United States Department of the Interior

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

IN REPLY REFER TO:

AD/PSO/RIB 6-047-2d
Mail Stop 3062

SEP 13 1996

Mr. Jack J. Grynberg
President
Grynberg Petroleum Company
5000 South Quebec, Suite 500
Denver, Colorado 80237-2707

Dear Mr. Grynberg:

This is to follow up our April 8, June 3, and July 12, 1996, letters in response to your March 18, 1996, Freedom of Information Act (FOIA) request.

We have completed our consultations with the affected companies. Enclosure 1 is a 290-page copy of documents responsive to your request.

Certain information in these materials has been withheld under FOIA Exemption 4.

Our policy, in keeping with the spirit of FOIA, is the prompt release of records to the greatest extent possible. At the same time, we must protect the rights of individuals and the administrative processes surrounding such rights. The FOIA regulations require us to withhold information protected under FOIA exemptions at 43 CFR § 2.13 (1995) when disclosure is prohibited by statute or Executive Order, or if sound grounds exist to apply an exemption.

EXEMPTION 4

We have determined that the materials containing commercial and financial information are privileged and confidential. This information is being withheld pursuant to Exemption 4 of the FOIA, which exempts from disclosure ". . . trade secrets and commercial or financial information obtained from a person and privileged or confidential." We have replaced the deleted information with the marking "X-4."

Our policy is to employ Exemption 4 of the FOIA by withholding from public release any financial information that could jeopardize the financial standing and/or competitive position of those associated with this information. We believe that the public release of this information could jeopardize the competitive and financial standing of those parties associated with this information.

As the Royalty Management Program FOIA Officer, I am the official denying a portion of your request. If you disagree with this determination, you have the right under Department of the Interior regulations at 43 CFR § 2.18 (1995) to appeal to:

Freedom of Information Act Appeals Officer
Interior Service Center, MS 1414
1849 C Street, NW.
Washington, D.C. 20240

Your written appeal must be delivered to the FOIA Appeals Officer no later than 20 working days from the date of this letter. The appeal must include copies of your original request and of the initial denial. To expedite the appellate process and to ensure full consideration of your appeal, include a brief statement as to why you believe this decision is in error. Both the envelope containing the appeal and the face of the appeal itself should include the legend "FREEDOM OF INFORMATION APPEAL."

In accordance with 43 CFR § 2.20(a)(1) (1995), we assess user fees to fulfill a FOIA request. Personnel charges cover our costs to conduct document searches and to review, identify, and delete privileged and confidential information. Other charges cover the direct costs of providing the material. Standard charges are:

Professional support	$ 18.60/hour
Clerical support	$ 9.20/hour
Photocopies	$ .13/page
Microfiche	$ .08/page
Computer/magnetic tapes	$ 25.00/each
8 mm. tape	$10.00/each
Computer Diskettes	$ 1.25/each
Computer (CPU) time	$ 35.00/minute ($25.00 minimum)

Fees for overdue bills include a $35 administrative charge plus interest at the prevailing Treasury rate.

Enclosure 2 is a bill for $468.63, the cost to fulfill your FOIA request. This includes the costs of the 535 pages of documents provided with our April 8 and July 12 letters.

This completes our response to your FOIA request. If you have any questions, please contact me at (303) 231-3013.

Sincerely,

Gregory K. Kann
Freedom of
Information Act Officer

Enclosures

SHEEP MOUNTAIN CO_2 TRANSPORTATION ISSUE: <u>COMPRESSION</u>

Issue

Is compression of the Sheep Mountain CO_2 solely an integral and necessary part of transportation or a function of placing the CO_2 in marketable condition, and should the costs of compression be allowed or denied in the transportation allowance accordingly?

Background

Sheep Mountain CO_2 is transported from the Sheep Mountain Unit in Huerfano County, Colorado, to tertiary recovery projects in West Texas, a distance of about 408 miles. Transportation is via the Sheep Mountain Pipeline. The Unit and the pipeline are jointly owned and operated by ARCO Oil and Gas Company (ARCO) and Exxon Company, U.S.A. (Exxon). Owing to the physical properties of CO_2 and the design optimization of the transportation system, the CO_2 is transported in a supercritical (dense fluid) phase, which requires a pressure in excess of X·Y psia. (CO_2 separates into liquid and vapor phases at pressures below 1,071 psia; two phase flow is highly undesirable for pipeline transportation, causing physical damage to pipeline equipment and measurement difficulties. Transportation in the supercritical phase also allows a smaller diameter pipeline, permitting a greater volume of product to be transported in a smaller space and resulting in an overall lower cost per Mcf for transportation.)

Wellhead pressures at Sheep Mountain vary between Y.Y and Y.Y psig. The produced CO_2 is dehydrated and compressed from wellhead pressures to approximately X-Y psia at conditioning facilities located at each of the five drill sites in the production field. This compressed CO_2 is then collected from the five drill sites by two field pipelines, which converge at the Origin Meter Station (OMS) where the CO_2 is measured for royalty purposes. The OMS marks the beginning of the Sheep Mountain Pipeline. At the OMS the CO_2 enters the pipeline at pressures between X.4 and X.4 psia. The pressure of the CO_2 in the pipeline drops to a low of X.4 psia at the Raton Pass crossing then builds to X.4 psia at the Seminole delivery point in west Texas. This pressure increase is the result of hydrostatic load of the CO_2 in the pipeline that occurs because of the 5,000 ft elevation drop from the Sheep Mountain Unit to the west Texas delivery points. If the pipeline did not have to cross Raton Pass, delivery pressure would have been approximately X.4 psia. In fact, in order to assure that pipeline pressure does not exceed design requirements as elevation is lost on the downhill side of Raton Pass, ARCO and Exxon had to install a pressure reduction station. The irony of the situation is that while ARCO and Exxon must focus on <u>achieving</u> and maintaining sufficient pipeline pressure to keep the CO_2 in supercritical phase from the field to the top of Raton Pass, they must focus on <u>reducing</u> pipeline pressure on the downhill side of Raton Pass to west Texas.

Purchasers of the CO_2 generally boost the delivered pressure to meet the unique conditions of their individual tertiary recovery operations. One operator boosts the delivered Sheep Mountain CO_2 to X.4 psia to meet its field (injection) requirements. We are unaware of the existence of a "standard delivery pressure" or industry marketablility standard for CO_2 which could be equated to standards established and recognized for natural gas. However, we have been advised that all long distance CO_2 pipelines in the United States have been designed to maintain CO_2 in the supercritical phase.

As previously mentioned, the compression function occurs at the five drillsites rather than somewhere along the pipeline. Although compression equipment could have been installed either upstream or downstream of the OMS without affecting the operation of the pipeline, drill-site compression was chosen for reasons of design optimization, economics, and environmental considerations. Advantages of locating the compression facilities at the drill sites included the availability of space and easy access; availability of existing buildings, utilities, and common support systems, much of which would have had to be duplicated in the limited space at the OMS; minimization of environmental impact; and mitigation of product deliverability risks owing to catastrophic failure on a part of the operation, which would cause cessation of deliveries if equipment were located at a common facility.

ARCO/Exxon Position

ARCO and Exxon contend that the compression equipment at Sheep Mountain is only used to place and maintain the CO_2 in a supercritical phase, thereby allowing the most efficient transportation through the Sheep Mountain Pipeline. For this reason, ARCO and Exxon assert that the compression is an integral and necessary part of transportation. Furthermore, ARCO and Exxon state that the fact that compression occurs at the drillsites should not be an inssue in deciding whether the function is part of transportation. Conceivably, the compression function could have been performed downstream of the OMS and the royalty meter. Lastly, because the delivery pressure in West Texas must be further increased by purchasers to meet their individual project requirements, ARCO and Exxon contend that the West Texas CO_2 market does not dictate the pressure needed for transportation.

Analysis

The Sheep Mountain CO_2 is heated, dehydrated, cooled, and compressed at the five drill sites in the Sheep Mountain Unit, and then moved via field pipelines to the OMS where it is measured for royalty purposes. The Minerals

Management Service (MMS) has traditionally viewed the point of royalty measurement as the point at which production is in marketable condition, and has consistently interpreted the regulations, court decisions, and lease terms as requiring the lessee to absorb all costs necessary to place the product in marketable condition. Marketable condition refers to products that are sufficiently free of impurities and, in the case of gaseous products, at a pressure that will be accepted by a purchaser. Accordingly, MMS has traditionally disallowed compression costs for natural gas in the computation of transportation allowances. Only one instance exists where MMS specifically disallowed compression costs for CO_2. At Exxon's Shute Creek processing facility CO_2 production exiting the plant is recompressed at the plant tailgate. Exxon contended that recompression of the CO_2 was required as a final step in the manufacturing process. The MMS determined that recompression was not a function of processing the gas but part of the cost to place production in marketable condition. All CO_2 recompression costs were denied at the Shute Creek facility.

Although compression prior to royalty measurement would, following traditional practice, be considered a function of placing the gaseous product in marketable condition, the MMS does recognize the compression of CO_2 performed after the initial delivery in the field, and which is critical to transportation, as an allowable component of the transportation allowance. For example, such compression costs were granted in computing the McElmo Dome Unit transportation allowance for Mobil's segment of CO_2 pipeline that connects the Cortez Pipeline with the Sheep Mountain Pipeline in West Texas. The primary function of the compressors along Mobil's pipeline is to maintain the pressure at all points along the pipeline. Compression performed (after initial delivery from the field) where the primary function is to move production from one pipeline into another pipeline that leads to a sales point is also an allowable component of the transportation costs; such compression costs were also granted in computing the transportation allowance for Mobil's pipeline. However, in Mobil's case McElmo Dome CO_2 is compressed and enters the transportation pipeline at the McElmo Dome Unit at a pressure of X, Y psia. Mobil did not request that these compression costs be included in the transportation allowance calculation.

In summary, MMS's current policy is to allow CO_2 compression costs where the compressors are located along the pipeline and compression is necessary to maintain pipeline pressure. Compression costs are disallowed where compressors are used to make initial delivery from the production field into a pipeline.

In the case of Sheep Mountain there is no contract specifying pipeline pressure or identifying a "marketable condition." Rather, pipeline pressure is dictated by the need to transport the CO_2 in the supercritical phase and to insure movement over mountain passes. (The dehydration of the CO_2 prior to transportation is a requirement both for marketing and to meet pipeline design standards.) There is no argument that the design and operating specifications of the Sheep Mountain Pipeline are optimum and the most economical. In fact, as previously mentioned, we have been advised that all existing long distance CO_2 pipelines in the United States have been designed to maintain CO_2 in the supercritical phase.

<u>Options</u>

Option 1: Deny all costs incurred by ARCO and Exxon for compression at Sheep Mountain.

Pro: This action would be consistent with the decision involving the initial delivery of Mobil's CO_2 from the McElmo Dome Unit to the Cortez Pipeline and MMS's longstanding policy of denying any costs associated with gathering, measuring, compressing, dehydrating, or performing other services necessary to market natural gas production. The CO_2 from Sheep Mountain must be compressed to meet designed pipeline pressure for optimum transportation, regardless of whether this compression is performed by the lessee or the transporter.

Con: This action does not recognize the difficulties involved in transporting CO_2 from the Sheep Mountian Unit; difficulties that do not exist in transporting CO_2 from the McElmo Dome Unit. It also may not account for all the actual costs incurred by ARCO and Exxon to transport Sheep Mountain CO_2.

Option 2: Allow compression costs in the Sheep Mountain transportation allowance calculation.

Pro: Including compression costs in the Sheep Mountain transportation allowance calculation would acknowledge that the CO_2 must be transported in a supercritical phase under unusual pressures and stringent conditions.

Con: Allowance of these compression costs would be contrary to MMS's past policy of denying any costs associated with gathering, measuring, compressing, dehydrating, or performing other services necessary to market production.

Option 3: Allow a portion of the compression costs in the Sheep Mountain transportation allowance calculation.

Pro: Compression facilities for placing production in marketable condition and compression facilities associated with transporting the production are usually separate, distinct facilities. For economic and environmental reasons, ARCO and Exxon combined these two types of facilities into one plant and located the various plants at each individual drillsite. Although the facilities are located on the leases, a portion of the compression costs could be attributable to placing production in marketable condition and the remaining portion of the compression costs could be attributable to the transportation function. Including that portion of the compression costs associated with the transportation function in the transportation allowance calculation would recognize ARCO's and Exxon's actual costs associated with transportation.

Con: It would be difficult, if not impossible, to create a formula that would accurately apportion compression costs between the two separate functions.

SHEEP MOUNTAIN CO_2 TRANSPORTATION ISSUE: <u>ALLOWANCE CAP</u>

Issue

Should MMS grant ARCO and Exxon an exception to the 50 percent cap normally established for onshore transportation allowances?

Background

The MMS's historic policy has been to limit transportation allowances for onshore leases to 50 percent of the value of the product as specified in the Conservation Division Manual, section 647.5.3E. If a lessee believes it is entitled to relief from this limitation, MMS has required the lessee to specifically request, in writing, an exception to the limitation. In certain instances, the Secretary of the Interior (Secretary), upon request of the lessee, may grant exceptions to the 50 percent allowance limitation.

ARCO and Exxon object to the 50 percent transportation allowance limitation on the grounds that it unlawfully deprives the lessee of its right to deduct from royalty all reasonable costs of transporting the royalty share of production from the field to a distant market. ARCO and Exxon originally proposed using a seven-year transportation allowance reporting period, then proposed a two-year transportation allowance reporting period with a loss roll-forward provision. In a draft decision sent to ARCO and Exxon on January 5, 1990, the MMS required ARCO and Exxon to calculate the Sheep Mountain Pipeline transportation allowance on a yearly basis. ARCO and Exxon now offer a compromise position that they be allowed to deduct all actual transportation costs[1] not to exceed X-4 percent of the value of the CO_2. ARCO and Exxon observe that this proposal will always yield a positive royalty value and can be administered on an annual basis. ARCO and Exxon emphasize that this proposal will result in their subsidizing a significant portion of the transportation costs.

Analysis

Owing to the physical properties of the CO_2 and the limited use of CO_2 miscible flood technology, the ratio of transportation costs to commodity value is much

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[1] Actual transportation costs as calculated by ARCO and Exxon are based on a weighted average prime interest rate and include compression, abandonment, and interest during contruction costs.

greater for the Sheep Mountain CO_2 transportation/pipeline operation than for normal methane transportation/pipeline operations. Typically, the market for CO_2 is limited to a small class of operators using miscible CO_2 flooding in tertiary recovery projects. These tertiary recovery projects are usually located great distances from the CO_2 source field. Sales contracts for Sheep Mountain CO_2 index the commodity value of CO_2 to the posted prices of oil recovered at the west Texas tertiary recovery projects. During the design phase of the Sheep Mountain Pipeline oil prices were high. These prices began declining at about the same time initial deliveries of Sheep Mountain CO_2 began. Calculated transportation allowances as a percentage of the CO_2 price are shown in the following table.

Year	Calculated transportation allowance[1] ($/Mcf)	Unit price[2] ($/Mcf)	Allowance as a percentage of price
1983			
1984			
1985			
1986			
1987			

[1] The calculated allowances are based on projected expenses. Costs for compression, abandonment, and interest during construction are not included. The rate of return used in computing the return-on-investment component of the allowance is X-4 percent, the prime interest rate in effect at the beginning of the period for which the allowance would be approved.

[2] Unit prices were provided by ARCO and Exxon. These prices are provided for illustrative purposes only and may not represent the price accepted for royalty purposes.

As shown in the above table, the projected cost of transporting Sheep Mountain CO_2 exceeded the 50 percent allowance limitation for the first two years of operation, a period during which initial throughput is low. As yearly throughput increases, the projected allowances will drop below the 50 percent limitation.

Currently, the Director, MMS, has granted an exception to the 50 percent allowance limitation for onshore leases in one instance. In a decision dated August 28, 1986, Chevron U.S.A. Inc. (Chevron) appealed the 50 percent limitation applied to sulfur recovered at the Carter Creek Gas Processing Plant. The Director granted Chevron's request to exceed the 50 percent limitation but decided that under no circumstances shall a transportation allowance exceed 100 percent of the sales value of the sulfur under any individual selling arrangement. In another decision dated October 30, 1987, the Director rendered a decision in an appeal filed by Mobil Producing Texas and New Mexico Inc. (Mobil) on various issues involving the transportation of CO_2 from the McElmo Dome Unit in Colorado. This decision was rendered without prejudice to Mobil's right to seek relief from the 50 percent ceiling on transportation alllowance by submitting a request for relief to MMS. Thus, the Director indicated that MMS would grant relief to Mobil from the 50 percent limitation if Mobil provided specific figures or documentary evidence in support of its contention that it was entitled to relief. MMS's current policy is to grant a transportation allowance up to 99 percent of the value of the product.

<u>Options</u>

Option 1: Limit the Sheep Mountain transportation allowance to 50 percent of the value of the product.

Pro: The MMS has consistently enforced the CDM guidelines established for transportation allowances (including the 50 percent limitation) and lessees have, for many years, conputed and paid royalties on this basis. This longstanding interpretation of the leases by the parties supports the 50 percent limitation and limiting the Sheep Mountain transportation allowance would be consistent with this policy.

Con: In cases where a lessee can demonstrate that unusual circumstances warrant relief from the 50 percent limitation, MMS may grant an exception to the 50 percent allowance limitation. ARCO and Exxon have demonstrated that during the first few years of operation when throughput of the system is low, actual allowance costs will exceed the 50 percent limit. Upholding the 50 percent limitation will merely force ARCO and Exxon to appeal to the Director. It is highly probable that the Director would grant ARCO and Exxon an exception to the limitation and remand the case back to MMS for recalculation.

Option 2: Grant ARCO and Exxon an allowance in excess of the 50 percent limitation.

Pro: This action would recognize that ARCO and Exxon transport Sheep Mountain CO_2 under unusual circumstances and the costs of transportation are in excess of the 50 percent limitation for the first few years.

Con: Given the uniqueness of the commodity, the atypical operational constraints of the pipeline, and the fact that the allowance only exceeds 50 percent of the value in the first few years, adopting this option would produce no adverse effect.

Recommendation

The MMS should grant ARCO and Exxon an exception to the transportation allowance limitation for the first two years. It is recommended that ARCO and Exxon be limited to the lesser of the actual transportation costs or 99 percent of the value of the product.

(2)

Side-by-Side Analysis
Sheep Mountain CO2 Unit
McElmo Dome CO2 Unit

	Sheep Mountain Unit	McElmo Dome Unit
	ARCO Oil and Gas Company, Operator Exxon Company, U.S.A., Working Interest Owner	Mobil Producing Texas & New Mexico Inc., Working Interest Owner
Unit Location	Huerfano County, Colorado	Dolores County, Montezuma County, Colorado
Unit Operator	ARCO Oil and Gas Company (ARCO)	Shell Western E & P Inc. (Shell)
Pipelines through which unit CO2 is transported	Sheep Mountain Pipeline*	Cortez Pipeline* McElmo Creek Unit Pipeline Llano Pipeline Mobil Producing Texas & New Mexico Inc. Pipeline* Sheep Mountain Pipeline* West Texas Pipeline*
	* Pipelines for which an allowance was requested or granted.	* Pipelines for which an allowance was requested or granted.

Units/leases where unit production is sold/exchanged/provided in-kind	ARCO Seminole-San Andreas Unit Wellman Unit GMK South Unit Denver Unit Sable Unit Wasson ODC Unit Willard-San Andreas Unit Exxon Cornell Unit Seminole-San Andreas Unit Means-San Andreas Unit Willard-San Andreas Unit Dollarhide Field Devonian Unit Denver Unit Yates Field Unit Means Queen No. 1 Oil Unit Sable Unit GMK South Unit H.O. Mahoney Lease South Wasson Clearfork Unit	Mobil Willard-San Andreas Unit Wellman Unit H.O. Mahoney Lease Denver Unit South Wasson Clearfork Unit Dollarhide Field Devonian Unit East Vacuum Unit McElmo Creek Unit Seminole-San Andreas Unit
Initial Reservoir Conditions	Pressure: X-4 psia, Dakota Fm. sia, Entrada Fm. Temperature: X-4 F, Dakota Fm. F, Entrada Fm.	Pressure: X-4 , Leadville Fm. Temperature: X-4 Leadville Fm.
Pressure of Production at Surface Separation Facilities	Pressure: X-4 psig, Dakota Fm. psig, Entrada Fm. Temperature: Minimum of X-4 F	Pressure: X-4 psig Temperature: X-4 F

On-Unit Treatment of Production	Production is heated at the wellsite, moved to a treatment plant and dehydrated. Low-pressure gas is compressed from X-4 psig to X-4 psig, cooled and combined with dehydrated high-pressure gas. The combined stream is compressed to X-4 psig, cooled, metered and sent by pipeline to the central metering station. ARCO/EXXON HAVE REQUESTED THAT ALL COSTS FOR COMPRESSION AT THE WELLSITE TREATMENT PLANTS BE INCLUDED IN THE TRANSPORTATION ALLOWANCE CALCULATION.	Production is transported from the well cluster facilities to the compressor stations. The gas is heated, compressed to X-4 psig, cooled, dehydrated, compressed to X-4 psig, cooled, and discharged to the Cortez pipeline. MOBIL HAS NOT REQUESTED THAT ANY OF THE COSTS OF COMPRESSION AT THESE COMPRESSOR STATIONS BE INCLUDED IN THE TRANSPORTATION ALLOWANCE CALCULATION.
Pipeline Meter Location	The custody transfer meter is located downstream of the wellsite compression plants. Gas streams from all wellsite facilities are combined into one stream and metered at the pipeline origin meter station.	The custody transfer meters are located downstream of the compressor stations. Gas streams from each of the compressor stations are metered separately.
Off-Unit Treatment of Production	The pressure of the gas at the origin meter station is sufficient for the gas to cross over Raton Pass without dropping below the critical pressure needed to maintain single-phase flow. Because of the drop in elevation from Raton Pass to delivery points in West Texas, the gas must be decompressed so as not to exceed contractual delivery requirements. ARCO/EXXON HAVE NOT REQUESTED THAT COSTS FOR DECOMPRESSING THE GAS BE INCLUDED IN THE TRANSPORTATION ALLOWANCE CALCULATION.	In order to deliver McElmo Dome CO2 to the Willard, Wellman, Seminole-San Andreas Units, and the H.O. Mahoney Lease, the gas must pass from the Cortez Pipeline through the Mobil Pipeline into the Sheep Mountain Pipeline. Because the operating pressure of the Sheep Mountain Pipeline is higher than the operating pressure in Mobil's pipeline, Mobil must compress the gas before sending the gas to the Sheep Mountain Pipeline. MOBIL HAS REQUESTED THAT COSTS TO COMPRESS THE GAS IN ORDER TO MEET THE PRESSURE REQUIREMENTS OF THE SHEEP MOUNTAIN PIPELINE BE INCLUDED IN THE TRANSPORTATION ALLOWANCE CALCULATION.

(2)

Side-by-Side Analysis
Sheep Mountain CO2 Unit
McElmo Dome CO2 Unit

	Sheep Mountain Unit ARCO Oil and Gas Company, Operator Exxon Company, U.S.A., Working Interest Owner	McElmo Dome Unit Mobil Producing Texas & New Mexico Inc., Working Interest Owner
Unit Location	Huerfano County, Colorado	Dolores County, Montezuma County, Colorado
Unit Operator	ARCO Oil and Gas Company (ARCO)	Shell Western E & P Inc. (Shell)
Pipelines through which unit CO2 is transported	Sheep Mountain Pipeline*	Cortez Pipeline* McElmo Creek Unit Pipeline Llano Pipeline Mobil Producing Texas & New Mexico Inc. Pipeline* Sheep Mountain Pipeline* West Texas Pipeline*
	* Pipelines for which an allowance was requested or granted.	* Pipelines for which an allowance was requested or granted.

Units/leases where unit production is sold/exchanged/provided in-kind	ARCO Seminole-San Andreas Unit Wellman Unit GMK South Unit Denver Unit Sable Unit Wasson ODC Unit Willard-San Andreas Unit Exxon Cornell Unit Seminole-San Andreas Unit Means-San Andreas Unit Willard-San Andreas Unit Dollarhide Field Devonian Unit Denver Unit Yates Field Unit Means Queen No. 1 Oil Unit Sable Unit GMK South Unit H.O. Mahoney Lease South Wasson Clearfork Unit	Mobil Willard-San Andreas Unit Wellman Unit H.O. Mahoney Lease Denver Unit South Wasson Clearfork Unit Dollarhide Field Devonian Unit East Vacuum Unit McElmo Creek Unit Seminole-San Andreas Unit
Initial Reservoir Conditions	Pressure: X-4 psia, Dakota Fm. psia, Entrada Fm. Temperature: X-4 F, Dakota Fm. F, Entrada Fm.	Pressure: X-4 , Leadville Fm. Temperature: X-4 Leadville Fm.
Pressure of Production at Surface Separation Facilities	Pressure: X-4 psig, Dakota Fm. psig, Entrada Fm. Temperature: Minimum of X-4 F	Pressure: X-4 psig Temperature: X-4 F

On-Unit Treatment of Production	Production is heated at the wellsite, moved to a treatment plant and dehydrated. Low-pressure gas is compressed from X-Y psig to X-Y psig, cooled and combined with dehydrated high-pressure gas. The combined stream is compressed to X-Y psig, cooled, metered and sent by pipeline to the central metering station.	Production is transported from the well cluster facilities to the compressor stations. The gas is heated, compressed to X-Y psig, cooled, dehydrated, compressed to X-Y psig, cooled, and discharged to the Cortez pipeline.
	ARCO/EXXON HAVE REQUESTED THAT ALL COSTS FOR COMPRESSION AT THE WELLSITE TREATMENT PLANTS BE INCLUDED IN THE TRANSPORTATION ALLOWANCE CALCULATION.	MOBIL HAS NOT REQUESTED THAT ANY OF THE COSTS OF COMPRESSION AT THESE COMPRESSOR STATIONS BE INCLUDED IN THE TRANSPORTATION ALLOWANCE CALCULATION.
Pipeline Meter Location	The custody transfer meter is located downstream of the wellsite compression plants. Gas streams from all wellsite facilities are combined into one stream and metered at the pipeline origin meter station.	The custody transfer meters are located downstream of the compressor stations. Gas streams from each of the compressor stations are metered separately.
Off-Unit Treatment of Production	The pressure of the gas at the origin meter station is sufficient for the gas to cross over Raton Pass without dropping below the critical pressure needed to maintain single-phase flow. Because of the drop in elevation from Raton Pass to delivery points in West Texas, the gas must be decompressed so as not to exceed contractual delivery requirements.	In order to deliver McElmo Dome CO2 to the Willard, Wellman, Seminole-San Andreas Units, and the H.O. Mahoney Lease, the gas must pass from the Cortez Pipeline through the Mobil Pipeline into the Sheep Mountain Pipeline. Because the operating pressure of the Sheep Mountain Pipeline is higher than the operating pressure in Mobil's pipeline, Mobil must compress the gas before sending the gas to the Sheep Mountain Pipeline.
	ARCO/EXXON HAVE NOT REQUESTED THAT COSTS FOR DECOMPRESSING THE GAS BE INCLUDED IN THE TRANSPORTATION ALLOWANCE CALCULATION.	MOBIL HAS REQUESTED THAT COSTS TO COMPRESS THE GAS IN ORDER TO MEET THE PRESSURE REQUIREMENTS OF THE SHEEP MOUNTAIN PIPELINE BE INCLUDED IN THE TRANSPORTATION ALLOWANCE CALCULATION.

LABARGE COMPARISON SPREADSHEET (allowance cost only)

	LABARGE	WHITNEY	CARTER
FEED GAS MMCFD			
CAPACITY			
THRUPUT		X-4	
REVENUE			
CH4			
CO2	$36,763,000		
N2	[illegible]		
S			
NGL		X-4	
COND			
TOTAL			
OPERATING COSTS			
NO DEPR OR ROR			
TOTAL			
$/Mcf thruput			
CAPITAL COSTS		X-4	
$/Mcfd capacity			
Net Revenue			
$/Mcf thruput			

(1)

LABARGE COMPARISON SPREADSHEET (Total Cost Case)

	LABARGE	CARTER
FEED GAS MMCFD		
CAPACITY		
THRUPUT		
REVENUE		
CH4		
CO2		
N2		
S		
NGL		
COND		
TOTAL	X-4(	X-4(
OPERATING COSTS		
NO DEPR OR ROR		
TOTAL		
$/Mcf thruput		
CAPITAL COSTS		
$/Mcfd capacity		
Net Revenue		
$/Mcf thruput		

28

United States Department of the Interior

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

M. Reynolds 2-30-95
SK 2/3/95

IN REPLY REFER TO:

MMS-VSD-OG:95-0047
Mail Stop 3152

FEB - 3 1995

Memorandum

To: Office of the Solicitor
Division of Energy and Resources
Attn: Geoff Heath, Attorney Advisor

Original signed by
Martin C. Grieshaber

From: Chief, Valuation and Standards Division

Subject: Revenue Impact--Actual Costs v. Cortez Pipeline Tariff
Shell/Mobil--McElmo Dome Unit--CO_2 Production

The Valuation and Standards Division (VSD) was asked to calculate the revenue impact for the difference between the actual transportation costs versus the use of the Cortez Pipeline tariff rate, for the following time periods:

- March 1, 1988 - 1992
- 1992 - present & estimate for the future.

Since neither Shell or Mobil have provided the data to make an in-depth analysis, VSD is unable to calculate the revenue impact, accurately. However, in reviewing a request from Shell for an exception to the 50 percent limitation, certain amounts listed as "other expenses" included non-allowable costs, as follows:

CATEGORY	3/1/88-12/31/88	AMOUNTS 1989	AMOUNTS 1990	AMOUNTS 1991
Interest				
Banking Fees		X-4		
Totals				

Example: For 1989

Shell claimed total costs of
Less nonallowable costs of

X-4

Allowable expenses
Shell's percentage
Shell's throughput = X-4

Shell's expense/Shell's throughput (X-4 / X-4 = X-4 /Mcf)

Cortez pipeline Tariff Rate claimed = $0.39 per Mcf
Allowance rate X-4 per Mcf

Underpayment per Mcf X-4 per Mcf

Please be advised that the allowance rate of X-4 per Mcf used in the calculation shown above includes Federal and State income taxes, a profit margin of 7 percent, as well as any other potential non-allowable costs. Further, the Cortez Pipeline tariff rate increased from $0.39 per Mcf to $0.493 per Mcf during all of 1990 and to $0.525 per Mcf during all of 1991.

Included are copies of the documents you requested, Attachment 1 through Attachment 4:

Attachment 1 -- Shell IBLA decision, decided Jan 23, 1990, regarding income taxes.

Attachment 2 -- Field Report that backed off a termination date.
2/11/92 memo on Shell Appeal 90-0752

Attachment 3 and Attachment 4 -- Examples of recent FERC oil OCS tariff denials.

If you have any question please call Shirley Keller (303) 275-7217.

4 Attachments

bcc: RM Chron:95-0047
RM Chron DC/Lkwd (2)
VSD Chron (2)
O&G Chron (2)
States
LMS:RMP:VSD:O&G:SKELLER:MS3152:275-7217:P:\USERS\OANDG\KELLER\95-0047
final:mkr:02/03/95

United States Department of the Interior

OFFICE OF HEARINGS AND APPEALS
INTERIOR BOARD OF LAND APPEALS
4015 WILSON BOULEVARD
ARLINGTON, VIRGINIA 22203

IN REPLY REFER TO:

TAKE PRIDE IN AMERICA

SHELL WESTERN E & P, INC.

IBLA 87-47 Decided January 23, 1990

Appeal from a decision of the Director, Minerals Management Service, affirming an order of the Royalty Valuation and Standards Division disallowing Federal and state income taxes as elements of transportation costs in calculating royalties on carbon dioxide transported by pipeline. MMS-84-0013-MISC.

Set aside and remanded.

1. Oil and Gas Leases: Royalties: Generally

MMS unfairly discriminates against a CO_2 lessee in denying a deduction for that component of a pipeline tariff relating to Federal and state income taxes solely on the basis that such lessee is an affiliate of the pipeline operator.

APPEARANCES: William G. Riddoch, Esq., Houston, Texas, for appellant; Peter J. Schaumberg, Esq., and Howard W. Chalker, Esq., Office of the Solicitor, U.S. Department of the Interior, Washington, D.C., for the Minerals Management Service.

OPINION BY ADMINISTRATIVE JUDGE FRAZIER

Shell Western E & P, Inc. (SWEPI), has appealed from the August 6, 1986, decision of the Director, Minerals Management Service (MMS), affirming an order of the Chief, Royalty Valuation and Standards Division, MMS, disallowing Federal and state income taxes as elements of transportation costs in calculating royalties on carbon dioxide (CO_2) produced from the McElmo Dome (Leadville) Unit, 1/ located in Dolores and Montezuma Counties,

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1/ McElmo Dome is a consolidation of several previous units into a single unit covering a subsurface unitized formation known as the Mississippian Leadville Formation underlying lands in Ts. 36, 37, 38, 39 N., and Rs. 17, 18, 19, and 20 W., New Mexico Principal Meridian. Unitized substances in McElmo Dome are all oil and gas within or produced from the unitized formation. The term "gas" specifically and expressly includes carbon dioxide. Robert D. Lanier, 90 IBLA 293, 93 I.D. 66 (1986) (carbon dioxide produced from McElmo Dome under Federal oil and gas leases).

Colorado, and transported via a pipeline owned by the Cortez Pipeline Company (Cortez) 2/ over 500 miles to the Denver Unit CO_2 project in western Texas.

SWEPI, the successor in interest to Shell Oil Company (Shell), is the operator of the McElmo Dome Unit. On October 25, 1983, representatives of Shell met with representatives of MMS to provide an overview of and a status report on Shell's McElmo Dome/Denver Unit CO_2 Project. At the meeting, MMS requested information concerning the tariff to be charged to Shell by Cortez for transportation of Shell's share of CO_2 produced from McElmo Dome and sold by Shell to the Denver Unit, via the 500-mile pipeline then under construction from southwestern Colorado to the Wasson Field in West Texas where the Denver Unit is located.

By letter dated December 9, 1983, Shell advised MMS of certain information provided by Cortez concerning the tariff to be established for transportation of CO_2 from McElmo Dome to the Denver Unit. In the letter, Shell proposed that the Cortez tariff be allowed as a transportation deduction from the proceeds received by Shell for the sale of CO_2, and that Shell not be required to pay royalty under the Federal leases on that amount.

By letter dated March 29, 1984, MMS advised SWEPI that the Cortez tariff calculation procedure was acceptable to MMS, with the exception that Federal and state income taxes should not be considered in computing transportation costs. MMS explained that "Federal and State income tax should be eliminated before transportation costs are computed. Should they be retained in the computation, royalty must be paid on that portion of the pipeline tariff represented by the Federal and State income taxes" (Letter from MMS to SWEPI dated Mar. 29, 1984, at 2).

By letter dated May 1, 1984, SWEPI appealed the March 29, 1984, decision to the Chief, Royalty Valuation and Standards Division, MMS, arguing as follows:

> There currently is no market for CO_2 produced from the McElmo Dome (Leadville) Unit except for CO_2 purchased by the Denver Unit. The actual cost of transporting CO_2 through the Cortez pipeline from Southwestern Colorado to West Texas is a marketing cost which must be assumed by the royalty owner as well as the working interest owners. These actual costs of transportation, which will in the future include payment of both Federal and State income taxes, constitute the Cortez tariff and are incurred by the Federal lessee who transports CO_2 to the Denver Unit for sale. SWEPI, as a Federal lessee transporting CO_2 to the Denver Unit for sale, is entitled to be reimbursed by the purchaser of CO_2 for the tariff charged for transporting such CO_2, subject to certain limitations as set forth in the Denver Unit CO_2 Sale and

2/ Cortez is a general partnership owned by Shell Cortez Pipeline Company, Mobil Cortez Pipeline Company, and Continental Resources Cortez Pipeline Company.

> Purchase Contract. Since the Sale of CO_2 to the Denver Unit was the first such sale of CO_2 from the McElmo Dome (Leadville) Unit - and is still the only such sale - it was necessary to agree with the Denver Unit working interest owners that they would not bear the full cost of the Cortez pipeline tariff.
>
> Thus, any actual costs of transportation borne by SWEPI which are not reimbursed by the Denver Unit were agreed to through negotiation with the Denver Unit working interest owners. The MMS, however, by its determination not to permit deduction of all the actual transportation charges (the tariff) incurred by SWEPI has arbitrarily and without justification imposed a penalty on SWEPI which was neither negotiated nor anticipated. The full tariff paid by SWEPI should be permitted to be deducted from the price received for CO_2 sales by SWEPI for royalty payment purposes to the MMS.

(Letter dated May 1, 1984, from SWEPI to MMS, at 3-4).

