulates the terms for settling any year-end imbalance which may exist whether the lessee owed gas to the lessor or vice versa. In either event, the final imbalance is valued based on the contractor's bid price per

MMBtu at each

point of delivery at the time said imbalance was accrued. The lessees either will pay MMS additional monies or request a refund.

The lessee also had the option of settling any year-end gas imbalances by making available equivalent quantities of gas, of similar quality and equivalent value, at agreed upon points of delivery. However, none of the lessees chose this option.

The agreement also stated that the final GIS was due 30 days after the pilot ended (December 31, 1995) or 15 days after the lessee came into possession of all necessary information for the last delivery month, whichever was later. The lessee was to notify MMS of its method of settlement 15 days after it issued its final GIS.

Based on the final lease gas imbalances, 47 of 79, or 60 percent, of the pilot leases had a year-end imbalance. In the aggregate, MMS' contractors were under-delivered by 35,958 MMBtu as compared to the 48,587,550 MMBtu reported for the pilot or 0.064 percent. As of July 22, 1996, 6 of the 10 lessees needing to settle imbalance differences had their settlement volumes and values approved by the team with the remaining 4 still in progress.

AUDIT COLLECTION STATISTICS
SOURCE: *1994 MINERAL REVENUES REPORT*

Year	Audit Collections	Royalties	Percent
1985	$75,433,000	$4,771,191,975	1.58%
1986	$115,930,000	$3,329,159,704	3.48%
1987	$79,384,000	$3,138,362,618	2.53%
1988	$52,201,000	$2,840,419,213	1.84%
1989	$107,416,000	$2,977,090,743	3.61%
1990	$65,966,000	$3,743,724,858	1.76%
1991	$97,003,000	$3,381,795,421	2.87%
1992	$122,670,000	$3,399,013,251	3.61%
1993	$140,493,000	$3,641,478,156	3.86%
1994	$267,787,000	$3,456,089,810	7.75%
Totals	$1,124,283,000	$34,678,325,749	3.24%

INTERNAL ADMINISTRATIVE SAVINGS ANALYSIS

We considered different ways to estimate the potential administrative cost savings that the Minerals Management Service (MMS) could achieve with an expanded gas royalty-in-kind (RIK) program in the Gulf of Mexico (GOM). This appendix presents the results of the method we chose**.**

Introduction

In performing our analysis of potential administrative cost savings, we identified functions that could be eliminated or decreased, along with new functions that would be required as a result of taking our royalty gas in kind. Potential administrative cost savings were estimated based on discussions with the divisions regarding what each division currently does for GOM gas leases, compared to what they would do under a permanent gas RIK program. Net Receipt Sharing data was used to verify the results and produced substantially the same results. (Net Receipt Sharing is a method legislated by Congress for MMS to deduct its costs from the states who receive federal royalties from leases within their state.) The pilot represented less than
6 percent of MMS' share of royalty gas in the GOM. Therefore, certain assumptions had to be made to project administrative cost savings and cost increases associated with a permanent program.

For this report we are using the following assumptions to project administrative cost savings:

- A permanent program would have contract terms and conditions similar to the pilot.
- The MMS would take approximately 100 percent of its GOM gas royalties in kind, including Section 6 and Section 8(g) leases.
- The MMS would realize savings only if the program became permanent (any temporary program requires us to remain able to provide our current level of service once a pilot has ended).
- The MMS would not realize audit or valuation savings until after the audit cycle is completed for the period during which royalties were paid in value (approximately 6 years after a permanent program begins).
- The average cost per FTE[1] is $68,000 including salary, benefits, and other associated costs such as travel, training, supplies, and equipment.

As anticipated, there were no actual administrative cost savings from the pilot because of the small percentage of leases involved. With less than 6 percent of GOM gas royalties being taken in kind, all activities associated with taking our royalties in value for the GOM

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[1] Full Time Equivalent. This represents the equivalent of one full time employee.

continued

and we incurred additional costs to run the pilot. We would not have administrative cost savings unless we take a substantial volume of gas in kind.

There would be marginal cost savings before the audit cycles on royalties paid in value have been completed because we would have to continue performing audits on such royalties during the first 6 years of the program. The MMS also would incur additional costs to administer a program where we take our gas royalties in kind.

We have projected potential administrative cost savings that could be realized after the program has been functioning for 6 years. There would be incremental administrative cost savings during the first 6 years; there also would be certain cost increases during this period to get the program functioning. Below are additional one time costs that would need to be considered:

- Reduction in Force costs
- Computer programming costs

If MMS were to take 100 percent of the GOM royalty gas in kind, the total annual administrative cost savings that might be realized, after the audit cycle for royalties taken in value is completed, is approximately $3.6 million, as summarized below:

Changes to Administrative Costs

	FTE's		Dollar Savings
COST SAVINGS			
Audit	44.5	$	3,026,000
Valuations and Standards Division	3.9	$	265,200
Compliance Verification Division	0.0	$	0
Data Management Division	0.0	$	0
Office of Enforcement	0.0	$	0
Reports and Financial Division	0.0	$	0
Systems Management Division	0.0	$	0
Administrative Operations and Executive Direction	9.4	$	639,200
Subtotal Cost Savings	57.8	$	3,930,400

COST INCREASES

Royalty Management Program	(4.0)	$	(272,000)
Offshore Minerals Management (OMM) GOM Region	(1.0)		$(68,000)
Subtotal Cost Increases	(5.0)	$	(340,000)
Net Administrative Cost Savings	52.8	$	3,590,400

These areas are discussed below.

Cost Savings

Audit

Audit comprises the Dallas Compliance Division, the Lakewood Compliance Division, the Houston Compliance Division, the State and Indian Compliance Division, and the Audit share of the Deputy Associate Director (DAD) for Compliance staff. Audit has the primary responsibility for performing valuation and volume audits for oil, gas, geothermal, coal, and other minerals produced on federal onshore and offshore lands and Indian lands.

Audit potentially could realize a savings of approximately 44.5 FTE's if MMS takes its GOM royalty gas in kind. The FTE savings for Audit are summarized below.

Area	FTE's
Audit Residencies	22.0
Other Major Payors	22.5
Potential Audit Savings	44.5

The FTE's that potentially could be affected by a GOM gas RIK program were identified as follows:

Total FTE's		234
FTE's unaffected by GOM gas taken in kind		
State and Indian Compliance Division	26	
Contract Settlements[2]	80	
Subtotal		106
FTE's potentially involved in GOM gas		128
Residencies	55	
Other major payors	73	

Residencies

There are 55 people assigned to 11 residencies, averaging 5 FTE's each. Three FTE's are needed for onshore, Indian, offshore oil, Pacific offshore oil and gas, non-GOM gas special projects, supervision, and administrative work. Two FTE's are needed for GOM gas valuation work, resulting in a potential savings of 22 FTE's if all GOM royalty gas is taken in kind.

Other major payors

There are approximately 20-25 other major payor audits performed each year. These range from a staff load of two to four auditors. Two FTE's are needed for onshore, Indian, offshore oil, Pacific offshore oil and gas, non-GOM gas special projects, supervision, and administrative work. One FTE is needed for GOM gas valuation work, resulting in a potential savings of 20 to 25 FTE's if MMS were to take its GOM gas in kind. For this report we used the midpoint of 22.5 FTE's.

[2] The MMS has been auditing contract settlements, which were modifications to gas sales contracts that contained unrealistic purchases prices and/or volumes, to determine whether royalties were due on the monies received. This work would not be affected if MMS were to take its GOM royalty gas in kind, since the audits are for prior periods.

DAD Compliance staff

Based on interviews with DAD Compliance staff, there are no resources at the DAD Compliance staff level that currently are involved with GOM gas issues.

Valuation and Standards Division

The Valuations and Standards Division (VSD) comprises the Economic Valuation Branch, the Oil and Gas Valuation Branch, the Solid Minerals Valuation Branch, and the Division staff. The VSD is involved in a wide range of valuation determinations and transportation and processing allowance approvals, and in outreach, for oil, gas, geothermal, coal, and other minerals for onshore, offshore, and Indian lands.

The VSD potentially could realize savings of approximately 3.9 FTE's if MMS were to take its GOM royalty gas in kind. The FTE savings for VSD are summarized below.

Area	**FTE's**
Economic Valuation Branch	1.0
Oil and Gas Valuation Branch	2.0
Management, Administration, and Support	0.9
Potential VSD Savings	3.9

The FTE's in VSD that potentially could be affected by a GOM gas RIK program were identified as follows:

Total FTE's		34.5
FTE's unaffected by GOM gas taken in kind		
Solid Minerals staff	8.0	
FTE dedicated to Indian major portion analysis	3.0	
FTE dedicated to geothermal valuation and policy	1.0	
Cooperative student	0.5	
Subtotal		12.5
FTE's that work with oil and gas valuation, management, and support (identified below)		22.0

Oil and Gas Valuation Branch	8.0
Economic Valuation Branch	6.0
Management, Administration, and Support	8.0

Oil and Gas Valuation Branch

The 2.0 FTE savings in the Oil and Gas Valuation Branch were determined by taking the 8.0 FTE's that work with oil and gas valuation times 25 percent (estimated ratio of GOM gas efforts to all branch efforts).

The current Oil and Gas Valuation Branch workload that would be unaffected or largely unaffected by GOM gas taken in kind includes:

- Federal onshore, Indian, and Pacific offshore gas valuation determinations;
- Federal onshore, offshore, and Indian oil valuation determinations;
- Product valuation regulation drafting/writing for oil and onshore gas;
- Internal valuation policy development for oil and onshore gas;
- Valuation training for internal and external customers;
- Appeals on federal onshore, Indian, and Pacific offshore gas valuation matters;
- Appeals on all oil valuation matters;
- Freedom of Information Act requests; and
- Non-standard Indian agreement review/comment.

The current Oil and Gas Valuation Branch workload that would be eliminated if all GOM gas were to be taken in kind includes:

- GOM gas valuation determinations
- Appeals on GOM gas valuation matters

Economic Valuation Branch

The 1.0 FTE savings in the Economic Valuation Branch was determined by taking the 6.0 FTE's that work with oil and gas valuation times 16.67 percent (estimated ratio of GOM gas efforts to all branch efforts).

The current Economic Valuation Branch workload that would be unaffected or largely unaffected by GOM gas taken in kind includes:

- Federal onshore, Indian, and Pacific offshore gas processing allowance limitation exception requests review and approval;
- Federal onshore, Indian, and Pacific offshore gas transportation allowance limitation exception requests review and approval;
- Offshore, onshore, and Indian oil transportation allowance limitation exception requests review and approval;
- FERC oil tariff exception requests;
- Posted price bulletin maintenance and support;
- Net profit share lease support;

- Royalty rate reduction requests;
- General economic analysis/advice concerning tax proposals, oil futures market, depreciation, netback applications, rate of return, and capitalization; and
- Appeals related to above.

The current Economic Valuation Branch workload that would be eliminated if all GOM gas were to be taken in kind includes:

- GOM offshore gas processing allowance limitation exception requests review and approval;
- GOM offshore gas transportation allowance limitation exception requests review and approval; and
- Appeals related to above.

VSD Management, Administration, and Support

The 0.9 FTE savings in Management, Administration and Support (MAS) was determined by taking the 8.0 FTE's in MAS times 11.32 percent (ratio of estimated FTE savings for VSD [3] to remaining positions other than MAS [26.5]).

The VSD's MAS positions are identified below:

Division Chief and Secretary	2.0
OGVB Chief and Secretary	2.0
EVB Chief and Secretary	2.0
Budget/Procurement/Administrative support	1.0
LAN and Other Hardware/Software Support	1.0
Total MAS FTE	8.0

Compliance Verification Division

The Compliance Verification Division (CVD) comprises the Financial Compliance Branch and the Production Accountability Branch. The CVD is responsible for AFS/PAAS comparisons, geothermal exception processing, various royalty rate issues, the Liquid Verification System, the Gas Verification System, various exception monitoring systems including late payment, insufficient estimates, financial lease terms, injection balancing, and transportation and processing allowances, and various other monitoring systems including offshore refunds/recoupments/cross lease netting, Indian recoupments, adjustments, royalty rate, and Indian severance tax.

The CVD would not realize net savings if MMS were to take its GOM royalty gas in kind.

Financial Compliance Branch

Areas that would not be affected by a GOM gas RIK program:

- Financial Lease Term Exceptions,
- Insufficient Estimate Monitoring,
- Indian Recoupment Monitoring,
- Adjustment Monitoring,
- Royalty Rate Monitoring,
- Indian Severance Tax Monitoring,
- Transportation and Processing Allowance Exceptions, and
- Special Projects not related to GOM RIK Gas.

Areas that potentially could be affected by GOM RIK gas:

- Offshore Refunds/Recoupments/Cross Lease Netting
- Late Payment Exception Processing

There would be a potential savings of one FTE for offshore refunds/recoupments/cross lease netting and a potential savings of two FTE from the Source One Management contract. Late payment exception processing would have a reduction of about 7.46 percent. This relatively small savings should be offset, at least partially, by an increased workload caused by having additional payors, resulting in additional Form MMS-2014 and additional late payment exceptions.

Production Accountability Branch

Areas that would not be affected by a GOM gas RIK program:

- Geothermal Exception Processing,
- Royalty Rate Exception Processing,
- Liquid Verification System,
- Gas Verification System, and
- AFS/PAAS comparisons for non-GOM gas exceptions.

Areas that potentially could be affected by a GOM gas RIK program:

- AFS/PAAS Comparisons for GOM gas exceptions

There are approximately 4.34 FTE’s involved in offshore AFS/PAAS comparisons. Approximately 70 percent, or 3.0 FTE’s, are involved with GOM gas exceptions. The CVD believes that this is the amount of FTE’s that would be required if MMS were to take its GOM gas in kind.

Data Management Division

The Data Management Division (DMD) comprises one branch and the division staff. The DMD is responsible for all lease and Payor Information Form (PIF) work and reference data related Form MMS-2014 error correction for terminable and non-terminable leases, Indians, states, and federal treasury accounts for oil, gas, geothermal, coal, and other minerals for onshore, offshore, and Indian lands.

There is a potential of only a fraction (.016) of an FTE savings in DMD; therefore this amount is not included in the above summary. There are only two FTE's in DMD that work with offshore leases, and the amount of time that is spent on the GOM gas PIF work that would be eliminated is negligible.

The FTE's in DMD that potentially could be affected by a GOM gas RIK program were identified as follows:

Total FTE's		41
FTE's unaffected by GOM gas taken in kind		
Rentals staff	4	
Solid Minerals staff	5	
Onshore lease, PIF, and error correction staff	18	
Division staff	12	
Subtotal		39
Offshore lease, PIF, and error correction staff		2

Offshore Lease, PIF, and Error Correction staff

There are two FTE's that are dedicated to offshore lease work, PIF work, and reference data-related error corrections. The lease work would be unaffected by taking GOM gas in kind. This work represents about .5 FTE. The PIF work represents about one FTE. This work would have a minor change as the workload would go from having an established PIF data base that is revised as needed to reflect changes in payors to a data base that has to be established from the ground up with every new gas RIK contract. The change in PIF workload would only be a fraction of an FTE, and would not represent an FTE savings or additional cost. Reference data-related error correction represents about .5 FTE. GOM gas error correction represents 29 percent or .145 FTE. Based on the pilot, about 80 percent of the GOM gas lines would be eliminated, so the FTE savings would be .016 (.145 FTE committed to GOM gas error correction times 80 percent).

Office of Enforcement

The Office of Enforcement (OE) is responsible for debt collection, settlements, Notices of Noncompliance, Equal Employment Opportunity, and bankruptcy coordination for oil, gas, geothermal, coal, and other minerals for onshore, offshore, and Indian lands.

There is a potential of only a fraction (.10) of an FTE savings in OE, therefore this amount is not included in the above summary.

The FTE's in OE that potentially could be affected by a GOM gas RIK program were identified as follows:

Total FTE's		25.0
FTE's unaffected by GOM gas taken in kind		
Debt Collection Section	13.0	
FTE dedicated to Notices of Noncompliance	3.0	
Equal Employment Opportunity	2.0	
FTE dedicated to bankruptcy coordination	1.0	
Subtotal		19.0
FTE's that work with settlements involving various minerals on onshore, offshore, and Indian lands		6.0

Settlements

We reviewed tracking system information from the 37 open settlement cases and determined that only 2 settlement cases contained substantial offshore GOM gas valuation issues. Both cases also involve onshore issues and other matters (statute of limitations, administrative offset, etc.). The OE estimates that 40 percent of the workload of these cases involve GOM gas valuation issues. Therefore, we multiplied the 6.0 FTE by .02 (percent of open cases relating to GOM gas) to determine an estimated savings of 0.12 FTE for OE if MMS were to take its GOM gas in kind.

Reports and Financial Division

The Reports and Financial Division (RFD) is made up of the Reports Branch, the Financial Branch, and the division staff. The RFD is responsible for the financial aspects of RMP including the general ledger, cash applications, and the distribution and disbursement of all revenues to the Indians, states, and federal treasury accounts for oil, gas, geothermal, coal, and other minerals for onshore, offshore, and Indian lands. In addition, RFD is responsible for the oil RIK program and royalty and production reporting.

There is a potential of only a fraction (.064) of an FTE savings in RFD; therefore, this amount is not included in the above summary. The FTE's in RFD that potentially could be affected are royalty error correction and payor account reconciliation. Both of these areas currently expend very minimal time on GOM gas leases and there would not be a measurable savings if MMS were to take its GOM gas in kind.

The FTE's in RFD that potentially could be affected by a GOM gas RIK program were identified as follows:

Total FTE's		94
FTE's unaffected by GOM gas taken in kind		
General Ledger Section	8	
Distribution and Disbursements Section	9	
Royalty-In-Kind Section (Oil)	7	
Production Error Correction	10	
Document Processing	9	
Division and Branch staffs	24	
Subtotal		67
FTE's potentially affected by GOM RIK gas		27

Royalty Error Correction Section	12
Cash Application Section	15

The Royalty Error Correction Section (RECS) has eight FTE's dedicated to error correction. There are about 80 rejected GOM gas lines each month that are corrected by RECS. Based on the pilot, about 80 percent of these lines would be eliminated, for a savings of about 64 lines each month. This reduction in error lines would not result in any FTE savings.

The Cash Application Section (CAS) is responsible for onshore terminable leases, payor account reconciliations, and cash applications. Payor account reconciliations and cash applications involve GOM gas leases, as well as all other products in the GOM, Pacific offshore, federal onshore, and Indian leases. Payor account reconciliation involves six FTE's and cash applications involves three FTE's. Both of these functions are document driven, not lease or product type driven. Therefore, there would be a small savings resulting from elimination of any documents that contained only GOM gas leases. This savings would be minimal because there are very few, if any, payors who currently report only GOM gas leases. There would be a minor cost increase in both of these functions as new gas marketing payors would be added, resulting in more documents to be worked. The RFD believes that any change in work load in these two areas would be so minimal that no change in FTE's would be required.

Systems Management Division

The Systems Management Division (SMD) is responsible for providing information and data systems services for RMP and its constituencies. The SMD's services include operations and maintenance of the RMP Mainframe Data Center, telecommunication network support, training, electronic data interchange, electronic messaging, and contract support. The work is performed by 52 SMD FTE and approximately 146 employees of the contractor firm, AMS/OC. The system supports all RMP efforts involving oil, gas, geothermal, coal, and other minerals for onshore, offshore, and Indian lands.

The SMD and related contractor costs are generally fixed in nature. Any reduction in lines processed due to taking gas in kind would not result in savings in computer operations or maintenance. In fact, SMD may incur additional costs if MMS were to take its GOM gas in kind should any system software changes be necessary to support the new collection approach. We have noted the effect of any potential system changes in the functional area which would need the change. Therefore, we did not identify any potential savings or costs specifically for SMD resulting from MMS taking its GOM gas in kind.

Administrative Operations and Executive Direction

Administrative Operations and Executive Direction (AOED) comprises the staffs of the Director's Office and the Associate Directors for Administration and Budget and Policy and Management Improvement, including appeals staff.

There is a potential savings of 10.4 FTE's for AOED. These savings are summarized below.[3]

Area	**FTE's**
Administrative Operations	7.4
Executive Direction	2.0
Potential AOED Savings	9.4

[3] The projected savings for AOED (other than appeals staff) were calculated on a pro rata basis, with the assumption that a net reduction in Royalty Management Program (RMP) and OMM staffs would result in a corresponding reduction in support staff. The projected savings in appeals staff were identified by analyzing current workload.

The FTE's in AOED that potentially could be affected by a GOM gas RIK program were identified as follows:

	RMP	OMM	Totals
Current FTE levels	660	858	1518
Levels needed for GOM gas in-kind program	615.6	859	1474.6
Percentage increase/(decrease)	-6.73%	0.12%	-2.86%

Administrative Operations Staff	170	
Percentage Decrease in RMP/OMM Staffs	-2.86%	
Potential FTE savings in Administrative Operations staff		-4.9
Potential FTE savings in Appeals staff		-2.5
Executive Direction staff	70	
Percentage decrease in RMP/OMM staffs	-2.86%	
Potential FTE savings in Executive Direction staff		-2.0
Total AOED potential savings		-9.4

Cost Increases

Area	FTE's
RMP	4.0
OMM - GOM Region	1.0
Potential MMS FTE Increases	5.0

There will be certain additional costs that will be incurred if MMS were to take 100 percent of its GOM royalty gas in kind. We estimated that RMP would need four FTE's to do the tasks unique to the administration of the pilot that were performed by the pilot team. Their duties would include:

- program administration,
- contract administration,

- contract price verification and pricing exception follow-up, and
- contract reconciliation and close-out activities.

The OMM's Gulf of Mexico Region estimates that a permanent program would require an additional FTE for the tasks that they would be required to perform on an on-going basis. The FTE would be needed because of:

- the ever changing flow of production from throughout the Gulf of Mexico into different pipeline systems (involving different indexes) for operational and/or economic reasons;
- over 30 major deepwater projects;
- an additional 1,700 leases projected for FY 1997; and
- the impact of the royalty relief act on the flow of production.

Conclusion

Based on the method described in this appendix, if MMS were to take a substantial volume of the Gulf of Mexico royalty gas in kind, the total annual administrative cost savings that might be realized are approximately $3.6 million. This represents a savings of approximately $.0044 per MMBtu.

Appendix 12

EARLY EXAMINATION OF GAS ROYALTY-IN-KIND BY THE MINERALS MANAGEMENT SERVICE

The changes in the U.S. gas market fostered by the Federal Energy Regulatory Commission (FERC) Order 636 and earlier deregulation prompted the Minerals Management Service (MMS) to explore more efficient ways to manage gas royalties. In early 1994, the Assistant Secretary for Land and Minerals Management and the Director, MMS, suggested an examination of royalty-in-kind (RIK) procedures for the royalties on gas produced on federal leases. They were familiar with the gas RIK program in Texas in which a portion of the State's gas royalties is taken, on an in-kind basis, and used in state facilities such as schools, prisons and public office complexes. In making their suggestion, the Assistant Secretary and the Director, MMS, sought to determine if such an approach for federal royalty gas would (1) reduce administrative costs associated with federal gas royalty collections and (2) enhance net federal royalty revenues.