By memorandum dated September 10, 1984, the Chief, Royalty Valuation and Standards Division (RVSD), recommended to the Chief, Division of Appeals, Office of Program Review, that the March 29, 1984, decision be upheld, providing the following rationale for its position:

> The RVSD upholds its previous position with regard to income taxes. In William and Meyers Oil and Gas Law, Vol. 3, § 604.6(b) clearly defines which costs may be considered as a cost of operation; "the current cost of operation has been held to include taxes (<u>other than income taxes</u>) payable by the owner of the working interests." In addition, in Matzen v. Hugeton Production Co., (321 P.2d 576), the Supreme Court of Kansas upheld evidence which established that "from an accounting standpoint, income tax is a sharing of profits, not a cost; that in cost accounting, income tax is never used as a factor in determining cost of operation, cost of sales, nor of any other item." [Emphasis in original.]

By letter to the Chief, Division of Appeals, Office of Payment Review, MMS, dated February 7, 1985, SWEPI registered its disagreement with RSVD's September 10, 1984, memorandum. SWEPI argued that RSVD's reliance upon the definition of "cost of operation" from <u>Williams and Myers</u> was misplaced, stating that "[i]t is a partial quote from Section 604.6(b) * * * taken out of context, which relates to a subject completely different from transportation costs which are allowed as a deduction from the value of royalties" (Letter dated Feb. 7, 1985, from SWEPI to the Chief, Division of Appeals, Office of Payment Review, MMS, at 7). According to SWEPI, "[t]he entire scope of the discussion in this part of the treatise is limited to costs of 'paying production', within the overall construction of a habendum clause in an oil and gas lease for purposes of determining the duration of the lease," and that "[t]his section of the treatise has no relevance at all to costs incurred in the transportation of a product, in this case, CO_2, or computation of royalty payments." Id. SWEPI argued as follows:

> The issue under appeal here is not the identification of which costs of production are to be assessed against the non-operator-lessor's usual royalty interest, but is instead the identification of "costs subsequent to production" which are usually borne proportionately by the operating and the non-operating interests. 3 R. Williams, Oil and Gas Law Sections 645.1-.2 (1981). Indeed, the quoted definition itself clearly identifies the party whose income taxes are not to be included in the current cost of operations, i.e., "the owner of the working interest," and not a common carrier pipeline.

(Letter dated Sept. 7, 1985, at 8).

In addition, SWEPI maintained that RSVD "misses the mark" by placing its reliance upon Matzen v. Hugoton Production Co., 321 P.2d 576 (Kas. 1958). SWEPI conceded that the "Matzen court properly determined that an operator-lessee and a non-operator-lessor must bear the burden of their own income tax without contribution from the other party" (Sept. 11, 1985, letter (emphasis in original)). SWEPI contended, however, that Matzen "does not stand for the proposition that income taxes of a common carrier pipeline carrier must be borne exclusively out of the operator lessee's interest." Id. at 9. SWEPI reasons as follows:

> What distinguishes the holding of Matzen from the issue in the SWEPI Appeal is the fact that the court disallowed deduction of the lessee's income taxes from the lessor-landowners' royalty. Whereas in the MMS Decision, pipeline owners' income taxes which are included in a pipeline tariff and passed on as a cost to a shipper-lessee as an overall transportation charge are disallowed as deductible costs for the purpose of computing the transportation allowance for royalty purposes. Stated simply, the Matzen case involved income taxes of a lessee, and the instant appeal involves income taxes of a common carrier pipeline. The former is not, and the latter is, a proper component of transportation expense deductible from lessor royalty. [Emphasis in original.]

(Letter dated Feb. 7, 1985, at 10).

By memorandum dated May 6, 1985, from the Chief, RVSD, to the Chief, Division of Appeals, Office of Program Review, the Chief, RVSD, responded to SWEPI's arguments. RVSD explained that its decision to disallow Federal and state income taxes as transportation costs was based upon the Conservation Division Manual (CDM 647.5), which "provides standard guidelines for determining allowable pipeline transportation deductions for royalty purposes for Federal and Indian onshore lands" (Memorandum dated May 6, 1985, at 2). The CDM specifies transportation allowances for (1) producer-owned and operated pipelines (CDM 647.5A); (2) producer-owned (by production payments) pipelines which are not operated by the lessee (CDM 647.5B); and (3) pipelines owned by parties other than the lessee (CDM 647.5C). RVSD determined that because SWEPI "owns a major interest of the Cortez Pipeline Company through its subsidiary, Shell Cortez Pipeline Company * * * the CDM guidelines under 'producer-owned and operated pipelines,' 647.5A, are most applicable in this case" (Memorandum dated May 6, 1985, at 3). These guidelines provide as follows:

> Intangible and direct costs in the following or like categories which can be shown to the satisfaction of the Supervisor to be part of the operating costs: Insurance (hazard, liability, workman's compensation, etc.); Taxes (Social Security, property taxes assessed on the pipeline and other equipment approved as pipeline investment items, etc. <u>However, corporate income taxes are not an allowable deduction</u>) * * *. [Emphasis added].

RVSD explained that its policy is to deny Federal and state income taxes as transportation costs when the "pipeline is producer-owned and transporting that producer's production only to a sales point" (Memorandum dated May 6, 1985, at 3). By contrast, RVSD noted that "[i]n situations where a third-party pipeline, generally a common carrier, imposes a tariff on a producer under arm's-length conditions, MMS will approve the entire tariff, regardless of how such tariff is derived, as the producer's actual cost of transportation that may be deducted from Federal royalty." Id. Further, "[i]f a pipeline is a common carrier, and carries both affiliated and nonaffiliated production, it is MMS policy to accept a published tariff for the nonaffiliated production, but to require actual cost data to justify an allowance for affiliated production." Id. at 3.

By letter to the Division of Appeals, Office of Program Review, MMS, dated September 9, 1985, SWEPI maintained that other producers not related to the pipeline company would be able to deduct the entire pipeline tariff, whereas it would only be allowed to deduct less than that amount since the portion of the tariff attributable to Federal and income taxes will not be recognized as a transportation cost. SWEPI concluded that this application of the CDM was arbitrary, resulting in "undue discrimination against the producer-owners of the Cortez CO_2 pipeline, a common carrier" (Letter dated Sept. 9, 1985, at 6). SWEPI asserts:

> The producer-owners are subject to liability for a higher royalty payment to the MMS than are other producers of CO_2 from the McElmo Dome (Leadville) Unit or from other CO_2 sources who transport CO_2 through the Cortez CO_2 pipeline, but who do not own an interest in the Cortez CO_2 pipeline, solely because the transportation of CO_2 is not regulated.

Id.

By decision dated August 6, 1986, the Director, MMS, denied SWEPI's appeal, and affirmed the order of the RSVD, explaining its policy of denying the deduction of Federal and state income taxes as transportation costs on the following basis:

> This policy is premised on the impossibility of accurately allocating the correct tax burden to the pipeline, as well as the other activities of the pipeline/producer. An inflated pipeline tariff in those circumstances would benefit the lessee in providing for a greater reduction from royalty (and thereby depriving the lessor of its full royalty entitlement). The MMS adopted the policy of limiting the transportation allowance to actual costs exclusive of income tax. The MMS policy is a reasonable measure intended to eliminate the potential for abuse that could result from expense manipulation between pipelines and production facilities not wholly independent of each other.

(Decision dated Aug. 6, 1986, at 6).

[1] As noted by appellant, MMS relied upon Matzen to support its decision to deny a deduction for incomes taxes as transportation costs. However, the record demonstrates that despite its application of Matzen against SWEPI, MMS does not follow Matzen as a general rule. MMS appears untroubled by the general concept of allowing a lessee to include income taxes paid by a pipeline as an element of transportation costs, since it allows such a deduction if there is a published tariff for a common carrier which includes income taxes as transportation costs. 3/ When there is no published tariff, as in the instant case, only lessees who are affiliates of pipeline owners are not allowed to deduct income taxes as transportation costs from the value upon which royalty is calculated. MMS' application of the Matzen rule only when the lessee is an affiliate of the pipeline owner is untenable.

In Getty Oil Co., 51 IBLA 47 (1980), the Director, Geological Survey (GS), affirmed an order of the Acting Oil and Gas Supervisor, Gulf of Mexico Area, GS, requiring Getty to pay additional royalties for gas sold to its "wholly controlled" subsidiary in accordance with a contract between Getty and the subsidiary. GS contended that since Getty had the right to rescind the contract, and thus sell the gas at higher interstate prices, the Area Supervisor should properly value the gas for royalty purposes as if Getty had sold it at the highest price obtainable on the interstate market.

The Board stated that "[e]ssential to Getty's appeal is the validity of its agreement for the sale of gas to [its subsidiary]." 51 IBLA at 49. The Board's analysis of this issue is relevant to the issue of whether MMS should have denied SWEPI the income tax deduction on the basis that it wanted to "eliminate the potential for abuse that could result from expense

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3/ The Board has held that section 28 of the Mineral Leasing Act of 1920, as amended, 30 U.S.C. § 185 (1982), provides the authoirity for issuance of a right-of-way for a carbon dioxide pipeline for transportation of production from Federal oil and gas leases. Exxon Corp., 97 IBLA 45, 94 I.D. 139 (1987). Such pipelines are required by statute to be operated as "common carriers." 30 U.S.C. § 185(r)(1) (1982).

manipulation between pipelines and production facilities not wholly independent of each other" (Decision by Director, MMS, dated Aug. 6, 1986, at 6). The Board stated:

> We agree with appellant that a parent corporation and its wholly owned subsidiary may enter into a valid contract. In United States v. Weissman, 219 F.2d 837 (2nd Cir. 1955), Judge Learned Hand wrote: "It is true that there can be legal transactions between two corporations all of whose shares are owned by a single individual, and that the same obligations will arise out of them as would arise, had they been between either corporation and a third person." It is the general rule that courts will not, because of stock ownership or interlocking directorates, disregard the separate legal identities of corporations, unless such relationship is used to defeat public convenience, justify wrongs (e.g., violation of antitrust laws), protect fraud, or defend crime. Norton v. Integral Corp., 584 S.W.2d 932, 935 (1979).

51 IBLA at 50.

MMS proceeds on the assumption that when the lessee is an affiliate of the pipeline operator, the income tax burden of the operator may somehow be shifted to the lessee, thereby reducing the amount upon which Federal royalty on the CO_2 is calculated. MMS' policy, while "intended to preclude abuse and overcome audit burdens," unfairly discriminates against lessees who are affiliates of pipeline operators. In the absence of some manifestation that affiliated companies are using their corporate relationship to defeat MMS royalty collection efforts, the general rule recognized in Getty Oil Co. applies. 4/ MMS does not allege, and there is nothing in the record to suggest, that Cortez is not transporting SWEPI's CO_2 at a price equal to that obtainable under an arms-length contract. MMS' denial of a transportation allowance for income taxes in this case solely on the basis that SWEPI is an affiliate of the pipeline operator was improper.

4/ Moreover, the factual predicates of the MMS decision are substantially undermined by the fact that SWEPI owns only a 50-percent interest in the Cortez pipeline. While the Board has, indeed, recognized that economic incentives exist which might impel producers to shift profits to wholly owned subsidiaries as a means of decreasing royalty obligations (see Transco Exploration Co., 110 IBLA 282, 96 I.D. 367 (1989)), the economic viability of such a strategy declines where, as here, outside interests in the subsidiary are substantial. Thus, while a parent corporation might well desire to have profits transferred form one corporationn to another in an attempt to lessen royalty payments of 12.5 percent on the value of production, the incentive to do so when the parent corporation owns only 50 percent of the second corporation evaporates, since such a procedure results in the net loss of 37.5 percent. Similarly, it is difficult to see how the manipulation of allocation of income taxes works effectively where the parent corporation owns only 50 percent of one of the entities involved, particularly where the expressed fears of MMS can only be realized by increasing the tax burden of the partially-owned entity.

Accordingly, pursuant to the authority delegated to the Board of Land Appeals by the Secretary of the Interior, 43 CFR 4.1, the decision of the Director, MMS, is set aside and remanded for action consistent with this opinion.

Gail M. Frazier
Administrative Judge

I concur:

James L. Burski
Administrative Judge

Attachment 4

United States Department of the Interior

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

IN REPLY REFER TO:

MMS-VSD-OG:94-0146
Mail Stop 3152

NOV 23 1994

<u>CERTIFIED MAIL--</u>
<u>RETURN RECEIPT REQUESTED</u>

Mr. Colling K. Tam
Section Supervisor, Oil Revenue Accounting
Unocal Corporation
P.O. Box 4531
Houston, Texas 77210-4531

Dear Mr. Tam:

By letter dated March 22, 1994, the Unocal Corporation (Unocal) requested the Minerals Management Service (MMS) approval for an allowance in excess of the 50-percent limitation to transport condensate (Product Code 02) from Platform Habitat in the Pitas Point Area, offshore California, to Port Hueneme, onshore California, for the actual cost data in Calendar Year (CY) 1993 and CY 1994 estimated cost data. This request applies to the following accounting identification (AID) numbers, and selling arrangements (S/A), for Payor Code 73770.

AID No.	S/A
088-000234-0-001	001
088-000346-0-001	001

The MMS has reviewed the documentation submitted with your request which shows that the costs to transport condensate from Platform Habitat to Port Hueneme were X-4 percent of the value of condensate transported during CY 1993. In accordance with 30 CFR § 206.104(b) (1993), Unocal is authorized to deduct a transportation allowance for condensate in excess of the 50-percent limitation, subject to future review and audit. The allowance that may be deducted will be the actual costs incurred each month, but may not exceed X-4 percent of the value of condensate transported from Platform Habitat to Port Hueneme for CY 1993 actual cost data and CY 1994 estimated cost data.

Until such time as Unocal's application for an exception to the 50-percent limitation is approved by MMS, Unocal may not deduct allowances in excess of the limit on the Report of Sales and Royalty Remittance (Form MMS-2014). In addition, the Oil Transportation Allowance Report (Form MMS-4110) filed by Unocal should not reflect allowance rates in excess of the limit prior to receipt of this letter. Upon receipt of this approval letter, Unocal may report its actual costs not to exceeo X-4 percent on Forms MMS-2014 and MMS-4110 for CY 1993 actual costs and CY 1994 estimated costs.

A request for an exception to the 50-percent limitation must be submitted annually. Your request, with sufficient justification to obtain MMS approval, should be submitted within 30 days after the end of the calendar year or within 30 days after the non-arm's-length situation is amended or terminated.

In addition to the above request, Unocal requested an exception from the requirement to compute actual costs for transporting crude oil from the leases listed below under non-arm's-length contracts. This request applies to the following Federal Energy Regulatory Commission (FERC) Tariffs for the period January 1 through December 31, 1994.

Lease No.	FERC Tariff No.	Segment	Transportation Allowance Rate/bbl.
088-000241-0 088-000240-0	7	Platform "B" to Rincon Facility, Ventura County	$0.21
		Platform "A" Tie-in to Rincon Facility, Ventura County	$0.20
088-000202-0 088-000203-0	9	Platform Gina to Mandalay Facility, Ventura County	$0.19
088-000437-0 088-000441-0 088-000444-0	3	Platform Irene to Lompoc HS&P Facility, California	$0.98*
088-000215-0 088-000216-0 088-000217-0	9	Platform Gilda to Mandalay Facility, Ventura County	$0.21

* The transportation rate shown in the Point Pedernales Pipeline Company FERC Tariff No. 3 is $2.00 per barrel. However, MMS previously determined that X-4 per barrel is attributable to transportation of wet barrels and X-4 per barrel is attributable to processing the wet oil at the Lompoc HS&P Facility.

Federal regulations and instructions establish the procedures for calculating and reporting transportation allowances. Title 30 CFR § 206.105(b)(5) (1993) states in part:

> A lessee may apply to the MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(4) of this section. <u>The MMS will grant the exception only if the lessee has a tariff for the transportation system approved by the Federal Energy Regulatory Commission</u> . . . . [Emphasis added.]

UNCOAL CORPORATION
FEDERAL ENERGY COMMISSION (FERC) TARIFF
FOR THE PERIOD JANUARY 1, THROUGH DECEMBER 31, 1984

MMS PROJECT NUMBER	FERC TARIFF NUMBER	ACCOUNTING IDENTIFICATION NUMBER	TRANSPORTATION POINT FROM	TRANSPORTATION POINT TO	TRANSPORTATION RATE PER BARREL
94-0189	51	054-002391-0-002	HIGH ISLAND BLOCK 573	HIGH ISLAND ONSHORE FACILITY	$1.25
94-0191	30	054-004000-0-001	SOUTH TIMBALIER BLOCK 53	SOUTH TIMBALIER 52	$0.317
94-0193	42	055-000827-0-001 054-001228-0-001 054-001230-0-001	SHIP SHOAL 208	ST. JAMES STATION	$0.195
94-0194	51	054-002423-0-001	HIGH ISLAND BLOCK 334	HIGH ISLAND ONSHORE FACILITY	$1.40
94-0195	42	054-001031-0-001 054-001529-0-001	SHIP SHOAL 253	ST. JAMES STATION	$0.475
94-0196	51	054-002392-0-001 054-002392-0-002 054-002393-0-001	HIGH ISLAND BLOCK 573	HIGH ISLAND ONSHORE FACILITY	$1.25
		054-002757-0-001 054-002722-0-002 054-002721-0-001 054-003950-0-001	HIGH ISLAND BLOCK 595	HIGH ISLAND ONSHORE FACILITY	$1.35
94-0197	42	054-001036-0-001 054-007757-0-001	SHIP SHOAL 269	ST. JAMES STATION	$0.70

Appeals Procedure and Bonding Requirements

You have the right to appeal in accordance with the provisions of 30 CFR 290 (1993). Any appeal taken will be to the Director, Minerals Management Service (MMS), and the notice of appeal must be filed within 30 days from receipt of this letter with:

Minerals Management Service
Attention: Ms. Deborah Gibbs Tschudy
Chief, Valuation and Standards Division
P.O. Box 25165, MS 3150
Denver, Colorado 80225-0165
Telephone: (303) 275-7200
Fax No.: (303) 275-7227

Any notice of appeal must be accompanied by a written showing, as you deem adequate, to justify reversal or modification of this directive. Within 60 days from receipt of this letter, the appellant will be permitted to file an additional statement of reasons or written briefs. Extensions for filing the statement of reasons will not be permitted unless requested in writing by the appellant within 60 days from receipt of this letter. The request for extension must be submitted to the Deputy Associate Director for Valuation and Operations at the address shown above.

You should be aware that compliance with the orders and directives contained in this letter shall be suspended by reason of an appeal pursuant to 30 CFR § 243.2 (1993) unless the Director, MMS, notifies the appellant in writing that the decision or order shall not be suspended pending appeal.

Title 30 CFR § 243.2 further provides that unless the amount under appeal is $1,000 or less, suspension of an order or decision requiring the payment of a specified amount of money shall be contingent upon the appellant's submission within a time period prescribed by MMS of an MMS-specified surety instrument deemed adequate to indemnify the lessor from loss or damage. Nothing in this paragraph shall be construed to prohibit an appellant from paying any demanded amount pending appeal.

UNCOAL CORPORATION
FEDERAL ENERGY COMMISSION (FERC) TARIFF
FOR THE PERIOD JANUARY 1, THROUGH DECEMBER 31, 1994

MMS PROJECT NUMBER	FERC TARIFF NUMBER	ACCOUNTING IDENTIFICATION NUMBER	TRANSPORTATION POINT FROM	TRANSPORTATION POINT TO	TRANSPORTATION RATE PER BARREL
94-0174	51	054-002647-0-001 054-002648-0-001	EAST BREAKS BLOCK 160	HIGH ISLAND OFFSHORE FACILITY	$1.40
94-0176	12	054-002176-0-002 054-002176-0-003	SOUTH PASS BLOCK 49 PLATFORM OFFSHORE	SOUTH PASS BLOCK 27 ONSHORE FACILITY	$0.90
94-0177	16	055-000787-0-001	SOUTH MARCH ISLAND BLOCK 48	BURNS TERMINAL	$0.60
94-0178	41	054-006358-0-001	GARDEN BANKS BLOCK 189-A	INTERSECTION OF HIGH ISLAND SEGMENT III	$2.75
			INTERSECTION OF HIGH SEGMENT III	HIGH ISLAND ONSHORE	$1.80
94-0179	43	054-000989-0-001	EUGENE ISLAND 276-B	EUGENE ISLAND 259-A	$0.30
	30		EUGENE ISLAND 276-B	EUGENE ISLAND 259-A	$0.09
			BLOCK 28, SHIP SHOAL AREA	GIBSON STATION	$0.095
94-0180	51	054-002645-0-001 054-002646-0-001	EAST BREAKS BLOCK 158	HIGH ISLAND ONSHORE FACILITY	$1.65
94-0181	51	054-002696-0-001 054-002697-0-001 054-002698-0-001	HIGH ISLAND BLOCK A-536-537	HIGH ISLAND ONSHORE FACILITY	$1.20
94-0182	51	054-003241-0-001	HIGH ISLAND BLOCK A442	HIGH ISLAND ONSHORE FACILITY	$1.40
94-0183	16	054-004858-0-001	EUGENE ISLAND BLOCK 42	BURNS TERMINAL	$0.60
94-0185	30	054-005502-0-001 054-005503-0-002 054-005550-0-002	EUGENE ISLAND BLOCK 212	EUGENE ISLAND BLOCK 213	$0.95
94-0186	16	054-004442-0-001	SOUTH MARSH ISLAND BLK 9	BURNS TERMINAL	$0.60
94-0187	55	054-001034-0-001	SHIP SHOAL 266	ST. JAMES STATION	$1.19
94-0188	40	054-006987-0-001 054-007989-0-001	GREEN CANYON BLOCK 6	EWING BANK 978	$0.90

Attachment 3

United States Department of the Interior

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

IN REPLY REFER TO:

MMS-VSD-OG:94-0174
Mail Stop 3152

OCT 28 1994

CERTIFIED MAIL--
RETURN RECEIPT REQUESTED

Mr. T. A. Winkelmann
Supervisor, Oil Revenue Accounting
Unocal Corporation
P.O. Box 4531
Houston, Texas 77210-4531

Dear Mr. Winkelmann:

Thank you for the additional information you provided on June 24, 1994, on behalf of Unocal Corporation to the Minerals Management Service (MMS). You requested the use of various Federal Energy Regulatory Commission (FERC) Tariffs in lieu of computing actual costs for transporting oil production from the Accounting Identifications (AID) numbers listed on Enclosure 1. Your request was for January 1 through December 31, 1994.

The MMS hereby denies your request. Federal regulations and instructions establish the procedures for transportation allowances. Title 30 CFR § 206.105(b)(5) (1993) states in part:

> A lessee may apply to the MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(4) of this section. The MMS will grant the exception only if the lessee has a tariff for the transportation system approved by the Federal Energy Regulatory Commission . . . . [Emphasis added.]

On October 8, 1992, FERC issued the Order Granting Petitions for Declaratory Orders and Disclaiming Jurisdiction, Oxy Pipeline Inc., 61 FERC § 61,051 (1992), which states in part:

> The jurisdictional issue of whether the ICA [Interstate Commerce Act] applies to outer Continental Shelf oil pipelines requires the Commission to interpret its authority over oil pipelines on the outer Continental Shelf under Section 1(1) of ICA. That section provides in pertinent part of the Act ". . . shall apply to common carriers engaged . . . [t]he transportation of oil . . . by pipeline . . . .
>
> > from one State or Territory of the United States, or the District of Columbia, to any other State or Territory of

б / (

> the United States, or the District of Columbia, or from one place in a Territory to another in the same Territory, or from any place in the United States through a foreign country to any other place in the United States, or from or to any place in the United States to or from a foreign country, but only insofar as such transportation or transmission takes place within the United States.

> The Commission agrees with Oxy that the ICA does not expressly cover pipelines transporting oil solely on or across the outer Continental Shelf. While the outer Continental Shelf appertains to the United States, the outer Continental Shelf is not a State or Territory of the United States.

In the issuance of this order, the FERC renounced jurisdiction over oil pipelines transporting oil solely on or across the Outer Continental Shelf. Therefore, MMS cannot approve your request to use various FERC tariffs in lieu of computing actual costs for transporting oil production from the subject AID numbers for January 1 through December 31, 1994. Your transportation allowances for the subject AID numbers will be approved as prescribed at 30 CFR § 206.105 entitled "Determination of transportation allowance":

> (b) Non-arm's-length or no contract.
>
> (1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable, actual costs as provided in this paragraph. . . . A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month Form MMS-4110 is filed with MMS, unless MMS approves a longer period upon their showing good cause by the lessee.

The regulations provide additional information and instructions for calculating transportation allowances.

You have the right to appeal this decision. Please refer to the enclosed Appeals Procedure and Bonding Requirements (Enclosure 2).

If you have any questions, please call Ms. Shirley Barton at (303) 275-7222.

Sincerely,

Deborah Gibbs Tschudy

Deborah Gibbs Tschudy
Chief, Valuation and
Standards Division

2 Enclosures

Accordingly, pursuant to the authority delegated to the Board of Land Appeals by the Secretary of the Interior, 43 CFR 4.1, the decision of the Director, MMS, is set aside and remanded for action consistent with this opinion.

Gail M. Frazier
Gail M. Frazier
Administrative Judge

I concur:

James L. Burski
James L. Burski
Administrative Judge

and that "[t]his section of the treatise has no relevance at all to costs incurred in the transportation of a product, in this case, CO_2, or computation of royalty payments." Id. SWEPI argued as follows:

> The issue under appeal here is not the identification of which costs of production are to be assessed against the non-operator-lessor's usual royalty interest, but is instead the identification of "costs subsequent to production" which are usually borne proportionately by the operating and the non-operating interests. 3 R. Williams, Oil and Gas Law Sections 645.1-.2 (1981). Indeed, the quoted definition itself clearly identifies the party whose income taxes are not to be included in the current cost of operations, i.e., "the owner of the working interest," and not a common carrier pipeline.

(Letter dated Sept. 7, 1985, at 8).

In addition, SWEPI maintained that RSVD "misses the mark" by placing its reliance upon Matzen v. Hugoton Production Co., 321 P.2d 576 (Kas. 1958). SWEPI conceded that the "Matzen court properly determined that an operator-lessee and a non-operator-lessor must bear the burden of their own income tax without contribution from the other party" (Sept. 11, 1985, letter (emphasis in original)). SWEPI contended, however, that Matzen "does not stand for the proposition that income taxes of a common carrier pipeline carrier must be borne exclusively out of the operator lessee's interest." Id. at 9. SWEPI reasons as follows:

> What distinguishes the holding of Matzen from the issue in the SWEPI Appeal is the fact that the court disallowed deduction of the lessee's income taxes from the lessor-landowners' royalty. Whereas in the MMS Decision, pipeline owners' income taxes which are included in a pipeline tariff and passed on as a cost to a shipper-lessee as an overall transportation charge are disallowed as deductible costs for the purpose of computing the transportation allowance for royalty purposes. Stated simply, the Matzen case involved income taxes of a lessee, and the instant appeal involves income taxes of a common carrier pipeline. The former is not, and the latter is, a proper component of transportation expense deductible from lessor royalty. [Emphasis in original.]

(Letter dated Feb. 7, 1985, at 10).

By memorandum dated May 6, 1985, from the Chief, RVSD, to the Chief, Division of Appeals, Office of Program Review, the Chief, RVSD, responded to SWEPI's arguments. RVSD explained that its decision to disallow Federal and state income taxes as transportation costs was based upon the Conservation Division Manual (CDM 647.5), which "provides standard guidelines for determining allowable pipeline transportation deductions for royalty purposes for Federal and Indian onshore lands" (Memorandum dated May 6, 1985, at 2). The CDM specifies transportation allowances for (1) producer-owned and operated pipelines (CDM 647.5A); (2) producer-owned (by production payments) pipelines which are not operated by the lessee (CDM 647.5B); and (3) pipelines

> This policy is premised on the impossibility of accurately allocating the correct tax burden to the pipeline, as well as the other activities of the pipeline/producer. An inflated pipeline tariff in those circumstances would benefit the lessee in providing for a greater reduction from royalty (and thereby depriving the lessor of its full royalty entitlement). The MMS adopted the policy of limiting the transportation allowance to actual costs exclusive of income tax. The MMS policy is a reasonable measure intended to eliminate the potential for abuse that could result from expense manipulation between pipelines and production facilities not wholly independent of each other.

(Decision dated Aug. 6, 1986, at 6).

[1] As noted by appellant, MMS relied upon Matzen to support its decision to deny a deduction for incomes taxes as transportation costs. However, the record demonstrates that despite its application of Matzen against SWEPI, MMS does not follow Matzen as a general rule. MMS appears untroubled by the general concept of allowing a lessee to include income taxes paid by a pipeline as an element of transportation costs, since it allows such a deduction if there is a published tariff for a common carrier which includes income taxes as transportation costs. 3/ When there is no published tariff, as in the instant case, only lessees who are affiliates of pipeline owners are not allowed to deduct income taxes as transportation costs from the value upon which royalty is calculated. MMS' application of the Matzen rule only when the lessee is an affiliate of the pipeline owner is untenable.

In Getty Oil Co., 51 IBLA 47 (1980), the Director, Geological Survey (GS), affirmed an order of the Acting Oil and Gas Supervisor, Gulf of Mexico Area, GS, requiring Getty to pay additional royalties for gas sold to its "wholly controlled" subsidiary in accordance with a contract between Getty and the subsidiary. GS contended that since Getty had the right to rescind the contract, and thus sell the gas at higher interstate prices, the Area Supervisor should properly value the gas for royalty purposes as if Getty had sold it at the highest price obtainable on the interstate market.

The Board stated that "[e]ssential to Getty's appeal is the validity of its agreement for the sale of gas to [its subsidiary]." 51 IBLA at 49. The Board's analysis of this issue is relevant to the issue of whether MMS should have denied SWEPI the income tax deduction on the basis that it wanted to "eliminate the potential for abuse that could result from expense

---

3/ The Board has held that section 28 of the Mineral Leasing Act of 1920, as amended, 30 U.S.C. § 185 (1982), provides the authoirity for issuance of a right-of-way for a carbon dioxide pipeline for transportation of production from Federal oil and gas leases. Exxon Corp., 97 IBLA 45, 94 I.D. 139 (1987). Such pipelines are required by statute to be operated as "common carriers." 30 U.S.C. § 185(r)(1) (1982).

United States Department of the Interior

OFFICE OF HEARINGS AND APPEALS
INTERIOR BOARD OF LAND APPEALS
4015 WILSON BOULEVARD
ARLINGTON, VIRGINIA 22203

IN REPLY REFER TO:

TAKE PRIDE IN AMERICA

SHELL WESTERN E & P, INC.

IBLA 87-47 Decided January 23, 1990

Appeal from a decision of the Director, Minerals Management Service, affirming an order of the Royalty Valuation and Standards Division disallowing Federal and state income taxes as elements of transportation costs in calculating royalties on carbon dioxide transported by pipeline. MMS-84-0013-MISC.

Set aside and remanded.

1. Oil and Gas Leases:-Royalties: Generally

MMS unfairly discriminates against a CO_2 lessee in denying a deduction for that component of a pipeline tariff relating to Federal and state income taxes solely on the basis that such lessee is an affiliate of the pipeline operator.

APPEARANCES: William G. Riddoch, Esq., Houston, Texas, for appellant; Peter J. Schaumberg, Esq., and Howard W. Chalker, Esq., Office of the Solicitor, U.S. Department of the Interior, Washington, D.C., for the Minerals Management Service.

OPINION BY ADMINISTRATIVE JUDGE FRAZIER

Shell Western E & P, Inc. (SWEPI), has appealed from the August 6, 1986, decision of the Director, Minerals Management Service (MMS), affirming an order of the Chief, Royalty Valuation and Standards Division, MMS, disallowing Federal and state income taxes as elements of transportation costs in calculating royalties on carbon dioxide (CO_2) produced from the McElmo Dome (Leadville) Unit, 1/ located in Dolores and Montezuma Counties,

1/ McElmo Dome is a consolidation of several previous units into a single unit covering a subsurface unitized formation known as the Mississippian Leadville Formation underlying lands in Ts. 36, 37, 38, 39 N., and Rs. 17, 18, 19, and 20 W., New Mexico Principal Meridian. Unitized substances in McElmo Dome are all oil and gas within or produced from the unitized formation. The term "gas" specifically and expressly includes carbon dioxide. Robert D. Lanier, 90 IBLA 293, 93 I.D. 66 (1986) (carbon dioxide produced from McElmo Dome under Federal oil and gas leases).

Colorado, and transported via a pipeline owned by the Cortez Pipeline Company (Cortez) 2/ over 500 miles to the Denver Unit CO_2 project in western Texas.

SWEPI, the successor in interest to Shell Oil Company (Shell), is the operator of the McElmo Dome Unit. On October 25, 1983, representatives of Shell met with representatives of MMS to provide an overview of and a status report on Shell's McElmo Dome/Denver Unit CO_2 Project. At the meeting, MMS requested information concerning the tariff to be charged to Shell by Cortez for transportation of Shell's share of CO_2 produced from McElmo Dome and sold by Shell to the Denver Unit, via the 500-mile pipeline then under construction from southwestern Colorado to the Wasson Field in West Texas where the Denver Unit is located.

By letter dated December 9, 1983, Shell advised MMS of certain information provided by Cortez concerning the tariff to be established for transportation of CO_2 from McElmo Dome to the Denver Unit. In the letter, Shell proposed that the Cortez tariff be allowed as a transportation deduction from the proceeds received by Shell for the sale of CO_2, and that Shell not be required to pay royalty under the Federal leases on that amount.

By letter dated March 29, 1984, MMS advised SWEPI that the Cortez tariff calculation procedure was acceptable to MMS, with the exception that Federal and state income taxes should not be considered in computing transportation costs. MMS explained that "Federal and State income tax should be eliminated before transportation costs are computed. Should they be retained in the computation, royalty must be paid on that portion of the pipeline tariff represented by the Federal and State income taxes" (Letter from MMS to SWEPI dated Mar. 29, 1984, at 2).

By letter dated May 1, 1984, SWEPI appealed the March 29, 1984, decision to the Chief, Royalty Valuation and Standards Division, MMS, arguing as follows:

> There currently is no market for CO_2 produced from the McElmo Dome (Leadville) Unit except for CO_2 purchased by the Denver Unit. The actual cost of transporting CO_2 through the Cortez pipeline from Southwestern Colorado to West Texas is a marketing cost which must be assumed by the royalty owner as well as the working interest owners. These actual costs of transportation, which will in the future include payment of both Federal and State income taxes, constitute the Cortez tariff and are incurred by the Federal lessee who transports CO_2 to the Denver Unit for sale. SWEPI, as a Federal lessee transporting CO_2 to the Denver Unit for sale, is entitled to be reimbursed by the purchaser of CO_2 for the tariff charged for transporting such CO_2, subject to certain limitations as set forth in the Denver Unit CO_2 Sale and

2/ Cortez is a general partnership owned by Shell Cortez Pipeline Company, Mobil Cortez Pipeline Company, and Continental Resources Cortez Pipeline Company.

(28)

United States Department of the Interior

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

M. Reynolds 2-30-95

IN REPLY REFER TO:

MMS-VSD-OG:95-0047
Mail Stop 3152

FEB - 3 1995

Memorandum

To: Office of the Solicitor
Division of Energy and Resources
Attn: Geoff Heath, Attorney Advisor

Original signed by
Martin C. Grieshaber

From: Chief, Valuation and Standards Division

Subject: Revenue Impact--Actual Costs v. Cortez Pipeline Tariff
Shell/Mobil--McElmo Dome Unit--CO_2 Production

The Valuation and Standards Division (VSD) was asked to calculate the revenue impact for the difference between the actual transportation costs versus the use of the Cortez Pipeline tariff rate, for the following time periods:

- March 1, 1988 - 1992
- 1992 - present & estimate for the future.

Since neither Shell or Mobil have provided the data to make an in-depth analysis, VSD is unable to calculate the revenue impact, accurately. However, in reviewing a request from Shell for an exception to the 50 percent limitation, certain amounts listed as "other expenses" included non-allowable costs, as follows:

CATEGORY	3/1/88-12/31/88	AMOUNTS 1989	AMOUNTS 1990	AMOUNTS 1991
Interest				
Banking Fees		X-4		
Totals				

Example: For 1989

Shell claimed total costs of
Less nonallowable costs of

X-4

Allowable expenses
Shell's percentage
Shell's throughput = X-4

Shell's expense/Shell's throughput (X-4 / X-4 = X-4)/Mcf)

Cortez pipeline Tariff Rate claimed = $0.39 per Mcf
Allowance rate X-4 per Mcf

Underpayment per Mcf X-4 per Mcf

Please be advised that the allowance rate of X-4 per Mcf used in the calculation shown above includes Federal and State income taxes, a profit margin of 7 percent, as well as any other potential non-allowable costs. Further, the Cortez Pipeline tariff rate increased from $0.39 per Mcf to $0.493 per Mcf during all of 1990 and to $0.525 per Mcf during all of 1991.

Included are copies of the documents you requested, Attachment 1 through Attachment 4:

Attachment 1 -- Shell IBLA decision, decided Jan 23, 1990, regarding income taxes.

Attachment 2 -- Field Report that backed off a termination date.
2/7/92 memo on Shell Appeal 90-0752

Attachment 3 -- Examples of recent FERC oil OCS tariff denials.
and
Attachment 4

If you have any question please call Shirley Keller (303) 275-7217.