In February of 1994, the Associate Director for Policy and Management Improvement (PMI) within MMS commenced an assessment to determine if administrative cost savings and federal revenue enhancements could be achieved within the context of a Federal RIK program patterned after that employed in Texas. Attainment of these objectives would hinge, in major part, on the extent to which Federal RIK gas could be the least costly source of supply for federal facilities around the United States. Could Federal RIK gas be delivered to military installations, prisons and office complexes at a cost which would justify displacement of conventional sources of gas supply? Also, would there be administrative savings for MMS and industry in taking the RIK gas at the lease and then taking responsibility for its delivery at the location of the federal end user?

In attempting to answer these questions, PMI staff met with representatives from the Defense Fuel Supply Center (DFSC) of the Department of Defense (DOD). The activities of the DFSC were relevant to MMS's efforts since, in addition to buying gas for Defense installations, DFSC buys gas for the Department of Energy (DOE), Veterans Administration medical centers around the country, the Social Security Administration, Internal Revenue Service (IRS) of the Department of the Treasury and other sundry federal facilities outside of the Defense Department. The program had reduced gas acquisition costs for the various participating agencies. Of particular interest was the fact that the DFSC had revamped its gas procurement program to reflect changes which had occurred in the gas market. As part of this revamping, DFSC had moved to a policy of dealing strictly with marketing companies in obtaining gas at the lowest possible price. DFSC has no contractual arrangements with any gas producers which means that they are not committed to purchasing gas from particular sources. This information raised concerns about the role of Federal RIK gas in such an effort if we were committed to supplying gas to particular federal customers. The meeting suggested that MMS may not be able to establish a longer term contractual arrangement with federal users in which Federal RIK gas would consistently be the lowest-cost source of gas.

PMI staff also had several conversations with DOE representatives to learn about DOE's sales procedures for gas from the Naval Petroleum Reserve in California. In these sales, DOE had attempted to act as their own marketing company, but had achieved only limited success. One failed marketing venture included an attempt to market gas to the DFSC of the Department of Defense. This experience prompted DOE to begin selling gas to marketing companies. In the sale of gas to marketing companies, DOE issued a Request for Bids (RFB) but at the time of these conversations DOE was considering streamlining their procedures by moving to a simpler Invitation for Bids (IFB). These initial conversations were useful in the later drafting of the IFB used in the MMS Royalty Gas Marketing Pilot.

Since PMI's task was in major part to learn more about the Texas RIK Program and its applicability to MMS gas royalty issues, a meeting was arranged with the managers of the Energy Marketing Program of the Texas General Land Office (GLO) in Austin Texas. From this meeting, PMI staff were able to gather the following information regarding the Texas RIK program for gas: (1) Texas remained prepared to sell a certain percentage of in-kind gas on the spot market. (25 to 35 percent). In the Texas RIK program, the proportion of the gas which is sold on the spot market is determined by the difference between projected monthly supply of gas and the demand for gas from customers. (2) In the Texas program, in-kind gas is not taken at the lease unless the sales point is at the wellhead. If the gas is processed gas, Texas receives its share of the in-kind residue gas and is paid in cash for the royalty portion returned to the lessee. Gas liquids are not taken in kind but a royalty is collected on the sales value of the liquids. (3) In the Texas program, the GLO takes the gas at the first sales point. If transportation costs are incurred by the operator in getting the gas to the sales point, there is no allowance for these costs. (4) The GLO employs a marketing representative to coordinate the sales and transportation of gas throughout the State.

PMI raised the following concerns and issues in assessing the applicability of Texas system to federal gas royalties:

> (1) If MMS were to adopt a Texas type of system for RIK gas, the MMS could simply not take the gas and let the lessee pay a conventional royalty RIK in those instances in which supply were to exceed demand during any particular time period. However, such an approach would increase the uncertainty faced by federal lessees in being able commit specific volumes of gas to a particular purchaser.
>
> (2) In the Texas program the GLO takes the gas at the sales point. If transportation costs were incurred by the federal lessee in transporting the gas to the sales point, there would be no allowance for these costs. For the MMS supplying gas to particular federal customers, the Agency would want to operate in a similar manner. However, such an approach would be at odds with the current regulatory practice of granting transportation allowances.

(3) A system such as the Texas Energy Marketing Program would impose financial burdens on gas producing lessees which are not currently borne under federal royalty regulations. Most obviously, this additional burden would arise from the manner in which allowances are handled under Texas system. In the Texas program, in-kind gas is not taken at the lease. If the gas is processed, no allowance is granted to lessees for processing costs. Gas liquids are not taken in kind; however, a royalty is collected on the sales value of the liquids. A system such as the Texas Energy Marketing Program would impose additional financial burdens on federal lessees because of the manner in which allowances are handled. Any steps that might be taken to rectify the problem with allowances would probably increase the administrative burden on the MMS or decrease revenues, or both.

(4) A federal gas RIK program designed along the lines of the Texas Energy Marketing Program would be premised on MMS' ability to actually market gas to other federal facilities. However, the failed attempt by DOE to market gas to DOD was not encouraging. Negotiations between these Departments were not successful. Currently, DOE sells all its gas to marketing companies. In light of DOE's experience, it was not clear that MMS would have had a viable niche in selling in-kind royalty gas to particular federal customers. As noted above, other Departments make gas purchases through marketing companies to obtain gas as inexpensively as possible--regardless of the source. It appeared unlikely that MMS could establish a longer term contractual arrangement with federal agencies in which the Federal RIK gas would consistently be the lowest-cost source of gas. From the purchaser's perspective, lost flexibility and payment of higher prices could be the result of a long-term commitment to purchase gas from a particular source. From MMS's perspective, it appeared that higher prices for the in-kind gas may be obtainable by not targeting particular customers--federal or otherwise.

Subsequent to the meeting with the managers of the Texas Energy Marketing Program, PMI began to explore the possibility of using competitively chosen marketing companies to dispose of Federal RIK gas. Two alternatives were addressed initially: (1) using marketing companies as agents in the sale of MMS gas; and (2) selling the gas directly to marketing companies at the lease. In these alternatives, no attempt would be made to channel or steer the gas the federal facilities or particular customers. Given that fair market value could be ensured in the sale of the gas to marketing companies in a truly competitive environment, the ultimate disposition of the gas would be of no concern to the Minerals Management Service.

PMI staff conducted an informal survey of eight marketing companies. This sample included marketing firms which are affiliates of larger integrated firms, marketing firms which are not affiliates but own their own pipelines and companies committed solely to the marketing of gas. These companies were asked a series of questions on a variety of issues which would be critical to any gas RIK program or pilot into which MMS might enter. For example, under an arrangement in which the companies were making an outright purchase, they were asked how price would be determined. Each of the companies said that the price would be an "indexed price" but that they could be flexible in accommodating our needs. The price would be based on a published price with an adjustment. Each company expressed a willingness to function as as a marketing intermediary in selling the federal gas. In response to a question on the fee per Mcf to market Federal RIK gas, the commonly quoted range was $0.02 - $0.03 per Mcf. These companies made clear the fact that the margin would be lower with larger volumes. Also, the margins could be affected by other considerations such as the number of locations involved. When asked if there were a minimum volume of RIK gas that would make this effort worthwhile for their company, the most common response was 10,000 Mcf per day but most of the companies said that they could be flexible. Also, since the gas would be taken at the lease, companies were asked about the requisite condition of the gas at the time that the gas is taken; all companies said that would be willing to take the gas at the lease after simple separation. When asked about the preferred length of the contract, the answers ranged from 30 days to one year.

In April, the staff of PMI prepared a memorandum to the Director, MMS, recommending a pilot to test royalty-in-kind collection procedures for federal offshore gas. The memorandum specified two possible options for consideration:

(1) testing the viability of taking RIK gas from the production of selected offshore leases in the Gulf of Mexico and distributing the gas to federal facilities in Texas and Louisiana, or

(2) testing a procedure in which RIK gas would be taken at the lease and sold to a competitively chosen marketing company at that point.

In an April 22, 1994 meeting, the Director decided upon option 2 since it seemed to offer a more efficient way to take advantage of the recent developments which had occurred in the gas market as a result of recent deregulation. Also, questions over pipeline access in various user markets were another reason for the Director not selecting the first option. In making his decision, the Director specified that the pilot should run during the entire 1994-95 winter season with gas produced from volunteered leases in the Gulf of Mexico.

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
WASHINGTON, DC 20240

JUN 28 1994

Dear

As part of the Administration's reinventing government initiative, the Minerals Management Service (MMS) is examining ways to simplify Federal royalty management procedures to achieve cost savings for the Department of the Interior, industry, and taxpayers. One option we are considering is taking some of the Government's royalty gas in kind. Under this option, MMS would assume many of the marketing and transportation responsibilities for the selected royalty gas. Also, by taking royalty gas in kind, we may be able to eliminate reports associated with gas valuation and allowances for transportation and processing.

To assess this option, MMS will conduct a royalty gas marketing pilot in the Gulf of Mexico. The pilot will

- run for 1 year commencing January 1, 1995,
- take the gas at the lease or, alternatively, at a centralized gathering point and transfer it to a competitively chosen marketing company,
- exclude gas which is produced from leases subject to section 8(g) of the Outer Continental Shelf Lands Act (OCSLA), 43 U.S.C. 1337(g),
- examine the revenue implications and assess whether there are significant advantages in reporting, valuing, tracking, and auditing.

We have identified your company as the operator of one or more leases in the Gulf of Mexico, and we invite you to participate in this pilot. We request that, as the designated operator, you notify your mineral interest owners of this opportunity.

The provisions of OCSLA allow MMS to choose which leases will provide royalty gas in kind. However, when we select participants for this pilot, we will give preference to leases for which all interest owners have expressly volunteered to participate. We anticipate that, if the pilot indicates that taking royalty gas in kind is beneficial, benefits would accrue to all parties. Working with volunteers to evaluate the pilot will make it easier for all parties to assess the results.

Interest owners may volunteer for the pilot by submitting the information specified in Enclosure 1. For those wishing to supply the information via electronic media, instructions may be found in Enclosure 2. The completed form or diskette should be mailed or faxed by July 22, 1994, to:

Mr. John Bratland
U.S. Department of the Interior
Minerals Management Service, Mail Stop 4013
1849 C Street N.W.
Washington, D.C. 20240

Fax No. 202-208-3118

Thank you for considering participation in this important pilot program. We will notify you if you have been selected. If you have any questions, please call Mr. Bratland at 202-208-3979 or Mr. Jim McNamee at 303-275-7126.

Sincerely,

Tom Fry
Director

2 Enclosures

Gulf of Mexico Royalty Gas Marketing Pilot
Volunteer Information Form

Interest Owner (Company Name) ______________________________

Name: ______________________________

Title: ______________________________

Telephone No: ______________________________

MMS Lease No (a)	FMP Meter No (b)	Interest Owner Percentage (c)	Average Daily Lease Volume MCF/Day (d)	Btu Content (Dry) (e)	Lease Royalty Rate (f)	Gas Volunteered for Pilot (in MMBtu's) (c)x(d)x(e)x(f)

SEE ENCLOSURE 2, PARAGRAPH 3, FOR DESCRIPTIONS OF THE INFORMATION TO INCLUDE IN EACH FIELD

VOLUNTEER INFORMATION FORM
ELECTRONIC FILING INSTRUCTIONS (OPTIONAL)

1. You may supply the information requested on floppy diskette using dBase IV. Those who wish to use other database packages or mainframe downloads should call for special instructions on a case-by-case basis. You may use either a 3 1/2" or a 5 1/4" diskette.