4 Attachments

bcc: RM Chron:95-0047
RM Chron DC/Lkwd (2)
VSD Chron (2)
O&G Chron (2)
States
LMS:RMP:VSD:O&G:SKELLER:MS3152:275-7217:P:\USERS\OANDG\KELLER\95-0047
final:mkr:02/03/95

On October 8, 1992, FERC issued the Order Granting Petitions for Declaratory Orders and Disclaiming Jurisdiction, Oxy Pipeline Inc., 61 FERC § 61,051 (1992), which states in part:

> The jurisdictional issue of whether the ICA [Interstate Commerce Act] applies to outer Continental Shelf oil pipelines requires the Commission to interpret its authority over oil pipelines on the outer Continental Shelf under Section 1(1) of ICA. That section provides in pertinent part of the Act ". . . shall apply to common carriers engaged in . . . [t]he transportation of oil . . . by pipeline . . . .
>
>> from one State or Territory of the United States, or the District of Columbia, to any other State or Territory of the United States, or the District of Columbia, or from one place in a Territory to another in the same Territory, or from any place in the United States through a foreign country to any other place in the United States, or from or to any place in the United States to or from a foreign country, but only insofar as such transportation or transmission takes place within the United States.
>
> The Commission agrees with Oxy that the ICA does not expressly cover pipelines transporting oil solely on or across the outer Continental Shelf. While the outer Continental Shelf appertains to the United States, the outer Continental Shelf is not a State or Territory of the United States.

In the issuance of this order, FERC renounced jurisdiction over oil pipelines transporting oil solely on or across the Outer Continental Shelf. Therefore, MMS cannot approve your request to use the various FERC tariffs in lieu of calculating actual costs for transporting oil or condensate production from the subject AID numbers from January 1 through December 31, 1994. Your transportation allowances for the subject AID numbers will be approved as prescribed at 30 CFR § 206.105 entitled "Determination of transportation allowance":

> (b) Non-arm's-length or no contract.
>
> (1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable, actual costs as provided in this paragraph . . . . A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month Form MMS-4110 is filed with MMS, unless MMS approves a longer period upon their showing good cause by the lessee.

The regulations provide additional information and instructions for calculating transportation allowances.

Unocal also requested MMS approval for a transportation allowance at certain rates for each lease. Effective March 1, 1988, MMS approval is no longer required before a lessee may deduct an allowance from royalties due, so long as the appropriate allowance report (Form MMS-4110, in this case, for oil transportation) has been filed by the lessee prior to taking the allowance, according to 30 CFR § 206.105(b)(1) (1993).

You have the right to appeal this decision. Please refer to the enclosure for the Appeals Procedure and Bonding Requirements (Enclosure 1).

In an effort to improve the services we provide our customers, we have enclosed a questionnaire regarding the quality of our response to your request. We would appreciate your taking a few minutes to fill out the questionnaire and return it to us in the self-addressed envelope (Enclosure 2).

If you have questions regarding this matter, please call Ms. Shirley Keller at (303) 275-7217.

Sincerely,

David A. Hubbard

for Deborah Gibbs Tschudy
Chief, Valuation and
Standards Division

2 Enclosures

United States Department of the Interior

TAKE PRIDE IN AMERICA

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

IN REPLY REFER TO:

MMS-VSD-EVB:92-0467
Mail Stop 3921

SEP 16 1993

CERTIFIED MAIL--
RETURN RECEIPT REQUESTED

Mr. R. Terry Williams
Director, Royalty Issues and Audits
Controller's Department
ARCO Oil and Gas Company
1601 Bryan Street
Dallas, Texas 75201-3499

Dear Mr. Williams:

Your June 23, 1992, letter requested permission to utilize certain proposed interest rates in calculating interest during construction (IDC) costs. These IDC costs are to be included in the depreciable asset base for purposes of determining the applicable transportation allowances for the Sheep Mountain CO_2 project in Colorado.

As you know, final action on this issue was delayed pending consultation with the State and Tribal Royalty Audit Committee and preparation of an option paper for our Director on the general allowability of IDC costs. Subject to the conditions listed in the enclosure titled "Summary of Findings and Conclusions," the IDC costs are permissible.

The information you submitted has been reviewed. We have approved, subject to future audit, the interest rates that you have proposed for the 4-year construction period (1980-83). The enclosure describes in detail the basis for our determination.

As agreed by the participants in our July 21, 1993, meeting in Denver, we will not address the allowability of other specific audit-related costs here. Determinations on those costs await further justification/explanation from you and further review by the State of Colorado.

If you have any questions, please call David Wiechman at (303) 231-3161.

Sincerely,

Deborah Gibbs Tschudy

Deborah Gibbs Tschudy
Chief, Valuation and
Standards Division

Enclosure

bcc: RM Chron:92-0467
RM Chron/DC
RM Chron/Lakewood
VSD Chron(2)
EVB Chron

D. Wiechman
Susan Lupinski
Dave Loomis, State of Colorado
Pat Milano, SIPAO

LMS:RMP:VSD/EVB:MS3921:WIECHMAN:231-3161:09/03/93:mkr:N:\USR\ECON\IDC

ROYALTY MANAGEMENT PROGRAM
VALUATION AND STANDARDS DIVISION

Findings and Conclusions on Proposed Interest Rates for Interest During Construction Costs for the Sheep Mountain CO_2 Project

Issue

The issue is whether the costs of interest during construction (IDC) are permissible for allowance purposes and whether the proposed alternative methods of calculating IDC are reasonable approximations of the actual costs incurred. In addition, can the effective interest rate calculated from the interest expenses and debt load be utilized if more specific data are not available? Further more, can short-term borrowing be included in the calculation of an effective interest rate?

Background

- The Sheep Mountain CO_2 project, in southern Colorado, is a 50-50 joint venture of ARCO Oil and Gas Company (ARCO) and Exxon Corporation (Exxon). ARCO is the operator.

- ARCO requested that IDC costs be included in the project's depreciable asset base for purposes of determining the appropriate transportation allowance.

- The Minerals Management Service's (MMS) February 5, 1992, determination letter permitted the inclusion of the IDC costs in the depreciable asset base. The letter required that ARCO submit sufficient documentation to justify any interest rates claimed.

- It is general MMS practice to utilize actual cost data that can be documented as being applicable to the subject project.

- ARCO, by letter dated June 23, 1992, submitted documentation requesting use of an interest rate for each of the 4 years (1980-83) that the Sheep Mountain project was under construction.

- Prior to final action on the ARCO request, MMS consulted with the State of Colorado and the State and Tribal Royalty Audit Committee (STRAC) on whether IDC is a proper inclusion in a royalty allowance base. As a result of the STRAC feedback, the Valuation and Standards Division developed an option paper for the Director on the allowability of IDC.

<u>Findings</u>

- ARCO claimed that neither they nor Exxon had data available regarding the actual interest costs incurred specifically for this project. ARCO stated that both of the companies fund all of their debt requirements through general borrowing at the corporate level.

- The Royalty Valuation and Standards Division, by letter dated August 25, 1992, requested that both companies explicitly verify that there was no financing undertaken specifically for the Sheep Mountain project.

- ARCO, by letter dated October 8, 1992, submitted written statements from both companies, testifying that neither company had borrowed funds specifically for the Sheep Mountain project.

- ARCO proposed an alternative methodology to approximate the project's actual borrowing costs. They submitted documentation showing the average interest costs for each company for each of the 4 years. ARCO then averaged the two companies' interest rates to arrive at a project annual interest rate for each year of the construction period.

- ARCO proposed to approximate their actual parent-company-level financing during the 4 years by using the interest rates associated with ARCO's nine bond issues during the construction period. ARCO submitted copies of the company's annual report to shareholders, which listed the nine bonds and their associated interest rates.

- We used Moody's Industrial Manual to verify the interest rates that ARCO claimed for the nine bond issuances during the construction period.

- The MMS' policy on permissibility of interest charges in transportation and processing allowances is that, "When a company issues bonds to raise money for capital investment, the corresponding interest charge capitalized during the development phase . . . should be limited to the interest on only that part of the bond proceeds applied to construction of these facilities."

- Exxon claims that it does not possess records comparable to ARCO's. Instead, Exxon proposes to calculate their effective interest rate during the construction period by dividing their annual interest expense by the corporation's total outstanding debt.

- A review of Moody's Industrial Manual provided no evidence of long-term debt undertaken by Exxon during the 1980-84 time period.

- Exxon's interest expense and debt figures include both long-term and short-term financing. Under normal circumstances, long-term financing entails higher interest rates than does short-term financing.

- Exxon's methodology includes borrowing from periods prior to 1980 when interest rates were generally lower than those of the project construction period. The calculation method yields interest rates that are consistently lower than those used by ARCO.

- As a point of reference, a comparison of the figures proposed by ARCO and Exxon found that their interest rates were generally lower than both the Standard & Poor's BBB industrial bond rates and the prime interest rates during the same time periods. A summary of these data follows:

Summary of Interest Rates During Sheep Mountain Construction Period

	1980	1981	1982	1983
ARCO				
Exxon				
Project average				
BBB industrial bond rate	11.5% - 14.24%	13.2% - 16.82%	13.28% - 17.03%	11.68% - 13.67%
Prime Rate	15.27%	18.87%	14.86%	10.79%

- Standard accounting practice, as articulated in section 167 of the Accounting Standards Current Text, General Standards as of June 1, 1988, published by the Financial Accounting Standards Board, states that IDC is to be calculated using the actual interest rates of borrowing. It elaborates that if actual data are unavailable, the best available information should be utilized.

- The Director concurred that IDC is a permissible cost for allowance purposes, subject to audit and approval of costs incurred in the project development phase.

Conclusions

- Where interest costs are incurred during a project's development phase, such costs generally will be permitted in the capitalized cost basis for a transportation or processing allowance, subject to audit and approval of costs incurred.

- For purposes of calculating IDC, it is MMS' general practice to utilize actual data whenever possible and, when such data are not available, to utilize the next-best information available.

- ARCO's and Exxon's assertions that the project was financed out of parent company borrowing appear to be consistent with general business practice.

- The methodology that MMS will accept in determining interest rates for IDC costs will depend upon the specificity of data available. The most specific data available should be used to determine the IDC interest rates. The hierarchy to be followed is as follows:

  A. Any project-specific or related borrowing.

  B. Any company-level general borrowing during the applicable time period.

1. Any specific bond issues or separate financing during the period.

2. An effective borrowing interest rate calculated by dividing interest expenses by debt.

- ARCO's proposed use of its nine bond interest rates is consistent with MMS' policy and practice.

- Exxon's proposed calculation of an effective interest rate using long-term and short-term interest expenses and debt should be accepted given our understanding, based on Exxon's statements, that it is the best information available.

- The project average rates proposed by ARCO and Exxon and highlighted in the summary table above should be applied in calculating IDC over the construction period.

- Any interest rates approved for IDC costs are subject to audit.

(1)

United States Department of the Interior

TAKE PRIDE IN AMERICA

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

IN REPLY REFER TO:

VSD/EVB
Mail Stop 3921

AUG 20 1993

Memorandum

To: Director

From: Associate Director for Royalty Management James W. Shaw

Subject: Policy on Interest During Construction (IDC)

Attached is an option paper on IDC (see Attachment 1). The issue is whether IDC is an allowable deduction for royalty allowance purposes. We need to reach a final decision in order to resolve a longstanding valuation/transportation issue involving carbon dioxide produced in Colorado.

We tried to use a balanced approach in summarizing technical points and the positions of affected parties. Note that the States and tribes are uniformly opposed to inclusion of this cost component and to most any component that increases allowance amounts and decreases royalty value. They feel that the need to limit further royalty deductions outweighs the correctness of the technical/accounting principles involved.

Before writing the option paper, we involved the State and Tribal Royalty Audit Committee (STRAC) in two stages. First we asked the STRAC membership to review the 1988 discussion paper that established our initial policy on IDC (see Attachment 2). We received written comments from several STRAC members and got oral feedback during a subsequent STRAC meeting. We incorporated these comments in the option paper. Then, after drafting the option paper, we sent it to the STRAC membership for comment on the facts included. At this stage we received comments only from the State of Alaska and our office of Policy and Management Improvement (PMI). The State of Alaska comments repeated earlier contentions that the existing oil and gas product value regulations do not permit IDC deductions. The State also opposes permitting IDC on the grounds that it would further intrude on States' royalty rights, with a consequential reduction in royalty value. We did not change the option paper based on these comments. Based on the PMI comments, however, we clarified several points.

We request that you review the option paper and other background material attached and select a policy option. We recommend Option 1, continuing to permit IDC, subject to audit and approval, as the appropriate policy. ~~If you need more information, I will arrange to have a briefing for you, or~~ you may contact Mr. Dave Hubbard of our Valuation and Standards Division at (303) 275-7260.

			Option 1	Option 2	Option 3
APPROVED:	Tom Fry, Director	8/29/93 Date			

DRAFT OPTION PAPER

Attachment 1

INCLUDING INTEREST DURING CONSTRUCTION IN TRANSPORTATION AND PROCESSING ALLOWANCES

Issue

The purpose of allowances for royalty purposes is to permit the lessee to deduct the actual, reasonable costs of moving or processing the product before sale. Interest During Construction (IDC) is a charge requested for inclusion in the allowance cost base in two separate cases. The IDC is interest payable on construction loans during project development. The question is whether IDC is an actual, reasonable cost attributable to the lessee's transportation or processing facilities.

I. History of Policy

Findings on General Permissibility of IDC

The Financial Accounting Standards Board (FASB) addresses IDC in detail. The FASB holds that interest cost shall be capitalized as part of the historical cost of acquiring certain assets. Specifically, where interest is incurred during the period of construction necessary to bring a plant asset to the condition of its intended use, the interest cost may be treated as a cost of the asset. Such interest is considered a real cost of putting the asset into usable condition. The rationale is that capital raised through borrowing is employed for construction purposes, and if the capital item were purchased, the price would include an implicit interest charge. The result of capitalizing such interest charges, then, is that interest emerges as a depreciation or amortization charge during the project's income-producing period.

If project-specific financing is obtained, the interest rate for that debt is used to determine capitalized interest costs. If asset expenditures exceed the amounts of specific new borrowings, the capitalization rate applied to the excess should be a weighted average of the rates applicable to other borrowings of the enterprise. Where development period interest is capitalized, it should be limited to the amount related to borrowed capital applied to construction. Likewise, revenues received during the development period should be credited against development expenditures to reduce the amount of deferred development expenditures.

Checks of several financial texts showed consistency with FASB's treatment of IDC. The Internal Revenue Service provides similar treatment.

Historical Allowance Components

Where allowances are based on the lessee's actual costs of building and operating a facility, the permissible costs include the following:

1. Yearly depreciation.[1]

2. Return on capital investment (allowable rate of return times beginning-of-year, undepreciated capital balance).[1]

3. Operating, maintenance, and overhead costs.

Total allowable costs divided by annual throughput gives the per-unit transportation or processing allowance.

Historically, interest charges as components of transportation and processing allowances were treated as follows:

1. Where a rate of return was claimed against the remaining undepreciated capital balance, a separate yearly interest charge for borrowed capital funds could not also be claimed because the rate of return already served as a proxy for that charge.

2. If a lessee incurred interest charges on money borrowed to cover routine operating and maintenance costs, such interest directly allocable and attributable to the facility would be permissible as a separate component of the allowance. This interest charge would be a true cost to the lessee not accounted for otherwise, as in a rate of return.

In fact, the above principles were embodied in the preambles to the revised oil and gas product value regulations effective March 1, 1988:

> . . . interest on money borrowed for operations would be considered as a valid operating expense. Interest on money borrowed to build a transportation facility is not considered allowable. A return on investment is given in lieu of interest on capital investments . . . .

Although the previous two sentences cover non-allowability of interest on borrowed funds, their purpose is to bar "double-dipping" of interest charges during the productive life of the facility (synonymous with the period during which an allowance can be claimed for royalty purposes). The revised regulations did not address the concept of IDC. They address rate of return <u>on</u> the remaining undepreciated base, but do not address interest as <u>part</u> of the beginning capitalized base. The specifics of IDC were not addressed by

---

[1] Under the revised oil, gas, and coal product valuation regulations, the lessee has the option to claim a yearly return on the <u>initial</u> capital investment in lieu of yearly depreciation and return on that year's beginning capital balance.

these rules because the issue had not yet been raised, and thus not contemplated by the rules' authors.

Past Precedence

In 1988 the first case involving IDC arose. A Federal coal lessee in Colorado, Western Fuels-Utah, Inc. (Western Fuels), requested that "deferred development expenses" be part of the cost basis for washing and transportation allowances. Part of these expenses were IDC--interest charges payable during the project development phase on money borrowed to build the facilities. These charges were included in the capitalized basis to be depreciated or amortized. The coal's royalty value was based on total costs reported to the State Public Utility Commission, including capitalized IDC, plus a reasonable profit. The Minerals Management Service's (MMS) policy, as documented in an issue paper of November 1988, has been that IDC is a generally-accepted cost of acquiring certain assets and can be a very real part of lessees' actual, reasonable costs. The discussion paper summarized the circumstances where interest charges other than a rate of return on undepreciated capital would be permitted, as follows:

1. When, during the development period of a project, interest incurred on a loan for construction costs that are integral to, or directly allocable and attributable to, transportation or processing facilities, is properly capitalized and thus becomes part of the basis for undepreciated capital upon which a rate of return is later applied.

2. When interest is incurred on loans for routine operating and maintenance expenses.

Of course, such interest charges are subject to audit.

As a result, the interest charges included in "deferred development expenses" by Western Fuels were judged to qualify as part of the capitalized basis for allowance purposes. The principles discussed here are being applied in the ongoing audit of Western Fuels.

If IDC deductions are not permitted in the Western Fuels case, an apparent problem arises. Their royalty value is computed as cost-plus-profit, with IDC as part of the cost base. The ongoing audit follows the principle that IDC is properly a part of both value and allowances. If the allowance does not include an IDC component, then logically IDC should not be part of the value base either.

The revised coal rules became effective March 1, 1989. They contained no reference to IDC for several reasons. First, the rules were near completion before the issue ever arose. A revision to accommodate this lone issue would have required a new round of public comments and further delayed the final coal rules. Also, the Western Fuels case was seen as one-of-a-kind, and it was not considered necessary to develop separate rules to address this issue.

Treatment of IDC in Geothermal Regulations

During development of the revised geothermal valuation regulations effective November 8, 1991, the issue of IDC arose again. Several commenters stated that carrying costs incurred during the construction phase of a project, including both debt and equity, are an integral part of the lessee's invested capital because investments do not produce income until the facility is operational. Consistent with the principles discussed above, the preamble to the rules states:

> The MMS agrees that debt and equity costs associated with power generation and transmission facilities are part of the lessee's actual capital costs to install those facilities. The regulations governing allowable capital investments . . . are intended to reflect inclusion of debt and equity costs.

and

> Interest charges incurred by a lessee on capital borrowed to finance construction of a project, also known as interest during construction (IDC), are currently recognized by MMS as part of the depreciable capital investment base on which the transmission and generating cost rates are calculated . . . . However, the interest . . . must be . . . clearly attributable and allocable to the powerplant or transmission line for which the money was borrowed, and must be incurred during the planning and construction phases of those facilities; these payments also must be verifiable upon audit. In those cases where IDC . . . cannot be attributed to a particular powerplant or transmission line, MMS may, at its discretion, approve an amount provided the lessee submits a written request and provides adequate documentation supporting the proposed amount.

II. Current Issues

Sheep Mountain Audit

An ongoing audit involves another project in Colorado, this time involving carbon dioxide production. The project includes pipeline transportation to Texas, with substantial capital investment. The operators have requested approval to include IDC in their capitalized basis. In discussing this issue with State of Colorado auditors, they requested that Royalty Management Program (RMP) get feedback from the State and Tribal Royalty Audit Committee (STRAC) on the concept of IDC before a final decision was made. Thus in February of 1993, RMP sent copies of the 1988 discussion paper and other related information to the STRAC membership for their comment.

STRAC Written Comments

Comments were received from the States of Colorado, Alaska, and Montana, and the Navajo Nation. The comments from Montana and the Navajo Nation were non-specific to the IDC issue; they voiced general objections to any more deductions that would reduce the royalty share. Comments from Colorado and Alaska provided specific objections to inclusion of IDC in allowances. A summary of their comments is included as Appendix 1.

STRAC Verbal Comments

The RMP also discussed this issue with members of STRAC at a STRAC meeting held in Denver on April 6-7, 1993. The major theme of their comments was that royalties continue to be diluted by more and bigger allowances. The attendees were concerned that issues such as this were snowballing; in the words of one attendee, "Where will this stop?" There was concern not only that allowance of IDC would be very costly, but that lessees would request retroactive approvals. The attendees were unanimous in their opposition to allowing IDC.

However, the attendees were also unanimous in their agreement with the correctness of FASB's handling of IDC. Their differences with MMS's proposed approach were philosophical; they felt that just because a procedure is technically correct does not mean it must be applied for allowance purposes. The attendees felt MMS has the authority to set the ground rules for allowances without strict adherence to standard accounting theory.

III. Summary

Need for resolution of IDC issue

Inclusion of IDC is permitted in the Western Fuels case now under audit. It is also permissible under the geothermal product value regulations. However, neither the oil, gas, or coal product value regulations (effective March 1, 1988 for oil and gas and March 1, 1989 for coal) address IDC specifically. Resolution of the Sheep Mountain audit (and similar future cases) requires a final decision on permissibility of IDC in allowance computations.

OPTIONS

1. Continue allowing IDC subject to audit and approval of costs incurred in development phase.

   Pros:

   - Reflects longstanding philosophy to permit actual, reasonable costs
   - Consistent with FASB guidelines, IRS rules, financial texts
   - Policy established in 1988 stays consistent
   - Industry would support

Cons:

- States and Indians oppose
- Would increase allowances claimed
- Could be numerous retroactive applications once policy widely known

2. Change policy -- deny IDC.

Pros:

- States and Indians would support
- Would limit allowances claimed
- Would avoid retroactive requests for IDC

Cons:

- Contradicts MMS philosophy to permit actual costs
- Contradicts accepted accounting principles
- Inconsistent policy
- May require redo of Western Fuels audit
- Industry appeals can be expected

3. Allow IDC, but only under strict conditions. For example: (a) the lessee must demonstrate project-specific financing or (b) the lessee must demonstrate that its proposed handling of IDC for allowances is the same as used in its other financial reporting.

Pros:

- States and Indians may be more supportive
- Would limit allowances claimed

Cons:

- Counter to actual cost philosophy
- Contradicts accepted accounting principles
- Inconsistent policy
- May affect Western Fuels audit
- Industry appeals can be expected

RECOMMENDATION

We believe Option 1, continuing our past policy on IDC, is the most appropriate course of action. It is technically correct and provides consistency with past applications. Perhaps most important is that it reflects MMS's consistent allowance philosophy to permit actual, reasonable costs. Of course, rates and cost basis used for IDC purposes would be subject to audit and approval.

Although States and Indians would support Option 2, and likely Option 3, neither selection would conform with standard accounting treatment or our own stated philosophy to allow actual costs. Also, either of these options could compromise our past treatment of the Western Fuels case, and would create an inconsistency with the geothermal rules.

WRITTEN STRAC COMMENTS ON IDC

- The Conservation Division Manual did not allow for interest incurred during the construction phase of transportation or processing facilities.
- The new oil and gas product valuation regulations do not address the issue. However, the preamble states "Interest on money borrowed to build a transportation facility is not considered allowable. A return on investment is given in lieu of interest on capital investments."
- The MMS does not use standard accounting theory in some other areas, such as allowing taxes as a deduction, so why here?
- The FASB statement on capitalization of interest was issued in 1979, yet MMS did not authorize interest to be capitalized in the decade that followed.
- The operators should not be allowed to deduct IDC because they have failed to prove their corporate debt to be integral to, or directly allocable and attributable to, the Sheep Mountain facility.
- The companies should be required to demonstrate that they capitalized the interest for financial accounting and tax purposes.
- Since there was no borrowing <u>specifically</u> for this project, no allowance for IDC is justified.
- A deduction should not be allowed for both IDC and a return on investment related to the same capital items; it could lead to excessive royalty losses to States and tribes.
- If IDC is allowed, companies will be encouraged to finance projects even if the company has the needed funds at hand; companies may structure financing to maximize permissible deductions.
- If MMS allows IDC to be capitalized, it should change its regulations rather than its policy.

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

TAKE PRIDE IN AMERICA

IN REPLY
REFER TO:

Mail Stop 653

NOV 1[illegible] 1988

MMS-RVS-EVB:88-1172

NOV 18 1988

Memorandum

To: Chief, Royalty Valuation and Standards Division

From: Chief, Economic Valuation Branch

Subject: Permissibility of Interest Charges in Transportation and Processing Allowances

Attached is a discussion paper concerning inclusion of interest charges in transportation and processing allowances. If you concur with the conclusions, they will be used as guidelines for resolution of future allowance issues related to interest charges.

David A. Hubbard

David A. Hubbard

Attachment
Interest as a Deduction In Transportation or Processing Allowances

[X] Concur ______[illegible signature]______

[ ] Concur with the following changes ____________________

INTEREST AS A DEDUCTION IN TRANSPORTATION OR PROCESSING ALLOWANCES

Issue

- In calculating transportation and processing allowances applied as deductions from royalties payable by lessees of Federal and Indian minerals, questions have frequently arisen regarding the applicability of interest charges. This issue is common to all leasable minerals, including, for example, oil transportation allowances, gas processing allowances, and coal washing allowances. Of particular concern is the occurrence of both an interest deduction and a deduction for return on investment related to the same capital item(s). This concern arose in a specific case being handled currently by the Solid Minerals Valuation Branch and involving Western Fuels-Utah, Inc. (Western Fuels). In addition, there is a question as to deductibility of interest for allowance purposes when the interest payable by a lessee is the result of a general debt obligation, such as a bond issuance, not necessarily tied to the specific transportation or processing project.

History and Precedent

- At least as early as 1937, the Secretary recognized that

  > The Government does not wish to collect royalty on that part of the value which is derived from the cost of manufacturing, inasmuch as the Government's equity is confined to the value of the raw material involved.

  He also directed that natural gas royalties be based on the higher of either the combined value of gas and derivative products as measured by the lessee's gross field realizations less actual extraction costs, or the value of one-third of all natural-gas gasoline extracted and sold plus the value of the dry residue gas.[1/]

- In addition to processing costs, the Federal government has long recognized the cost of transporting lease production to the nearest market as a legitimate deduction in determining royalty value. The first apparent case where an interest deduction was permitted as part of a transportation allowance resulted from United States v. General Petroleum Corporation of California et al. (March 30, 1946; Supplemental Opinion January 10, 1947). In that case the government had allowed the actual cost of operating a gas pipeline, in addition to depreciation on the pipeline capital investment, but had refused to allow a return on capital investment. The court ruled, however, that a reasonable return on the capital investment should have been allowed, and that the return was as much a cost to the company as its daily out-of-pocket expenses.

[1/] Memorandum of June 7, 1937, from the Acting Secretary of the Interior to the Director, U. S. Geological Survey, concerning natural gas royalty computations.

In its Supplemental Opinion, the court embodied this rate of return in the form of an interest rate:

> It is a matter of common knowledge that the rate of interest prevailing in this community on sums approximating the amounts designated in the judgment was, for the period in question, less than 7% per annum. Such rate of interest was approximately 4% per annum. The court finds that interest at the rate of 4% is fairly compensatory, and it establishes such rate as just compensation.

- Subsequently, the Conservation Division Manual (CDM) of the U. S. Geological Survey provided for the inclusion of interest or return on undepreciated investment items that are integral parts of, or are directly allocable or attributable to, onshore processing facilities and producer-owned transportation facilities. This was the <u>only</u> form of interest specifically allowed on a yearly basis, because permitting both a rate of return on undepreciated capital <u>and</u> a separate interest deduction for borrowed funds would have resulted in separate charges representing the same cost component and thus would have overstated the true cost to the lessee. The Appendix provides data on rates of return that have been permitted in calculating oil and gas allowances, as well as information on rates used in coal and geothermal allowance computations.

- The general policy and philosophy regarding interest charges as components of transportation and processing allowances thus evolved as follows:

  (1) Where a rate of return was claimed against the remaining undepreciated capital amount, a separate yearly interest charge for borrowed capital funds could not also be claimed, because the rate of return already served as a proxy for that charge.

  (2) If a lessee incurred interest charges on money borrowed to cover routine operating and maintenance costs, such interest directly allocable and attributable to the facility in question would be permissible as a separate component of the allowance. Such an interest charge would be a true cost to the lessee not accounted for otherwise, as in a rate of return.

  In fact, the above principles were embodied in the preambles to the new oil and gas product value regulations:

  > . . . interest on money borrowed for operations would be considered as a valid operating expense. Interest on money borrowed to build a transportation facility is not considered allowable. A return on investment is given in lieu of interest on capital investments . . . .

<u>Interest Incurred During Development/Case Example</u>

- Another type of interest charge that has rarely been evident in past allowance applications, and one that apparently was not contemplated by the new oil and gas product value regulations, is interest that was incurred and capitalized during a project's development phase. An example occurs in a recent coal washing and transportation allowance application by Western Fuels covering Federal Leases Nos. C-023703 and C-026669.

In its application, Western Fuels capitalized certain "Deferred Development Expenses," including interest and other development costs incurred to bring the mine to commercial production (including costs of constructing the transportation and washing facilities). The development expenses in given development years were reduced by the value of coal sold. These capitalized development costs were then amortized on a yearly basis over the project life, and together with depreciation charges, were claimed as yearly depreciation and amortization expenses. Likewise, the yearly rate of return was claimed against the total undepreciated <u>and</u> unamortized capital investment. At issue was whether the rate of return should be applied against the "Deferred Development Expenses," including the interest charges capitalized during the development period.

- Standard accounting theory holds that where interest is incurred during the period of construction necessary to bring a plant asset to the condition of its intended use, the interest cost may be treated as a cost of the asset. Such interest is considered a very real cost of putting the asset into usable condition--just as much so as "hard" capital equipment and materials. The rationale is that capital raised through borrowing is employed for construction purposes--and, if the capital item(s) were purchased, the purchase price would include an implicit interest charge. The result of capitalizing such interest charges, then, is that interest emerges as a depreciation/amortization charge during the project's income-producing period.

- Accepted practice is that where development period interest is capitalized, it should be limited to the amount related to borrowed capital applied to construction. Likewise, revenues received during the development period should be credited against development expenditures to reduce the amount of deferred development expenditures. In the case of underground coal mining, any coal removed and sold while driving the main tunnels and entries should be credited against the development expenditures (in this case including interest). Development costs, including interest, are amortized either over reserve tonnages being developed or the life of the mine.

- For tax purposes, mine development expenses may be deducted when computing taxable income for the year, or, if a proper election is made, such expenses for each mine or deposit may be deferred and recovered through amortization. The election to defer must be made yearly and, once made, is binding with respect to that year. Development expenses for each mine or deposit must be treated consistently within the tax year; part of the expenses cannot be capitalized and the remainder expensed.

- In the Western Fuels case, the proposed allowance approval by the Minerals Management Service (MMS) permits the inclusion of capitalized interest as a component of depreciation/ amortization and, hence, permits a rate of return on the undepreciated/ unamortized balance including interest. Once the project enters the production phase, no yearly deduction for interest charges (apart from the rate of return on remaining undepreciated capital investment) are permitted.

Conclusions

- In calculating transportation and processing allowances, an interest charge separate from the rate of return on undepreciated capital should generally be permitted only under the following circumstances:

  (1) When, during the development period of a project, interest incurred on a loan for construction costs that are integral to, or directly allocable and attributable to, transportation or processing facilities, is properly capitalized and thus becomes part of the basis for undepreciated capital upon which a rate of return is later applied.

  (2) When interest is incurred on loans for routine operating and maintenance expenses.

  Of course, such interest charges are subject to MMS audit and approval.

- Conversely, some circumstances under which interest charges should generally <u>not</u> be permitted are as follows:

  (1) When the lessee attempts to claim, during the production phase of the project, interest payments for loans on capitalized items (this is not permitted because a separate rate of return is being applied against remaining undepreciated capital).

  (2) When some part of the interest capitalized during the development phase is not related to borrowed capital applied to construction--i.e., the amount of interest that may be capitalized for allowance purposes should be limited to the interest charge that would have been avoided if expenditures for the transportation or processing facility hadn't been made.

  (3) When the interest claimed in the capitalized basis is otherwise not directly allocable or attributable to the transportation or processing project/facility.

- The interest charges included by Western Fuels in its "Deferred Development Expenses" thus appear to properly qualify as part of the capitalized basis to which a rate of return may apply for allowance purposes. This conclusion is contingent, however, upon MMS audit and verification of these charges, including application of the guidelines listed immediately above.

- When a company issues bonds to raise money for capital investment, the corresponding interest charge capitalized during the development phase of the transportation or processing facility should be limited to the interest on only that part of the bond proceeds applied to construction of these facilities. In such instances the company must provide an allocation schedule demonstrating disposition of the bond proceeds and interest corresponding to each such disposition. In this way MMS may determine which portions of a bond issuance, and the corresponding interest, are truly allocable to development of the transportation or processing facility. Likewise, if bond proceeds were used to pay ongoing operating and maintenance expenses during the production phase, a similar allocation schedule, including associated interest charges, would be required.

July 14, 1993

MMS-RVS-OG

To: Debbie Gibbs
Jim Morris
Colette Haines
Dave Hubbard
Charlie Brook

From: Susan Lupinski

Subject: Synopsis of Discussion on Cost Items, Sheep Mountain CO_2 Meeting of July 13, 1993

The following is a synopsis (as best as I can remember) of the discussion we had about the cost items for the Sheep Mountain CO_2 project.

RIGHT-OF-WAY

There is no clear precedence for how to treat right-of-way (ROW) costs.

"Is ROW a real, depreciable item?" We think the State is using the nexus that if land is not depreciable, then the ROW for land is also not depreciable. If you buy land, it can be sold later for the same (or more) money and therefore is not a "wasting" asset. However, the ROW on land expires at the end of the term and has no value; it cannot be sold, traded, etc. In essence, our discussion seemed to indicate that ROW is a wasting asset and should be depreciated.

The CDM is silent on allowing ROW in the transportation section. However, the processing allowance section denies pipeline ROW as a plant capital cost (presumably because it is a transportation cost) but allows including plant roads ROW in the plant capital investment costs. Even though not stated in the transportation section, the same "logic" may permit us to allow the pipeline ROW as a capital investment for the transportation system.

The Transportation and Processing Section (T&P) has a policy that allows a company to depreciate a lump sum ROW payment over the life of the pipeline. However, the example illustrating this policy does not show that the company may take a return on investment (ROI) for this item. Also, this policy applies to the post 3-1-88 time period, no definitive policy for pre 3-1-88 exists. To date, T&P has not encountered this situation, so there is no precedence in actual projects. In an appeal situation, if we require ARCO/Exxon to expense ROW and given that our current policy is to depreciate ROW, would the appeal be granted?

Jim Morris will look through the Gower compilation and see if there are any cases that cover this subject. He will also search some of the law literature to see if he can find any treatises that discuss whether real estate law considers ROW as a depreciable property.

Lastly, if we direct ARCO/Exxon to amortize the ROW over 20 years and treat it as a yearly O&M expense, ARCO/Exxon will not get a ROI benefit. This creates a new category of expenses that has never before been allowed in allowance calculations. Our discussion indicated that we think this would be a bad precedent to establish. It also takes a cost that covers several years and puts it into a yearly cost category.

TESTING/START-UP

This cost was necessary to place the pipeline in service. The cost should be capitalized and depreciated.

SPARE PARTS

Costs for spare parts should be expensed in the year the part is installed in the pipeline. An inventory of spare parts is not necessary to place the pipeline in service, it is merely good operating practice.

OTHER

If these costs were incurred prior to pipeline completion, they will be allowed as capital investment costs. If the phones, xerox, field office or warehouse remain at the site after the pipeline began operations, costs must be prorated and any post-operation costs must be expensed.

ORIGIN METER STATION-NO. SEGMENT

All costs for measurement are costs of placing production in marketable condition or costs to market the production. The costs of these components are disallowed.

Costs associated with the on-line densitometers and control valves used to maintain pressure are allowable compression costs. The costs of these components are allowed.

The total amount must be prorated between measurement and compression. Only costs associated with compression will be allowed.

SEMINOLE METER STATION-SO. SEGMENT DELIVERY POINT

All the costs appear to be for measurement and are costs of marketing production. Even in FERC tariffs, if components of the tariff are for measurement, MMS disallows that portion of the tariff for calculating transportation allowances. This entire amount is disallowed.

PAYROLL MARKUP

The State's discussion of payroll costs indicates that ARCO/Exxon uses 8.4% of the payroll cost for mark-up. Only actual, reasonable costs are used to calculate allowances. This cost is disallowed.

FEASIBILITY STUDY

Feasibility studies are specifically allowed as capital investment costs in MMS' 2-5-92 valuation letter, signed by the Director. This cost will be allowed as a capital investment cost.

OTHER

Based on the description provided by ARCO/Exxon, the costs appear to be allocable to the construction of the pipeline. If true, these costs will be allowed as capital costs. If these costs were for lease use purposes (for instance, the grading of the roads is for roads to the wellsites) these costs are not allowable.

[1] From: James P. Morris 7/15/93 12:30PM (1345 bytes: 20 ln)
To: Susan Lupinski, Deborah Gibbs Tschudy, Colette Ann Haines, David A. Hubbard, Charles A. Brook
Subject: Re: Synopsis of items discussed at July 13 Sheep Mountain mtg.

------------------------------ Message Contents ------------------------------

I have done a little research and found the following:

I reviewed American Jurisprudence 2nd Edition and I believe that a Right-of-Way is real property. I think we would be hard pressed to come to the conclusion that the CDM had a different meaning in mind.

Finding examples where we specifically approved the inclusion of the ROW in the Rate of Return calculation was more difficult since it would have required that we asked for that level of detail when making the approval. I found one case, an approval of a producer owned pipeline on the Wind River Reservation in 1984. This looks like a high profile case and RVSD requested all of the data to support the capital costs. In the calculation they list the ROW expense in capital costs, we allowed the expense to be used in both the depreciation and in the ROI.

Do we need to talk again before we meet with ARCO and Colorado?

THIS COPY STAYS IN 88-282 !!!

United States Department of the Interior

TAKE PRIDE IN AMERICA

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

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AUG 13 1992

<u>CERTIFIED MAIL--</u>
<u>RETURN RECEIPT REQUESTED</u>

Mr. J. Wayne Achee
Acting Division Manager
Exxon Company, U.S.A.
P.O. Box 1600
Midland, Texas 79702-1600

Dear Mr. Achee:

I have reviewed Mr. Robert Olsen's letter dated December 16, 1991, and your letter dated April 24, 1992, addressing certain issues raised in the Minerals Management Service's (MMS) draft decisions outlining the requirements for determining transportation and processing allowances for gas produced from the LaBarge Project, Wyoming. The draft decisions were prepared in response to a decision issued by the Interior Board of Land Appeals (IBLA) on March 8, 1991 (IBLA 86-626), which also focused on the transportation and processing allowances for the LaBarge Project production. The issues ruled on by IBLA were under appeal by Exxon Company, U.S.A. (Exxon) for gas production prior to March 1, 1988, the effective date of the new oil and gas valuation regulations. However, IBLA's decision also has bearing on certain aspects of the allowance determinations for gas produced on and after March 1, 1988.

The MMS has given considerable thought to the concerns expressed in your letter before preparing this decision for the valuation, for royalty purposes, of the gas produced from the LaBarge Project. The MMS has decided that the basic requirements outlined in the draft decisions must be adhered to in valuing the gas, particularly the method for allocating the transportation and processing costs and the limitation on the extraordinary processing cost allowance.

The purpose of the remainder of this letter is twofold: (1) to issue a new decision in light of the IBLA decision pertaining to production prior to March 1, 1988; and (2) to provide a final decision for production on and after March 1, 1988, that takes into account the impact of the IBLA decision on the transportation allowance determination for that period and our review of the issue of extraordinary cost for processing gas production. Our decision is explained below and has been divided into two parts, one governing production occurring prior to March 1, 1988, and the other governing production on and after March 1, 1988.

VALUATION FOR PRODUCTION PRIOR TO MARCH 1, 1988

Post-Plant Transportation

A deduction from the sales point value is permitted for the costs of transporting the methane, the carbon dioxide (CO_2), and the sulfur from the Shute Creek Plant to the respective sales points for each product (post-plant transportation allowance). Post-plant transportation allowances should be determined for each product based on the actual costs incurred to transport that product through its transportation system.

In determining the post-plant transportation allowance for CO_2, the costs of CO_2 recompression are considered costs necessary to transport that gas to market and should be included in the allowance calculation. This decision recognizes the need to achieve and maintain a dense vapor phase for the CO_2 for efficient and safe transportation. It also implements IBLA's guidance that the purpose of costs incurred be the focus in determining whether they should be included in the transportation allowance.

The regulations at 30 CFR § 206.106(b) (1987) specifically prohibit an allowance for the expenses of boosting residue gas, and therefore, the recompression costs associated with the methane are not allowable in determining the methane post-plant transportation allowance.

For the period prior to March 1, 1988, it has been MMS' policy to approve onshore transportation allowances up to 50 percent of the sales point value of the product. However, where the lessee has been able to demonstrate actual costs that exceed 50 percent, MMS has approved higher allowances. For the LaBarge Project, because recompression costs are an allowable component of the CO_2 post-plant transportation allowance, that allowance is permitted up to the actual cost amount, not to exceed 99 percent of the CO_2 sales point value under each selling arrangement. Exxon's transportation costs for methane and sulfur do not exceed 50 percent of the sales point values, and the transportation allowances for these products are therefore limited to actual costs.

Processing

A deduction from the plant tailgate value of each royalty-bearing product, or portion thereof, recovered at the Shute Creek Plant is permitted for the costs of processing that product (processing allowance). Based on IBLA's decision, the recovered methane is also eligible for a processing allowance for the period prior to March 1, 1988. Individual processing allowances for each royalty-bearing product must be calculated by allocating the total costs of processing to each recoverable product contained in the raw gas stream delivered to the plant based on the fraction of that product's volume to the total volume of recoverable products (in Mcf). The recoverable products to be used in the allocation of the processing costs are CO_2, nitrogen, sulfur, methane, and helium.

The processing costs must be allocated to the full volumes of each recoverable product, including both those portions that are royalty bearing and non-royalty-bearing. ~~The non-royalty-bearing portions are those fractions that~~ are recoverable by the plant processes at Shute Creek but cannot be sold due to market constraints (such as the nitrogen and the vented CO_2). Helium also is non-royalty bearing. It is MMS' position that all products recovered at the plant benefit from the processing operation on a proportional basis, even though a portion of certain products are not sold. Those products that are not sold do, nonetheless, have value, although that value is insufficient to warrant additional expenditures to save those fractions. Fractions of the gas stream lost due to plant process, such as unrecoverable CO_2 at the Tailgas Unit of the sulfur recovery process, should not be allocated a proportionate share of processing costs. For example, X.4 percent of the CO_2 inlet stream is unrecoverable due to plant process and is therefore exempt from the allocation of processing costs.

Based on IBLA's decision that the Shute Creek Plant is processing an atypical gas stream not subject to the limitations under 30 CFR § 206.106 (1987), Exxon is granted a processing allowance for the actual processing costs allocated to the royalty-bearing fractions of the methane, CO_2, and sulfur, not to exceed 99 percent of the tailgate value of the respective product. Only those costs allocated to the royalty-bearing fraction may be deducted from the value of that fraction. Any processing costs remaining unrecovered due to the limitation shall not be deductible. ✓

Pre-Plant Transportation

A transportation allowance may be deducted from the plant inlet value of each of the royalty-bearing products or portions thereof recovered at the Shute Creek Plant for the costs of transporting those products in the raw gas stream from the field to the plant (pre-plant transportation allowance). The pre-plant transportation allowances for methane, CO_2, and sulfur should be determined by allocating the total costs of the pre-plant transportation facilities to each recovered product in the same proportion as described above for allocating processing costs. In accordance with IBLA's decision, the costs of the central dehydration facilities may be included in determining the total costs of the pre-plant transportation facilities.

The pre-plant transportation allowance for any product may not exceed 99 percent of the plant inlet value of that product; the total of all allowances (post-plant transportation, processing, and pre-plant transportation) for any product may not exceed 99 percent of the sales point value of that product.

VALUATION FOR PRODUCTION ON AND AFTER MARCH 1, 1988

Post-Plant Transportation

For production on and after March 1, 1988, the post-plant transportation allowances for methane, CO_2, and sulfur should be determined in the same manner as outlined for the period prior to March 1, 1988. Again, the costs of CO_2 recompression are permitted in calculating the CO_2 post-plant transportation allowance, whereas the recompression costs for methane are not deductible in accordance with 30 CFR § 206.153(i) (1991).

Processing

Pursuant to 30 CFR § 206.158(a) (1991), a processing allowance is permitted against the value of the gas plant products recovered at the Shute Creek Plant on and after March 1, 1988. However, only those gas plant products, or portions thereof, that are royalty bearing are eligible to receive a processing allowance in accordance with 30 CFR § 206.158(d)(1) (1991). The gas plant products currently qualifying to receive a processing allowance are CO_2 and sulfur. The methane is considered residue gas and is therefore not eligible for a processing allowance (30 CFR § 202.158(c)(1) (1991)).

Pursuant to 30 CFR § 206.158(b) (1991), the allocation of the processing costs is limited to the gas plant products--CO_2, nitrogen, sulfur, and helium--recovered at the plant, but, as is the case prior to March 1, 1988, such costs must be allocated to the entire recoverable volume of each gas plant product, including any portions that are non-royalty-bearing. However, only those costs attributable to the marketed portions (currently CO_2 and sulfur) may be deducted from the value as a processing allowance.

The processing allowances for the CO_2 and sulfur may not exceed 99 percent of their tailgate values in accordance with 30 CFR § 206.158(c)(3) (1991). Exxon is granted an exception to the 66 2/3 percent limitation on the basis that it has demonstrated that its processing costs for the CO_2 and sulfur are reasonable, actual, and necessary and are in excess of 66 2/3 percent of the tailgate values of the products.

Pre-Plant Transportation

The pre-plant transportation allowances for each royalty-bearing product--methane, CO_2, and sulfur--produced on and after March 1, 1988, must be determined similarly to the pre-plant transportation allowances for periods prior to March 1, 1988, by allocating the total pre-plant transportation costs in the same proportion as the recoverable volumes of each product contained in the raw gas stream transported to the plant. In a decision dated October 19, 1988, the Assistant Secretary for Land and Minerals Management agreed to follow, for the period on and after March 1, 1988, IBLA's guidance concerning the costs of the central dehydration facilities. Thus, the proportionate share of the dehydration costs may be included in the determination of the pre-plant transportation allowances for methane, CO_2, and sulfur.

Again, the pre-plant transportation allowance for any product may not exceed 99 percent of the plant inlet value of that product, and the total of all allowances for the transportation and processing of any product may not exceed 99 percent of the sales point value of that product.

Extraordinary Costs

The IBLA recognized that the Shute Creek Plant was designed to process an atypical gas stream which the regulations in effect prior to March 1, 1988, did not adequately address. As the IBLA correctly observed, the LaBarge gas stream is atypical in a methane recovery project in that only about

21 percent of the feed gas stream is methane and <u>no</u> liquefiable hydrocarbons are present. The March 1, 1988, regulations (53 F.R. 1230, January 15, 1988) specifically included provisions that were written with the full understanding of the nature of the gas from the LaBarge Project. Title 30 CFR § 206.158(d) (1991), providing for an extraordinary processing allowance, was included, in large part, with the Shute Creek Plant in mind. As evidence of this, MMS stated in the preamble to these regulations (53 F.R. 1240) that it was including "a provision for an extraordinary processing cost allowance for atypical types of gas production operations."

To contend with the physical uniqueness of the LaBarge Project feed gas stream, the Shute Creek Plant design is extremely complex and atypical when compared to typical methane recovery plants. Examples of its atypical characteristics include the existence of two separate Selexol recovery systems to address the extremely high proportionate presence of CO_2 and hydrogen sulfide in the feed gas stream as well as a complex nitrogen rejection/recovery process. Due to the atypical composition of the LaBarge Project feed gas stream and the complex nature of the Shute Creek Plant, the cost to process the principal recoverable product, methane, is extraordinary compared with traditional methane recovery plants. As evidenced by industry surveys of gas processing plants, the range of variable costs for processing methane are between \$0.025 and \$0.60 per Mcf. The Shute Creek Plant experiences, at current full throughput of 600 million cubic feet per day, a cost of approximately X.4 per Mcf of methane, which is well beyond the aforementioned range.

Based on the atypical composition of the LaBarge Project feed gas stream and the unusual complexity and operating cost of the Shute Creek Plant, MMS concludes that the costs of processing at the Shute Creek Plant are extraordinary, unusual, and unconventional by industry standards within the meaning of 30 CFR § 206.158(d). As such, an allowance for the extraordinary costs of processing at the Shute Creek Plant is hereby granted in accordance with the provisions of 30 CFR § 206.158(d)(2) (1991). The extraordinary processing cost allowance is permitted against the value of the methane for those processing costs allocated to the gas plant products but left unrecovered due to either the imposition of allowance limits or the venting of unsold products due to market constraints (such as the nitrogen and CO_2), and excludes any processing costs attributable to helium. The extraordinary processing cost allowance, however, may not exceed 50 percent of the plant tailgate value of the methane.

Enclosed are sample royalty value calculations based on 1987 actual data showing the allocation of the LaBarge Project processing and transportation costs and the allowable portions of those costs to be used in claiming the transportation and processing allowances on a Form MMS-2014. Enclosure 1 shows the sample calculations for the period prior to March 1, 1988, using actual data for Calendar Year 1987; Enclosure 2 details the calculations for the period on and after March 1, 1988, using the same 1987 data.

Exxon is herewith directed to recalculate all royalties due in accordance with the valuation instructions outlined above for all production prior to March 1, 1988, and all production on and after March 1, 1988. The results of the recalculations must be submitted to MMS within 120 days of receipt of this letter.

The MMS reserves the right to amend this decision in the event of changed circumstances or a determination that such an amendment is necessary to produce a fair and reasonable value for royalty purposes. Such an amendment may be made only following notice to Exxon for production following the date of notice.

This order is approved and adopted as the final action of the Department of the Interior and, therefore, is not subject to appeal to the IBLA (Blue Star, Inc., 41 IBLA 333 (1979)).

Sincerely,

David C. O'Neal
Assistant Secretary -
Land and Minerals Management

2 Enclosures

ENCLOSURE 2

LABARGE VALUATION FOR FEDERAL ROYALTY PURPOSES
POST-MARCH 1, 1988, PRODUCTION

(Based on Data for Calendar Year 1987)

Product	Sales Volume	Post-Plant Transp. Costs	Plant Tailgate Value	% Volume Processed (Excl. CH_4)	****Proc. Costs Alloc. on Inlet Volume	Proc. Costs Limited by Roy-bearing Fraction	*Allow. Proc. Costs	Plant Inlet Value	****Pre-Plant Transp. Alloc. on Volume	**Allow. Transp. Costs	***Royalty Value
CH_4	34,492										
CO_2	54,932					X-4					
S	9,380										
N_2	0										
He	803	X-4									
TOTAL:	99,607		X-4					X-4			

*The lesser of 99% of the plant tailgate value for CO_2, N_2 and S, or the processing costs allocated to the royalty-bearing fraction of each respective product.

**The pre-plant transportation costs allocated to the royalty-bearing fraction of each respective product, not to exceed 99% of plant inlet value.

***The minimum value for royalty purposes can be no less than 1% of the sales value of any gas plant product. However, for methane, the only processing allowance available is for extraordinary costs with such allowance limited to 50 percent of the plant tailgate value.

****Volumes used for allocation purposes must include recovered products, whether sold or not, and exclude fractions of the gas stream lost due to plant process, such as unrecoverable CO_2 at the tail gas unit of the sulfur recovery process. (For the purposes of this exhibit, approximately X-4 of the inlet volume of the CO_2 is considered unrecoverable.)

All volumes in MMcf; all costs and values in $1,000's)

LABARGE VALUATION FOR FEDERAL ROYALTY PURPOSES
PRE-MARCH 1, 1988 PRODUCTION

(Based on Data for Calendar Year 1987)

Product	Sales Volume	Post-Plant Transp. Costs	Plant Tailgate Value	% Volume Processed (Incl. CH_4)	****Proc. Costs Alloc. on Inlet Volume	Proc. Costs Limited by Roy-bearing Fraction	*Allow. Proc. Costs	Plant Inlet Value	****Pre-Plant Transp. Alloc. on Volume	**Allow. Transp. Costs	***Royalty Value
CH_4	34,492										
CO_2	54,932					X-4					
S	9,380										
N_2	0										
He	803										
TOTAL:	99,607				Y-4						X-4

*The lesser of X-4 of the plant tailgate value for CO_2, N_2, S, and methane, or the processing costs allocated to the royalty-bearing fraction of each respective product.

**The pre-plant transportation costs allocated to the royalty-bearing fraction of each respective product, not to exceed Y-4 of plant inlet value.

***The minimum value for royalty purposes can be no less than 1% of the sales value of any product.

****Volumes used for allocation purposes must include recovered products, whether sold or not, and exclude fractions of the gas stream lost due to plant process, such as unrecoverable CO_2 at the tail gas unit of the sulfur recovery process. (For the purposes of this exhibit, approximately Y-4 of the inlet volume of the CO_2 is considered unrecoverable.)

(All volumes in MMcf; all costs and values in $1,000's)

United States Department of the Interior

TAKE PRIDE IN AMERICA

MINERALS MANAGEMENT SERVICE
WASHINGTON, DC 20240

FEB 5 1992

ENCLOSURE AND APPENDICES
CONTAIN COMPANY PROPRIETARY
INFORMATION FOR RELEASE ONLY
TO EXXON COMPANY, U.S.A.

CERTIFIED MAIL--
RETURN RECEIPT REQUESTED

Mr. R. R. Hickman
Exxon Company, U.S.A.
P.O. Box 1700
Midland, Texas 79702

Dear Mr. Hickman:

Through various oral and written presentations, Exxon Company, U.S.A. (Exxon), and ARCO Oil and Gas Company (ARCO) jointly requested approval of a transportation allowance for carbon dioxide (CO_2) produced from the Sheep Mountain Unit (Sheep Mountain), Huerfano County, Colorado. On its own behalf, Exxon also requested a royalty valuation procedure for the subject production.

The Minerals Management Service (MMS) has reviewed all information submitted. The valuation of Exxon's CO_2 produced prior to March 1, 1988, will be determined as follows: The value at the point of royalty settlement for Exxon's portion of Sheep Mountain CO_2 that is exchanged, supplied, or provided in-kind under various contracts to west Texas tertiary recovery units will be based on the prices established in arm's-length CO_2 sales and purchase contracts in existence for each unit, less MMS-approved Sheep Mountain Pipeline transportation allowances. If no arm's-length contract exists for a unit where Exxon delivers Sheep Mountain CO_2, the prices established in comparable arm's-length CO_2 sales and purchase contracts in a nearby unit, field, or area will establish value. Each value determined by this method shall be used to determine the value for the allocable portion of the CO_2 at Sheep Mountain boundary measurement point.

The transportation allowance for the period prior to March 1, 1988, must be determined under the following conditions: Capitalized and expensed compression costs may be included in computing the transportation allowance. Dehydration costs cannot be included in the transportation allowance calculation. The prime interest rate as compiled by the Federal Reserve Board of Dallas will be used to calculate the Sheep Mountain CO_2 transportation allowance. Interest during construction (IDC) cannot be included in the depreciable capital base used to calculate yearly depreciation until ARCO and Exxon provide adequate documentation supporting their proposed IDC figure. Abandonment costs for the Sheep Mountain CO_2 pipeline cannot be included in the allowable expenses. The Sheep Mountain CO_2 transportation allowance will not be subject to the 50-percent limitation. ARCO and Exxon may deduct actual transportation costs (calculated in accordance with this letter) not to exceed 99 percent of the value of the CO_2.

This decision applies only to production occurring prior to March 1, 1988. Production occurring on or after March 1, 1988, must be valued in accordance with the regulation at 30 CFR 206 (1990).

The enclosed "Summary of Findings and Conclusions" provides the basis for this determination.

You have the right to appeal this determination in accordance with the provisions of 30 CFR 290 (1990), and 43 CFR §§ 4.411 and 4.413 (1990). Any appeal taken will be to the Interior Board of Land Appeals, Office of Hearings and Appeals, Office of the Secretary, and the notice of appeal must be filed in my office within 30 days from the date of receipt of this letter.

If you have any questions, please call Mr. Donald T. Sant, Deputy Associate Director for Valuation and Audit, at (303) 231-3899.

Sincerely,

/s/ S. Scott Sewell
Director

Enclosure

Enclosure

CONTAINS COMPANY PROPRIETARY INFORMATION FOR RELEASE ONLY TO EXXON COMPANY, U.S.A.

ROYALTY MANAGEMENT PROGRAM
ROYALTY VALUATION AND STANDARDS DIVISION

Summary of Findings and Conclusions on Sheep Mountain Carbon Dioxide Valuation and Transportation Allowance

BACKGROUND

The Sheep Mountain Unit (Sheep Mountain) is a carbon dioxide (CO_2) field in Huerfano County, Colorado. ARCO Oil and Gas Company (ARCO) is the operator of the unit and lessee of record for nearly 100 percent of the unitized land.

Exxon Company, U.S.A. (Exxon), has an "agreement on principles" with ARCO, dated May 1, 1981, whereby Exxon receives 50 percent of the CO_2 production from Sheep Mountain (delivered in the field) in exchange for Exxon's capital investments in Sheep Mountain field facilities and the Sheep Mountain Pipeline.

In August 1985, Exxon requested a transportation allowance and royalty valuation method for the subject CO_2. Numerous submittals and meetings, listed below in chronological order, followed:

Date	Event
August 29, 1985	Meeting held between Exxon, ARCO, and Minerals Management Service (MMS) representatives; joint submittal of transportation allowance request is provided to MMS.
April 7, 1986	Exxon submits letter proposing a valuation methodology for Sheep Mountain CO_2 production.
April 13, 1987	The MMS provides Exxon with a draft decision detailing a valuation and transportation allowance method.
June 12, 1987	Exxon and ARCO jointly submit additional information relative to the transportation allowance calculation.
June 17, 1987	Meeting held between Exxon, ARCO and MMS representatives to discuss the April 13 draft decision and transportation allowance information provided in the June 12 joint submittal. Meeting held between Exxon and MMS representatives to discuss valuation method.

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Date	Event
August 28, 1987	Exxon submits second letter containing additional information on its proposed valuation methodology.
December 12, 1989	Meeting held between Exxon, ARCO, and MMS representatives to discuss in further detail several transportation allowance issues.
January 5, 1990	The MMS provides Exxon with a second draft decision detailing a valuation and transportation allowance method.
March 8, 1990	Meeting held between Exxon, ARCO, and MMS representatives to discuss the January 5 draft decision. Exxon and ARCO provide MMS with a joint submittal containing additional discussion of transportation allowance issues.

The valuation procedure and transportation allowance calculation described in the following sections incorporate all information presented orally at the meetings and in writing through the various submittals. This decision pertains only to CO_2 produced prior to March 1, 1988, in accordance with regulations at 30 CFR § 206.103 (1987) and MMS policy in effect at that time. Valuation and transportation allowances for production on or after March 1, 1988, should be computed in accordance with 30 CFR §§ 206.152, 206.156, and 206.157 (1988).

SHEEP MOUNTAIN CO_2 VALUE

Findings

Disposition of Production

° The CO_2 is transported through the Sheep Mountain Pipeline to oil fields in the Permian Basin of west Texas where it is used in tertiary recovery projects. The Sheep Mountain Pipeline is operated by ARCO Pipe Line Company. The portion of the pipeline between Sheep Mountain and the Bravo Dome CO_2 Unit interconnection in New Mexico is owned equally by ARCO and Exxon. The remainder of the pipeline from the Bravo Dome CO_2 Unit interconnection to west Texas is owned 35 percent by ARCO, 35 percent by Exxon, and 30 percent by Amerada Hess Corporation. All cost information submitted to MMS is relative only to that portion of the pipeline from Sheep Mountain to west Texas that is owned by ARCO and Exxon.

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° The point of royalty measurement, designated by the Bureau of Land Management, is the Sheep Mountain origin meter station. Sales points coincide with the various delivery points at the tertiary recovery projects in west Texas.

° Exxon disposes of its share of Sheep Mountain CO_2 under 13 contracts. Eight of these contracts are in-kind supply agreements and five are exchange or supply/make-up agreements.

Exxon's Valuation Proposal

° In its letter of April 7, 1986, Exxon proposes to value any Sheep Mountain CO_2 production sold under an arm's-length agreement at the sales price established in the agreement, less transportation costs. For any production disposed under in-kind or exchange agreements, Exxon proposes using a current market value of CO_2 in the Denver City area (a location near Denver City, Texas, where several CO_2 pipelines converge), less transportation costs. Because all of Exxon's share of Sheep Mountain CO_2 is currently disposed of under in-kind, exchange, or supply/make-up agreements rather than sold, Exxon proposes using the current market value in the Denver City area to value its Sheep Mountain CO_2.

° In its draft decision dated April 13, 1987, MMS disagreed with Exxon's proposal to use Denver City area market values and determined that the value for Exxon's portion of Sheep Mountain CO_2 would be based on the prices established in the arm's-length CO_2 sales and purchase contract(s) in existence for each tertiary recovery unit where Exxon delivers Sheep Mountain CO_2.

° In its response letter of August 28, 1987, Exxon contends that Denver City has become the principal market place for CO_2 in the Permian Basin (west Texas and southeast New Mexico) and explains that the Denver City area is the nearest available market for Sheep Mountain CO_2 and is the first point downstream of Sheep Mountain where Exxon can sell significant quantities of Sheep Mountain CO_2. Exxon contends that the Denver City area is the best point at which Exxon's in kind or exchanged production can be valued. For this reason, Exxon proposes using prices in its most recently negotiated arm's-length agreements for CO_2 transported to or through Denver City as the basis for determining royalty value. Exxon argues that the value of Sheep Mountain CO_2 disposed of in-kind, exchanged, or supplied to end-use customers is its "replacement" value; that is, the value at which Exxon would have to replace Sheep Mountain CO_2 by purchasing other CO_2 at Denver City.

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- Exxon disagrees with the MMS valuation method for the following reasons:

  -- The tertiary recovery units where Exxon supplies CO_2 in kind are not the nearest available market for Sheep Mountain CO_2. Rather, the Denver City area is the nearest market.

  -- The MMS method is unreasonable because it does not reflect the value of Sheep Mountain CO_2 that Exxon currently uses in kind, primarily because the value is based on "outdated" CO_2 prices.

  -- The value of CO_2 supplied in kind is its replacement cost, not the average price provided in the arm's-length CO_2 sales contracts for that particular unit.

- Exxon alleges that the MMS method does not indicate how to value Sheep Mountain CO_2 used in tertiary recovery units where no arm's-length sales exist. Because Exxon currently supplies CO_2 to tertiary recovery units where no arm's-length sales exist, Exxon claims that its valuation method (using Denver City's prices) is more workable than the MMS method.

- Exxon also alleges that the MMS method is not consistent with the new valuation regulations (effective March 1, 1988) whereas Exxon's proposed method is consistent with the new regulations.

MMS Valuation Procedures

General MMS Policies

- The MMS delineates a market area as an established market where arm's-length contracts are regularly negotiated and where publicly available posted or spot prices exist. As acknowledged by Exxon, no posted prices for CO_2 exist for Denver City. Also, although three major CO_2 pipelines (Sheep Mountain, Bravo Dome, and Cortez Pipelines) pass through the Denver City area, Denver City is not the terminus of these pipeline systems and no arm's-length contracts exist that cite Denver City as the final delivery point.

- The MMS views in-kind, exchange, and supply/make-up agreements as operational agreements entered into for the convenience of the contracting parties. Under the lease terms, regulations, and enabling laws, the Secretary of the Interior has broad regulatory authority to determine the "reasonable value" of production. The Secretary is not limited to the actual "value" received in order to determine the value of production for royalty purposes. The value to the lessee is not always the value for royalty purposes.

- The MMS normally accepts the prices established in arm's-length contracts as representative of value for royalty purposes. In those instances where no arm's-length contracts exist, MMS policy is to look to prices established in comparable arm's-length contracts in nearby units as the best measure of value.

CO_2 Disposed of Under In-Kind Agreements

- Exxon supplies Sheep Mountain CO_2 to the Cornell, Seminole-San Andreas, Means-San Andreas, Willard-San Andreas, Dollarhide Field Devonian, Denver, Yates Field, and Means Queen No. 1 Oil Units under in-kind agreements.

- In every tertiary recovery unit, each working interest owner has a responsibility to pay for or supply its unit participation share of the total volume of CO_2 used in unit operations. In-kind supply agreements allow a working interest owner in a tertiary recovery project to supply its share of the required CO_2 "in kind" in lieu of sharing in the cost of purchasing CO_2 for the project. In units where a working interest owner cannot supply CO_2 in kind, the unit operator usually purchases CO_2 and charges the working interest owner's account for the amount of CO_2 purchased. The contract under which the unit operator purchases CO_2 on behalf of working interest owners that are not able to supply their own CO_2 in kind is considered by MMS as the principal CO_2 sales and purchase contract for that unit.

- Arm's-length principal CO_2 sales and purchase contracts exist in the Seminole-San Andreas, Willard-San Andreas, Dollarhide Field Devonian, Denver, and Yates Field Units. The sales prices established in these contracts will determine royalty value for CO_2 furnished under Exxon's in-kind supply agreements in these five units.

- There are no principal CO_2 sales and purchase contracts in the Cornell, Means-San Andreas, and Means Queen No. 1 Oil Units. To value Exxon's in-kind deliveries in such situations, MMS policy is to use the prices established in comparable arm's-length contracts in nearby units to determine royalty value. For CO_2 disposed at the Cornell Unit, the Willard-San Andreas Unit is the nearest unit where a comparable arm's-length contract exists. For CO_2 disposed at the Means-San Andreas and Means Queen No. 1 Units, the Seminole-San Andreas Unit is the nearest unit where a comparable arm's-length contract exists. The sales prices established in the Willard-San Andreas Unit and Seminole-San Andreas Unit principal CO_2 sales and purchase contracts therefore will determine the royalty value for Sheep Mountain CO_2 supplied in kind by Exxon to the Cornell, Means-San Andreas, and Means Queen No. 1 Oil Units.

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CO_2 Disposed of Under Exchange and Supply/Make-Up Agreements

- Exxon has two exchange agreements with X-4 X-4 under which Sheep Mountain CO_2 is delivered to the Seminole-San Andreas, Sable, Denver, and GMK South Units for X-4 account. In addition, Exxon also delivers Sheep Mountain CO_2 to the H. O. Mahoney lease and various unspecified units for X-4. In exchange, X-4 delivers McElmo Dome CO_2 at various points for Exxon's account.

- Exxon has three supply/make-up contracts with X-4 under which X-4 supplies McElmo Dome CO_2 to the Denver and South Wasson Clearfork Units on behalf of Exxon to meet Exxon's in-kind obligations for a limited period of time. Exxon subsequently delivers make-up volumes of Sheep Mountain CO_2 in the same units to meet X-4 obligation to deliver CO_2 to these units.

- Arm's-length principal CO_2 sales and purchase contracts exist in the Seminole-San Andreas, Denver, South Wasson Clearfork, and GMK South Units. The sales prices established in these contracts will determine royalty value for the CO_2 disposed of under Exxon's exchange or supply/make-up agreements in these four units.

- The Sable Unit has a non-arm's-length principal CO_2 sales and purchase contract. The MMS has determined that this non-arm's-length contract is comparable to arm's-length contracts executed at approximately the same time for like-quality products in the area. The sales price established in the Sable Unit principal CO_2 sales and purchase contract, therefore, will determine royalty value for the CO_2 Exxon exchanges at the Sable Unit.

- No principal CO_2 sales and purchase contract exists at the H. O. Mahoney lease where Exxon delivers Sheep Mountain CO_2. The Willard-San Andreas Unit is the nearest unit to the H. O. Mahoney lease where a comparable arm's-length contract exists. The sales price established in the Willard-San Andreas Unit principal CO_2 sales and purchase agreement will determine the royalty value for Sheep Mountain CO_2 supplied to the H. O. Mahoney lease.

- The remaining delivery points at which Exxon exchanges or supplies CO_2 have not been specified in Exxon's contracts. If arm's-length principal CO_2 sales and purchase contracts exist in units where Exxon delivers Sheep Mountain CO_2, the prices established in those contracts will determine royalty value. If non-arm's-length principal CO_2 sales and purchase contracts exist, the price established in the non-arm's-length contracts may be used to determine royalty value if the contracts are comparable to other arm's-length contracts executed at approximately the same time for like-quality products in the same field or area. Otherwise, Exxon must designate which comparable arm's-length principal CO_2 sales and purchase contracts from nearby units will be used to determine royalty value.

Timing of Royalty Payments

° Applicable laws, regulations, and lease terms specifically require that royalty is due on production removed or sold from the leased lands. For each of the valuation scenarios discussed above, MMS will require royalties on the volume of CO_2 leaving Sheep Mountain, regardless of when Exxon receives final settlement.

Conclusions

° The valuation of Exxon's CO_2 produced prior to March 1, 1988, is subject to the provisions of 30 CFR § 206.103 and MMS policy in effect at that time.

° The MMS has consistently used arm's-length contracts as the basis for determining value. This policy is consistent with industry's position that prices established in arm's-length contracts are proof of market value, a value freely arrived at in an open market by parties of opposing economic interests. The arm's-length contracts executed at the same time as the exchange or in-kind agreements are the best measure of value.

° Exxon's proposal to use prices in its most recently negotiated arm's-length agreements for CO_2 transported to or through Denver City as a measure of value for its Sheep Mountain CO_2 is contrary to MMS valuation principles of using comparable arm's-length contracts to establish value. Exxon's proposal would use prices established in recently executed contracts to value Sheep Mountain CO_2 provided by in-kind, exchange, or supply/make-up agreements that were executed several years earlier. The CO_2 source, delivery points, terms, duration, and other factors specified in these recently executed contracts may not correspond to terms specified in Exxon's older Sheep Mountain CO_2 in-kind, exchange, or supply/make-up agreements.

° Exxon's allegation that the MMS method does not apply in tertiary recovery units where no arm's-length contracts exist, whereas Exxon's method does, is unfounded. The policy of using prices established in comparable arm's-length contracts as the best measure of royalty value can indeed be applied to instances where no arm's-length contracts exist in the tertiary recovery units. For those tertiary recovery units where no arm's-length contracts exist, MMS would look to prices established in comparable arm's-length contracts in nearby units as the best measure of value. This valuation method is consistent with past MMS policy and practice.

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° Exxon's allegation that the proposed MMS valuation method for production disposed of under in-kind, exchange, and supply/make-up agreements is not consistent with the new regulations, is unfounded and irrelevant. The new regulations are effective for production on or after March 1, 1988, and, therefore, they are not applicable to production prior to March 1, 1988, the period for which Exxon is requesting a valuation procedure. However, although the method determined by MMS applies to the period prior to the March 1, 1988, effective date of the new regulations, contrary to Exxon's assertion, the method prescribed by MMS is also consistent with these new regulations. Exxon has correctly determined that MMS would use the benchmark system to value production disposed of under in-kind, exchange, and supply/make-up agreements as detailed in the new regulations at 30 CFR § 206.152(c) (1988). However, Exxon has incorrectly applied the benchmarks.

° The value at the point of royalty settlement for Exxon's portion of Sheep Mountain CO_2 that is exchanged, supplied, or provided in kind to arious west Texas tertiary recovery units will be based on the prices es.ablished in arm's-length CO_2 sales and purchase contracts in existence for each unit, less MMS-approved Sheep Mountain Pipeline transportation allowances. If no arm's-length contract exists for a unit where Exxon delivers Sheep Mountain CO_2, the prices established in comparable arm's-length CO_2 sales and purchase contracts in a nearby unit, field, or area (as identified in the "Findings" section) will establish value. Each value determined by this method shall be used to determine the value of the allocable portion of the CO_2 at Sheep Mountain boundary measurement point. Allocable portions will be determined by dividing each individual west Texas monthly delivery by the total monthly west Texas deliveries to arrive at a percentage allocation. A hypothetical example for month A is provided below:

Measured CO_2 Production at Sheep Mountain Origin Meter Station, Month A: 5,000 Mcf

Exxon's West Texas Deliveries During Month A:	Volume	Percent
Deliveries to Unit B	100 Mcf	10%
Deliveries to Unit C	500 Mcf	50%
Deliveries to Unit D	400 Mcf	40%
Total West Texas Deliveries	1,000 Mcf	100%

MMS-Approved Values

Unit B	\$2.00/Mcf
Unit C	\$1.75/Mcf
Unit D	\$1.50/Mcf

Calculation of Royalty Value

Unit	Arm's-length price		Percent of volume leaving Sheep Mountain	Value for royalty purposes
B	$2.00	x	10 percent of 5,000	$1,000
C	$1.75	x	50 percent of 5,000	$4,375
D	$1.50	x	40 percent of 5,000	$3,000

These amounts represent the value of all Sheep Mountain CO_2 produced during month A.

° By regulation, royalty shall never be less than the gross proceeds accruing, or which could accrue, to Exxon for the sale or disposition of Sheep Mountain CO_2.

SHEEP MOUNTAIN CO_2 TRANSPORTATION ALLOWANCE

Findings

° Information relative to the calculation of the Sheep Mountain CO_2 transportation allowance was jointly submitted by ARCO and Exxon in letters dated August 29, 1985; June 12, 1987; and March 8, 1990. Specific information was detailed in exhibits 1 through 34 of the August 29, 1985, letter.

° The transportation allowance costs submitted by ARCO and Exxon are separated into four major components: depreciation, expenses, interest, and throughput. Each major component will be discussed separately.

° The following discussion pertains only to the calculation of transportation allowances for the period prior to March 1, 1988. The calculation of transportation allowances on or after March 1, 1988, must be in accordance with the requirements of 30 CFR §§ 206.156 and 206.157.