2. Please use the following structure in creating your database:

Field Name	Field Type	Width	Decimal	Index
MMS_LEASE	Character	10		N
FMP_METER	Character	11		N
INT_PCT	Numeric	8	6	N
AVG_VOL	Numeric	7	0	N
BTU_DRY	Numeric	5	3	N
ROY_PCT	Numeric	8	6	N
VOL_AMT	Numeric	10	0	N

3. The following is a description of each field:

MMS_LEASE — The 10 digit MMS-assigned Lease Number for the OCS lease. An example of a correct OCS Lease Number is 0540009970. Please do not include the dashes when entering the data.

FMP_METER — The 11-digit number of the facilities measurement point meter assigned by Offshore Minerals Management. This number is used by the operator in reporting on Form MMS-4054, Oil and Gas Operations Report.

INT_PCT — Your ownership interest, stated to 6 decimal places, in the offshore lease. For example, a 20 percent interest in the lease would be entered as 0.200000. The decimal is automatically positioned in the proper place when the database is created using the above structure.

AVG_VOL — The average daily volume for the entire lease stated in thousand cubic feet (Mcf) at a pressure base of 15.025 psia. Use the most recent calendar month for which production information is available. Enter this number as a whole number with no decimals.

BTU_DRY — The Btu content (dry) stated in Btu's per <u>Mcf.</u> The correct number will be close to 1.000 plus or minus a fraction. For example, gas with a content of 986 Btu's per <u>cubic foot</u> would be entered as 0.986. Gas with a content of 1.365 Btu's per <u>Mcf</u> would be entered as 1.365.

ROY_PCT — The royalty rate for the lease stated to 4 decimal places. For example, a lease with a 1/6 royalty would be stated as 0.1667.

VOL_AMT — This number represents the number of MMBtu's of gas that would have been volunteered for delivery in-kind by the interest owner based on the month used to compute the average daily volume (AVG_VOL) above. It is the INT_PCT multiplied by AVG_VOL multiplied by BTU_DRY multiplied by ROY_PCT. The result is rounded to the nearest whole number and entered as VOL_AMT.

4. Please label the diskette with your company name, a contact name, title, and telephone number, and forward to Mr. John Bratland at the address contained in the letter.

A NOTE ON THE DEGREE OF LINKAGE BETWEEN GAS PRICE INDICES AND THE USE OF ALTERNATIVE INDICES IN BID FORMULATION

The change of price indices in the Invitation for Bids (IFB)

One of the issues that arose during the implementation of the Royalty Gas Marketing Pilot (pilot) pertained to the designation of "correct indices" in the IFB. The IFB issued on October 23, 1994 included a designated price index for each of the 36 groups of participating leases included in the Pilot. Shortly after issuance of the IFB, the MMS received suggestions that the indices should be changed for 17 of the 36 groups of leases. The original designations contained in the IFB were challenged with the criticism that inappropriate or incorrect indices would add to the uncertainty faced by prospective bidders in the formulation of bids. In response, the pilot team prepared an amendment to the IFB in which suggested changes were made.

The experience of modifying the price indices raised several questions. What is the relationship between the price indices? Is the gas market in the region sufficiently integrated to generate a high correlation between gas price indices? Can bids be formulated based on more than one index or even the "incorrect" index? The following comments discuss the answers to these questions.

Gas market integration as a consequence of deregulation

The deregulation of the U.S. gas market accounts for the tight linkage between the price indices employed in the pilot. The tight linkage reflects the enhanced level of competition that has resulted from this deregulation. The market that has emerged offers an increased range of choice to both buyers and sellers at all stages of the gas market. Producers are no longer locked into a market situation in which the only purchaser is "the pipeline." The increased competition and added range of choice for buyers and sellers are facilitated by ready availability of gas price information for locations near the lease. Moreover, the emergence of marketing centers such as Henry Hub has enhanced the efficiency and ease with which gas transactions can be completed.

Gas from different locations is in potential competition with gas from other locations within the region. Arbitrage in the market for gas from different sources tends to keep gas prices in tight alignment. Buyers of gas seek price differentials reflecting relatively lower prices from particular sources and avoid prices that appear relatively high. Thus, the alignment between price indices is maintained. This price competition means that events affecting part of the gas market will eventually affect all of the gas market. For example, particularly cold weather in one region of the United States will not affect some price indices in isolation from other price indices. However, some indices may be affected first with brief lags occurring before all indices have felt the brunt of the increase in demand. These lags account for the fact that correlation between indices is very high but not precisely perfect.

Correlations between price indices

The alignment between price indices is reflected, in major part, by the correlation between the indices used in the pilot. For the entire year 1995, the period covered by the pilot, the correlation coefficients for *all of the indices used in the pilot* ranged between 0.985 to 0.999. For the preceding year, 1994, the range of values for the correlation coefficients ranged from 0.973 to 0.999. An additional set of correlations were calculated for the 13 month period from April of 1995 through April of 1996. The reason for calculating this additional set of correlations was to establish the degree of correlation for a period inclusive of the 1995-96 winter season in which prices were volatile in addition to being high. In this latter 13 month period, the correlation coefficients for all of the indices used in the pilot ranged from 0.884 to .999 although most of the coefficients were above 0.980.

The table below shows the correlation coefficients *only* for the indices that were changed in the amendment to the IFB. The table shows the indices initially specified in the IFB (first column) and

INSIDE FERC **PRICE INDEX IN ORIGINAL INVITATION FOR BIDS (IFB)**	***INSIDE FERC*** **PRICE INDEX SPECIFIED IN AMENDMENT TO THE IFB**	**CORRELATIONS FOR 1994 BETWEEN FIRST OF MONTH INDICES**	**CORRELATIONS FOR 1995 BETWEEN FIRST OF MONTH INDICES**	**CORRELATIONS APRIL 95 THROUGH APRIL 96 FIRST OF MONTH INDICES**	**AVERAGE DIFFERENCE BETWEEN INDICES 1994**	**AVERAGE DIFFERENCE BETWEEN INDICES 1995**
NORTHERN NATURAL GAS, TX, OK, KN	HOUSTON SHIP CHANNEL (HSC)	0.956	0.951	0.981	$0.23	$0.20
SOUTHERN NATURAL GAS, LOUISIANA	COLUMBIA GULF, LOUISIANA	0.994	0.999	0.999	$0.05	$0.00
TEXAS EASTERN, EAST LA ZONE	TEXAS EASTERN, WEST LA ZONE	0.999	0.999	0.983	$0.01	$0.03
TRANSCO, ZONE 2	NAT. GAS PIPELINE CO., LOUISIANA	0.995	0.999	0.886	$0.07	$0.04
SOUTHERN NATURAL GAS, LOUISIANA	TENNESSEE GAS PIPELINE CO., LA & ZONE 1	0.995	0.997	0.999	$0.00	$0.03
TRUNKLINE, FIELD ZONE	TEXAS EASTERN, EAST LA ZONE	0.998	0.997	0.996	$0.04	0.05

TENNESSEE GAS PIPELINE CO., LA & ZONE 1	TEXAS EASTERN, EAST LA ZONE	0.998	0.999	0.998	$0.05	$0.04

the indices used as a replacements in the amendment (second column). As the table above shows, a high degree of correlation exists between indices that were the object of the November 8, 1994 changes in the IFB.

Added uncertainty in formulating bids using the "incorrect indices"

At the time when the MMS received comments that some indices were "incorrect", some called attention to the fact that a high correlation exists between gas price indices and that the industry is generally aware of this high degree of correlation. They suggested that a bid for RIK gas coming from a particular lease could be based on more than price index.[1] While acknowledging the possibility that bids could be based on more than one index, the team members expressed concern over the consequences of forcing prospective bidders to formulate bids employing what could be considered an inappropriate index. A principal fear was that an incorrect index could create uncertainty that could, in turn, result in lower bids per MMbtu. The MMS was eager to facilitate a bidding process in which the prospective bidders had the best information available and in so doing, minimize the confusion and uncertainty involved in bid formulation.

The table above shows that the use of alternative price indices does introduce added uncertainty even though a high correlation may exist between indices within any given year. The two left-most columns in the table show the indices in the original IFB and the revised indices, respectively. In addition to the correlations between the respective indices, the table shows the average difference between the two indices in the left-most columns. These averages differences are shown for the years 1994 and 1995.

If the indices were good substitutes for each other in the formulation of bids, one should be able to predict the 1995 corrected index in the amendment to the IFB (in the column second from the extreme left) with the historical information on the 1994 price index shown the left-most column. Unfortunately, such predictions are not sufficiently precise to warrant the use one index in place of the other. This conclusion is born out by comparing the average differnce in the indices for the years 1994 and 1995. These average difference are shown in the two right-most columns of the table. While more sophisticated statistical techniques can be used in making such a prediction, the results shown in the table suggest the likely results of such efforts. In one instance, the average difference between the two indices changed by as much as $0.05 from one year to the next. For a gas marketing company, such a change could significantly affect the margin of profit on gross sales. Thus, the issue of using correct indices is not an idle concern since it represents an area of avoidable uncertainty in future auctions of Federal RIK gas.

[1] This latter observation was supported by comments offered in RIK workshops held in August and September of 1995.

PARTICIPATION BY SMALLER OR NEWLY ESTABLISHED FIRMS

During the implementation phase of the Royalty Gas Marketing Pilot (pilot), the Department of Energy (DOE) requested that MMS consider means by which a separate portion of the royalty-in-kind (RIK) gas could be made available to small businesses. However, this request posed a problem for MMS since one of its principal concerns in the design of the pilot was the risk associated with default on the part of a gas marketing firm. The types of possible default of greatest concern included a failure to immediately take 100 percent of the RIK gas as it was made available by the producer/lessee or a failure to pay for gas taken. Thus, MMS sought to select gas marketing contractors with an established performance history in the industry.

Several meetings were held with DOE staff and representatives of the minority business community to discuss the issues that would be raised by introducing “set-aside volumes” and accommodating the needs of small or disadvantaged gas marketing firms. In these meetings, MMS emphasized the fact that it faced several constraints in the design of the pilot. These constraints included the following considerations.

(1) The pilot was an experiment to determine if administrative savings could be achieved and revenue neutrality assured by taking gas royalties on an in-kind basis. Since the pilot involved the testing of several new and untried procedures, MMS found it necessary to free the pilot of avoidable complications. Special arrangements introduced to accommodate the needs of smaller firms could present complications for MMS in evaluating the success of the pilot.

(2) The MMS was bound by the Outer Continental Shelf Lands Act (OCSLA) to receive fair market value in the sale of offshore royalty gas. If “set-aside” arrangements implemented to accommodate the needs of smaller firms were to result in receipt of less than a full competitive market price, MMS would be in violation of its legal mandate.

(3) The pilot was being conducted with relatively small volumes of gas being produced from geographically dispersed leases in the Gulf of Mexico. This fact meant that the bid-enhancing effects of larger gas volumes would be difficult for MMS to achieve even in the absence of “set asides” for smaller firms.

(4) Since smaller, less experienced firms could pose a higher risk for MMS, fewer viable options would be available to MMS in recouping lost revenue in the event of a default.

For the above reasons, MMS declined to incorporate “set-aside” arrangements in the RIK pilot. By mutual understanding, MMS and DOE agreed that the pilot was not the appropriate vehicle in which to address the participation of smaller firms. The MMS understood the importance of having smaller, less experienced firms compete in a future market for Federal RIK gas. The DOE appreciated the constraints under which MMS had to operate in the designing and implementing the gas RIK pilot. The DOE observed the bid opening on November 3, 1994 and continued to take an active interest in the pilot during 1995.