Depreciation

° The items that comprise the depreciation component (exhibits 6 through 14) include pipeline capital, salvage value, compression-related capital investment, interest during construction (IDC), and inflation. The following is a discussion of each item.

Pipeline capital -- ARCO and Exxon request X - 4 in capital investment costs for constructing the pipeline. This figure includes costs for

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materials, labor, engineering, feasibility, environmental assessments, construction, and inspection. Capital investment costs that are directly allocable and attributable to the physical construction of a pipeline are generally accepted by MMS as part of the depreciable capital. However, pipeline capital investment costs for the Clovis Operations Center include costs for "purchase of land" upon which the operations center is built. Land is not a depreciable asset and is not properly included in the undepreciated capital investment. The capital investment cost of X-4 requested by ARCO and Exxon must be reduced by the purchase price of the land.

Salvage value -- ARCO and Exxon used a zero salvage value in calculating the depreciation. The Conservation Division Manual (CDM), a procedural guide of the U.S. Geological Survey (USGS), predecessor Agency to MMS, directs that a salvage value of 10 percent should be applied to tangible items when determining the depreciable investment cost to be used in allowance calculations, unless the lessee can justify a different salvage value. In justifying their zero salvage value, ARCO and Exxon claim that "[n]o known pipeline transportable commodities have significant supply at one end of the pipeline and demand at the other, so use of the line after depletion of Sheep Mountain is unlikely." In addition, ARCO and Exxon argue that after the depreciation period, the value of the 20-year-old equipment is estimated to be less than the cost to move it to a useful location. The MMS considers this acceptable justification and will allow a salvage value of zero. However, if it becomes apparent in the future that the pipeline will be salvaged or used for other purposes, MMS would no longer accept a zero salvage value.

Compression and dehydration-related capital investment -- Five drill sites were constructed at Sheep Mountain, each containing a conditioning plant capable of heating, dehydrating, and compressing the CO_2 produced from the various wells drilled from each site. Included in the depreciation component of the original request is compression-related capital associated with these conditioning plants, including the equipment and installation costs for the heaters, dehydrators, and compressors and the costs allocated to the electrical power supply system and the electrical/control system necessary to operate this equipment. ARCO and Exxon assert that compression is essential to transport Sheep Mountain CO_2 to west Texas and is not a marketing requirement. ARCO and Exxon argue that MMS draft decisions are premised on the assumption that the compression function at Sheep Mountain is indistinguishable from typical compression functions performed by lessees to condition hydrocarbon gas for marketing.

--The point at which compression occurs is significant to the issue of whether to allow compression costs in the transportation allowance. Compression occurring prior to the point of royalty measurement is considered by MMS as necessary to place production in marketable condition and is a function to be performed at no cost to the lessor. The regulation at 43 CFR § 3162.7-1(a) (1987), "Disposition of production," stipulates that the lessee shall put into marketable condition, if economically feasible, all oil, other hydrocarbons, gas, and sulphur produced from the leased land. This regulation applies to CO_2 under the term "gas."

--The Notice to Lessees and Operators No. 1 (NTL-1), "Procedures for Reporting and Accounting for Royalties," provides in pertinent part under Section III, "Gas and Associated Liquids Production, Sales, and Royalty Requirements":

> . . . Under no circumstances will the royalty value be computed on less than the gross proceeds accruing to the operator from the sale of such leasehold production. Gross proceeds include, but are not limited to, tax reimbursements and payments to the operator for gathering, measuring, compressing, dehydrating, or performing other services necessary to market the production. Likewise, no deduction will be allowed for the cost which an operator occurs [sic] by reason of placing the gas in a marketable condition as an operator is obligated to do so at no cost to the lessor.

The preceding statement is primarily concerned with gross proceeds. However, it is very explicit that gathering, dehydrating, and compressing CO_2 are considered part of the activities to be conducted by the lessee at no cost to the lessor.

--The CDM addresses the lessee's responsibility to make lease production marketable. The CDM, section 647.2.3A, directs in pertinent part:

> The lessee is obligated to place lease production in marketable condition without deduction of costs for measuring, compressing, or otherwise conditioning the gas for market. Under no circumstances will royalty be computed on less than the gross proceeds accruing to the lessee from the sale of leasehold production.

--Decisions by the Director, USGS, and the U.S. District Court for the District of Columbia in The California Company v. Secretary of the Interior (No. 16132), August 10, 1961, have upheld the principle that the lease operator is obligated to perform necessary dehydration and compression operations.

° On March 8, 1991, the Interior Board of Land Appeals (IBLA), addressed Exxon Corporation's appeal of a denial by MMS to allow inclusion of dehydration costs in a transportation allowance for production transported to the Shute Creek gas processing plant (IBLA 86-626). In this decision, IBLA determined that MMS must consider the purpose of dehydration in determining whether an allowance is proper. In the Shute Creek case, IBLA found that dehydration at the central dehydration facility serves only one purpose: transportation. The gas processing plant had to be located 40 miles distant because of environmental constraints. If the gas processing plant was closer to the field, the central dehydration facility would not have been built. The IBLA concluded that dehydration costs for the Shute Creek case were allowable transportation costs.

° The CO_2 produced at Sheep Mountain is moved to drill-site conditioning plants located within the unit where it is heated, dehydrated, compressed, cooled, and metered prior to moving to the pipeline origin meter station. In order to determine whether compression and dehydration at Sheep Mountain should be included in the transportation allowance calculation, MMS must consider what purpose the functions serve.

° ARCO and Exxon contend that the compression equipment at Sheep Mountain is only used to place and maintain the CO_2 in a supercritical phase, thereby allowing the most efficient transportation through the Sheep Mountain Pipeline. Additionally, ARCO and Exxon contend that the west Texas CO_2 market does not dictate the pressure needed for transportation as evidenced by the fact that several west Texas purchasers further increase the delivery pressure to meet their individual project requirements. For these reasons, ARCO and Exxon assert that the compression is an integral and necessary part of transportation and is not a marketing requirement. Based on the evidence presented, the compression function at Sheep Mountain does not serve the purpose of conditioning the gas for market. In accordance with the directives established by IBLA in the Shute Creek case, ARCO and Exxon may include compression costs in the Sheep Mountain transportation allowance calculation.

° A typical Sheep Mountain CO_2 delivery contract for west Texas specifies that the CO_2 shall not contain any free water or more than 30 pounds of water per 1,000 Mcf at 14.7 psia and 60 °F. In order to meet these contract specifications, the CO_2 produced at Sheep Mountain must be dehydrated. Thus, dehydration clearly serves the purpose of placing Sheep Mountain CO_2 in marketable condition. Applicable regulations, court cases, and lease terms require the lessee to absorb all costs necessary to condition the production for market. No dehydration costs shall be included in the Sheep Mountain transportation allowance calculation.

° ARCO and Exxon request X-4 in capital investment costs for compression-related capital (exhibit 10). Exhibit 14 describes the types of expenditures and the portion of these expenditures allocated to the compression function. Capital investment costs that are directly allocable and attributable to compression-related equipment are generally accepted by MMS as part of the depreciable capital. However, if these costs include any costs associated with the dehydration function, the capital investment figure must be reduced by such costs.

IDC -- ARCO and Exxon argue that because construction of the transportation facilities was a relatively long-term effort, the real cost of installing the facilities exceeded the as-spent investment capital. ARCO and Exxon claim that money tied up in the facilities could have been utilized in other investments and, therefore, have included IDC as part of the depreciable capital. ARCO and Exxon contend that capitalization of interest costs recognizes that interest costs are an integral part of the costs necessary to bring an asset to the condition necessary for its intended use.

--When a company uses borrowed capital to finance construction of a facility, MMS policy will permit an interest charge separate from the rate of return on undepreciated capital in calculating transportation allowances subject to MMS audit and approval. However, this interest charge is permitted only under the following circumstances:

(1) When, during the development period of a project, interest incurred on a loan for construction costs that are integral to, or directly allocable and attributable to, transportation facilities is properly capitalized and thus becomes part of the basis for undepreciated capital upon which a rate of return is later applied; or

(2) When interest is incurred on loans for routine operating and maintenance expenses.

--Conversely, interest charges will generally not be permitted under the following circumstances:

(1) When the lessee attempts to claim, during the production phase of the project, interest payments for loans on capitalized items (this is not permitted because a separate rate of return is applied against the remaining undepreciated capital);

(2) When some part of the interest capitalized during the development phase is not related to borrowed capital applied to construction (the amount of interest that may be capitalized is limited to the interest charge that would have been avoided if expenditures for the transportation facility had not been made); or

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(3) When the interest claimed in the capitalized base is otherwise not directly allocable or attributable to the transportation facility.

--If a company issues bonds to raise money for capital investment instead of borrowing the capital, the corresponding interest charge capitalized during the development phase of the transportation facility may be permitted in the transportation allowance calculation but is limited to the interest on only that part of the bond proceeds applied to construction of that facility. In such instances, the company must provide, upon request, an allocation schedule demonstrating disposition of bond proceeds and interest corresponding to each disposition.

--The explanation of IDC provided in ARCO and Exxon's exhibit 6 indicates that instead of borrowing money to construct the Sheep Mountain Pipeline or issuing bonds to raise the capital, ARCO and Exxon used internally available company funds. The IDC figure of X-4 does not represent actual out-of-pocket interest charges incurred by ARCO and Exxon. Instead, the IDC cost is based on the assumption that had the money been borrowed, ARCO and Exxon would have incurre X-4 in interest charges.

--The MMS allows inclusion of IDC in the depreciable capital investment figure when such costs are actual amounts clearly attributable and allocable to the project for which the money was borrowed and were incurred during the planning and construction phases of the project. The IDC also must be verifiable upon audit. In those cases where IDC cannot be attributed to a particular pipeline, MMS may, at its discretion, approve an amount provided the lessee submits a written request and provides adequate documentation supporting the proposed amount.

--ARCO and Exxon support inclusion of IDC by arguing that both the Financial Accounting Standards Board and the Internal Revenue Service required capitalization of the interest cost. However, ARCO and Exxon have not provided sufficient documentation detailing or illustrating how the IDC figure was calculated. Accordingly, the IDC figure is not included in the capital expenditure costs used to calculate yearly depreciation. The MMS will reconsider including IDC in the depreciable capital base if ARCO and Exxon submit sufficient documentation that more fully explains the proposed IDC figure.

<u>Inflation</u> -- ARCO and Exxon also claim that the value of the completed facilities is higher than the cumulative capital investment due to inflation during the long-term construction period. For this reason, ARCO and Exxon have inflated all capital investments prior to 1983 before including them in the depreciable base. ARCO and Exxon emphasize the time lag between initial construction and final completion of the pipeline as justification to request

inflation as a depreciable cost. However, long-term construction is in fact usual for major pipeline facilities, both onshore and offshore.

--The CDM, section 647.5A.3B, limits investment costs to those costs for real property and those delivered and installed costs for equipment or other facilities which are depreciable. Allowable investment costs are limited to those items which are an integral part of the pipeline (downstream from the point of measurement on the leasehold); these costs should not include items normally considered to be lease equipment.

--Inflation is not a depreciable asset, nor is it an integral part of the pipeline. Accordingly, inflation will not be allowed as a depreciable investment cost.

Expenses

° The CDM, section 647.5A.3B, limits operating expenses in the calculation of a transportation allowance to the following:

> Operating costs are those nondepreciable expenditures required to operate and maintain the pipeline system and shall be limited to the lesser of the following values: actual operating costs or 10 percent of the undepreciated initial or adjusted investment cost as of the beginning of the year for which the operating costs are being computed.

° Operating expenses (exhibits 15 through 30) are comprised of operating and maintenance (O&M) costs (exclusive of power costs), power costs, ad valorem taxes, overhead, incremental working capital, and allocated abandonment expense. The following is a discussion of each expense group.

O&M costs -- The O&M costs are comprised of pipeline O&M and compression-related O&M (exhibits 19 and 21). The expenses described for pipeline O&M and compression-related O&M costs are allowable costs in calculating the transportation allowance. ARCO and Exxon also include power costs in the pipeline O&M. Power costs necessary to operate pipeline equipment are allowable expenses. The total allowable pipeline O&M costs for 1983 and 1984 are X-4 and X-4 respectively, as shown on ARCO and Exxon's exhibit 17. The total allowable compression-related O&M costs for 1983 and 1984 are X-4 and X-4 respectively, as shown on ARCO and Exxon's exhibit 20.

Power costs -- ARCO and Exxon designate the following categories of power usage as compression-related power expenditures: compression, heating/cooling, vapor recovery (booster compression), electrical/control and automation, general drill site preparation, gas production costs, and dehydration. Based on the descriptions provided by ARCO and Exxon, the power costs associated with compression, heating/cooling, vapor recovery, electrical/control and automation, and general drill site preparation are directly allocable to the compression function; these costs may be included in the allowance calculation. However, the power costs associated with production and dehydration are costs attributable to normal lease equipment operation. The CDM, section 647.5A.3B, directs that approved investment and operating costs cannot include items normally considered to be lease equipment costs. ARCO and Exxon describe the production and dehydration costs as costs that include well operating costs, wireline work, and costs associated with operating tri-ethylene glycol dehydration equipment. The power supply costs associated with these functions cannot be included in the allowance calculation. Information on ARCO and Exxon's exhibit 24 indicate that no production and dehydration power costs have been included. Therefore, the total allowable power costs for 1983 and 1984 are X-4 and X-4, respectively, as shown on exhibit 24.

Ad valorem taxes -- Taxes imposed on transportation equipment (except income taxes) are an acceptable expense item. Exhibit 25 of the ARCO and Exxon submittal details all ad valorem taxes allocated to the Sheep Mountain Pipeline project. The total allowable ad valorem costs for 1983 and 1984 are X-4 and X-4, respectively, as shown in column 7 of ARCO and Exxon's exhibit 25.

Overhead -- The MMS allows actual overhead costs up to an amount equal to 10 percent of the operating costs. ARCO and Exxon have not submitted any actual cost data to support a claim for the overhead expense. Instead, they assume the overhead to be 10 percent of the sum of O&M costs, plus power costs, plus ad valorem taxes for each year. ARCO and Exxon representatives stated orally in the August 29, 1985, meeting that the expected actual overhead expenses were in excess of 10 percent of the operating costs. They allege that 10 percent of total operating costs is historically a conservative figure for overhead in oil and gas producing fields and is likely to be even more conservative for a CO_2 transportation operation requiring extensive engineering manpower. ARCO and Exxon object to the 10 percent ceiling on overhead as a rule applicable in all cases. However, they will accept a 10 percent overhead ceiling for the Sheep Mountain Pipeline transportation allowance if all compression-related costs are included.

--The MMS guidelines contained in the CDM, section 647.7.3E, and applicable to the period prior to March 1, 1988, establish a 10 percent ceiling for allowable overhead. Furthermore, the guidelines specify that MMS can request verification of overhead costs by requesting copies of the invoices. This policy has been upheld in the U.S. District Court for the District of Wyoming in the June 22, 1988, decision, The Shoshone Tribe, et al. v. Donald P. Hodel, et al. (No. C81-131 K). The Court found that general and administrative overhead costs may be deducted from royalty where the costs can be substantiated and only to the extent that the deduction does not exceed 10 percent of O&M.

--For the period prior to March 1, 1988, ARCO and Exxon will be limited to a 10 percent ceiling on overhead. Compression-related expenses will be allowed as part of the expenses against which the ceiling is applied.

Incremental working capital -- This expense is a theoretical expense and does not represent actual transportation costs. Therefore, the incremental working capital expense cannot be included as an expense item in computing the transportation allowance.

Abandonment expense -- It is not MMS policy to participate in abandonment expenses. Also, it is not MMS policy to remain associated with pipelines or plants should they be converted to other uses and not abandoned. ARCO and Exxon assert that the costs associated with abandoning the pipeline should be included in the transportation allowance. The proposal includes only those costs pertaining to the segments covered by right-of-way pipeline removal agreements. However, because ARCO and Exxon do not know how much additional pipeline length may be required to be removed, they request reservation of the right to make supplemental applications to include any future costs of abandonment.

--In determining allowances, MMS allows only reasonable, actual operating costs, depreciation, and a return on undepreciated capital investment. Costs specifically prohibited from deduction by lease terms, regulations, court decisions, and policy include those for compression, dehydration, gathering, and other expenses incidental to marketing, Federal and State income taxes, abandonment costs, actual and theoretical line losses, and costs that are not directly related to the transportation of lease production. These are all costs in which the lessor historically has not shared and, in many cases, are costs that are not relevant to the lessor's interest or responsibility. For these reasons as well as the fact that costs to abandon certain segments of the CO_2 pipeline are currently speculating and will not actually be incurred until many years in the future, MMS cannot approve the inclusion of an abandonment cost element in the allowance calculation.

Interest

° ARCO and Exxon calculated the interest component by using a "weighted-average prime-rate during construction" figure (exhibits 8, 31, and 32). The CDM, section 647.5A.3A, provides in part:

> . . . Unless otherwise justified, the prime interest rate in effect at the time of initial allowance approval should be used as the rate of allowable return on the depreciated investment. Once established, the rate will be continuous (fixed) over the life of the pipeline.

° Past MMS policy has been to use the prime interest rate (as published in the Wall Street Journal) in effect at the beginning of the period for which the initial allowance is granted. This rate then remains fixed for the remainder of the 20-year depreciable life. The interest rate on January 3, 1983, was 11 percent. The April 13 and January 5 draft decisions stated that this rate should be used as the rate of allowable return on the depreciated investment.

° The IBLA discussed the principles and philosophies behind the rate of return policy contained in the CDM in three pertinent cases involving the rate of return used to calculate processing and transportation allowances (IBLA 87-350, decided May 23, 1989; IBLA 89-299, decided October 26, 1989; and IBLA 88-158, decided June 28, 1990). In the May 23 decision, involving Phillips Petroleum Company (Phillips), IBLA rejected the prime rate used by MMS to calculate gas processing allowances at the Lee, Lusk, and Douglas processing plants and remanded the case to MMS for recalculation. However, the IBLA apparently rejected the prime rate selected in the Phillips case only because it was for a period other than the audit period under appeal. In the October 26 decision, involving transportation and washing allowances for Black Butte Coal Company (Black Butte), IBLA upheld MMS use of the prime interest rate but emphasized that a reasonable rate of return depends on economic conditions at the time involved. The IBLA concluded that Black Butte had not shown the assigned rate to be unreasonable. In the June 28 decision, involving Mobil Producing Texas & New Mexico, Inc. (Mobil), IBLA upheld usage of the prime rate in calculating a transportation allowance for CO_2 produced from the McElmo Dome Unit. The IBLA conclusions in the Phillips, Black Butte, and Mobil cases can be inferred to mean that the prime rate methodology applied to allowances prior to March 1, 1988, generally would be supported by IBLA if the prime rate chosen reflects the economic conditions for the time period involved.

° The IBLA has consistently upheld usage of a prime rate methodology as embodied in the CDM; MMS will continue to apply this methodology to allowances for the period prior to March 1, 1988. However, instead of using the prime rate as published in the Wall Street Journal MMS will use the prime rate as published by the Federal Reserve Board (Board), Federal Reserve Bank of Dallas. The prime rate data compiled by the Board represents an average of the rates of 29 banks located in major cities across the U.S. and thus should provide a sound basis for establishing the prime rate used for allowance purposes. Prime rates published by the Wall Street Journal are derived similarly but are not available for the same historical periods as are the Board data.

° The prime interest rate on January 1, 1983 (as compiled by the Board), was 11.5 percent. ARCO and Exxon will be required to use the prime interest rate of 11.5 percent to calculate the Sheep Mountain CO_2 transportation allowance.

Throughput

° ARCO and Exxon provided actual throughput figures for 1983 and 1984 (exhibits 33 and 34). These figures should be used to calculate the actual 1983 and 1984 transportation allowance.

Two-Year, Loss Roll-Forward Provision

° In the original August 29, 1985, allowance request, ARCO and Exxon proposed using a 7-year transportation allowance reporting period. In the April 13 draft decision, MMS required ARCO and Exxon to use a 1-year reporting period for transportation allowances. In the June 12, 1987, allowance request, ARCO and Exxon proposed using a 2-year allowance accounting period as an alternative to the original proposal of a 7-year transportation allowance accounting period. ARCO and Exxon selected the 2-year accounting period because it ". . . will reduce the number of hours required on both the applicants' and the Federal Government's part to recalculate and monitor the transportation allowance." However, the ARCO and Exxon proposal also includes a "loss roll-forward provision" whereby actual transportation costs not captured in a given 2-year period would be carried forward so as to enable such costs to be potentially recouped in future years.

° ARCO and Exxon contend that low throughput was normal during the early years of pipeline operation because demand for CO_2 in west Texas was initially low. These low throughputs combined with high actual transportation costs resulted in transportation expenses that exceed the value of the product during the initial period of the project. ARCO and Exxon claim that this is a potential problem throughout the life of the project because of wide variations in CO_2 consumption demands. They also claim that if the loss roll-forward provision is not an integral part of the MMS-approved transportation allowance, the allowance would "unlawfully penalize" the lessee for commencing a major CO_2 production and transportation project.

° The MMS policy is to grant allowances on a yearly basis based on the lessee's reasonable, actual costs incurred to transport lease production.

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Cap on Transportation Allowances

° Historical MMS policy has been to limit transportation allowances for onshore leases to 50 percent of the value of the product as specified in the CDM, section 647.5.3E. If a lessee believed it was entitled to relief from this limitation, MMS had required the lessee to specifically request, in writing, an exception to the limitation. However, in cases where a lessee could demonstrate that unusual circumstances warranted relief from the 50 percent limitation, MMS has granted exceptions to the allowance limitation.

° ARCO and Exxon have adequately demonstrated that transportion of Sheep Mountain CO_2 occurs under unusual circumstances and that the costs of transportation are in excess of the 50 percent limitation the first few years. Given the uniqueness of the commodity and the atypical operational constraints of the pipeline, ARCO and Exxon may deduct actual transportation costs not to exceed 99 percent of the value of the CO_2.

Scope of Transportation Allowance

° In the April 13 draft decision, MMS advised ARCO and Exxon that the allowance granted will cover transportation costs from Sheep Mountain to the individual contract delivery points at or near the various tertiary recovery units in west Texas. In the June 12, 1987, submittal to MMS, ARCO and Exxon contend that ". . . while the transportation allowance will pertain only to the Sheep Mountain CO_2 Pipeline, all costs incurred in the delivery of CO_2 from an outlet on the Sheep Mountain CO_2 Pipeline to the ultimate point of connection with the inlet facilities on any given consuming unit should be fully deductible from Federal royalty payments if such inlet facilities are designated as the contractual change of title or delivery point."

° The MMS policy is to allow all reasonable actual transportation costs incurred by the lessee to move production off the lease to the point of first sale or title transfer.

CONCLUSIONS

Depreciation

Pipeline capital -- The MMS bases allowable depreciation on the actual out-of-pocket costs incurred for property and equipment (including delivery and installation) integral to the pipeline. Exhibit 10 of the ARCO and Exxon submittal shows X-4 of spent capital for the pipeline. This figure must be reduced by the cost incurred to purchase land for the Clovis Operation Center.

Salvage value -- Although a 10 percent salvage value is normally required by MMS, ARCO and Exxon have provided sufficient justification to support their claim for a zero salvage value. If the pipeline is later deemed to be salvageable, MMS must be notified.

Compression-related capital investment -- The MMS will allow compression costs, including all costs relative to the installation of power facilities to operate the compressors, in the transportation allowance calculation. No dehydration costs shall be included.

IDC -- The MMS recognizes IDC as part of the depreciable capital investment base on which the transportation allowance rate is calculated. ARCO and Exxon have not provided adequate documentation supporting their proposed IDC figure; therefore, the IDC figure is not included in the depreciable capital base used to calculate yearly depreciation. The MMS will reconsider including IDC in the depreciable capital base if ARCO and Exxon submit sufficient documentation that more fully explains the proposed IDC figure.

Inflation -- Inflation is not considered by MMS to be a depreciable asset. Inflation of capital prior to 1983 will not be allowed in computing the transportation allowance.

Expenses

O&M -- The pipeline O&M costs (including the power necessary to operate the pipeline) and all compression-related O&M costs are acceptable operating costs.

Power costs -- The compression-related power costs requested by ARCO and Exxon will be allowed in the transportation allowance computation.

Ad valorem taxes -- The ad valorem taxes requested by ARCO and Exxon will be allowed in the transportation allowance computation.

Overhead -- The MMS has consistently applied a 10 percent ceiling on overhead in all transportation allowances, both onshore and offshore, for many years. The MMS considers this 10 percent ceiling a reasonable allocation of overhead costs. The 10 percent ceiling rate will be used to calculate the Sheep Mountain Pipeline transportation allowance for the period prior to March 1, 1988. During audit, ARCO and Exxon may be required to substantiate this 10 percent figure. As discussed above, compression-related costs will be included in the costs against which the 10 percent ceiling is computed.

Incremental working capital -- The incremental working capital expense proposed by ARCO and Exxon is a theoretical expense and does not represent

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an actual transportation cost. This expense will not be allowed in the transportation allowance computation.

Abandonment expense -- Costs of abandoning pipelines or other transportation-related facilities are not allowable transportation costs. Current and/or future liability for abandonment expenses are a cost to be borne solely by the lessee. The Sheep Mountain Pipeline transportation allowance shall not include the costs for abandoning the pipeline.

Interest

° The MMS historically has used a prime rate methodology for calculating transportation allowances. The Sheep Mountain transportation allowance for the period prior to March 1, 1988, will be calculated using this same method. The interest expense must be based on the prime interest rate in effect at the beginning of the period for which the initial allowance is granted based on the prime interest rate compiled by the Federal Reserve Board. This rate was 11.5 percent on January 1, 1983.

Two-Year, Loss Roll-Forward Provision

° The MMS and its predecessor Agency historically have granted transportation allowances on a yearly basis based on actual costs incurred by the lessee for production transported during that year. The MMS will continue to require ARCO and Exxon to calculate and report the Sheep Mountain CO_2 transportation allowance on a yearly basis. In addition, MMS will not allow any loss roll-forward provision. The MMS does not believe that a yearly allowance without a loss roll-forward provision unlawfully penalizes the lessee. It has been the policy of MMS to allow only reasonable actual costs up to the established limit calculated on a yearly basis. The MMS will not approve any excess cost to be recouped in subsequent years.

Cap on Transportation Allowance

° **The Sheep Mountain CO_2** transportation allowance will not be subject to the 50 **percent limitation.** ARCO and Exxon may deduct actual transportation costs **not to exceed 99** percent of the value of the CO_2.

✓

Scope of Transportation Allowance

° The MMS policy is to allow all reasonable actual transportation costs incurred by the lessee to move lease production off-lease to the point of first sale or title transfer. If CO_2 production from Sheep Mountain is transported along pipeline segments other than the Sheep Mountain Pipeline prior to the point of first sale or title transfer, MMS will allow transportation costs associated with these segments to be deducted. These

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costs will be subject to the same qualifications and limitations as the costs incurred on the Sheep Mountain Pipeline. However, the total cost to move production from the Sheep Mountain Unit through the Sheep Mountain Pipeline, including any additional pipeline segments not on the Sheep Mountain Pipeline, cannot exceed 99 percent of the value of the product.

Calculation of Sheep Mountain CO_2 Transportation Allowance

° An example detailing the method ARCO and Exxon should use to calculate the Sheep Mountain CO_2 transportation allowance is provided for illustrative purposes only. The example uses the pipeline capital investment figure of x-4 as provided by ARCO and Exxon. This figure must be adjusted to exclude the cost to purchase land for the Clovis Operation Center. In addition, ARCO and Exxon must recalculate depreciation and return on investment based on the adjusted capital investment figure.

° Appendix 1 is a sample of a 20-year straight-line depreciation schedule for the Sheep Mountain CO_2 Pipeline. An investment figure of x-4 [x-4 (pipeline) and x-4 (compression)], a salvage value of zero, and a prime interest rate of 11.5 percent were used, as previously discussed.

° Appendix 2 provides a summary of the MMS-allowable operating costs and the 10 percent overhead calculation.

° Appendix 3 shows the method of calculating transportation allowance rates. For 1983 and 1984, the sample calculated transportation allowance rates are x-4/Mcf and x-4/Mcf, respectively. These allowance rates will change when the allowance is recalculated to exclude the cost to purchase land for the Clovis Operation Center.

° Transportation allowances cannot exceed 99 percent of the product's value at the nearest competitive sales point.

° To deduct a transportation allowance, ARCO should follow the standard two-line entry format required by the MMS Auditing and Financial System as outlined in the September 1986 issue of the Payor Handbook, Section 3.9, "Reporting Allowances." If further clarification is needed regarding the Form MMS-2014 reporting requirements, ARCO may contact personnel in the MMS Lessee Contact Branch.

° ARCO and Exxon should recalculate the allowance rates for 1983 and 1984 using the revised capital investment figure and should submit actual cost data for Calendar Years 1985 through 1987 and for January and February 1988 following the approved method outlined above. Allowances for the period subsequent to February 1988 will be calculated in accordance with the new allowance regulations which became effective March 1, 1988.

Appendix 1

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SAMPLE DEPRECIATION SCHEDULE FOR SHEEP MOUNTAIN CARBON DIOXIDE PIPELINE BASED ON THE INITIAL ALLOWABLE CAPITAL INVESTMENT OF X-4 ERO SALVAGE VALUE, AND 20-YEAR STRAIGHT-LINE DEPRECIATION

Allowance Year	Beginning of Year Undepreciated Investment	Annual Depreciation[2]	End of Year Undepreciated Investment	Return on Investment[3]
1983	$			
1984				
1985				
1986				
1987				
1988				
1989				
1990				
1991				
1992		X-4		
1993				
1994				
1995				
1996				
1997				
1998				
1999				
2000				
2001				
2002				
2003				

[1] This figure must be adjusted to exclude the cost to purchase land for the Clovis Operation Center.

[2] X-4 /20 years.

[3] Beginning of year undepreciated investment times prime interest rate of 11.5 percent.

Appendix 2

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OPERATING EXPENSES

	1983	1984
Operating and Maintenance Expenses		
Pipeline		
Compression		
Power Costs		
Ad Valorem Tax[4]	X-4	
Total Allowable Operating Costs		
Overhead (10% of Allowable Costs)		
Total Operating Expenses	X-4	

[1]From ARCO Oil and Gas Company (ARCO) and Exxon Company, U.S.A.'s (Exxon) exhibit 17.

[2]From ARCO and Exxon's exhibit 20

[3]From ARCO and Exxon's exhibit 24

[4]From ARCO and Exxon's exhibit 25.

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SAMPLE TRANSPORTATION ALLOWANCE CALCULATION SHEEP MOUNTAIN CARBON DIOXIDE PIPELINE 1983 AND 1984

$$\text{Transportation Allowance} = \frac{\text{Depreciation}^{1}\ (D) + \text{Operating Expenses}^{2}\ (E) + \text{Return on Investment}^{1}\ (I)}{\text{Throughput}}$$

1983 /Mcf*

X-4

1984 /Mcf*

*The transportation allowance cannot exceed 99 percent of the value of the product at the point of sale.

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[1] Depreciation and return on investment figures from Appendix 1 with the provision that the capital investment figure must be adjusted to exclude the cost to purchase land for the Clovis Operation Center.

[2] Operating expenses from Appendix 2.

Chook 7/12/91

United States Department of the Interior

TAKE PRIDE IN AMERICA

MINERALS MANAGEMENT SERVICE
WASHINGTON, DC 20240

FEB - 5 1992

ENCLOSURE AND APPENDICES
CONTAIN COMPANY PROPRIETARY
INFORMATION FOR RELEASE ONLY
TO ARCO OIL AND GAS COMPANY

CERTIFIED MAIL--
RETURN RECEIPT REQUESTED

Mr. E. M. Pringle
ARCO Oil and Gas Company
P.O. Box 1610
Midland, Texas 79702

Dear Mr. Pringle:

Through various oral and written presentations, ARCO Oil and Gas Company (ARCO) and Exxon Company, U.S.A. (Exxon), jointly requested approval of a transportation allowance for carbon dioxide (CO_2) produced from the Sheep Mountain Unit (Sheep Mountain), Huerfano County, Colorado. On its own behalf, ARCO also requested a royalty valuation procedure for the subject production.

The Minerals Management Service has reviewed all information submitted. The valuation of ARCO's CO_2 produced prior to March 1, 1988, will be determined as follows: The prices established in the arm's-length contracts at the Seminole-San Andreas, Wellman, GMK, and Denver Units will establish the value for royalty purposes for that allocable portion of CO_2 from Sheep Mountain delivered to each unit. The price established in the non-arm's-length contract for the Sable Unit is comparable to prices in other contemporaneous arm's-length contracts for the sale of CO_2 and can be used as the basis of value for royalty purposes for that allocable portion of Sheep Mountain CO_2 sold to the Sable Unit. The value for royalty purposes of CO_2 supplied in kind to the Seminole-San Andreas, Wasson ODC, and Willard Units will be based on the prices established in the principal CO_2 sales and purchase contracts in existence at these units. For Sheep Mountain CO_2 delivered to the Seminole-San Andreas Unit, but subject to ARCO's exchange agreement, the value for royalty purposes will be that value established in the Seminole-San Andreas Unit principal CO_2 sales and purchase contract.

The transportation allowance for the period prior to March 1, 1988, must be determined under the following conditions: Capitalized and expensed compression costs may be included in computing the transportation allowance. Dehydration costs cannot be included in the transportation allowance calculation. The prime interest rate as compiled by the Federal Reserve Board of Dallas will be used to calculate the Sheep Mountain CO_2 transportation allowance. Interest during construction (IDC) cannot be included in the depreciable capital base used to calculate yearly depreciation until ARCO and Exxon provide adequate documentation supporting their proposed IDC figure. Abandonment costs for the Sheep Mountain CO_2 pipeline cannot be included in the allowable expenses. The Sheep Mountain CO_2 transportation allowance will not be subject to the 50-percent limitation. ARCO and Exxon may deduct actual transportation costs (calculated in accordance with this letter) not to exceed 99 percent of the value of the CO_2.

This decision applies only to production occurring prior to March 1, 1988. Production occurring on or after March 1, 1988, must be valued in accordance with the regulations at 30 CFR 206 (1990).

The enclosed "Summary of Findings and Conclusions" provides the basis for this determination.

You have the right to appeal this determination in accordance with the provisions of 30 CFR 290 (1990), and 43 CFR §§ 4.411 and 4.413 (1990). Any appeal taken will be to the Interior Board of Land Appeals, Office of Hearings and Appeals, Office of the Secretary, and the notice of appeal must be filed in my office within 30 days from the date of receipt of this letter.

If you have any questions, please call Mr. Donald T. Sant, Deputy Associate Director for Valuation and Audit, at (303) 231-3899.

Sincerely,

/s/ S. Scott Sewell

S. Scott Sewell
Director

Enclosure

Enclosure

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ROYALTY MANAGEMENT PROGRAM
ROYALTY VALUATION AND STANDARDS DIVISION

Summary of Findings and Conclusions on Sheep Mountain Carbon Dioxide Valuation and Transportation Allowance

BACKGROUND

The Sheep Mountain Unit (Sheep Mountain) is a carbon dioxide (CO_2) field in Huerfano County, Colorado. ARCO Oil and Gas Company (ARCO) is the operator of the unit and lessee of record for nearly 100 percent of the unitized land.

Exxon Company, U.S.A. (Exxon), has an "agreement on principles" with ARCO, dated May 1, 1981, whereby Exxon receives 50 percent of the CO_2 production from the Sheep Mountain Unit (delivered in the field) in exchange for Exxon's capital investments in the Sheep Mountain field facilities and the Sheep Mountain Pipeline.

In August 1985, ARCO requested a transportation allowance and royalty valuation method for the subject CO_2. Numerous submittals and meetings, listed below in chronological order, followed:

Date	Event
August 29, 1985	Meeting held between ARCO, Exxon, and Minerals Management Service (MMS) representatives; joint submittal of transportation allowance request is provided to MMS.
April 17, 1986	ARCO submits letter proposing a valuation methodology for Sheep Mountain CO_2 production.
April 13, 1987	The MMS provides ARCO with a draft decision detailing a valuation and transportation allowance method.
June 12, 1987	ARCO and Exxon jointly submit additional information relative to the transportation allowance calculation.
June 17, 1987	Meeting held between ARCO, Exxon, and MMS representatives to discuss the April 13 draft decision and transportation allowance information provided in the June 12 joint submittal.

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Date	Event
December 12, 1989	Meeting held between ARCO, Exxon, and MMS representatives to discuss in further detail several transportation allowance issues.
January 5, 1990	The MMS provides ARCO with a second draft decision detailing a valuation and transportation allowance method.
March 8, 1990	Meeting held between ARCO, Exxon, and MMS representatives to discuss the January 5 draft decision. ARCO and Exxon provide MMS with a joint submittal containing additional discussion of transportation allowance issues.

The valuation procedure and transportation allowance calculation described in the following sections incorporate all information presented orally at the meetings and in writing through the various submittals. The decision pertains only to CO_2 produced prior to March 1, 1988, in accordance with regulations at 30 CFR § 206.103 (1987) and MMS policy in effect at that time. Valuation and transportation allowances for production on or after March 1, 1988, should be computed in accordance with 30 CFR §§ 206.152, 206.156, and 206.157 (1990).