DEPARTMENT OF THE INTERIOR

Minerals Management Service

Summary of Minerals Management Service Workshops on Expanded Use of Royalty-In-Kind (RIK) Procedures

AGENCY: Minerals Management Service, Interior

ACTION: Summary and overview of RIK workshops

SUMMARY: The Minerals Management Service (MMS) recently conducted a series of workshops to discuss ways of expanding the ongoing pilot program for collecting in-kind royalties on natural gas produced from Federal offshore leases. This notice contains a summary of the three workshops held in Houston (August 22, 1995), Denver (September 11) and New Orleans (September 15). The workshops were announced in a Federal Register Notice on July 19, 1995 (60 FR 37070).

On January 1, 1995, MMS initiated a Royalty Gas Marketing Pilot in the Gulf of Mexico. In the pilot, gas royalties are collected on an in-kind basis and sold directly to gas marketing companies.

The MMS has two objectives in conducting the current pilot. First, the MMS seeks to streamline royalty collections, and second, to test a process which promises increased efficiency and greater certainty in valuation. The MMS will issue an interim report on the pilot in November 1995 and a final report by June 30, 1996.

Comments offered in the workshops were generally favorable regarding the current pilot and were supportive of further MMS efforts to employ similar in-kind collection procedures. The workshops provided a useful forum for constructively discussing issues that have arisen in the current pilot and ways of improving future RIK efforts.

The comments and suggestions offered in the three workshops are combined into one narrative. The workshops were structured around the following panels: (1) requirements placed on lessees, (2) requirements placed on purchasers, (3) contract terms and auction procedures, and (4) considerations and recommendations for expanding RIK collections. The following summary is organized around the principal themes which emerged in all of the panel discussions.

Reporting and Payment Procedures

1. Producers at the workshops emphasized that major benefits of gas RIK are reporting relief, reduced scope of audits and avoidance of disputes over valuation issues.

2. Marketers raised concerns over reporting and payment procedures. For example, marketers noted the awkwardness of requiring payment on the 25th of the month following production because, by that date, the marketers do not have the information on actual volumes. They are obligated to pay on nominated volumes, which may differ from the volume received. Typically, marketers don't have the information on actual volumes until about 40 days after the end of the month. While marketers can accommodate some differences between volumes nominated and volumes received, large discrepancies can be a problem. If the marketers pay for a volume of gas, they want to be assured that volume will be allocated to them.

3. A workshop participant noted that MMS is constrained in this issue by the fact that royalty payments are due the end of the month following production. This fact means that MMS could postpone the due dates to the end of the month, but not later. The argument was made that the lessee's payment in kind satisfies the statutory requirements for timely payment, thus nullifying the requirement in terms of the purchaser's obligations. However, an MMS representative observed that, with delays in payments, the time value of money may be a concern, particularly in any future onshore programs in which the states eventually receive a portion of the royalty revenue forthcoming from the RIK gas purchasers.

4. A discussion followed on the requirement that producers must report to MMS information on RIK gas nominated each month. Producers question MMS' need to be informed about nominated volumes.

5. Producers pointed out that flash gas still poses a reporting burden that can be avoided. A producer attending the workshop suggested that flash gas should be included in the royalty gas volumes to eliminate the need to report it separately on an in-value basis. Several workshop participants thought that flash gas volumes could be included in the monthly imbalance account.

Producer Perspectives on Take Points for RIK Gas and Transportation Responsibility

1. Producers generally favor the use of the Facility Measurement Point (FMP) as the take point for the RIK gas. Several producers stated that responsibility for transportation downstream of the FMP belongs to the lessor or purchaser. Producers also said that the rates charged for the use of non-jurisdictional pipelines (pipelines over which the Federal Energy Regulatory Commission (FERC) has no regulatory jurisdiction) should be established through arm's-length negotiation between the producer and the purchaser. Some producers expressed the view that in the future, the Government needs to establish a procedure to accommodate changes in pipeline fees.

2. One producer and owner of non-jurisdictional pipelines defended the right to negotiate a pipeline fee in excess of the amount MMS allows as a deduction when lessees pay royalties in value. Producers typically do not transport third party gas on their lateral (non-jurisdictional) pipelines, and, if they do, they negotiate rates. The producer expressed the view that the same should apply with RIK gas. The producer wanted to be able to receive a higher rate of return on pipeline investment by charging negotiated arm's-length rates to third-party marketers. The producer added that lessees cannot realize as much return on their pipeline investments on royalty gas which is paid in value as they can in arm's-length situations.

3. However, another producer pointed out that an attempt by producers to charge purchasers high rates for lateral pipelines could be counterproductive. The producer stated that, because of the benefits to be achieved in an RIK environment, a producer would be "cutting off its nose to spite its face" if it did not try to negotiate reasonable rates with prospective purchasers. The danger of charging high rates for lateral pipelines would be that MMS may revert to collecting the royalties on an in-value basis. A marketer responded that a lessee may be less inclined to charge reasonable rates if the lessee did not want its gas taken in kind.

4. Several producers voiced concerns about the possibility of being forced to deliver RIK gas downstream of the FMP. One concern mentioned was the fact that some producers have no experience in moving gas away from the wellhead. But more common concerns revolved around bearing or sharing costs downstream of the FMP. One producer noted that in the design of the current pilot, there are no disputes over "marketable condition." Another producer added that if MMS were to move the take point downstream of the FMP, disputes over transportation and marketable condition would be rekindled. A producer made the point that in addition to above reasons, the lessee would encounter difficulty in taking a monetary transportation deduction in those instances in which in-value payments are not being remitted on the property.

5. The observation was made that the MMS may have difficulty capturing downstream value unless MMS assumes some cost and risk. Such costs could include the provision of capital for the building of lateral lines and expenses related to aggregation of gas production. However, a workshop participant noted that lessors normally do not participate in production, gathering, or transportation investments.

Purchaser's Viewpoints on Transportation Obligations and Associated Risk

1. In some cases, the purchasers of RIK gas had to make arrangements to transport gas through non-jurisdictional pipelines. Since the RIK gas is taken at or near the lease, the purchasers are responsible for transportation arrangements and costs. Comments revolved around the burdens placed on purchasers by this arrangement.

2. The point was made that most marketers are accustomed to buying large volumes at fixed points. In the case of this pilot, marketers had to get out maps and "do their homework." Rather than deal with the possible transportation uncertainties, one marketer focused on leases in areas where it already had contracts.

3. The issue of negotiating the charges on non-jurisdictional pipelines was a major focus of attention. The strong bargaining position of producers was noted; the observation was made that gas producers have no need to transport gas on non-jurisdictional lines that they do not own. They also do not have to provide transportation for others on their lines. One representative of a marketing company observed that in the collection of royalties in value, producers take an allowance on royalty payments for producer-owned laterals, and MMS knows the amount of the allowance. However, a third-party purchaser could not base its bid on that rate, because it may not be able to negotiate the same rate with the producer.

4. One marketer offered the idea that possibly MMS could negotiate non-jurisdictional pipeline rates up front and publish them in the Invitation for Bids (IFB, the contract instrument through which MMS competitively selected purchasers for RIK gas). Another marketer observed that a major issue is MMS' willingness to incur overhead costs in order to reduce the risk to the marketer. However, the point was acknowledged that the greater the task undertaken to reduce risk to marketers, the less reduction in administrative costs the MMS can achieve.

5. A commonly expressed view was that MMS could not force producers to charge marketers a rate based on the transportation allowances given for in-value royalty collection. The producers report a non-arm's-length rate, while the rate with marketers would be an arm's-length transaction. A marketer stated that it would be difficult to achieve a revenue neutral RIK program if lessees are allowed to charge more for lateral line transportation than their costs for purposes of non-arm's-length deductions under the in-value collection system.

6. Several gas marketing firms expressed a reluctance to bear either the transportation cost or the transportation risk associated with the purchase of RIK gas. The point was made that the Government's goals should be receipt of fair market value and reduction of risk faced by the purchaser (e.g., year-long risk for fluctuations in transportation charges). One workshop participant noted that it is not the industry norm for marketers to assume transportation risk for one year. Another noted that these are the most onerous contracts in the business and added that, normally, a marketer would avoid entering into long term contracts under conditions in which transportation terms can change during the period covered by the contract. Another marketer noted that in most contracts between marketers and producers, transportation risks are shared.

7. Several gas marketers at the workshop wanted to see the transportation burden shifted onto MMS or the producer. A workshop participant noted that a solution would be to allow the purchaser to net out actual costs to the index point. A marketer advanced the notion that MMS needs to specify that costs from the wellhead to market are the producers' and MMS' responsibility and suggested that MMS should allow credits or refunds. In other words, the purchasers should be allowed to deduct costs.

8. Several participants in the workshops recognized that there would be a downside to allowing the marketers to bid a price that would be net of actual transportation costs. A workshop participant noted that if MMS moved the delivery points downstream, cash reimbursements would be necessary. A deduction would also necessitate an audit function and in some cases, litigation. One workshop participant stated that having auditors in the marketing companies is a "show stopper." Some thought that a better option could be found in a provision in the sales contract for bi-lateral renegotiations in the event of material changes. Another thought that quarterly sealed-bid auctions of RIK gas may be a solution.

9. Other marketers saw the transportation cost and uncertainty in much less critical terms and recommended solutions that would not involve shifting costs and risk. One gas marketer suggested that much of the problem could be alleviated if producers would guarantee access and agree to charges in advance. Another gas marketer suggested that one way to deal with the lateral line issue is to publish a flat rate that MMS would allow for the charges incurred for the use of lateral pipelines, and then let the purchasers negotiate with producers. A marketer participating in the pilot stated that it had no problem negotiating rates for lateral lines when it called the producers. One marketer added that the best solution is to keep the lines of communication open and to negotiate reasonable rates. Another marketer asserted that all the risks involved in buying RIK gas can be managed by marketers in their bids, if they are diligent.

10. Other marketers emphasized that part of the solution to the issue of transportation risk can be found in allowing purchasers greater periods of time in which to prepare bids. The view was expressed that MMS should not focus on wellhead problems; MMS should allow the marketers to deal with these matters as they would for any other wellhead sale. The key is to allow enough time in the bidding process. A marketer noted that allowing more time to respond to bids would reduce the likelihood of bidder mistakes.

The "Must Take" Requirement, Gas Balancing and Gas Volume Control

1. The current pilot obligates the purchaser to take 100 percent of the gas made available by the producer at the take point. Marketers and producers have sharply differing perspectives regarding the "must take" provision of the RIK gas contract. In general, producers insist that this feature be included in any future pilot and also in the implementation of a permanent program of taking royalties in kind. Producers attending the workshops pointed out that marketers should prepare their bids with a full understanding of their obligation with respect to the "must take" provision of the contract.

2. In commenting on production uncertainty, one marketer noted that the IFB needs to be explicit about the fact that volumes can fluctuate; in fact, volumes can increase as well as decrease, and both situations may cause problems. Shut-ins are also possible. Another marketer observed that in light of production uncertainty, the must-take provision is too burdensome to the purchaser. Marketers must factor into their bids the additional risk associated with the must-take provision. If producers exercise this right with no flexibility, MMS will suffer a revenue loss as bids are adjusted to reflect the greater volume risk.

3. Specific procedures were suggested to deal with significant variations in production. For example, the lessee could be required to give the purchaser 60 days notice if prospective production increases were to exceed a pre-specified amount for reasons related to reworking of wells or development of new wells. Also a provision could be introduced which would give the contractor the right of first refusal for the increased volumes at the contract price. If refused, the RIK gas would be re-auctioned. Another alternative to address fluctuations would involve the introduction of a "change of conditions" clause in the MMS contract with the marketer. The clause would allow for renegotiation of the contract if volumes or other conditions change significantly.

4. A workshop participant noted that a royalty owner naturally will receive a lower value for gas than would a working interest owner because the royalty owner has no control over production. The suggestion was made that MMS enter into Joint Operating Agreements, with balancing arrangements, and act as a working interest owner. The only difference would be that MMS would not incur any operating costs. Someone responded by noting that the idea was not feasible because the lessor has leased away its right to control production and cannot be involved in operations or operating decisions. Also, the lessor cannot leave the royalty share of production in the ground and cannot share in the costs of production.

5. The volume uncertainty faced by the purchasers prompted some to suggest that

MMS consider alternative means to warrant volumes of gas in light of the fact that MMS has no control over production. One gas marketer noted that MMS could guarantee volumes if it were to incur the costs of aggregating and storing RIK gas. Even if volumes were not warranted, MMS could reduce risk to the purchaser by bearing some costs of pooling and aggregation.

6. Several producers raised the issue of processing contracts and the impact of losing the one-sixth of production through the taking of RIK gas. Plant Processing Agreements expose the participating lessees to potential penalties and residual liability problems. The penalties and liabilities for producers can arise if, over a period of time, one-sixth of the production stream is diverted and taken as RIK gas. One producer noted that under an involuntary RIK scenario, the loss of control of one-sixth of production could be a significant problem. Several producers stated that their processing problems were relatively minor; one producer indicated that these problems would disappear if greater numbers of producers were paying gas royalties on an in-kind basis. Most plant owners would be forced to adapt processing plant accounting procedures to accommodate the new royalty collection procedures.

7. In some cases, purchasers would need to explore the possibility of participating in existing gas processing arrangements. The processing of RIK gas means that there is a potential increase in bids because a producer would have an added incentive to retain its one-sixth share. But this uplift could be reduced by potential problems encountered by non-lessee bidders in making processing arrangements. This potential difficulty may dissuade prospective purchasers from bidding on RIK gas. However, one marketer expressed the view that entering existing processing arrangements would not be a problem; marketers can probably get access to plants. Someone suggested that the IFB indicate that the gas production stream from the lease is committed to processing. The suggestion was also made that for RIK gas which would otherwise be committed to processing, MMS may want to specify in the IFB a requirement that bidders provide documentation of processing arrangements.

8. One solution offered to deal with existing gas processing arrangements would allow producers the option of buying back their royalty gas at the highest bid price. This option would enable producers to maintain control over six-sixths of the volume. However, a marketer stated that doing so would probably reduce the number of bids. Marketers do not want to go through the effort of researching bids only to have the producers take back the gas.

9. Several workshop participants expressed the view that problems associated with volume uncertainty and control can be rectified by including the necessary information in the IFB and allowing a substantially longer period between the issuance of the IFB and the deadline for bid submission.

Communications Between Lessee and Marketer

1. In major part, the initial communication between the winning bidders (purchasers) and the producers was poor. Few marketers called to inquire about the gas and lateral pipelines needed to transport the gas. Marketers needed to know about gathering systems and charges for laterals. Since producers did not want the marketers to have problems, producers found it was necessary to initiate discussions in order to arrange delivery and lateral transportation. In part, the MMS may have contributed to this lack of communication by failing to include in the IFB (which became the contract), the name of the producer's designated liaison along with the telephone number.

2. One producer made the point that communication will almost certainly be better in future pilots. Marketers will be more alert to their own responsibilities in making appropriate transportation arrangements.

Contract Terms and Sealed-bid Auction Procedures

1. Questions were asked and suggestions offered concerning additional information which should be included in the IFB. For example, the suggestion was made that the IFB should give meter numbers and exact locations of the FMP or take point. Information on gas flow, Btu content, and non-jurisdictional or lateral pipelines should be included.

2. Questions were posed concerning the absence of meter number information and the designation of the FMP as the "take point" for the RIK gas. The MMS representative from the Gulf of Mexico Regional Office explained that the FMP number identifies a measuring station for the facility; it does not change. Meter numbers can change and thus were not used. The view was expressed that future IFB's need to be more explicit concerning gas purchaser's responsibility with respect to transportation. Also, an explicit statement must be included in the IFB indicating the policy with respect to transportation allowances.

3. Some discussion focused on alternative prices which could be used as a basis of bid formulation. One panelist stated that he prefers the use of published price indices, and that MMS should have the applicable producer recommend the index for each lease. Another panelist expressed concern over the volatility of price indices and suggested that MMS consider fixed price contracts, a mix of pricing methods, or the use of different methods for different bids groups. One workshop participant stated that MMS would obtain the highest price if it were able to specify one correct index. The point was made that a sound guide in determining the correct price index is to follow the flow of gas through the appropriate pipeline.

4. A marketer noted that the use of the New York Mercantile Exchange (NYMEX) futures price could be a problem onshore, because there is volatility of local price indices relative to NYMEX price in some areas. The price indices which appear in *Inside FERC*, *Natural Gas Intelligence*, and other publications indicate market value much closer to the lease, but still involve some risk related to upstream transportation costs.

5. Suggestions were offered to deal with situations in which several different price indices can be considered correct. Someone suggested that MMS explicitly offer bidders a choice of price indices, specifying in advance the procedure to be used by MMS in evaluating the differentials between the indices. But this idea was contested by the observation that if MMS offers a choice, people will try to use changes in the differentials to minimize payments to MMS. The creation of a "basket" or average index was also suggested for those situations in which several indices may work equally well. However, this suggestion was met with skepticism and the observation that one appropriate index would serve better as a basis bid formulation.

6. Several comments were offered on the size of gas royalty production packages to be offered in future RIK auctions. Several workshop participants observed that if MMS were to offer increased bid volumes (in groups), the packages of RIK gas would be made more attractive and would lower the per-unit risk to the purchaser. This approach could alleviate the volume warranty problem mentioned above. Several workshop participants suggested that the packages offered in future RIK pilots should be at least 2-3 MMcf (million cubic feet) per day, and preferably 5 to 10 MMcf per day. Typical volumes in the Outer Continental Shelf gas spot market range from 5 to 10 MMcf per day. A marketer added that all RIK gas in a package should flow into one price index point.

7. The subject of aggregation prompted some discussion of the alternate bid procedure made available to bidders in the current pilot. The alternate bid procedure allowed bids on self selected aggregations of groups. The bids would have taken the form of an "across the board" adjustment to the applicable price indices for the respective groups. Such bids would win the gas in the aggregation if the alternate bid were to exceed the total value of the highest individual bids or next highest alternate bid for any of the groups in the aggregation. The MMS was surprised by the apparent lack of interest in the alternate bid procedure. Marketers explained this lack of interest by noting the variation in lateral pipeline rates and costs over different fields. These differences between gas fields in the Gulf of Mexico dissuaded prospective bidders from applying an "across the board" adjustment to indices in the formulation of bids.

8. Marketers expressed an interest in an option that would allow prospective bidders to put together their own aggregations and allow differential bids (adjustments to the applicable index) for gas from different leases. The problem of bid ranking faced by MMS was noted with respect to this option.

9. Some marketers thought the financial qualification criteria for bidders were restrictive for small companies. One marketer observed that perhaps MMS could offer companies the option of providing letters of credit. Of course, this would be an added cost, unless the letter of credit was backed with an interest-bearing cash deposit. The suggestion was also made that the letter of credit need not cover the entire period of the contract. A letter of credit could cover a shorter period during which MMS is actually at risk. Another commenter stated that prior business experience was not necessarily a good indicator of credit worthiness, and that a better option would be to require all bidders to post a bond. Other comments included the suggestion that MMS require an escrow account and the proposal that factors other than prior business experience be used as a criterion in establishing credit worthiness; the assets held by the company would be one such example. One commenter stated that, regardless of the method selected, the requirements should be the same for all bidders.

Views on Future Pilot Expansion and RIK Efforts

1. Some workshop participants suggested MMS form a study group of current pilot participants to design the next pilot or program.

2. Several workshop participants suggested that MMS become more involved in the marketing of the gas. The point was made that because of the potentially large volume of RIK gas, MMS can enhance its revenues by pooling and aggregation. One marketer said the MMS should forget about its aversion to getting into the market place. The MMS has shown the ability to learn concepts and practices; why wouldn't MMS be able to gain expertise in gas marketing? If MMS were to market its gas, it could realize maximum value. Another marketer observed that MMS should learn to market gas, or hire someone to market its gas, if it wants to receive highest value. However, one participant noted that MMS would increase its administrative costs if it were to become more involved in the marketing of in-kind royalty gas.

3. Several producers suggested that future RIK regulations and procedures should be based on the Volunteer Agreement between MMS and participating lessees, as employed in the current pilot.

4. Strong support was voiced for an expanded pilot in the Gulf of Mexico, regardless of results obtained in the current pilot. A larger pilot, incorporating lessons learned from the current pilot would provide needed data.

5. Workshop participants voiced a diversity of opinions concerning the time of year in which to commence a another pilot.   However, a consensus seemed to hold the view that a pilot should commence in one of the summer months. The program should be in place when companies are making arrangements for the winter season.

6.   Several comments were offered concerning the administrative savings that MMS is likely to realize with RIK procedures. For example, the point was made that a full scale implementation of RIK would be necessary for MMS to realize major administrative savings. Partial implementation would require MMS to maintain an audit, valuation, reporting infrastructure for the royalties being paid in value.   Also, full scale implementation would reduce problems created for lessees and operators by having some lessees paying royalties in value and others paying royalties in kind.

7.   Support was expressed for an "evergreen option" in the awarding of gas marketing contracts. This option would involve a routine renewal of contracts. Such an option would be feasible under Federal contracting procedures if the renewal provision were pre-specified for a fixed number of years.

8.   Some discussion focused on complications which may be encountered in expanding the pilot to onshore gas royalties. For example, one workshop participant noted that onshore gathering costs may be a problem because third parties may not have any rights to transport gas upstream of plants.   Higher costs may also arise in the San Juan basin, in part, because of the prevalent use of stainless steel pipelines.

9.   The possibility of an oil RIK pilot was discussed. Much of the interest in such a pilot seemed to come from those participating in the current oil RIK program. The current oil RIK program is very unpopular among lessees; many at the workshops suggested that the current oil RIK program be replaced with a program designed along the lines of the current gas RIK pilot. Note was taken of the fact that the latter step could only be taken if the Secretary of the Interior were to make a determination that small refineries in the selected area have access to adequate supplies of crude oil at "reasonable prices."

FOR FURTHER INFORMATION CONTACT: Mr. Hugh Hilliard, Minerals Management Service, Mail Stop 4013, 1849 C Street, NW., Washington, DC 20240, telephone number (202) 208-3398; or contact Mr. James McNamee, Minerals Management Service, 12600 West Colfax, Lakewood, Colorado 80215, telephone number (303) 275-7126.

U.S. Department of the Interior
Office of Inspector General

SPECIAL REPORT

ROYALTY GAS MARKETING PILOT, MINERALS MANAGEMENT SERVICE

REPORT NO. 96-I-786
MAY 1996

United States Department of the Interior

OFFICE OF THE INSPECTOR GENERAL
Washington, D.C. 20240

MAY 31 1996

MEMORANDUM

TO: The Secretary

FROM: Wilma A. Lewis
Inspector General

SUBJECT SUMMARY: Final Special Report for Your Information - "Royalty Gas Marketing Pilot, Mineral Management Service" (No. 96-I-786)

Attached for your information is a copy of the subject final special report.