SHEEP MOUNTAIN CO_2 VALUE

Findings

Disposition of Production

- The CO_2 is transported through the Sheep Mountain Pipeline to oil fields in the Permian Basin of west Texas where it is used in tertiary oil recovery projects. The Sheep Mountain Pipeline is operated by ARCO Pipe Line Company. The portion of the pipeline between Sheep Mountain and the Bravo Dome CO_2 Unit interconnection in New Mexico is owned equally by ARCO and Exxon. The remainder of the pipeline from the Bravo Dome CO_2 Unit interconnection to west Texas is owned 35 percent by ARCO, 35 percent by Exxon, and 30 percent by Amerada Hess Corporation. All cost information submitted to MMS is relative only to that portion of the pipeline from Sheep Mountain to west Texas that is owned by ARCO and Exxon.

- The point of royalty measurement, designated by the Bureau of Land Management, is the Sheep Mountain origin meter station. Sales points coincide with the various delivery points at the tertiary recovery projects in west Texas.

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- ARCO disposes of its share of Sheep Mountain CO_2 under nine contracts. Four of these contracts are arm's-length, one is non-arm's-length, three are in-kind supply agreements, and one is an exchange agreement.

Value Under Arm's-Length Contracts

- ARCO supplies Sheep Mountain CO_2 to the Seminole-San Andreas, Wellman, GMK, and Denver Units under arm's-length sales contracts.

- The MMS normally accepts the prices established in arm's-length sales contracts as representative of value for royalty purposes. Upon review, the sales prices established in each of the four contracts were found to be acceptable for royalty value.

Value Under Non-Arm's-Length Contracts

- ARCO supplies Sheep Mountain CO_2 to the Sable Unit under a non-arm's-length sales contract.

- The MMS may accept non-arm's-length contracts as the basis for establishing value for royalty purposes if the lessee can demonstrate that those contracts are comparable to arm's-length contracts executed at approximately the same time for like-quality products in the same field or area. The MMS determined that the price established in ARCO's non-arm's-length sales contract at the Sable Unit meets the above criteria and, therefore, is acceptable to MMS as the basis for royalty determinations for that portion of Sheep Mountain CO_2 sold under this contract.

Value Under In-Kind Agreements

- ARCO supplies Sheep Mountain CO_2 to the Seminole-San Andreas, Wasson ODC, and Willard Units under in-kind agreements.

- In every tertiary recovery unit, each working interest owner has a responsibility to pay for or to supply its unit participation share of the total volume of CO_2 used in unit operations. In-kind supply agreements allow a working interest owner in a tertiary recovery project to supply its share of the required CO_2 "in kind" in lieu of sharing in the cost of purchasing CO_2 for the project. In units where a working interest owner cannot supply CO_2 in kind, the unit operator purchases CO_2 and charges the working interest owner's account for the value of CO_2 purchased. Additional CO_2 used in these units is purchased outright by each unit operator. The contract under which the operator purchases CO_2 on behalf of working interest owners that are not able to supply their own CO_2 in kind is considered by MMS as the principal CO_2 sales and purchase contract for that unit. ARCO proposes using the principal CO_2 sales and purchase contracts in

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existence at each unit as the basis for royalty determinations for CO_2 provided in kind to those units.

- The three principal CO_2 sales and purchase contracts for the Seminole-San Andreas, Wasson ODC, and Willard Units are arm's-length contracts. Therefore, the prices cited in these arm's-length contracts are acceptable as value for royalty purposes. ARCO should value Sheep Mountain CO_2 furnished under in-kind supply agreements to the Wasson ODC, Willard, and Seminole-San Andreas Units on the basis of the prices cited for CO_2 under the principal CO_2 sales and purchase contracts at each unit.

Value Under Exchange Agreements

- The final contract under which ARCO disposes of Sheep Mountain CO_2 is an exchange agreement with X-4. ARCO delivers Sheep Mountain CO_2 to the Seminole-San Andreas Unit for X-4 account in exchange for X-4 delivery of Cortez Pipeline CO_2 to the East Vacuum Grayburg-San Andreas Unit (East Vacuum Unit) for ARCO's account. ARCO proposes using the principal East Vacuum Unit CO_2 sales and purchase agreement as the basis for royalty value for the CO_2 delivered from Sheep Mountain for X-4 account at the Seminole-San Andreas Unit.

- ARCO contends in its letter of April 17, 1986, that ". . . the consideration being given by X-4 to ARCO for the Sheep Mountain Unit CO_2 delivered to Mobil under the Exchange Agreement is a volume of CO_2 equal in value to what ARCO would have otherwise had to pay pursuant to the principal Carbon Dioxide Sale and Purchase Agreement at the East Vacuum Unit. Therefore, the price paid under the principal Carbon Dioxide Sale and Purchase Agreement in the East Vacuum Unit is the best measure of the market value of the CO_2 produced at Sheep Mountain and exchanged to X-4 for X-4 account in West Texas."

- The MMS does not agree that the East Vacuum Unit agreement is the best measure of the market value of Sheep Mountain CO_2 exchanged under the X-4 ARCO exchange agreement. The exchange agreement is an operational agreement for ARCO's and X-4 convenience. The "value" that ARCO and X-4 gain from this exchange does not necessarily represent the value of CO_2 for royalty purposes.

- Under the lease terms, regulations, and enabling laws, the Secretary of the Interior has broad regulatory authority to determine the "reasonable value" of production. The Secretary is not limited to the actual "value" received in order to determine the value of production for royalty purposes. The value to the lessee is not always the value for royalty purposes. Because other Sheep Mountain CO_2 is sold at the Seminole-San Andreas Unit (where ARCO's Sheep Mountain CO_2 is exchanged), such a sale establishes a reasonable value for Sheep Mountain CO_2. Therefore, ARCO should use the price paid for Sheep Mountain CO_2 under the arm's-length principal Seminole-San Andreas Unit CO_2 sales and purchase agreement to establish the royalty value for that portion of Sheep Mountain CO_2 exchanged at the Seminole-San Andreas Unit with X.Y

Timing of Royalty Payments

- Applicable laws, regulations, and lease terms specifically require that royalty is due on production removed or sold from the leased lands. For each of the valuation scenarios discussed above, MMS will require royalties on the volume of CO_2 leaving Sheep Mountain, regardless of when ARCO receives final settlement.

Conclusions

- The valuation of ARCO's CO_2 produced prior to March 1, 1988, is subject to the provisions of 30 CFR § 206.103 and MMS policy in effect at that time.

- The prices established in the arm's-length contracts at the Seminole-San Andreas, Wellman, GMK, and Denver Units will establish the value for royalty purposes for that allocable portion of CO_2 from Sheep Mountain delivered to each unit.

- The MMS has determined that the price established in the non-arm's-length contract for the Sable Unit is comparable to prices in other contemporaneous arm's-length contracts for the sale of CO_2. Accordingly, the non-arm's-length contract price can be used as the basis of value for royalty purposes for that allocable portion of Sheep Mountain CO_2 sold to the Sable Unit.

- The value for royalty purposes of CO_2 supplied in kind to the Seminole-San Andreas, Wasson ODC, and Willard Units will be based on the prices established in the principal CO_2 sales and purchase contracts in existence at these units. The MMS has determined that the prices quoted in these three principal contracts are acceptable for royalty value purposes.

- For Sheep Mountain CO_2 delivered to the Seminole-San Andreas Unit, but subject to the exchange agreement between ARCO and X.Y the value for royalty purposes will be that value established in the Seminole-San Andreas Unit principal CO_2 sales and purchase contract.

- For each contract under which ARCO delivers Sheep Mountain CO_2 to a west Texas tertiary recovery unit, the royalty value at the point of royalty settlement (the Sheep Mountain origin meter) shall be the value as defined above, less the MMS-approved Sheep Mountain Pipeline transportation allowance. Each royalty value determined by this method shall be applied to a proportional volume of the CO_2 at the Sheep Mountain origin meter based on the delivered volumes for the same month. Volumes allocated for each value will be determined by dividing each individual west Texas monthly delivery by the total monthly west Texas deliveries to arrive at a percentage allocation. A hypothetical example for month A is provided below.

Measured CO_2 Production at Sheep Mountain Origin Meter Station, Month A:	5,000 Mcf	
ARCO's West Texas Deliveries During Month A	Volume	Percent
Deliveries to Unit B	100 Mcf	10
Deliveries to Unit C	500 Mcf	50
Deliveries to Unit D	400 Mcf	40
Total West Texas Deliveries	1,000 Mcf	100

MMS-Approved Values

Unit B	\$2.00/Mcf
Unit C	\$1.75/Mcf
Unit D	\$1.50/Mcf

Calculation of Royalty Value

Unit	Arm's-length price		Percent of volume leaving Sheep Mountain	Value for royalty purposes
B	\$2.00	x	10 percent of 5,000	\$1,000
C	\$1.75	x	50 percent of 5,000	\$4,375
D	\$1.50	x	40 percent of 5,000	\$3,000

These amounts represent the value of all Sheep Mountain CO_2 produced during month A.

- By regulation, value shall never be less than the *gross proceeds* accruing, or which could accrue, to the lessee for the sale or disposition of Sheep Mountain CO_2.

SHEEP MOUNTAIN CO_2 TRANSPORTATION ALLOWANCE

Findings

- Information relative to the calculation of the Sheep Mountain CO_2 transportation allowance was jointly submitted by ARCO and Exxon in letters dated August 29, 1985; June 12, 1987; and March 8, 1990.

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Specific information was detailed in exhibits 1 through 34 of the August 29, 1985, letter.

- The transportation allowance costs submitted by ARCO and Exxon are separated into four major components: depreciation, expenses, interest, and throughput. Each major component will be discussed separately.

- The following discussion pertains only to the calculation of transportation allowances for the period prior to March 1, 1988. The calculation of transportation allowances on or after March 1, 1988, must be in accordance with the requirements of 30 CFR §§ 206.156 and 206.157.

Depreciation

- The items that comprise the depreciation component (exhibits 6 through 14) include pipeline capital, salvage value, compression-related capital investment, interest during construction (IDC), and inflation. The following is a discussion of each item.

Pipeline capital -- ARCO and Exxon request X-4 in capital investment costs for constructing the pipeline. This figure includes costs for materials, labor, engineering, feasibility, environmental assessments, construction, and inspection. Capital investment costs that are directly allocable and attributable to the physical construction of a pipeline are generally accepted by MMS as part of the depreciable capital. However, pipeline capital investment costs for the Clovis Operations Center include costs for "purchase of land" upon which the operations center is built. Land is not a depreciable asset and is not properly included in the undepreciated capital investment. The capital investment cost of X-4 requested by ARCO and Exxon must be reduced by the purchase price of the land.

Salvage value -- ARCO and Exxon used a zero salvage value in calculating the depreciation. The Conservation Division Manual (CDM), a procedural guide of the U.S. Geological Survey (USGS), predecessor Agency to MMS, directs that a salvage value of 10 percent should be applied to tangible items when determining the depreciable investment cost to be used in allowance calculations, unless the lessee can justify a different salvage value. In justifying their zero salvage value, ARCO and Exxon claim that "[n]o known pipeline transportable commodities have significant supply at one end of the pipeline and demand at the other, so use of the line after depletion of Sheep Mountain is unlikely." In addition, ARCO and Exxon argue that after the depreciation period, the value of the 20-year-old equipment is estimated to be less than the cost to move it to a useful location. The MMS considers this acceptable justification and will allow a salvage value of zero. However, if it becomes apparent in the future that the pipeline will be salvaged or used for other purposes, MMS would no longer accept a zero salvage value.

Compression- and dehydration-related capital investment -- Five drill sites were constructed at Sheep Mountain; each containing a conditioning plant capable of heating, dehydrating, and compressing the CO_2 produced from the various wells drilled from each site. Included in the depreciation component of the original request is compression-related capital associated with these conditioning plants, including the equipment and installation costs for the heaters, dehydrators, and compressors and the costs allocated to the electrical power supply system and the electrical/control system necessary to operate this equipment. ARCO and Exxon assert that compression is essential to transport Sheep Mountain CO_2 to west Texas and is not a marketing requirement. ARCO and Exxon argue that MMS draft decisions are premised on the assumption that the compression function at Sheep Mountain is indistinguishable from typical compression functions performed by lessees to condition hydrocarbon gas for marketing.

--The point at which compression occurs is significant to the issue of whether to allow compression costs in the transportation allowance. Compression occurring prior to the point of royalty measurement is considered by MMS as necessary to place production in marketable condition and is a function to be performed at no cost to the lessor. The regulation at 43 CFR § 3162.7-1(a) (1987), "Disposition of production," stipulates that the lessee shall put into marketable condition, if economically feasible, all oil, other hydrocarbons, gas, and sulphur produced from the leased land. This regulation applies to CO_2 under the term "gas."

--The Notice to Lessees and Operators No. 1 (NTL-1), "Procedures for Reporting and Accounting for Royalties," provides in pertinent part under Section III, "Gas and Associated Liquids Production, Sales, and Royalty Requirements":

> . . . Under no circumstances will the royalty value be computed on less than the gross proceeds accruing to the operator from the sale of such leasehold production. Gross proceeds include, but are not limited to, tax reimbursements and payments to the operator for gathering, measuring, compressing, dehydrating, or performing other services necessary to market the production. Likewise, no deduction will be allowed for the cost which an operator occurs [sic] by reason of placing the gas in a marketable condition as an operator is obligated to do so at no cost to the lessor.

The preceding statement is primarily concerned with gross proceeds. However, it is very explicit that gathering, dehydrating, and compressing

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CO_2 are considered part of the activities to be conducted by the lessee at no cost to the lessor.

--The CDM addresses the lessee's responsibility to make lease production marketable. The CDM, section 647.2.3A, directs in pertinent part:

> The lessee is obligated to place lease production in marketable condition without deduction of costs for measuring, compressing, or otherwise conditioning the gas for market. Under no circumstances will royalty be computed on less than the gross proceeds accruing to the lessee from the sale of leasehold production.

--Decisions by the Director, USGS, and the U.S. District Court for the District of Columbia in The California Company v. Secretary of the Interior (No. 16132), August 10, 1961, have upheld the principle that the lease operator is obligated to perform necessary dehydration and compression operations.

- On March 8, 1991, the Interior Board of Land Appeals (IBLA), addressed Exxon Corporation's appeal of a denial by MMS to allow inclusion of dehydration costs in a transportation allowance for production transported to the Shute Creek gas processing plant (IBLA 86-626). In this decision, IBLA determined that MMS must consider the purpose of dehydration in determining whether an allowance is proper. In the Shute Creek case, IBLA found that dehydration at the central dehydration facility serves only one purpose: transportation. The gas processing plant had to be located 40 miles distant because of environmental constraints. If the gas processing plant was closer to the field, the central dehydration facility would not have been built. The IBLA concluded that dehydration costs for the Shute Creek case were allowable transportation costs.

- The CO_2 produced at Sheep Mountain is moved to drill-site conditioning plants located within the unit where it is heated, dehydrated, compressed, cooled, and metered prior to moving the pipeline origin meter station. In order to determine whether compression and dehydration at Sheep Mountain should be included in the transportation allowance calculation, MMS must consider what purpose these functions serve.

- ARCO and Exxon contend that the compression equipment at Sheep Mountain is only used to place and maintain the CO_2 in a supercritical phase, thereby allowing the most efficient transportation through the Sheep Mountain Pipeline. Additionally, ARCO and Exxon contend that the west Texas CO_2 market does not dictate the pressure needed for transportation as evidenced by the fact that several west Texas purchasers further increase the delivery pressure to meet their individual project requirements. For these reasons, ARCO and Exxon assert that the compression is an integral and necessary part

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of transportation and is not a marketing requirement. Based on the evidence presented, the compression function at Sheep Mountain does not serve the purpose of conditioning the gas for market. In accordance with the directives established by the IBLA in the Shute Creek case, ARCO and Exxon may include compression costs in the Sheep Mountain transportation allowance calculation.

° A typical Sheep Mountain CO_2 delivery contract for west Texas specifies that the CO_2 shall not contain any free water or more than 30 pounds of water per 1,000 Mcf at 14.7 psia and 60 °F. In order to meet these contract specifications, the CO_2 produced at Sheep Mountain must be dehydrated. Thus, dehydration clearly serves the purpose of placing Sheep Mountain CO_2 in marketable condition. Applicable regulations, court cases, and lease terms require the lessee to absorb all costs necessary to condition the production for market. No dehydration costs shall be included in the Sheep Mountain transportation allowance calculation.

° ARCO and Exxon request X.4 in capital investment costs for compression-related capital (exhibit 10). Exhibit 14 describes the types of expenditures and the portion of these expenditures allocated to the compression function. Capital investment costs that are directly allocable and attributable to compression-related equipment are generally accepted by MMS as part of the depreciable capital. However, if these costs include any costs associated with the dehydration function, the capital investment figure must be reduced by such costs.

<u>IDC</u> -- ARCO and Exxon argue that because construction of the transportation facilities was a relatively long-term effort, the real cost of installing the facilities exceeded the as-spent investment capital. ARCO and Exxon claim that money tied up in the facilities could have been utilized in other investments and, therefore, have included IDC as part of the depreciable capital. ARCO and Exxon contend that capitalization of interest costs recognizes that interest costs are an integral part of the costs necessary to bring an asset to the condition necessary for its intended use.

--When a company uses borrowed capital to finance construction of a facility, MMS policy will permit an interest charge separate from the rate of return on undepreciated capital in calculating transportation allowances subject to MMS audit and approval. However, this interest charge is permitted only under the following circumstances:

(1) When, during the development period of a project, interest incurred on a loan for construction costs that are integral to, or directly allocable and attributable to, transportation facilities is properly capitalized and thus becomes part of the basis for undepreciated capital upon which a rate of return is later applied; or

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(2) When interest is incurred on loans for routine operating and maintenance expenses.

--Conversely, interest charges will generally not be permitted under the following circumstances:

(1) When the lessee attempts to claim, during the production phase of the project, interest payments for loans on capitalized items (this is not permitted because a separate rate of return is applied against the remaining undepreciated capital);

(2) When some part of the interest capitalized during the development phase is not related to borrowed capital applied to construction (the amount of interest that may be capitalized is limited to the interest charge that would have been avoided if expenditures for the transportation facility had not been made); or

(3) When the interest claimed in the capitalized base is otherwise not directly allocable or attributable to the transportation facility.

--If a company issues bonds to raise money for capital investment instead of borrowing the capital, the corresponding interest charge capitalized during the development phase of the transportation facility may be permitted in the transportation allowance calculation but is limited to the interest on only that part of the bond proceeds applied to construction of that facility. In such instances, the company must provide, upon request, an allocation schedule demonstrating disposition of bond proceeds and interest corresponding to each disposition.

--The explanation of IDC provided in ARCO and Exxon's exhibit 6 indicates that instead of borrowing money to construct the Sheep Mountain Pipeline or issuing bonds to raise the capital, ARCO and Exxon used internally available company funds. The IDC figure of X.4 does not represent actual out-of-pocket interest charges incurred by ARCO and Exxon. Instead, the IDC cost is based on the assumption that had the money been borrowed, ARCO and Exxon would have incurred X.9 in interest charges.

--The MMS allows inclusion of IDC in the depreciable capital investment figure when such costs are actual amounts clearly attributable and allocable to the project for which the money was borrowed and were incurred during the planning and construction phases of the project. The IDC also must be verifiable upon audit. In those cases where IDC cannot be attributed to a particular pipeline, MMS may, at its discretion, approve an amount provided the lessee submits a written request and provides adequate documentation supporting the proposed amount.

--ARCO and Exxon support inclusion of IDC by arguing that both the Financial Accounting Standards Board and the Internal Revenue Service required capitalization of the interest cost. However, ARCO and Exxon have not provided sufficient documentation detailing or illustrating how the IDC figure was calculated. Accordingly, the IDC figure is not included in the depreciable capital base used to calculate yearly depreciation. The MMS will reconsider including IDC in the depreciable capital base if ARCO and Exxon submit sufficient documentation that more fully explains the proposed IDC figure.

Inflation -- ARCO and Exxon also claim that the value of the completed facilities is higher than the cumulative capital investment due to inflation during the long-term construction period. For this reason, ARCO and Exxon have inflated all capital investments prior to 1983 before including them in the depreciable base. ARCO and Exxon emphasize the time lag between initial construction and final completion of the pipeline as justification to request inflation as a depreciable cost. However, long-term construction is in fact usual for major pipeline facilities, both onshore and offshore.

--The CDM, section 647.5A.3B, limits investment costs to those costs for real property and those delivered and installed costs for equipment or other facilities which are depreciable. Allowable investment costs are limited to those items which are an integral part of the pipeline (downstream from the point of measurement on the leasehold); these costs should not include items normally considered to be lease equipment.

--Inflation is not a depreciable asset, nor is it an integral part of the pipeline. Accordingly, inflation will not be allowed as a depreciable investment cost.

Expenses

- The CDM, section 647.5A.3B, limits operating expenses in the calculation of a transportation allowance to the following:

  Operating costs are those nondepreciable expenditures required to operate and maintain the pipeline system and shall be limited to the lesser of the following values: actual operating costs or 10 percent of the undepreciated initial or adjusted investment cost as of the beginning of the year for which the operating costs are being computed.

- Operating expenses (exhibits 15 through 30) are comprised of operating and maintenance (O&M) costs (exclusive of power costs), power costs, ad valorem taxes, overhead, incremental working capital, and allocated abandonment expense. The following is a discussion of each expense group.

O&M costs -- The O&M costs are comprised of pipeline O&M and compression-related O&M (exhibits 19 and 21). The expenses described for pipeline O&M and compression-related O&M costs are allowable costs in calculating the transportation allowance. ARCO and Exxon also include power costs in the pipeline O&M. Power costs necessary to operate pipeline equipment are allowable expenses. The total allowable pipeline O&M costs for 1983 and 1984 are X-4 and X-4 respectively, as shown on ARCO and Exxon's exhibit 17. The total allowable compression-related O&M costs for 1983 and 1984 are X-4 and X-4 respectively, as shown on ARCO and Exxon's exhibit 20.

Power costs -- ARCO and Exxon designate the following categories of power usage as compression-related power expenditures: compression, heating/cooling, vapor recovery (booster compression), electrical/control and automation, general drill site preparation, gas production costs, and dehydration. Based on the descriptions provided by ARCO and Exxon, the power costs associated with compression, heating/cooling, vapor recovery, electrical/control and automation, and general drill site preparation are directly allocable to the compression function; these costs may be included in the allowance calculation. However, the power costs associated with production and dehydration are costs attributable to normal lease equipment operation. The CDM, section 647.5A.3B, directs that approved investment and operating costs cannot include items normally considered to be lease equipment costs. ARCO and Exxon describe the production and dehydration costs as costs that include well operating costs, wireline work, and costs associated with operating tri-ethylene glycol dehydration equipment. The power supply costs associated with these functions cannot be included in the allowance calculation. Information on ARCO and Exxon's exhibit 24 indicate that no production and dehydration power costs have been included. Therefore, the total allowable power costs for 1983 and 1984 are X-4 and X-4 respectively, as shown on exhibit 24.

Ad valorem taxes -- Taxes imposed on transportation equipment (except income taxes) are an acceptable expense item. Exhibit 25 of the ARCO and Exxon submittal details all ad valorem taxes allocated to the Sheep Mountain Pipeline project. The total allowable ad valorem costs for 1983 and 1984 are X-4 and X-4 respectively, as shown on ARCO and Exxon's exhibit 25.

Overhead -- The MMS allows actual overhead costs up to an amount equal to 10 percent of the operating costs. ARCO and Exxon have not submitted any actual cost data to support a claim for the overhead expense. Instead, they assume the overhead to be 10 percent of the sum of O&M costs plus power costs plus ad valorem taxes for each year. ARCO and Exxon representatives stated orally in the August 29, 1985, meeting that the expected actual overhead expenses were in excess of 10 percent of the operating costs. They allege that 10 percent of total operating costs is historically a conservative figure for overhead in oil and gas producing fields and is likely to be even more conservative for a CO_2 transportation operation requiring extensive engineering manpower. ARCO and Exxon object to the 10 percent ceiling on overhead as a rule applicable in all cases. However, they will accept a 10 percent overhead ceiling for the Sheep Mountain Pipeline transportation allowance if all compression-related costs are included.

--The MMS guidelines contained in the CDM, section 647.7.3E, and applicable to the period prior to March 1, 1988, establish a 10 percent ceiling for allowable overhead. Furthermore, the guidelines specify that MMS can request verification of overhead costs by requesting copies of the invoices. This policy has been upheld in the U.S. District Court for the District of Wyoming in the June 22, 1988, decision, The Shoshone Tribe, et al. v. Donald P. Hodel, et al. (No. C81-131 K). The Court found that general and administrative overhead costs may be deducted from royalty where the costs can be substantiated and only to the extent that the deduction does not exceed 10 percent of O&M costs.

--For the period prior to March 1, 1988, ARCO and Exxon will be limited to a 10 percent ceiling on overhead. Compression-related expenses will be allowed as part of the expenses against which the ceiling is applied.

Incremental working capital -- This expense is a theoretical expense and does not represent actual transportation costs. Therefore, the incremental working capital expense cannot be included as an expense item in computing the transportation allowance.

Abandonment expense -- It is not MMS policy to participate in abandonment expenses. Also, it is not MMS policy to remain associated with pipelines or plants should they be converted to other uses and not abandoned. ARCO and Exxon assert that the costs associated with abandoning the pipeline should be included in the transportation allowance. The proposal includes only those costs pertaining to the segments covered by right-of-way pipeline removal agreements. However, because ARCO and Exxon do not know how much additional pipeline length may be required to be removed, they request reservation of the right to make supplemental applications to include any future costs of abandonment.

--In determining allowances, MMS allows only reasonable, actual operating costs, depreciation, and a return on undepreciated capital investment. Costs specifically prohibited from deduction by lease terms, regulations, court decisions, and policy include those for compression, dehydration, gathering, and other expenses incidental to marketing, Federal and State income taxes, abandonment costs, actual and theoretical line losses, and costs that are not directly related to the transportation of lease production. These are all costs in which the lessor historically has not shared and, in many cases, are costs that are not relevant to the lessor's interest or responsibility. For these reasons as well as the fact that costs to abandon certain segments of the CO_2 pipeline are currently speculative and will not actually be incurred until many years in the future. The MMS cannot approve the inclusion of an abandonment cost element in the allowance calculation.

Interest

- ARCO and Exxon calculated the interest component by using a "weighted-average prime-rate during construction" figure (exhibits 8, 31, and 32). The CDM, section 647.5A.3A, provides in part:

  > . . . Unless otherwise justified, the prime interest rate in effect at the time of initial allowance approval should be used as the rate of allowable return on the depreciated investment. Once established, the rate will be continuous (fixed) over the life of the pipeline.

- Past MMS policy has been to use the prime interest rate (as published in the Wall Street Journal) in effect at the beginning of the period for which the initial allowance is granted. This rate then remains fixed for the remainder of the 20-year depreciable life. The interest rate on January 3, 1983, was 11 percent. The April 13 and January 5 draft decisions stated that this rate should be used as the rate of allowable return on the depreciated investment.

- The IBLA discussed the principles and philosophies behind the rate of return policy contained in the CDM in three pertinent cases involving the rate of return used to calculate processing and transportation allowances (IBLA 87-350, decided May 23, 1989; IBLA 89-299, decided October 26, 1989; and IBLA 88-158, decided June 28, 1990). In the May 23 decision, involving Phillips Petroleum Company (Phillips), IBLA rejected the prime rate used by MMS to calculate gas processing allowances at the Lee, Lusk, and Douglas processing plants and remanded the case to MMS for recalculation. However, the IBLA apparently rejected the prime rate selected in the Phillips case only because it was for a period other than the audit period under appeal. In the October 26 decision, involving transportation and washing allowances for Black Butte Coal Company (Black Butte), IBLA upheld the MMS use of the prime interest rate but emphasized that a reasonable rate of return depends on economic conditions at the time involved. The IBLA concluded that Black Butte had not shown the assigned rate to be unreasonable. In the June 28 decision, involving Mobil Producing Texas & New Mexico, Inc. (Mobil), IBLA upheld usage of the prime rate in calculating a transportation allowance for CO_2 produced from the McElmo Dome Unit. The IBLA conclusions in the Phillips, Black Butte, and Mobil cases can be inferred to mean that the prime rate methodology applied to allowances prior to March 1, 1988, generally would be supported by IBLA if the prime rate chosen reflects the economic conditions for the time period involved.

- The IBLA has consistently upheld usage of a prime rate methodology as embodied in the CDM; MMS will continue to apply this methodology to allowances for the period prior to March 1, 1988. However, instead of using the prime rate as published in the Wall Street Journal, MMS will use the prime rate as published by the Federal Reserve Board (Board), Federal Reserve Bank of Dallas. The prime rate data compiled by the Board represents an average of the rates of 29 banks located in major cities across the U.S. and thus should provide a sound basis for establishing the prime rate used for allowance purposes. Prime rates published by the Wall Street Journal are derived similarly but are not available for the same historical periods as are the Board data.

- The prime interest rate on January 1, 1983 (as compiled by the Board), was 11.5 percent. ARCO and Exxon will be required to use the prime interest rate of 11.5 percent to calculate the Sheep Mountain CO_2 transportation allowance.

Throughput

- ARCO and Exxon provided actual throughput figures for 1983 and 1984 (exhibits 33 and 34). These figures should be used to calculate the actual 1983 and 1984 transportation allowance.

Two-Year, Loss Roll-Forward Provision

- In the original August 29, 1985, allowance request, ARCO and Exxon proposed using a 7-year transportation allowance reporting period. In the April 13 draft decision, MMS required ARCO and Exxon to use a 1-year reporting period for transportation allowances. In the June 12, 1987, allowance request, ARCO and Exxon proposed using a 2-year allowance accounting period as an alternative to the original proposal of a 7-year transportation allowance accounting period. ARCO and Exxon selected the 2-year accounting period because it ". . . will reduce the number of hours required on both the applicants' and the Federal Government's part to recalculate and monitor the transportation allowance." However, the ARCO and Exxon proposal also includes a "loss roll-forward provision" whereby actual transportation costs not captured in a given 2-year period would be carried forward so as to enable such costs to be potentially recouped in future years.

- ARCO and Exxon contend that low throughput was normal during the early years of pipeline operation because demand for CO_2 in west Texas was initially low. These low throughputs combined with high actual transportation costs

CONTAINS COMPANY PROPRIETARY INFORMATION FOR RELEASE ONLY TO ARCO OIL AND GAS COMPANY

resulted in transportation expenses that exceed the value of the product during the initial period of the project. ARCO and Exxon claim that this is a potential problem throughout the life of the project because of wide variations in CO_2 consumption demands. They also claim that if the loss roll-forward provision is not an integral part of the MMS-approved transportation allowance, the allowance would "unlawfully penalize" the lessee for commencing a major CO_2 production and transportation project.

° The MMS policy is to grant allowances on a yearly basis based on the lessee's reasonable, actual costs incurred to transport lease production.

Cap on Transportation Allowances

° Historical MMS policy has been to limit transportation allowances for onshore leases to 50 percent of the value of the product as specified in the CDM, section 647.5.3E. If a lessee believed it was entitled to relief from this limitation, MMS had required the lessee to specifically request, in writing, an exception to the limitation. However, in cases where a lessee could demonstrate that unusual circumstances warranted relief from the 50 percent limitation, MMS has granted exceptions to the allowance limitation.

° ARCO and Exxon have adequately demonstrated that transportation of Sheep Mountain CO_2 occurs under unusual circumstances and that the costs of transportation are in excess of the 50 percent limitation the first few years. Given the uniqueness of the commodity and the atypical operational constraints of the pipeline, ARCO and Exxon may deduct actual transportation costs not to exceed 99 percent of the value of the CO_2.

Scope of Transportation Allowance

° In the April 13 draft decision, MMS advised ARCO and Exxon that the allowance granted will cover transportation costs from Sheep Mountain to the individual contract delivery points at or near the various tertiary recovery units in west Texas. In the June 12, 1987, submittal to MMS, ARCO and Exxon contend that ". . . while the transportation allowance will pertain only to the Sheep Mountain CO_2 Pipeline, all costs incurred in the delivery of CO_2 from an outlet on the Sheep Mountain CO_2 Pipeline to the ultimate point of connection with the inlet facilities on any given consuming unit should be fully deductible from Federal royalty payments if such inlet facilities are designated as the contractual change of title or delivery point."

° The MMS policy is to allow all actual, reasonable transportation costs incurred by the lessee to move production off the lease to the point of first sale or title transfer.

17

CONTAINS COMPANY PROPRIETARY
INFORMATION FOR RELEASE ONLY
TO ARCO OIL AND GAS COMPANY

CONCLUSIONS

Depreciation

Pipeline capital -- The MMS bases allowable depreciation on the actual out-of-pocket costs incurred for property and equipment (including delivery and installation) integral to the pipeline. Exhibit 10 of the ARCO and Exxon submittal shows X-4 of spent capital for the pipeline. This figure must be reduced by the cost incurred to purchase land for the Clovis Operation Center.

Salvage value -- Although a 10 percent salvage value is normally required by MMS, ARCO and Exxon have provided sufficient justification to support their claim for a zero salvage value. If the pipeline is later deemed to be salvageable, MMS must be notified.

Compression-related capital investment -- The MMS will allow the capitalized compression costs, including all costs relative to the installation of power facilities to operate the compressors, in the transportation allowance calculation. No dehydration costs shall be included.

IDC -- The MMS recognizes IDC as part of the depreciable capital investment base on which the transportation allowance rate is calculated. ARCO and Exxon have not provided adequate documentation supporting their proposed IDC figure; therefore, the IDC figure is not included in the depreciable capital base used to calculate yearly depreciation. The MMS will reconsider including IDC in the depreciable capital base if ARCO and Exxon submit sufficient documentation that more fully explains the proposed IDC figure.

Inflation -- Inflation is not considered by MMS to be a depreciable asset. Inflation of capital prior to 1983 will not be allowed in computing the transportation allowance.

Expenses

O&M -- The pipeline O&M costs (including the power necessary to operate the pipeline) and compression-related O&M costs are acceptable operating costs.

Power costs -- The compression-related power costs requested by ARCO and Exxon will be allowed in the transportation allowance computation.

Ad valorem taxes -- The ad valorem taxes requested by ARCO and Exxon will be allowed in the transportation allowance computation.

Overhead -- The MMS has consistently applied a 10 percent ceiling on overhead to all transportation allowances, both onshore and offshore, for many years. The MMS considers this 10 percent ceiling a reasonable allocation of overhead costs. The 10 percent ceiling rate will be used to calculate the Sheep Mountain Pipeline transportation allowance for the period prior to March 1, 1988. During audit, ARCO and Exxon may be required to substantiate this 10 percent figure. As discussed above, compression-related costs will be included in the costs against which the 10 percent ceiling is computed.

Incremental working capital -- The incremental working capital expense proposed by ARCO and Exxon is a theoretical expense and does not represent an actual transportation cost. This expense will not be allowed in the transportation allowance computation.

Abandonment expense -- Costs of abandoning pipelines or other transportation-related facilities are not allowable transportation costs. Current and/or future liability for abandonment expenses are a cost to be borne solely by the lessee. The Sheep Mountain Pipeline transportation allowance shall not include the costs for abandoning the pipeline.

Interest

- The MMS historically has used a prime rate methodology for calculating transportation allowances. The Sheep Mountain transportation allowance for the period prior to March 1, 1988, will be calculated using this same method. The interest expense must be based on the prime interest rate in effect at the beginning of the period for which the initial allowance is granted based on the prime interest rate compiled by the Federal Reserve Board. This rate was 11.5 percent on January 1, 1983.

Two-Year, Loss Roll-Forward Provision

- The MMS and its predecessor Agency historically have granted yearly transportation allowances based on actual costs incurred by the lessee for production transported during that year. The MMS will continue to require ARCO and Exxon to calculate and report the Sheep Mountain CO_2 transportation allowance on a yearly basis. In addition, MMS will not allow any loss roll-forward provision. The MMS does not believe that a yearly allowance without a loss roll-forward provision unlawfully penalizes the lessee. It has been the policy of MMS to allow only actual, reasonable costs up to the established limit calculated on a yearly basis. The MMS will not approve any excess cost to be recouped in subsequent years.

Cap on Transportation Allowance

- The Sheep Mountain CO_2 transportation allowance will not be subject to the 50-percent limitation. ARCO and Exxon may deduct actual transportation costs not to exceed 99 percent of the value of the CO_2.

Scope of Transportation Allowance

- The MMS policy is to allow all actual, reasonable transportation costs incurred by the lessee to move lease production off-lease to the point of first sale or title transfer. If CO_2 production from Sheep Mountain is transported along pipeline segments other than the Sheep Mountain Pipeline <u>prior to the point of first sale or title transfer</u>, MMS will allow transportation costs associated with these segments to be deducted. These costs will be subject to the same qualifications and limitations as the costs incurred on the Sheep Mountain Pipeline. However, the total cost to move production from Sheep Mountain through the Sheep Mountain Pipeline, including any additional pipeline segments not on the Sheep Mountain Pipeline, cannot exceed 99 percent of the value of the product.

Calculation of Sheep Mountain CO_2 Transportation Allowance

- An example detailing the method ARCO and Exxon should use to calculate the Sheep Mountain CO_2 transportation allowance is provided for illustrative purposes only. The example uses the pipeline capital investment figure of X-4 provided by ARCO and Exxon. This figure must be adjusted to exclude the cost to purchase land for the Clovis Operation Center. In addition, ARCO and Exxon must recalculate depreciation and return on investment based on the adjusted capital investment figure.

- Appendix 1 is a sample of a 20-year straight-line depreciation schedule for the Sheep Mountain CO_2 Pipeline. An investment figure of X-4 X-4 (pipeline) and X-4 compression)], a salvage value of zero, and a prime interest rate of 11.5 percent were used, as previously discussed.

- Appendix 2 provides a summary of the MMS-allowable operating costs and the 10 percent overhead calculation.

- Appendix 3 shows the method of calculating transportation allowance rates. For 1983 and 1984, the sample calculated transportation allowance rates are X-4/Mcf and X-4 /Mcf, respectively. These allowance rates will change when the allowance is recalculated to exclude the cost to purchase land for the Clovis Operation Center.

- Transportation allowances cannot exceed 99 percent of the product's value at the nearest competitive sales point.

- To deduct a transportation allowance, ARCO should follow the standard two-line entry format required by the MMS Auditing and Financial System as outlined in the September 1986 issue of the Payor Handbook, Section 3.9, "Reporting Allowances." If further clarification is needed regarding the Form MMS-2014 reporting requirements, ARCO may contact personnel in the MMS Lessee Contact Branch.

- ARCO and Exxon should recalculate the allowance rates for 1983 and 1984 using the revised capital investment figure and should submit actual cost data for Calendar Years 1985 through 1987 and for January and February 1988 following the approved method outline above. Allowances for the period subsequent to February 1988 will be calculated in accordance with the new allowance regulations which became effective March 1, 1988.

Appendix 1

<u>CONTAINS COMPANY PROPRIETARY INFORMATION FOR RELEASE ONLY TO ARCO OIL AND GAS COMPANY</u>

SAMPLE DEPRECIATION SCHEDULE FOR SHEEP MOUNTAIN CARBON DIOXIDE PIPELINE BASED ON THE INITIAL ALLOWABLE CAPITAL INVESTMENT OF X-4 ZERO SALVAGE VALUE, AND 20-YEAR STRAIGHT-LINE DEPRECIATION

Allowance Year	Beginning of Year Undepreciated Investment	Annual Depreciation[2]	End of Year Undepreciated Investment	Return on Investment[3]
1983				
1984				
1985				
1986				
1987				
1988				
1989				
1990				
1991				
1992		X-4		
1993				
1994				
1995				
1996				
1997				
1998				
1999				
2000				
2001				
2002				
2003				

[1]This figure must be adjusted to exclude the cost to purchase land for the Clovis Operation Center.

[2] X-4 /20 years.

[3]Beginning of year undepreciated investment times prime interest rate of 11.5 percent.

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
WASHINGTON, DC 20240

JAN 24 1992

Mr. F. David Loomis
Manager, Mineral Audit Section
Department of Revenue
State of Colorado
999 18th Street, Suite 1025
Denver, Colorado 80202

Dear Mr. Loomis:

Thank you for your letter of November 15, 1991, concerning the proposed transportation allowance decision for carbon dioxide produced from the Sheep Mountain Unit, Huerfano County, Colorado. In your letter you took exception to the Minerals Management Service's (MMS) decision to include capitalized and expensed compression costs in the allowance calculation and to permit the allowance to exceed the 50-percent limitation.

After careful consideration of your comments, I have decided to sign the transportation allowance decisions addressed to ARCO Oil and Gas Company (ARCO) and Exxon Company, U.S.A. (Exxon) as originally proposed by the Royalty Management Program (RMP). I concur with RMP's conclusion that the compression costs at Sheep Mountain are costs associated with transportation, not costs to place production in marketable condition. Also, RMP's analysis of the revenue and cost data indicates that the 50-percent limitation will be exceeded only in the first few years of pipeline operation when the throughput is low.

copy enclosed

Your letter also requested the right to respond to the Interest During Construction (IDC) issue when it is revisited by RMP upon application by ARCO and Exxon. In the future, if ARCO and Exxon request approval to include IDC in the Sheep Mountain transportation allowance calculation, MMS will consult with the State of Colorado prior to making a decision on this issue.

Again, thank you for your concern on these issues. If you have any questions, please contact Mr. Donald T. Sant, Deputy Associate Director for Valuation and Audit, at (303) 231-3899.

Sincerely,

/S/ S. Scott Sewell
Director

Enclosure

CAG Chron

bcc: MMS Gen File
AS/LM (2)
Dir. Chron
RF File
RM File
AD/RM
RM Chron/Lkwd/DC
RVS Chron
Chief, OSTPS

LMS/RM:RVS:OG:MS3520:LUPINSKI:sjl:12/23/91:231-3547:OANDG\LOOMIS
final:sjl:12/23/91

(16)

This decision is set up for the Director's signature because it is a change in policy. Traditionally, most all costs for compression were claimed to be costs of putting the product in marketable condition. However, we now believe the compression costs in the transportation of the carbon dioxide should be considered a function of transportation and included in the transportation allowance. There are no other known disputes between MMS and Exxon and Arco in this valuation issue. The State auditors will ~~not like~~ this decision but it is consistent with the principles in the IBLA decision in Exxon LaBarge. Attached is an expanded briefing sheet.

Brad

why IBLA?

ROYALTY MANAGEMENT PROGRAM
ROYALTY VALUATION AND STANDARDS DIVISION

Royalty Valuation Procedure and Transportation Allowance Calculation Sheep Mountain Unit

SUMMARY OF FACTS AND ISSUES

- Through various oral and written presentations, ARCO Oil and Gas Company (ARCO) and Exxon Company, U.S.A. (Exxon), jointly requested approval of a transportation allowance and separately requested approval of a royalty valuation procedure for carbon dioxide (CO_2) produced from the Sheep Mountain Unit (Sheep Mountain), Huerfano County, Colorado. The CO_2 is transported to west Texas where it is used in tertiary oil recovery projects.

- Royalty will be based on sales values in west Texas less an allowance for the costs of transporting CO_2 to the sales outlets.

- Arm's-length contract prices will establish value for all CO_2 sales under those contracts. Non-arm's-length contract prices will establish value for all CO_2 sales under those contracts if they are equivalent to prices in comparable arm's-length contracts. Arm's-length contract prices in a nearby unit, field, or area will establish value when non-arm's-length prices are not acceptable, or no sales occur.

- Two major issues are involved in the calculation of the Sheep Mountain transportation allowance; inclusion of compression costs and exception to the 50 percent allowance limitation. All other significant issues; e.g., rate of return, have been decided in accordance with the Minerals Management Service (MMS) historical guidelines and policies for transportation allowance calculations.

- A recent decision by the Interior Board of Land Appeals (IBLA) (IBLA-826, decided March 8, 1991) addressing allowable costs of transporting gas to the Shute Creek gas processing plant in Wyoming required MMS to consider the purpose of various costs in determining whether inclusion of these costs in an allowance calculation is proper. In essence, IBLA concluded that those costs incurred solely for the purpose of transporting production off the lease are allowable transportation costs. Other recent decisions of IBLA regarding transportation and processing allowance issues also have focused on considering the purpose of costs incurred as opposed to just the type of cost in determining deductibility.

- The Royalty Valuation and Standards Division (RVSD) analyzed the compression function at Sheep Mountain and found that compression is a critical element in keeping CO_2 in the single phase necessary for safe and efficient transportation. In light of this analysis and the directives contained in the IBLA decision, RVSD recommends that ARCO and Exxon be allowed to include compression costs in the transportation allowance calculation.

- Historical MMS policy has been to limit transportation allowances for onshore leases to 50 percent of the value of the product. However, ARCO and Exxon have adequately demonstrated that transportation of Sheep Mountain CO_2 occurs under unusual circumstances and costs are in excess of the 50 percent limitation. The RVSD has granted exceptions to the 50 percent limitation in other circumstances and recommends that ARCO and Exxon be allowed to deduct actual transportation costs not to exceed 99 percent of the value of the CO_2.

- The proposed decisions apply only to production occurring prior to March 1, 1988. Production occurring on or after March 1, 1988, must be valued in accordance with the regulations at 30 CFR 206 (1990). However, only one element of the Sheep Mountain transportation allowance will change. Beginning March 1, 1988, the return on investment will be calculated using the Standard and Poor's BBB bond rate instead of the prime interest rate.

- The State of Colorado generally agrees with MMS's decision on the valuation and transportation allowance calculation for CO_2. However, the State may object to the inclusion of compression costs in the allowance calculation. The State's position is that compression costs should be disallowed because such costs represent the cost of placing production in marketable condition.

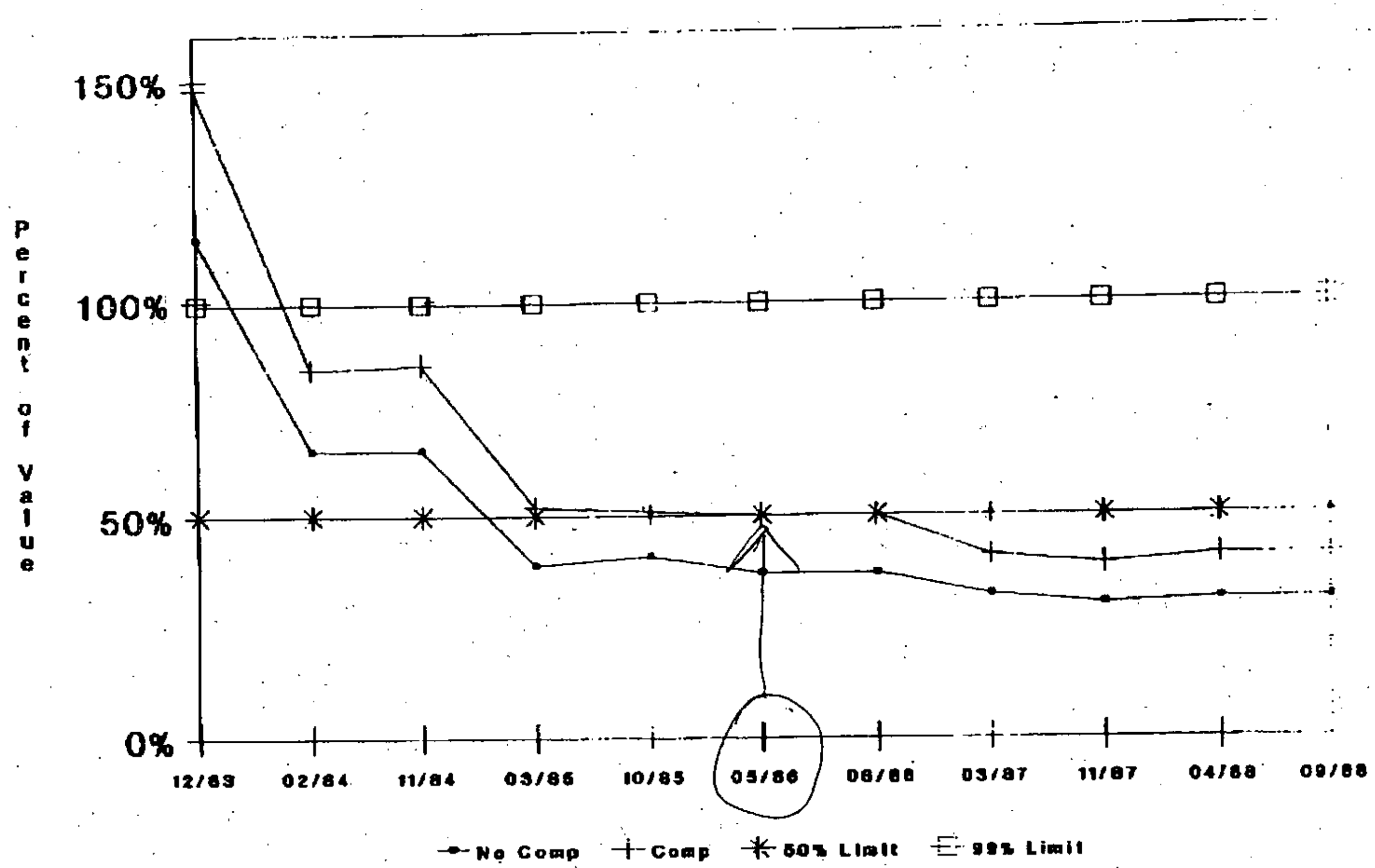
ARCO/EXXON SHEEP MOUNTAIN

	1987	1988
Sales Price/Mcf	X-4	
Transportation Allowance/Mcf		
With Compression	X-4	
Without Compression	X-4	
Allowance Expressed as a Percentage of Sales Price		
With Compression	40 percent	41 percent
Without Compression	31 percent	31 percent
Annual Federal Royalty Effect of Including Compression in Allowance[1/]	X-4	

1/ Federal participation in Sheep Mountain Unit = 55.59 percent.

SENT BY:Xerox Telecopier 7021 ;10- 7-91 ; 7:08 ; RVSD→ 3433982:# 4

Sheep Mountain Unit
Allowance as Percent of Value



EXXON CORPORATION - LABARGE PROJECT
IBLA 86-262 (March 8, 1991)
Key Elements of Decision

PRODUCTION FROM LABARGE PROJECT

° Reversed Director's decision denying the inclusion of the costs of dehydration in the determination of a transportation allowance.

- ruled that the field dehydration was solely for transportation

- required agency to look at purpose of gas conditioning expenditures -- because no market existed for dehydrated LaBarge gas, purpose of dehydration was not for marketing

- modified Assistant Secretary's decision dated October 19, 1988, by ordering field dehydration to be included in determination of a transportation allowance for production on and after March 1, 1988. ASLM had committed to this in its own decision

° Affirmed 50 percent transportation allowance limitation.

- Exxon provided no data demonstrating that the limitation was incorrect

° Provided IBLA's understanding of the evolution of the regulations regarding processing cost deductions that existed prior to March 1, 1988.

- the 66 2/3 percent limitation has been historically well suited to processing allowances for wet gas (gas containing liquefiable hydrocarbons) because of its simplicity and because it has approximated the lessee's actual costs of manufacture

- no regulations existed addressing how MMS should value a gas stream that contains no recoverable NGL's, such as the LaBarge gas stream consisting of methane, nitrogen, CO_2, sulfur, and helium

- furthermore, the regulations at 43 CFR 3103.3-1 and Exxon's lease terms provide for an allowance to exceed 66 2/3 percent of the value of any product with approval of the Secretary

- consequently, the 66 2/3 percent limitation is inadequate to approximate Exxon's actual costs of processing the LaBarge gas stream and should not be used in determining a processing allowance for LaBarge gas

° Reversed Director's decision requiring Exxon to place methane in marketable condition without benefit of an allowance.

- California Co. v. Udall does not bear on processing of LaBarge gas because such case pertained to conditioning gas for market without resorting to processing

- LaBarge gas must be processed; therefore, no case basis exists for requiring Exxon to process gas for the purpose of placing residue gas in marketable condition without a deduction for processing costs

- residue gas is clearly a product of processing and is therefore entitled to an allowance in accordance with 43 CFR 3103.3-1

MMS Viewing of California v. Udall

° Case supports Secretary's discretion to define production as production in marketable condition. Supports proposition that production must be an identifiable product.

- costs for conditioning a raw well stream, such as for separator, heater-treater, free-water knockout, and other production equipment, i.e., production costs, are not deductible because the costs are incurred prior to achieving identifiable products (oil and gas)

- costs for compression and dehydration for the purpose of meeting contractual specifications are costs of placing products in marketable condition and are not deductible

Implications on Policy

° Compression and dehydration

- would a deduction be required from value whenever compression or dehydration is performed without a direct tie to market requirements -- for example, if offshore gas is compressed and dehydrated at the platform prior to transportation to an onshore gas processing plant and further sale to a downstream end user, even though the installation of the equipment was originally to meet original interstate sales contract?

° If compression and dehydration are for other than achieving production in marketable condition, is the fuel used royalty bearing under lease terms?

° For pure CO_2 where no market exists at the lease, are all costs of compression and dehydration costs of transportation?

° Is gas containing no liquefiable hydrocarbons the only gas production to which the wet gas rule does not apply?

° Should these atypical gas streams be the only gas production for which extraordinary processing costs under the March 1, 1988, rules if such provision is retained?

18

United States Department of the Interior

TAKE PRIDE IN AMERICA

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY REFER TO:

MMS-RVS-OG
Mail Stop 3520

DEC 27 1991

Memorandum

To: Director, Minerals Management Service

From: Acting Associate Director for Royalty Management

Subject: Transportation Allowance for Sheep Mountain Unit Carbon Dioxide (CO_2) Production

We have conducted a thorough review of the State of Colorado's (State) position regarding the proposed Minerals Management Service (MMS) decision letters to Exxon Company U.S.A. and ARCO Oil and Gas Company granting a transportation allowance for CO_2 produced from the Sheep Mountain Unit, Huerfano County, Colorado, and transported to west Texas for sale. In its letter dated November 15, 1991, the State took exception to two specific aspects of the proposed decision. Those aspects are the inclusion of compression costs in the allowance calculation and permitting the allowance to exceed 50 percent of the value of the CO_2 sold in west Texas.

Our analysis of the position presented by the State is attached. In summary we found no compelling arguments to reconsider the MMS position presented in the proposed decision letters. Regarding the revenue impacts, we found it necessary to conduct a reconciliation of the State's Exhibits B and C to arrive at an accurate portrayal of effects. The attached analysis includes a description of the reconciliation as well as a schedule of estimated allowance rates that will result from the proposed decisions.

Our recommendation is to proceed with issuance of the transportation allowance decision letters now before you. If there are any questions, please contact Don Sant at FTS 326-3899.

Jimmy W. Mayberry

Jimmy W. Mayberry

Attachment

Attachment

ANALYSIS OF THE STATE OF COLORADO'S NOVEMBER 15, 1991, REMARKS REGARDING THE MINERALS MANAGEMENT SERVICE'S PROPOSED TRANSPORTATION ALLOWANCE DECISION FOR SHEEP MOUNTAIN UNIT CARBON DIOXIDE PRODUCTION

By letter dated November 15, 1991, the Mineral Audit Section, Department of Revenue, State of Colorado (State) responded to the Minerals Management Service's (MMS) proposed transportation allowance decision for carbon dioxide (CO_2) produced from the Sheep Mountain Unit, Huerfano County, Colorado. In this letter, the State took exception to MMS' decision to include capitalized and expensed compression costs in the allowance calculation and to permit the allowance to exceed the 50-percent limitation. The State offered arguments on four points to support its position. The following discussion synopsizes the State's arguments and presents MMS' response.

<u>Historically, MMS has considered compression costs as costs to place production in marketable condition</u>.

In its response, the State quotes extensively from Bureau of Land Management operating regulations, MMS policy letters, Kuntz Oil and Gas Law documents, and the Conservation Division Manual (CDM) (originally issued by the U. S. Geological Survey and later adopted by MMS). The State also cited two court cases that discussed the issue of natural gas in marketable condition. The State concluded that these regulations, guidelines, and legal precedent support their position that compression costs are nothing more than marketing costs and should not be allowed as deductions from value in the determination of royalties due.

All of the sources cited by the State contemplate marketable condition as it applies to natural gas. When these documents were formulated, production of CO_2 for the marketplace had not yet occurred on Federal lands. Even today, very few situations exist that involve sales of CO_2. Natural gas, however, is a commodity that has been produced and sold since the early part of this century. As a result, a large body of laws, regulations, and legal decisions exists that contemplates how to establish value for natural gas production. Also, industry has established specific operating standards that producers and pipelines must follow in order to produce and sell natural gas in the United States. In contrast, CO_2 has been produced and sold only since the early 1980's and no laws, regulations, or established industry standards specific to CO_2 exist for determining value. Thus, regulations, court cases, and guidance (such as the CDM) applicable to natural gas are used by MMS to value CO_2 but must be balanced with the actual circumstances that are unique to the production and transportation of CO_2.

<u>Sheep Mountain compression costs are distinct from the Exxon Corporation (Exxon) LaBarge Interior Board of Land Appeals (IBLA) case</u>.

The MMS' proposed Sheep Mountain decision cites the Exxon LaBarge IBLA decision, <u>Exxon Corp.</u>, 118 IBLA 221, issued March 8, 1991, as the basis for its decision to allow the compression costs in the Sheep Mountain allowance calculation. In 118 IBLA 221, the IBLA concluded that the purpose or function of a process must be examined to determine whether costs of that process are properly included in the determination of value. At LaBarge, the transportation function at issue was the dehydration of raw gas. The IBLA concluded that field dehydration conducted at the Black Canyon dehydration facility was solely for the purpose of transporting the gas to the Shute Creek plant for processing and therefore such dehydration costs should be allowed as a deduction in calculating royalty value.

In its arguments, the State focused on the function's point of occurrence and made the distinction that the field dehydration facility at LaBarge is located outside the *administrative* boundaries of the unit area, whereas the field compression facilities at Sheep Mountain are located within the boundaries of the unit area. The State asserts that this distinction is sufficient basis to conclude that the concepts of the LaBarge decision should not apply to Sheep Mountain. The State also cites an IBLA decision, <u>Mobil Producing Texas & New Mexico, Inc.</u>, 115 IBLA 164, issued June 28, 1990, to Mobil Producing Texas and New Mexico, Inc. (Mobil) in which the IBLA remanded a compression expense issue to MMS for reconsideration. In 115 IBLA 164, MMS agreed to reconsider its decision regarding compression. Based on MMS' response to the reconsideration, the State concluded that the point at which compression occurs is significant to the issue of whether to allow compression costs in the transportation allowance. The State claims that, consistent with the *Mobil decision*, the compression at Sheep Mountain is a cost to place production in marketable condition because it occurs prior to the point of royalty measurement and should be disallowed.

We disagree with the State's interpretation of the IBLA's decisions in both the Exxon and the Mobil cases. In both decisions the IBLA emphasized that the determining factor in deciding whether costs are allowable as deductions is the <u>purpose</u> of the function, <u>not</u> the point at which that function occurs. There is no dispute that the compression at Sheep Mountain occurs prior to the point of royalty measurement. To reduce costs and environmental damage, ARCO Oil Company (ARCO) and Exxon consciously chose to co-locate the compression facilities with the production facilities. Again, the physical location of the compression facilities at Sheep Mountain is not the governing factor. The primary purpose of the compression must be considered and, in the case of Sheep Mountain, that purpose is to keep the CO_2 in single phase throughout the pipeline as it is transported to west Texas.

We also disagree with the State's conclusion that any function occurring prior to the point of royalty measurement should be disallowed solely for that reason. There are numerous cases where transportation and processing costs occur prior to the royalty determination point and are allowed as deductions from the value of production for royalty purposes. In fact, in the Exxon LaBarge case, the point at which value is determined for the produced methane, CO_2, nitrogen, sulfur, and helium is at the tailgate of the plant and value is established based on functions (processing and pre-plant transportation) that occur prior to the point of value determination. To further illustrate the point, for oil produced offshore, meters are located both on the platforms, for purposes of allocation, and at the outlet of storage and transfer terminals for the purpose of royalty measurement. Costs incurred for the transportation of the oil from the platform to the royalty meter are deductible in determining royalty value.

In summary, the previously cited IBLA decisions, as well as other decisions of the IBLA, provide administrative guidance to MMS that consideration must be given to the purpose of compression at Sheep Mountain rather than the point at which the compression occurs. We conclude that the compression costs at Sheep Mountain are costs associated with transportation and consequently these costs should be included in the allowance calculation.

<u>Compression costs are merely marketing costs</u>.

The State's position is that the compression function occurring at Sheep Mountain is indistinguishable from the typical compression function required in natural gas pipeline situations and should not be allowed as a transportation deduction. The State cites language contained in typical CO_2 delivery contracts in west Texas for Sheep Mountain CO_2 as the basis for its position (State's Exhibit A). These contracts generally specify a delivery pressure of 1,800 to 2,100 psig. The State contends that these delivery pressures dictate the need for compression and therefore compression is simply a marketing cost. The State also notes that ARCO and Exxon have claimed that the minimum pressure needed to keep the CO_2 in a supercritical phase is X-4 but that the pressure needed to enter the pipeline at the unit boundary is X-4 psia. The State concludes that because the pressure of the produced CO_2 is below the pipeline entrance requirement of X-4 X-4 psia and the required contract delivery pressures of X-4 psig, compression is occurring strictly for the purpose of placing the product in marketable condition.

The ground elevation at the Sheep Mountain unit boundary is almost 9,000 feet. The Sheep Mountain pipeline leaves the unit, drops to an elevation below 6,000 feet, then rises to an elevation just over 8,000 feet to cross Raton Pass. From Raton Pass the elevation drops 5,000 feet to the west Texas delivery points. At the unit boundary, CO_2 enters the pipeline at X-4 psia then drops to a low of X-4 psia at Raton Pass. After the pipeline crests Raton pass, the hydrostatic load of the CO_2 in the pipeline increases the pressure to about X-4 psia which exceeds pipeline design specifications and causes the CO_2 to liquify. To mitigate these undesirable effects, the CO_2 pressure is reduced at a pressure-reduction station. When the CO_2 is finally delivered to points in west Texas, the pipeline pressure is about X-4 psia.

When ARCO and Exxon solicited bids for delivery of CO_2 in west Texas, potential purchasers were informed that delivery pressure would be about X-4 psia due to the hydrostatic load of the CO_2 in the pipeline that occurs downstream of Raton Pass. Thus, delivery pressures specified in the written contracts were the result of producer-established criteria that reflected actual CO_2 pressures available in west Texas. Compression was not performed to meet purchaser-established contract delivery pressures. Furthermore, we cannot concur with the State's belief that the pressures established in the contracts are standard delivery pressures for marketability purposes. We are unaware of the existence of any standard delivery pressures or industry marketability standards for CO_2 which could be equated to industry standards recognized for natural gas. Contract pressures for Sheep Mountain production are simply the reflection of available pressure at the delivery point.

The State notes that single-phase flow is achieved at X-4 psia but CO_2 at Sheep Mountain is compressed to X-4 psia. The State alleges that this proves that compression is performed solely to meet prescribed pipeline entrance requirements. The State also suggests that if the pipeline was owned by a third party, ARCO and Exxon would be required by that pipeline owner to compress the CO_2 to X-4 psia prior to delivery. Lastly, the State argues that just because ARCO and Exxon are pipeline owners, they should not gain favorable benefit above and beyond that of a lessee who does not own the pipeline. Again, the State incorrectly draws analogies between accepted standards and practices in the natural gas industry that do not have application to CO_2.

Significant elevation changes occur on the Sheep Mountain pipeline after the CO_2 leaves the origin meter station. Because there are no auxiliary compressor stations to maintain pressure, high initial pipeline delivery pressures (X-4 psia) are needed to insure that the CO_2 maintains a single phase flow X-4 psia or above) at Raton Pass. Again, these pressures are not dictated by contract delivery pressures, as suggested by the State, and would be necessary regardless of whether the pipeline was owned by ARCO and Exxon or a third party. If the pipeline were owned by a third party, ARCO and Exxon would simply be charged a transportation fee that included the costs of compression to maintain the CO_2 in a single phase flow.

<u>The royalty impact of this decision is detrimental to past, present, and future royalty collections</u>.

Based on audit work performed, the State analyzed data related to the proposed Sheep Mountain transportation decision and concluded that the State of Colorado will derive little, if any, benefit from the CO_2 produced from Sheep Mountain. The State provided two exhibits (Exhibits B and C) to illustrate its assertion.

We recalculated the Sheep Mountain transportation allowances as shown on Exhibit 1, Column 3, considering adjustment of the capital investment figure downward to reflect the State's disallowance of some costs, and inclusion of the power costs associated with compression. For comparison purposes, we have reiterated MMS' original calculations (Column 1) and the State's calculations (Column 2). Our analysis shows that during 1983 and 1984 the allowance will exceed the 50-percent limit. Much of this impact is due to the low throughput during the initial start-up of the pipeline. However, in 1985, the allowance is at the 50-percent limit and in subsequent years drops below that limit. We believe that these calculations accurately reflect the impact the proposed decision will have on the value of CO_2 produced from the Sheep Mountain Unit.

In addition to the comments above, MMS would like to offer a brief discussion on the issue of the 50-percent limitation. Although the State objects to allowing ARCO and Exxon to exceed the 50-percent limitation, it provided no arguments in support of its position.

The MMS has, in fact, routinely granted exceptions to the 50-percent limit since the mid-1980's to recognize lessees' actual and necessary costs incurred to transport royalty bearing production to market. This practice is consistent with administrative appeal decisions rendered by the Director, MMS. Furthermore, the amended oil and gas product valuation regulations that became effective March 1, 1988, provide for the granting of transportation allowances in excess of 50 percent to recognize actual, reasonable, and necessary transportation costs incurred by lessees. ARCO and Exxon have demonstrated that during the first few years of operation when throughput of the system is low, actual allowance costs will exceed the 50-percent limitation. We continue to recommend that ARCO and Exxon be granted an exception to the 50-percent limitation to recognize actual and necessary costs incurred to transport CO_2 from the Sheep Mountain Unit to the west Texas market.

Sheep Mountain CO_2 Transportation Allowance Decision
Comparison of State of Colorado and Minerals Management Service Data

		(1) MMS Calc.	(2) State Calc.	(3) Revised Allowance Calc.	(4) Weighted Average CO_2 Price	(5) 50 Percent Limit	(6) Throughput (Mcf)
Allowance	1983						
Rate (Mcf)	1984						
	1985			X-4			
	1986						
	1987						
	1988						

*Year when allowance drops below 50 percent limit

(1) Does not include some power costs associated with the compression function.

(2) Reflects deduction of X-4 of capital investments costs that were disallowed by the State of Colorado during a preliminary audit.

(3) Reflects deduction of capital costs, and includes electrical power costs associated with compression.

(4) Calculated by summing the products of all individual west Texas unit prices times the CO_2 volume delivered to each unit and dividing that sum by the total Sheep Mountain CO_2 volume delivered to west Texas.

(5) Weighted average price times 50 percent.

(6) Total Federal, State, and fee CO_2 volume measured at the origin meter station, Sheep Mountain Unit. In accordance with Sheep Mountain Unit Agreement, Exhibit B, Federal *participation* (based on acreage) is 0.5559341. The State's calculated revenue impact does not reflect the Federal participation factor.

(34)

United States Department of the Interior

TAKE PRIDE IN AMERICA

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY REFER TO:

Mail Stop 653

MMS-RVS-OG:90-0020

CERTIFIED MAIL--
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MAR 0 2 1990

Ms. Gay Anderson
Consultant Accountant
Mobil Exploration &
Producing U.S. Inc.
P.O. Box 650232
Dallas, Texas 75265-0232

Dear Ms. Anderson:

By letters dated December 21, 1989, and January 5, 1990, Mobil Exploration & Producing U.S. Inc. (Mobil), requested Minerals Management Service (MMS) to grant relief from the 50 percent limitation on transportation allowances regarding CO_2 production from the McElmo Dome Unit during calendar years 1985 and 1986.

As discussed in the telephone conversation on February 14, 1990, with Ms. Theresa Walsh Bayani, MMS, please submit the following information within 15 calendar days of receipt of this letter:

(1) The actual cost data for each of the items approved by MMS for inclusion in the 1941 pipeline consent decree tariff calculation procedure for the Cortez Pipeline.

(2) The actual State and Federal income taxes that would be included in the calculation procedure for the allowance for calendar years 1985 and 1986. This information may be included in the calculation procedure for the allowance as a result of the Interior Board of Land Appeals No. 87-47 decision dated January 23, 1990.

Thank you for your cooperation in this matter. If you should have any questions regarding this request, please call Ms. Bayani at (303) 231-3395.

Sincerely,

John L. Price

John L. Price
Chief, Oil and Gas Valuation Branch
Royalty Valuation and Standards Division

United States Department of the Interior

TAKE PRIDE IN AMERICA

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY REFER TO:

DAD-VA/RP, MS 662

NOV 3 1988

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ROYALTY VAL. & STDS. DIV.
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COLORADO

Mr. J. B. McNeil
LaBarge Project Manager
Exxon Company, U.S.A.
P.O. Box 3906
Midland, Texas 79702-3906

Dear Mr. McNeil:

On October 19, 1988, the Assistant Secretary - Land and Minerals Management issued an order to Exxon Company, U.S.A. (Exxon) (copy enclosed) which specified the valuation determination for gas produced from the Graphite, Lake Ridge, and Fogarty Creek Federal Units, LaBarge area, Sublette County, Wyoming. Gas from these units is processed in facilities collectively known as the LaBarge Project. The October 19, 1988, order is the final action of the Department of the Interior and, therefore, is not subject to appeal to the Interior Board of Land Appeals (IBLA). (Blue Star, Inc., 41 IBLA 333 (1979).)

Within 30 days of receipt of this letter, Exxon is directed to report and pay all royalties due calculated pursuant to the enclosed valuation determination for production from March 1, 1988, through September 30, 1988. Exxon is also directed to use the enclosed valuation determination in the calculation and payment of royalties for the production month of October 1988 and thereafter in accordance with applicable lease terms.

The valuation of production that occurred prior to March 1, 1988, is currently the subject of an appeal to IBLA. Exxon has posted a bond for those royalties due on production that occurred prior to March 1, 1988, pending the outcome of the appeal. We are evaluating the adequacy of the bond and will advise Exxon by separate letter regarding sufficiency of the bond.

Section 109 of the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA), promulgated in 30 CFR 241.51 (1988), authorizes the Minerals Management Service to assess civil penalties for failure or refusal to comply with the requirements of FOGRMA or any statute, regulation, rule, order, lease, or permit. Consequently, Exxon's failure to comply with the terms of this order may be considered a violation pursuant to 30 CFR 241.51(a)(3) and could subject Exxon to penalties of up to $5,000 per violation per day.

Sincerely,

Donald T. Sant

Jerry D. Hill
Acting Associate Director for
Royalty Management

Enclosure

cc: W. F. Atwood

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

OCT 1 9 1988

ENCLOSURE CONTAINS COMPANY PROPRIETARY INFORMATION FOR RELEASE ONLY TO EXXON COMPANY, U.S.A.

CERTIFIED MAIL--
RETURN RECEIPT REQUESTED

Mr. J. B. McNeil
LaBarge Project Manager
Exxon Company, U.S.A.
P.O. Box 3906
Midland, Texas 79702-3906

Dear Mr. McNeil:

Your letter dated April 6, 1988, to the Minerals Management Service transmitted a detailed royalty valuation proposal for the Graphite, Lake Ridge, and Fogarty Creek Federal Units, LaBarge area, Sublette County, Wyoming. Gas from these units is processed in facilities collectively known as the LaBarge project.

The enclosed Findings and Conclusions detail the decision of the Department of the Interior concerning the royalty valuation procedure for gas produced from these three units. The procedure presented therein was arrived at after careful consideration of: information presented at the March 15, 1988, meeting between Royalty Management and Exxon Company U.S.A. (Exxon) personnel; material enclosed to your April 6, 1988, letter; and facts gathered during an on-site plant inspection of the LaBarge facilities. This valuation determination is to be applied to gas produced on or after March 1, 1988, the effective date of the new valuation regulations and will remain in effect until Exxon is otherwise advised. Exxon will be provided 60 days notice prior to any change in the royalty valuation procedure detailed by the enclosed Findings and Conclusions.

This order is approved and adopted as the final action of the Department of the Interior and, therefore, is not subject to appeal to the Interior Board of Land Appeals. (Blue Star, Inc., 41 IBLA 333 (1979).)

Sincerely,

J. Steven Griles
Assistant Secretary -
Land and Minerals Management

Enclosure

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bcc: Sec. Surname
MMS Gen. File
Sec. Reading (2)
AS/LM (2)
Dir. Chron
RM File
RM Chron/Lkwd/DC
AD/RM
D. Sant, MS 662
RVS Chron

LMS/RM:RVS:OGV:MS653:TPHILLIPS:llb:10-5-88:FTS326-3181:OGR:LaBarge4
LMS/RM:RVS:OGV:MS653:TPHILLIPS:llb:revised:10-6-88:FTS326-3181:OGR:LaBarge4
Revised:LM:JCason:mwj:10/18/88:343-2191:NBI://mwj/general/mcneil-a

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ROYALTY MANAGEMENT PROGRAM

ROYALTY VALUATION AND STANDARDS DIVISION

Findings and Conclusions on Exxon Company's Proposal to Deduct Certain Processing and Transportation Costs and Specific "Extraordinary" Costs for Gas Produced From Three Federal Units, LaBarge Area, Sublette County, Wyoming

Background - General

° Exxon Company, U.S.A. (Exxon), as operator and working-interest owner in the Graphite, Lake Ridge, and Fogarty Creek Federal Units, LaBarge area, Sublette County, Wyoming, proposed on April 6, 1988, the deduction of costs involved in processing and transporting gas produced from the three units when computing Federal royalties. Federal leases comprise a large percentage of the three Federal units. Exxon holds leases on approximately 85 percent of the Federal lands.