At the request of the Minerals Management Service, we reviewed the Service's natural gas royalty-in-kind pilot project. We concluded that the Service had established effective administrative procedures over the pilot project and demonstrated that the royalty-in-kind concept holds promise. However, we also concluded that the current project was too limited in scope for the Service to be able to draw any definitive conclusions on how successful such a program could be. Accordingly, we made several suggestions which, if implemented in future pilot projects, would provide more meaningful results upon which a management decision can be made.

If you have questions concerning this matter, please contact me or Ms. Judy Harrison, Assistant Inspector General for Audits, at (202) 208-5745.

Attachment

C-IN-MMS-001-96

United States Department of the Interior

OFFICE OF THE INSPECTOR GENERAL
Washington, D.C. 20240

SPECIAL REPORT

MAY 20 1996

Memorandum

To: Director, Minerals Management Service

From: Judy Harrison Judy Harrison
Assistant Inspector General for Audits

Subject: Final Special Report on the Royalty Gas Marketing Pilot, Minerals Management Service (No. 96-I-786)

INTRODUCTION

This special report is to advise you of the results of our review of the Minerals Management Service's Royalty Gas Marketing Pilot. The review was initiated in response to a request from the Service to provide assistance in its evaluation of the gas royalty-in-kind concept.

BACKGROUND

The Minerals Management Service has royalty management responsibilities for minerals produced from Federal and Indian lands. These responsibilities include collecting certain rents, royalties, and other payments; maintaining accounting records; determining royalty liability; and auditing royalty payments to determine whether royalties received represent fair and equitable value to the lessor. To fulfill these obligations, the Service issues regulations concerning mineral production and develops procedures for the collection of royalties. The Service collects about $4.1 billion annually from mineral leasing activities and has collected about $76 billion since 1982, the year it was created, through 1995.

Traditionally, the Service has received royalties for natural gas produced on Federal leases in value (that is, cash payments). However, the Federal royalty gas valuation and collection procedures as stated in the Code of Federal Regulations (30 CFR 206) associated with the royalty-in-value system have long been subject to controversy and litigation. For example, approximately 50 percent of royalty appeals and litigation actions originate from valuation disputes. In an effort to find ways to resolve these disputes, the Service in 1994 initiated the Royalty Gas Marketing Pilot, which involved taking royalty gas in kind (that is, accepting gas production instead of receiving cash payments) and immediately selling the gas to marketers at or near the lease sites through competitively awarded contracts. Under the Pilot program

arrangement, the producer delivered the royalty gas directly to the contract marketer without the Service actually taking physical possession of the gas.

The Service's objective in conducting this pilot was to streamline the royalty collection process and to improve the efficiency of determining gas valuations without decreasing revenue collections. Other expected benefits included administrative cost savings, reduced audit effort, and fewer royalty appeals and litigation. In view of this innovative approach to royalty management, the Department of the Interior designated the Pilot as a National Performance Review Laboratory.

The Royalty Gas Marketing Pilot was formally announced in a June 28, 1994, letter from the Service's Director requesting gas producers in the Gulf of Mexico to volunteer leases for the project. In response to the request, many major and independent companies expressed interest in the Pilot, and the Service negotiated agreements with 19 producers who volunteered 84 leases. The Service aggregated the volunteered leases into 36 bid groups; issued a formal Invitation for Bids for the royalty gas on October 21, 1994; and opened the bids on November 21, 1994. (The flow of gas from the lease groups is illustrated in Appendix 1.) The Service received 23 bids from 22 marketers and awarded 14 contracts. The winning bids submitted by the contract marketers represented the highest offered prices for the royalty gas using standard published index prices as a base. The Service subsequently eliminated several bid groups when certain marketers requested to be released from the Pilot because their bids had not considered the full transportation costs for the royalty gas. Accordingly, the Pilot began with 32 groups consisting of 79 leases volunteered by 14 producers. The Pilot represented 6.5 percent of the approximately 1.9 billion cubic feet of Federal royalty gas produced daily from the Gulf of Mexico in 1995.

The Pilot was conducted from January through December 1995, after which time the leases reverted to royalty in value. At the time of our review, the Service was evaluating the Pilot results and said that it expected to issue a final report by June 30, 1996. The report will provide the Service's Quality Council with recommendations regarding the future of the gas royalty-in-kind program.

OBJECTIVE AND SCOPE

The objective of our review was to evaluate the Service's administration of the Royalty Gas Marketing Pilot and present information that the Service may use to establish a permanent gas royalty-in-kind program. The scope of our review covered the lease selection process; the contract bidding and award procedures; the monetary collection process; and the system of internal controls over the planning, implementation, and evaluation of the Pilot. We also determined whether impediments exist in changing the program from a voluntary to a mandatory taking of gas.

To accomplish our objective, we reviewed the Pilot's planning, implementation, and evaluation phases and analyzed data pertaining to the Pilot that were developed and compiled by the Service. We interviewed key personnel from numerous Service offices and surveyed representatives from 25 gas production, marketing, and distribution companies who either participated in or were knowledgeable of the Pilot. We also interviewed officials in states that had or attempted to have a royalty-in-kind program (see Appendix 2).

PRIOR AUDIT COVERAGE

Neither the Office of Inspector General nor the General Accounting Office has issued any audit reports in the past 5 years that specifically addressed our objective or the royalty-in-kind concept.

DISCUSSION

We found that the Minerals Management Service was effective in administering the Royalty Gas Marketing Pilot and had demonstrated the feasibility of taking gas royalties in kind as an alternative to the royalty-in-value system. However, we noted weaknesses in the Pilot design, revenue collections, marketing strategies, and administrative controls that the Service should consider in studying the royalty-in-kind concept.

Design

The Pilot did not represent overall gas operations in the Gulf of Mexico. This occurred because the Service conducted the Pilot as a voluntary project. That is, producers were under no obligation to participate and were allowed to select which leases to contribute. Although this procedure helped ensure cooperation from the participants while testing this approach, it limited the number of companies that participated and thus diminished the usefulness of the Pilot results. For example, some of the largest of the 143 operators in the Gulf, such as Shell Oil Company and Exxon Corporation, chose not to participate, and one company represented 49 percent of the lease production in the Pilot, although no single operator produced more than 9.4 percent of the gas in the Gulf. Further, the Service excluded from the Pilot certain leases with complex ownership arrangements, including Section 8(g) leases, which involve state ownership. We believe that in order to simulate a permanent and comprehensive royalty-in-kind program, future pilots should encompass a realistic balance of producing companies, lease types, and lease ownership situations. Otherwise, the concept will not be thoroughly tested, and pilot evaluations will not provide a useful basis for formulating policy decisions.

We did not identify any impediments to the Government's taking royalty gas on an involuntary basis other than the potential objections by industry to being selectively forced to participate in an experimental program. Objections were raised by slightly over one-half of the companies in our survey of industry, but no strong opposition was expressed, as industry recognized that the lease agreements authorized the Government to take royalty gas in kind. We believe that future pilots should require mandatory participation from the oil and gas industry to ensure the complete evaluation of the in-kind concept.

Industry officials expressed concern that certain provisions in the Invitation for Bids and the marketing contract were unfairly biased in favor of the Government. The provisions that industry generally objected to included the penalties for the marketer's failure to take the gas, the payment disputes clause, and the termination for convenience clause. Additionally, at least one company did not participate in the Pilot because of the contract provisions, which resulted in decreased competition. We believe that the Service should consider the companies' concerns when designing a future pilot. In that regard, industry has developed its own contract language to deal with the complicated business of buying and selling gas. Since the Government assumes the position of a gas marketer under a royalty-in-kind program, we suggest that future pilots consider incorporating standard industry contract clauses but ensure that the Government's interests are protected.

Despite the concerns raised by industry regarding the Pilot's design, we found that 80 percent of the companies in our survey endorsed the gas royalty-in-kind concept. The benefits cited by industry pertained mainly to their own potential cost savings associated with simplified royalty reporting, less Government audit activity, fewer royalty appeals, and less royalty litigation.

Revenue Collections

The Pilot did not achieve revenue neutrality in that revenues collected did not equal what would have been received had royalties been taken in value. Lease agreements and the Outer Continental Shelf Lands Act, as amended, stipulate that royalties be paid on the fair market value of production saved, removed, or sold from a lease. Uncertainty exists in the Service, however, regarding whether revenue neutrality under the royalty-in-kind system must be maintained for each individual lease or for all leases taken as a whole. Additionally, no guidance exists regarding whether revenue neutrality analyses may consider factors such as administrative cost savings, increased management efficiencies, and litigation avoidance realized under a royalty-in-kind system. Further, the effect of proposed amendments to the Federal gas valuation regulations (published in the "Federal Register" on November 6, 1995) on a royalty-in-kind system have not yet been determined. These issues have important ramifications regarding revenue neutrality and need to be addressed in the Service's evaluation of the Pilot.

At the time of our review, initial partial year estimates prepared by the Service indicated that royalty collections were approximately 5 percent less than if royalties had been received in value. Based on our audit results, we found that several reasons accounted for the low bid prices that produced the revenue shortfall. We believe that the primary cause was that some marketers reduced bid prices to offset their increased costs to transport gas on privately owned lateral pipelines that connected the Pilot leases to trunklines.[1] To illustrate, under the royalty-in-value system, only the actual transportation costs incurred by the lessee, who also generally owns the lateral pipeline, are deducted from the royalty payment. This differs from the royalty-in-kind system because the contract marketer may not own the lateral pipeline, and consequently, the contract marketer must negotiate a transportation fee with the pipeline owner, who may charge a fee in excess of actual costs. These additional costs increase the risks to the contract marketer's profits and in the Pilot translated to, in some cases, lower bids. However, we believe that the full extent of the effect of lateral pipelines on gas prices cannot be determined at this time because changes in future pilots regarding the size, location, and term length of gas sales contracts may affect market conditions and bids.

Other reasons cited by the Service for the decreased revenues included the following:

- The uncertainty of industry becoming involved in an experimental and unproven program.

- The difficulties encountered in designing and planning the Pilot, which caused a 3-month delay in the start date. The Pilot eventually began in January, after the contract marketers had generally secured their gas sources for the busy and profitable winter season.

- The 30-day deadline to respond to the Invitation for Bids, which many contract marketers stated was insufficient time to complete their bid preparations.

- The possible deductions in bids for the costs to deliver the royalty gas in pipeline-quality condition. Under the royalty-in-value system, no deductions would be allowed for these costs.

- The recovery of marketing costs in the bid prices, whereas no deduction for these costs would be allowed under the royalty-in-value system.

Despite these concerns, we believe the Service should continue to explore the royalty-in-kind process and that future pilots can be designed to address the identified problems.

[1] Trunklines are main pipelines that transport gas from production areas to gas processing plants or other terminals.

Marketing Strategies

We identified marketing-related strategies that the Service should consider in a future pilot to enhance revenue collections as follows:

- The Service could warrant, or guarantee, the volumes of royalty gas that are delivered to the contract marketer. Our survey of industry indicated that the lack of guaranteed gas volumes in the Pilot was reflected in lower bid prices. Although warranted volumes create a risk for the Government in that it must guarantee delivery of specified volumes, this risk can be minimized by following the customary industry practice of withholding a portion of the gas supply to cover unexpected drops in production. This reserve gas supply, known as "swing gas," can be stored or sold on the spot market when not needed to support the warranted gas.

- The Service package gas volumes in the sizes most desired by industry. Our survey of industry disclosed that most gas marketing companies preferred lease production to be packaged in sizes ranging between 5,000 to 20,000 MMBtu per day.[2] However, our analysis of the invitation for Bids disclosed that the 32 groups averaged only about 4,800 MMBtu per day and 21 (66 percent) of these groups produced less than 5,000 MMBtu per day. We found a direct correlation between bid prices and gas volumes. Specifically, the bid prices for the 11 groups producing over 5,000 MMBtu per day were almost 2 cents higher than those with smaller gas volumes, while the 4 groups producing over 10,000 MMBtu per day were almost 6 cents higher. The larger volume groups also generally attracted more bids, and thus more competition, than the smaller ones.

- The Service could package lease groups along the most logical transportation routes. For example, the Service could group gas volumes that are produced along a single pipeline system. This would simplify the bid preparation for industry and also provide companies with the opportunity to bid on multiple groups to satisfy their individual volume purchase requirements. Packaging gas from a single pipeline system would also help ensure that the gas is of a similar quality and would avoid the problem encountered in the Pilot in which remote stand-alone leases were combined with other leases. Our survey of industry disclosed that at least one company refused to submit bids on the Pilot groups which contained remote leases, since these properties produced relatively small quantities of gas and required that separate transportation agreements be negotiated with the pipeline owners.

- To address the lateral pipeline cost issue, the Service could attempt to negotiate reasonable transportation fees with the pipeline owners and publish these

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[2]One million British thermal units. A British thermal unit is the amount of heat needed to raise the temperature of 1 pound of water 1 degree Fahrenheit.

rates in the Invitation for Bids. Recognizing that the Service holds a strong and unique bargaining position as the lessor, pipeline owners may be more inclined to accept lower fees than would be negotiated with the contract marketers. This procedure may also attract more bidders by simplifying the bid preparation process and increase competition by eliminating the bargaining advantage that larger contract marketers have over smaller ones in dealing with pipeline owners.

- The Service could publish information in the Invitation for Bids concerning the quality of the gas, such as the Btu content. Full disclosure of the actual value and processing potential of the product may attract more bidders and possibly increase bid prices.

- A two-round bidding process could be utilized whereby the top three or so bidders are asked to submit their best and final offered prices. This process would extend the bargaining period and might motivate bidders to offer a higher price.

- The Invitation for Bids could include variable contract lengths. The Pilot contract length was 1 year; however, our industry survey indicated that some companies would bid higher for different term lengths. Contracts of two or more years in duration appeal to many gas marketing companies, as they place a premium on securing guaranteed and uninterruptible sources of gas to meet customer commitments. Conversely, some marketing companies prefer the price adjustment flexibility provided by short-term contracts of less than 1 year.

As an alternative to taking gas in kind and subsequently marketing it, the Service should explore the concept of taking and using the gas. We identified one successful state-operated royalty-in-kind program in which the state took and used the gas at its facilities. This concept, although more administratively challenging, could offer financial benefits to the U.S. Treasury.

Internal Controls

As part of our review, we examined the system of internal controls pertaining to the planning, implementation, and evaluation phases of the Pilot. In general, we found that the internal controls provided for a well-managed project and for a comprehensive evaluation of project results. However, we did identify a significant weakness in the initial design of the Pilot. Specifically, 17 (47 percent) of the original 36 lease groups in the Invitation for Bids contained incorrect price index points, which necessitated an amendment to the solicitation. This matter could have been avoided with a better review process to verify information presented in the Invitation for Bids.

Management Action

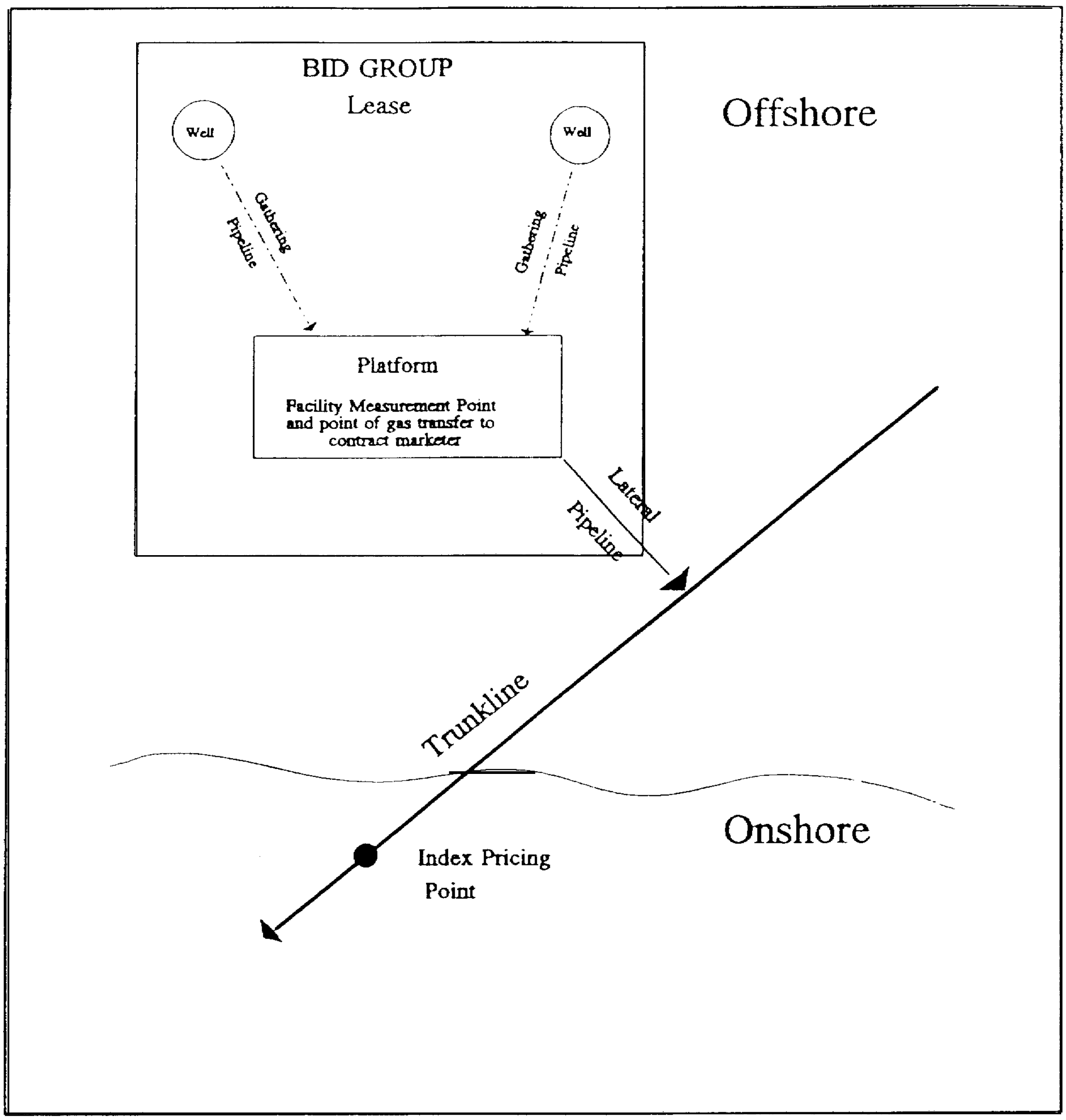
At the time of our review, the Service was conducting its own evaluation of the Pilot, including determining whether savings could be realized in reduced administrative costs, reduced audit effort, and avoidance of royalty appeals and litigation. Although the final results of these analyses were not available at the time of our review, Service officials said that significant benefits were not expected to be realized unless the gas royalty-in-kind program was implemented on a large scale, such as for all leases in the Gulf of Mexico.

In our opinion, the Service needs to consider the problems encountered and the ideas developed under the Pilot and establish overall goals and objectives for the program if it decides to study this concept further.

A response to this report is not required. However, if you have any questions regarding this report please call Mr. Alan Klein, Regional Audit Manager, Central Region, or Mr. Lee Scherfel, Senior Auditor, at (303) 236-9243.

cc: Assistant Secretary for Land and Minerals Management
Chief, Division of Management Control and Audit Follow-up,
Office of Financial Management
Audit Liaison Officer, Land and Minerals Management
Audit Liaison Officer, Minerals Management Service

DIAGRAM OF A PILOT LEASE GROUP



This diagram shows the flow of royalty gas from a simple bid group containing one lease. From individual wells, the royalty gas flows along gathering pipelines to the platform, where it is combined into a single stream. At the facility measurement point on the platform, the producer delivers the gas to the contract marketer. This is also where the Minerals Management Service sells the gas and transfers title to the contract marketer. The gas then flows through a lateral pipeline to a main trunkline and on to its eventual destination onshore. Transportation fees for trunklines are regulated by the Federal Energy Regulatory Commission, whereas fees for lateral pipelines are not subject to Government oversight. Finally, the index pricing point on the trunkline denotes the location of a published gas price that contract marketers use to base their bids.

OFFICES AND SITES
VISITED OR CONTACTED DURING AUDIT

Offices and Sites	Location
Department of the Interior	
Minerals Management Service	
Administration and Budget	
Procurement & Property Management Division	Herndon, Virginia
Policy and Management Improvement	
Office of the Associate Director	Washington, D.C.
Appeals Division*	Golden, Colorado
Policy Coordination Staff	Washington, D.C.
Royalty Management Analysis Division	Golden, Colorado
Royalty Management Program	
Office of Enforcement	Lakewood, Colorado
Royalty Liaison Office	Lakewood, Colorado
Office of the Deputy Associate Director for Compliance	Lakewood, Colorado
Dallas Compliance Division*	Dallas, Texas
Office of the Deputy Associate Director for Valuations and Operations	Lakewood, Colorado
Valuation and Standards Division*	Golden, Colorado
Reports and Financial Division*	Lakewood, Colorado
Offshore Minerals Management	
OCS Regional Office	New Orleans, Louisiana
Office of the Solicitor*	Washington, D.C.
State of Alaska	
Alaska Department of Royalty Accounting*	Anchorage, Alaska

*Contacted only.

Offices and Sites	Location
State of Texas	
Texas General Land Office*	Austin, Texas
State of Wyoming	
Wyoming State Land and Farm Loan Office, Mineral Leasing and Royalty Compliance*	Cheyenne, Wyoming
Oil and Gas Companies	
Amerada Hess Corporation	Houston, Texas
Amoco Production Company	New Orleans, Louisiana
Apache Corporation	Houston, Texas
Chevron U. S. A.*	Houston, Texas
CNG Energy Services Corporation	Houston, Texas
Coastal Oil & Gas Corporation	Houston, Texas
Delhi Gas Pipeline*	Dallas, Texas
Enron Oil & Gas Company	Houston, Texas
Enserch Corporation	Dallas, Texas
Exxon U.S.A.	Houston, Texas
Forest Oil Corporation	Denver, Colorado
ICC Energy Corporation	Dallas, Texas
The Louisiana Land & Exploration Company	New Orleans, Louisiana
MidCon Gas Services Corporation	Houston, Texas
Mobil Oil Corporation**	Dallas and Houston, Texas
Murphy Exploration Company	New Orleans, Louisiana
NGC Energy, Incorporated	Houston, Texas
Oryx Energy Company	Dallas, Texas
Shell Oil Company*	New Orleans, Louisiana
Superior Natural Gas Corporation	Houston, Texas
Taylor Energy Company	New Orleans, Louisiana
Texaco, Incorporated	New Orleans, Louisiana
Transcontinental Gas Pipe Line Corporation	Houston, Texas
Whiting Petroleum Corporation	Denver, Colorado
Zilkha Energy Company	Houston, Texas

**Contacted the Dallas office and visited the Houston office.

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U.S. Department of the Interior Office of Inspector General Eastern Division - Investigations 1550 Wilson Boulevard Suite 410 Arlington, Virginia 22209	(703) 235-9221

North Pacific Region

U.S. Department of the Interior Office of Inspector General North Pacific Region 238 Archbishop F.C. Flores Street Suite 807, PDN Building Agana, Guam 96910	(700) 550-7279 or COMM 9-011-671-472-7279