Exxon proposes:

1. The allocation of pre-plant transportation costs to the methane (CH_4), carbon dioxide (CO_2), sulfur, and nitrogen, with allocation on the basis of value, and a maximum cost limitation of 75 percent of the product values at the plant inlet. No costs would be allocated to helium or to unmarketable volumes of CO_2 or nitrogen;

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2. The allocation of processing costs to the sulfur and to the marketable volumes of CO_2 and nitrogen, with allocation on the basis of value, and a maximum cost limitation of 95 percent of the product values at the plant tailgate;

3. The allocation of post-plant transportation costs based on the cost of transporting the individual plant products (CH_4, CO_2, sulfur, and nitrogen) to their separate sales points, with a maximum cost limitation of 75 percent of the individual product sales revenues;

4. An extraordinary processing cost allowance against the value of the CH_4 based on that portion of reasonable, actual and necessary manufacturing costs in excess of the ordinary processing allowance, not to exceed 75 percent of the value of CH_4 at the plant tailgate; and

5. An alternative method of calculating royalty where the cost allowance is limited to the lesser of total manufacturing and transportation (M&T) costs or 80 percent of gross proceeds; if M&T costs exceed 80 percent of gross proceeds, the depreciable investment balance will be adjusted by adding to it costs that exceed 80 percent of gross proceeds, such added costs to be limited to a maximum of 20 percent of gross proceeds; no depreciation will be taken until total M&T costs excluding depreciation are less than 80 percent of gross proceeds, thereafter the depreciable investment will be fully depreciated (straight line) over the remaining life of the project.

- Exxon advises that its proposal is intended to satisfy the requirement of "value of production" under the leases, the "reasonable value" required by 30 CFR § 206.103 (1987) and the "value of production" under the royalty

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valuation regulations issued effective March 1, 1988. Its application is offered as a means of settling in a consistent manner all issues related to allowances for Exxon-owned facilities, retroactive to the date of commencement of LaBarge operations. Exxon believes that it is entitled to an extraordinary processing cost allowance and to relief from the normal transportation and manufacturing cost limitations because the extraordinary nature of the LaBarge project required Exxon to incur extraordinary and unusual costs.

Findings

- Gas from the three units is produced from the Madison formation gas reserves found at depths of between 14,000 and 18,000 feet below the surface. A typical reservoir analysis shows the gas content to be 65.4 percent (CO_2), 21.2 percent (CH_4), 7.7 percent nitrogen, 5.1 percent hydrogen sulfide, and 0.6 percent helium. There are no liquid hydrocarbons present in the produced gas.

- Exxon has constructed a gas processing plant at Shute Creek, about 50 miles from the field. A centralized dehydration facility is located in the field area to remove water before the gas is transported to the plant to prevent pipeline corrosion. The plant products are CH_4, CO_2, sulfur, helium, and nitrogen. The CH_4 is sold primarily at the tailgate of the Shute Creek plant. The CO_2 is sold at Rock Springs and Bairoil, Wyoming (with about 50 percent of unsold production vented at the plant). The sulfur is transported about 16 miles by railroad to Opal, Wyoming (a spur on the main line of the Union Pacific Railroad), which is the point of sale for the sulfur. The helium and a small percentage of the nitrogen are sold at the plant.

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- Exhibit I, "LaBarge Flow Diagram," shows the relative location of the operations:

   1. The centralized dehydration facility;

   2. The 40-mile "feed gas" pipeline from the units to the processing plant at Shute Creek;

   3. The Shute Creek processing plant;

   4. The 16-mile railroad spur from Shute Creek to Opal on the main line of the Union Pacific Railroad which is used to transport sulfur, and

   5. The two CO_2 pipelines to Rangely, Colorado, and Bairoil, Wyoming.

- The plant construction capital costs are about X-4 Annual plant operating costs are about X-4

- The "transportation" capital costs are about X-4 Principal components are:

   Dehydration facilities
   Feed Gas Pipeline
   Sulfur Transportation Facilities
   CO_2 Pipeline

   X-4

   Annual transportation operating costs are about X-4 excluding third party transportation costs of X-4

- Exxon reports total products sales revenue excluding helium of

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in 1987 and total processing and transportation costs of X-4 including depreciation X-4 return on investment X-4 based on Standard & Poor's BBB Industrial Bond Rate of 10.17 percent for January 1987), overhead X-4 and operating and maintenance costs X-4 Helium sales during 1987 totaled approximately X-4

- By decision dated October 29, 1984, the Royalty Valuation and Standards Division (RVSD) made the following determinations regarding Exxon's March 23, 1984, application to include all processing and transportation costs in royalty calculations on gas attributable to Federal leases within the Graphite, Lake Ridge, and Fogarty Creek Federal Units, LaBarge area, Sublette County, Wyoming:

  1. The costs of the field dehydration facility and the costs to build and operate the pipeline from the field to the Shute Creek plant are not deductible in computing Federal royalty;

  2. Processing costs can be approved for the associated products removed and sold (to a maximum of 66-2/3 percent) but no portion of the processing costs can be applied to the value of the CH_4; and

  3. The costs required to transport CO_2, CH_4, or sulfur to the first sales point downstream of the plant are deductible to a maximum of 50 percent of the value of the product.

- On November 29, 1984, Exxon filed an appeal with the Director, Minerals Management Service (MMS) from the RVSD decision. On January 18, 1985, Exxon filed a "Request for Special Exception Relief" with the Secretary of the Interior. By decision MMS-84-0066-O&G dated January 7, 1986, the Director upheld the RVSD decision, with the exception that a transportation allowance for the pipeline constructed from the field to the Shute Creek plant was authorized. Exxon appealed the Director's decision to the Interior Board of Land Appeals (IBLA) (86-626) where a decision is now pending. As of March 1, 1988, the effective date of the new valuation regulations, most existing valuation determinations were terminated. These Findings and Conclusions address the LaBarge valuation issues under the requirements of the new regulations. The conclusions, therefore, will only apply to gas produced on or after March 1, 1988.

Basic Issues

- Are the costs of the field dehydration facility and water injection deductible as a part of the costs of transporting the gas from the field to the Shute Creek processing plant?

- Can the pre-plant transportation costs and the plant processing costs be allocated to non-royalty-bearing products; i.e., helium, vented CO_2, and unsold nitrogen?

- Can the costs of pre-plant transportation and plant processing be allocated to each product in proportion to the value of the product?

- Are the costs of the CH_4 and CO_2 compression facilities at the Shute Creek plant deductible as a part of the manufacturing process?

- Should the transportation cost allowance limitation be increased from 50 percent to 75 percent for each product transported and sold and the processing cost limitation be increased from 66-2/3 percent to 95 percent for CO_2, sulfur, and nitrogen?

- Should an extraordinary processing cost allowance, in excess of ordinary

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processing allowances, not to exceed 75 percent of the value of CH_4 at the plant tailgate, be granted?

Field Dehydration Facility and Water Disposal by Subsurface Injection

- Exxon states that a transportation cost allowance for the dehydration facility (including the water disposal system) is justified as follows.

  1. The only purpose of the facility is to dry the sour gas so that it can be safely and economically transported to the manufacturing facility.

     a. Dehydration is only performed to minimize corrosion risks in the transportation system pipeline which traverses state highways and populated areas.

     b. Dehydration is not performed to meet purchaser specifications and is redundant since processes in the Shute Creek manufacturing facilities reduce water content to levels some X·4 times lower than required by the sales contract.

     c. The separate dehydration facility did not measurably reduce the scope and cost of the Shute Creek manufacturing facilities.

     d. Partial rehydration of the sour gas stream is necessary in order for the initial Selexol process at the Shute Creek plant to function efficiently.

  2. The dehydration facility with a conventional pipeline is more cost effective than other transportation alternatives.

a. Without dehydration, the feed gas pipeline would have to be constructed of corrosion resistant alloys to prevent corrosion and would require heating and insulation systems to prevent hydrate plugging.

b. Costs of such a wet sour gas transportation system were estimated to far exceed the current system.

c. A more expensive pipeline transportation system would have resulted in increased costs to Exxon and higher transportation allowances for royalty purposes.

° About X-4 barrels per day of water is injected into the water disposal wells. Of this amount, about X-4 percent is separated from the incoming gas stream at the slug catchers upstream of the dehydration facility and routed directly to the water disposal wells.

Applicable Regulations and Court Cases

° By decision dated January 7, 1986 (MMS-84-0066-O&G), the Director determined that an allowance for dehydration costs cannot be allowed irrespective of whether the dehydration is performed at field dehydration units, at a processing plant, or at both field dehydration units and at a central processing plant due to environmental considerations dictating the siting of the processing plant. It was determined that Exxon cannot deduct the cost of the dehydration at the field dehydration unit. Exxon included this issue in its appeal to the IBLA (IBLA-86-626) dated February 18, 1986.

° In its appeal to IBLA, Exxon takes the position that the dehydration facility is an integral part of the raw gas transportation system and that the costs of dehydration are costs incurred in transporting the gas. (In decision MMS-84-0066-O&G the Director determined that the costs of transporting gas from the field to the Shute Creek plant are deductible in computing Federal royalty.) Exxon states that the only purpose of the dehydration facility is to dry the sour gas so that it can be safely and economically transported to the manufacturing facility. Dehydration is only performed to minimize corrosion risks in the pipeline. It is not performed to meet purchaser specifications and is redundant since processes in the Shute Creek plant reduce water content to levels X.4 times lower than required by the sales contract. Exxon states that the "Romere Pass" case, California Company v. Udall 296 F.2d 384, 387 (D.C. Cir. 1961), and other legal decisions actually support its position.

- The valuation regulations effective March 1, 1988, at § 206.158 state in part that," . . . no processing cost deduction shall be allowed for the costs of placing lease products in marketable condition, including dehydration. . . ."

- Bureau of Land Management (BLM) regulations 43 CFR §§ 3162.1 and 3162.5-1 require that the lessee properly dispose of all produced water.

Allocation of Pre-Plant Transportation and Plant Processing Costs Against Non-Royalty-Bearing Products (Helium, Vented CO_2 and Unsold Nitrogen)

- Exxon proposes to allocate the transportation and plant processing costs of the nonmarketed components to the royalty bearing product volumes for the following reasons.

  1. Costs should be allocated only to royalty-bearing product volumes sold.

a. The entire raw gas stream, including non-marketable components, must be transported and manufactured to recover royalty-bearing product volumes;

b. The LaBarge raw gas stream is unique and not all volumes of products are currently marketed; and

c. Reasonable and actual costs of transporting and manufacturing raw gas necessarily include the cost of transporting and manufacturing volumes that are not marketed.

° The issue of allocation of costs of transporting and processing the non-marketed components of the gas stream to the royalty-bearing product volumes was not addressed in the RVSD decision dated October 29, 1984, or in the MMS decision dated January 7, 1986 (MMS-84-0066-O&G).

Applicable Regulations

° The regulations effective March 1, 1988, provide in pertinent part, in § 206.157(b)(3)(i) that, "Except as provided in this paragraph, the lessee may not take an allowance for transporting a product which is not royalty bearing without MMS approval." The regulations at § 206.158(d)(1) state in part that, " . . . MMS will not grant any processing allowance for processing lease production which is not royalty bearing. They also provide in 206.159(b)(3) that, "The processing allowance for each gas plant product shall be determined based on the lessee's reasonable and actual cost of processing the gas. Allocation of costs to each gas plant product shall be based upon generally accepted accounting principles. The lessee may not take an allowance for the costs of processing lease production which is not royalty bearing."

Allocation of Pre-Plant Transportation and Plant Processing Costs in Proportion to the Value of Each Product

- Exxon proposes to allocate transportation costs to all products and processing costs to all products except CH_4 in proportion to the value of each product sold for the following reasons.

  1. Allocation of costs to royalty-bearing products based on value of volumes sold is equitable and is consistent with the regulations revised effective March 1, 1988:

     a. The regulations provide that the lessee may propose to allocate transportation costs on the basis of product values; and

     b. The regulations provide that manufacturing costs will be allocated to products based on generally accepted accounting principles that would include value-based allocation.

- The issue of allocation on the basis of value instead of volume was not addressed in the RVSD decision dated October 29, 1984, or in the MMS decision dated January 7, 1986 (MMS-84-0066-O&G). Exxon requests in its application of April 6, 1988, that costs of pre-plant transportation and processing be allocated in proportion to the value of the products, except for helium. Exxon believes that allocation of costs on the basis of value is equitable and is consistent with the new regulations that provide that the lessee may propose to allocate transportation costs on the basis of product values and that also provide that processing costs will be allocated on generally accepted accounting principles.

Applicable Laws, Regulations, and Court Cases

° For transportation allowances, the regulations effective March 1, 1988, provide in 30 CFR § 206.157(b)(3)(ii) (53 F.R. 1280), " . . . the lessee may propose to the MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part." For processing allowances, the new regulations provide in 30 CFR § 206.159(b)(3) (53 F.R. 1283) " . . . The processing allowance for each gas plant product shall be determined based on the lessee's reasonable and actual costs of processing the gas. Allocation of costs to each gas plant product shall be based upon generally accepted accounting principles."

Compression of CH_4 and CO_2 at the Shute Creek Processing Plant

° Exxon states that methane and carbon dioxide "recompression" is justified and should be allowed for the following reasons.

1. CH_4 recompression is part of the manufacturing process.

   a. Recompression would not be required if gas was marketable at the well;

   b. During the complex manufacturing process, pressure must be reduced to manufacture pure CH_4 by cryogenic liquefaction;

   c. Recompression is required as the final step of the manufacturing process;

d. The CH_4 pressure after recompression is lower than the pressure of the raw gas stream at the well and at the inlet to the manufacturing facility; and

e. Field compression, if necessary in the future, will not change the requirement for manufacturing recompression.

2. CO_2 recompression is part of the manufacturing process.

a. Recompression would not be required if gas was marketable at the well;

b. During a portion of the complex manufacturing process, pressure is reduced from 4·4 psi to as low as 4·4 psi to manufacture pure CO_2;

c. Recompression is required as the final step of the manufacturing process;

d. Without recompression the value of the manufactured CO_2 would be significantly lower; and

e. Field compression, if necessary in the future, will not change the requirement for manufacturing recompression.

° Exxon states that even if MMS considers the cost of recompression to be for the purpose of placing production in marketable condition, the costs should be eligible for an extraordinary processing allowance pursuant to 30 CFR § 206.158(d)(1) and (d)(2) (53 F.R. 1281).

✓

- This issue was not specifically addressed in the RVSD decision dated October 29, 1984, or the MMS decision dated January 7, 1986, (MMS-84-0066-O&G).

Applicable Regulations

The applicable regulations have consistently required that the lessee place the products from the leased lands into marketable condition. The regulation 30 CFR § 206.153(i), effective March 1, 1988, states "The lessee is required to place residue gas and gas plant products in marketable condition at no cost to the Federal Government or Indian lessor unless otherwise provided in the lease agreement." "Marketable condition" is defined as " . . . lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." The regulation at § 206.158(d)(1) is more explicit and states in part " . . . no processing cost deduction shall be allowed for the costs of placing lease products in marketable condition, including dehydration, separation, compression, or storage, even if those functions are performed off the lease or at a processing plant."

Increase Transportation Cost Allowance Limitation From 50 Percent to 75 Percent for Each Product Transported and the Processing Cost Allowance Limitation From 66-2/3 Percent to 95 Percent for Each Product Processed, Except Methane

- Pursuant to 30 CFR § 206.156(c)(3) and § 206.158(c)(3) (53 F.R. 1281), Exxon requests that the transportation cost allowance limitation be 75 percent for each product and the processing cost allowance limitation be 95 percent for CO_2, sulfur, and nitrogen. Exxon argues that:

1. Currently reasonable, actual, and necessary costs that should be deductible as transportation and processing allowances exceed the total value of the CH_4, CO_2, nitrogen, and sulfur products sold; 5

2. Based on the regulation's threshold cost allowance limitations of 50 percent of value for transportation and 66-2/3 percent of value for processing, only X percent of reasonable, actual, and necessary costs of LaBarge facilities in the proposal could currently be taken as cost allowances;

3. The requested increase in cost allowance limitations will not provide for recovery of all reasonable, actual, and necessary costs and will not result in allowances of 100 percent of the value of any product.

Applicable Laws, Regulations, and Court Cases

- The regulations effective March 1, 1988, provide as follows in § 206.156(c)(3) regarding increasing the cost limitation for transportation allowances:

> "Upon request of a lessee, MMS may approve a transportation allowance deduction in excess of the limitations prescribed by paragraphs (c)(1) and (c)(2) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitations prescribed in paragraphs (c)(1) and (c)(2) of this section were reasonable, actual, and necessary. An application for exception shall contain all relevant and supporting documentation necessary for the MMS to make a determination. Under no circumstances shall the

value for royalty purposes under any selling arrangement be reduced to zero."

- The regulations effective March 1, 1988, provide as follows in § 206.158(c)(3) regarding increasing the cost limitation for processing allowances:

> "Upon request of a lessee, MMS may approve a processing allowance in excess of the limitation prescribed by paragraph (c)(2) of this section. The lessee must demonstrate that the processing costs incurred in excess of the limitation prescribed in paragraph (c)(2) of this section were reasonable, actual, and necessary. An application for exception shall contain all relevant and supporting documentation for MMS to make a determination. Under no circumstances shall the value for royalty purposes of any gas plant product be reduced to zero.

- Exxon proposed that the 75 percent limitation be applied to the value at the sales point when considering post-plant transportation costs and to the value at the inlet of the Shute Creek plant when considering the pre-plant transportation costs. This procedure has the effect of reducing the allowance below the amount otherwise approvable under the regulations; i.e., application of the percent limitation to the value for each product at the sales point or point of value determination.

<u>Approve Extraordinary Cost Allowance for Processing to be Applied Against CH_4</u>

- Pursuant to § 206.158(d)(2) Exxon requests an extraordinary cost allowance to be applied against the value of the CH_4 to be based on that portion of

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reasonable, actual, and necessary manufacturing costs in excess of the ordinary processing allowances, not to exceed Y·Y percent of the value of CH_4 at the tailgate of the Shute Creek plant. Exxon argues that:

1. Manufacturing enhances the value of all products including CH_4;

2. Manufacturing costs at LaBarge are by reference to standard industry conditions and practice, extraordinary, unusual, and unconventional;

3. LaBarge raw gas is unique--no similar gas resource has been developed; it contains only 21 percent CH_4, will not burn and contains no heavy hydrocarbon components;

4. Complex and interrelated manufacturing facilities are required to manufacture products;

5. No product accounts for 50 percent or more of revenue; and

6. The current combined value of all products is less than the total transportation and manufacturing costs.

<u>Applicable Laws, Regulations, and Court Cases</u>

° The valuation regulations effective March 1, 1988, provide for an extraordinary cost allowance in 30 CFR § 206.158(d)(2)(i) (53 F.R. 1282) as follows:

> "If the lessee incurs extraordinary costs for processing gas production from a gas production operation, it may apply to MMS for an allowance for those costs which shall be in

addition to any other processing allowance to which the lessee is entitled pursuant to this section. Such an allowance may be granted only if the lessee can demonstrate that the costs are, by reference to standard industry conditions and practice, extraordinary, unusual, or unconventional."

Conclusions

Field Dehydration Facility and Water Disposal by Subsurface Injection

° Dehydration is not considered a function of the transportation of the gas stream. Dehydration is clearly addressed at 30 CFR 206.158 as a cost to place production in a marketable condition and, therefore, is not to be borne by the lessor. Whether this step is performed in the field or in the processing plant, it must eventually be done before any product is sold. All marketed gas streams are dehydrated to eliminate corrosion and malfunction in gas handling systems. No gas purchaser will knowingly accept corrosive products into its system, hence, dehydration is essential to marketing. The LaBarge case, despite possibly high costs resulting from unusual composition, is no exception. The MMS has established precedent and procedure regarding the dehydration of gas, and the "Romere Pass" decision (California Company v. Udall, 296 F.2d 384 D.C. Circuit 1961) upheld these requirements. Also, the Director's decision dated January 7, 1986 (MMS-84-0066-O&G), determined that an allowance for dehydration costs should not be allowed for this project.

This decision on the field dehydration facility is consistent with the Director's decision in MMS-84-0066-O&G which is on appeal to the IBLA in case number 86-626. If the IBLA reverses the Director in case number

86-626 and allows Exxon to deduct the costs of the field dehydration facility as a transportation cost, or if the IBLA affirms the Director but upon judicial review thereof a court in a final, non-appealable decision determines that Exxon may deduct the costs of the field dehydration facility as a transportation cost, then this decision also shall be so modified.

° The BLM regulations at 43 CFR 3160 clearly state that it is the responsibility of the lessee to properly dispose of produced water. The new MMS valuation regulations do not negate this responsibility. Therefore, the MMS concludes that the lessor will not share in the costs of disposing of this water. Costs associated with drilling, completing, and operating any water injection well should not be included in any transportation allowance for the LaBarge project.

Allocation of Pre-Plant Transportation and Plant Processing Costs Against Non-Royalty-Bearing Products (Helium, Vented CO_2, and Unsold Nitrogen)

° The regulations, effective March 1, 1988, clearly state at 30 CFR 206.159 that no processing allowance may be taken for the costs of processing non-royalty-bearing lease production. The regulations applicable to transportation allowances at 30 CFR 206.157, do permit, with the approval of MMS, allowances for transporting products which are not royalty bearing. In the LaBarge case, the non-royalty-bearing products are helium, and unsold carbon dioxide and nitrogen. Since all of the helium produced is sold and generates revenue for Exxon, subject to an agreement with the Bureau of Mines, but no Federal royalty obligation under the oil and gas leases is incurred, MMS will not share in the cost of transporting or processing this product. Regarding the unsold volumes of carbon dioxide and nitrogen, MMS believes that since potentially valuable commodities are allowed to be vented without royalty obligation, no further allowances should be granted. The MMS concludes, therefore, that only those transportation and processing costs that are properly allocated to royalty-bearing products should be included in the allowance calculations.

Allocation of Pre-Plant Transportation and Plant Processing Costs in Proportion to the Value of Each Product

° Allocation of pre-plant transportation and plant processing costs based upon the value of the products sold would result in an inordinate amount of costs allocated to helium. As the full well stream is in the gaseous phase, the costs of transporting each product should be the same. Allocation of processing costs should likewise be done on the basis of the relative volumes of products in the incoming feed stream, excluding the volume of CH_4 (no ordinary processing allowance can be taken against the value of the residue gas), but including the volumes of helium and unsold nitrogen and CO_2. The processes utilized at the LaBarge facilities to manufacture each individual product are interrelated and one process may apply to multiple products.

Compression of CH_4 and CO_2 at the Shute Creek Processing Plant

° Compression is not considered a function of the processing of the gas stream. Compression is clearly addressed at 30 CFR 206.158 as a cost of placing lease products in marketable condition and, therefore, is not to be borne by the lessor. The LaBarge case is no exception.

Increase Transportation Cost Allowance Limitation from 50 Percent to 75 Percent for Each Product Transported and the Processing Cost Allowance Limitation from 66-2/3 Percent to 95 Percent for Each Product Processed, Except CH_4

- When allowed pre-plant transportation costs, properly allocated by volume, are combined with post-plant transportation costs, the 50 percent allowance limitation (as applied against sales value) is not met for any product. Therefore, MMS concludes that an exemption to this limit is not warranted.

- When allocated by plant feed stream volume percentages (excluding CH_4), the processing costs for CO_2 exceed 100 percent of the CO_2 plant tailgate value. The processing costs allocated to sulfur approach the 66-2/3 percent limit but do not exceed it. The processing costs allocated to nitrogen exceed 100 percent of the nitrogen plant tailgate value. In that Exxon has demonstrated that the processing costs are reasonable, actual, and necessary, the MMS approves a 95 percent processing allowance limit for CO_2 and nitrogen. The processing allowances for sulfur will be limited to the customary 66-2/3 percent ceiling.

Approve Extraordinary Cost Allowance for Processing to be Applied Against CH_4

- The MMS has carefully considered the applicability of the extraordinary processing allowance for the LaBarge project and has concluded that approval of such an allowance would be premature at this time. The MMS is in the process of preparing a policy which will define the conditions (feed gas composition, processes involved, costs thresholds, etc.) under which an extraordinary allowance should be granted. Until such a policy is adopted, no extraordinary processing allowances will be approved. Further, a review of information related to certain other gas processing plants located in the Wyoming Overthrust Belt has revealed that the Shute Creek Plant is neither the most expensive to operate ($/Mcf throughput) nor was it the most costly to construct ($/Mcf capacity).

At the time that a policy on extraordinary costs is adopted, MMS will consider whether any of Exxon's requests meet the criteria, including an allowance for the costs of the field dehydration facility.

Summary of LaBarge Valuation Methodology

° In summary, the value, for royalty purposes, of each individual LaBarge product should be determined as follows:

  - Actual post-plant transportation costs, including costs incurred under third-party agreements, should be deducted from the product sales value. The resulting value is the product tailgate value. In no case shall the tailgate value be less than 50 percent of the sales value, on the basis of a selling arrangement.

  - Processing costs, excluding costs of recompression and allocated by volume, should be deducted from the product tailgate value. The allowable processing costs should be allocated to all products, royalty-bearing and non-royalty-bearing, on the basis of that product's volume percentage in the sour gas feed stream (excluding CH_4). No allowance may be taken for any product which is not royalty-bearing. The processing allowances for CO_2 and nitrogen are limited to 95 percent of the tailgate value. For sulfur, the processing allowance is limited to 66-2/3 percent of the tailgate value of the sulfur.

  - Pre-plant transportation costs allocated by volume, excluding the costs of dehydration and subsurface water disposal, should be deducted from the plant inlet values. The allowable pre-plant transportation costs should be allocated to all products, royalty-bearing or not, on the basis of that product's volume percentage in the sour gas feed stream (including CH_4). No allowance may be taken for any product which is not royalty-bearing. Under no circumstance shall the combined pre-plant and post-plant transportation allowance be more than 50 percent of any product's sales value on the basis of a selling arrangement.

- Based on the methodology discussed above and the unaudited revenue and cost figures supplied by Exxon, the LaBarge product values upon which royalties would be based had this been for production occuring on or after March 1, 1988 are shown in Exhibit II.

- In accordance with 30 CFR 206, Exxon should file Form MMS-4109 and Form MMS-4295 before claiming any allowance on Form MMS-2014.

EXHIBIT II

LABARGE VALUATION FOR FEDERAL ROYALTY PURPOSES
(Data for Calendar Year 1987)

Product	Sales Volume	Post-Plant Transp. Costs	Plant Tailgate Value	$ Volume Processed (Excl. CH_4)	Proc. Costs Alloc. on Volume	*Allow. Proc. Costs	Plant Inlet Value	Pre-Plant Transp. Alloc. on Volume	**Transp. Cost Limit	***Allow. Transp. Costs	Royalty Value
CH_4	34,492										
CO_2	54,932									X-4	
S	9,380				X-4						
N_2	44										
He	803										
TOTAL:	99,651	X-4									X-4

*The lesser of [illegible] of the plant tailgate value for CO_2 and N_2 and 66-2/3% for S, or the processing costs allocated to the royalty-bearing fraction of each respective product.

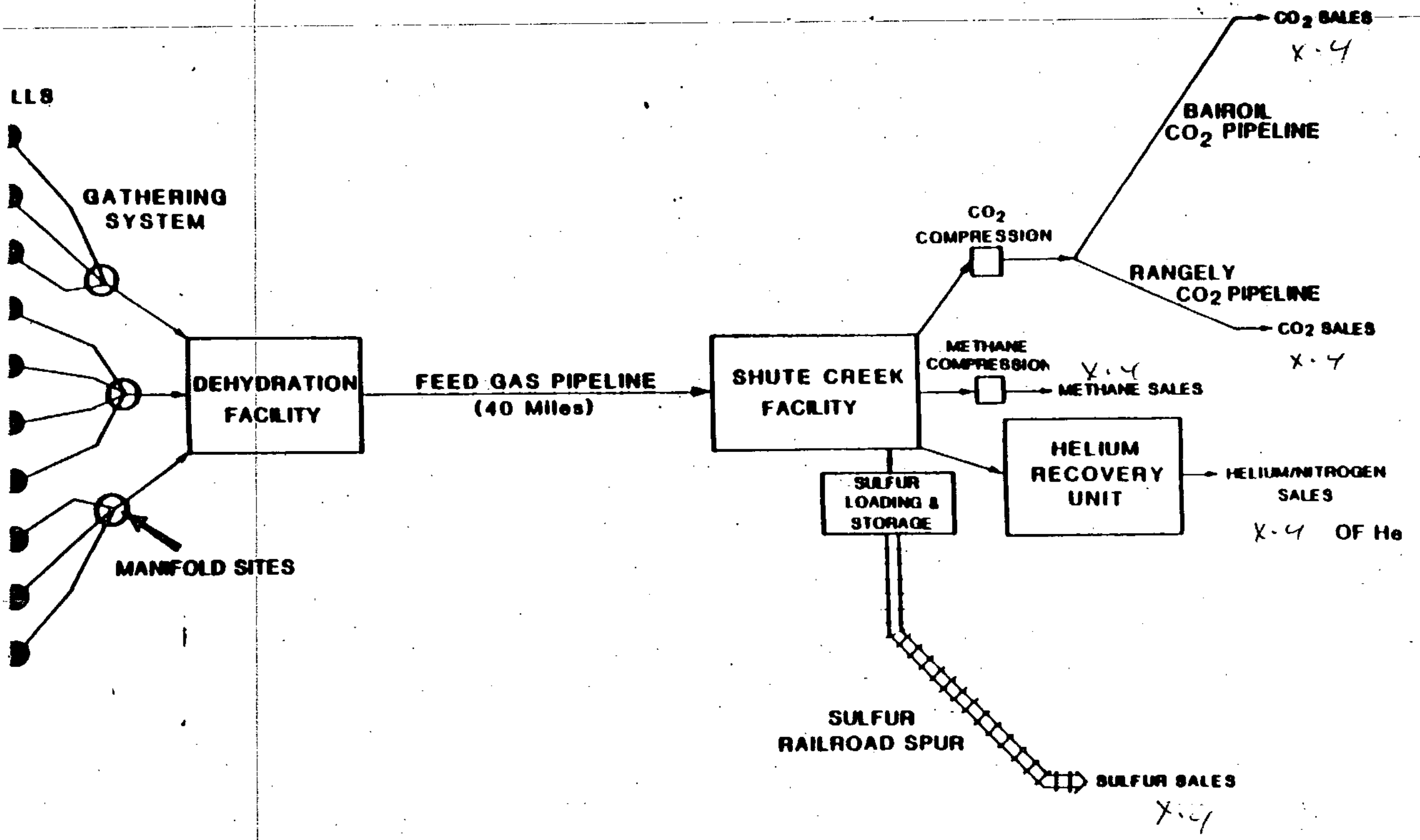
**A maximum of 50 percent of the sales point value less post-plant transportation costs already taken.

***The lesser of the transportation cost limit or the pre-plant transportation costs allocated to the royalty-bearing fraction of each respective product.

(All volumes in MMcf; all costs and values in 000's)

EXHIBIT I

LABARGE FLOW DIAGRAM



1/07/87

ISSUE DOCUMENT

~~EXXON PROPOSAL THAT THE~~
TRANSPORTATION COST ALLOWANCE
LIMITATION BE INCREASED FROM
50% TO 75% FOR EACH PRODUCT
AND THE PROCESSING COST
ALLOWANCE LIMITATION BE INCREASED
FROM 66 2/3% TO 95% FOR
CARBON DIOXIDE, SULFUR AND NITROGEN

Valuaton Issue:

Should the transportation cost allowance limitation be increased from 50% to 75% for each product and the processing cost allowance limitation be increased from 66 2/3% to 95% for carbon dioxide, sulfur and nitrogen, or should the normal cost allowance limitations for transportation and processing be used?

Background:

Exxon proposes in its April 6, 1988, application that the transportation cost aloowance limitation for transportation and processing be increased to 75% and 95%, respectively. Exxon states that reasonable, actual and necessary costs which should be deductible as transportation and processing allowances currently exceed the total value of the methane, carbon dioxide, nitrogen and sulfur products sold, and that based on the normal 50% and 66 2/3% of value limitations for transportation and processing, respectively, only 53% of reasonable, actual and necessary costs of LaBarge facilities could currently be taken as costs allowances. Further, the requested increase in cost allowance limitations will not provide for recovery of all reasonable, actual and necessary costs. Exxon proposes that the 75% limitation be applied for post-plant transportation costs to the value at the sales point and separately for the pre-plant transportation costs to the value at the inlet of the Shute Creek plant.

Applicable Laws, Regulations and Court Cases:

Prior to March 1, 1988, it was consistent MMS (formerly United States Geological Survey (USGS)) policy and practice to permit transportation costs to a maximum of 50% of the product value at the sales point. The policy of approving transportation allowances was based on the decision, Continental Oil Company v. United States 184 F.2d 802 (9th Cir. 1950) which determined that the value of Federal oil and gas products must be determined at the nearest sales point and transportation costs can be deducted from the value in computing Federal royalty if products are moved to this point. The practice of limiting transportation costs to 50% of product value was stated in the Conservation Division Manual as follows:

> Part 647.5.3 (Pipelines) - "Under no circumstances should transportation costs exceed 50 percent of the product's fair market value at the nearest competitive sales point."

> Part 647.6.3 (Trucking) - "Under no circumstances should trucking costs for crude oil or condensate exceed 50 percent of the product's fair market value at the nearest competitive sales point."

Prior to March 1, 1988, regulations provided that processing costs could exceed 66 2/3% of the value of the product only on approval by the Secretary. §43 CFR 3103.3-1(c) stated as follows:

> "In determining the amount or value of gas and liquid products produced, the amount or value shall be met after an allowance for the cost of manufacture. The allowance for cost of manufacture may exceed two-thirds (2/3) of the amount or value of any product only on approval by the Secretary of the Interior."

The regulations effective March 1, 1988, provide as follows in §206.156(c)(3) regarding increasing the cost limitation for transportation allowances:

> "Upon request of a lessee, MMS may approve a transportation allowance deduction in excess of the limitations prescribed by paragraphs (c)(1)

and (c)(2) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitations prescribed in paragraphs (c)(1) and (c)(2) of this section were reasonable, actual, and necessary. An application for exception shall contain all relevant and supporting documentation necessary for the MMS to make a determination. Under no circumstances shall the value for royalty purposes under any selling arrangement be reduced to zero."

The regulation effective March 1, 1988, provide as follows in §206.158(c)(3) regarding increasing the cost limitation for processing allowances:

"Upon request of a lessee, MMS may approve a processing allowance in excess of the limitation prescribed by paragraph (c)(2) of this section. The lessee must demonstrate that the processing costs incurred in excess of the limitation prescribed in paragraph (c)(2) of this section were reasonable, actual, and necessary. An application for exception shall contain all relevant and supporting documentation for MMS to make a determination. Under no circumstances shall the value for royalty purposes of any gas plant product be reduced to zero.

<u>Option No. 1</u>

The Secretary, as part of an "agreement" with Exxon to resolve the outstanding royalty valuation issues and to specify the methodology for determining Federal royalty, may determine that the requested increases in cost limitations for transportation and/or processing may be approved prior to March 1, 1988.

<u>Option No. 2</u>

The Secretary, as part of an "agreement" with Exxon to resolve the outstanding royalty valuation issues and to specify the methodology for determining Federal royalty, may determine that the requested revenues in cost limitations for transportation and/or processing may be approved subsequent to March 1, 1988.

Option No. 3

The Secretary, as part of an "agreement" with Exxon to resolve the outstanding royalty valuation issues and to specify the methodology for determining Federal royalty, may determine that the requested reveneus in cost limitations for transportation and/or processing may be approved both prior to and subsequent to March 1, 1988. Using Exxon's cost and price data for 1987, the estimated reduction in value for royalty by increasing the transportation and processing cost limitations as requested is about X-Y annually. (This is computed using a transportation cost limitation of 75% of the value of the final sales product - not applying the 75% separately to both pre-plant and post-plant transportation which is not in accord with the regulations. Note that, using Exxon's proposal, the total of pre-plant and post-plant transportation costs comprise only X-Y of the methane product sales, revenues and the comparable percentage for the other products is under 50%).

Option No. 4

The Secretary may elect not to approve the requested increases in cost limitations for transportation and processing.

CCURTIS:llb:4-29-88:NBI:OGV:38-0282

(40a)

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225
Mail Stop 653

IN REPLY
REFER TO:

MMS-RVS-OG:87-0210

JUL 1 1987

ENCLOSURE CONTAINS COMPANY PROPRIETARY
INFORMATION FOR RELEASE ONLY TO
MOBIL PRODUCING TEXAS & NEW MEXICO INC.

Mr. Hector Casas
Gas Accounting Supervisor
Mobil Producing Texas & New Mexico Inc.
Nine Greenway Plaza
Houston, Texas 77046

Dear Mr. Casas:

By letter dated March 16, 1987, you requested approval of transportation allowances pertaining to CO_2 production transported from the McElmo Dome Unit in southwestern Colorado through the Cortez Pipeline, Mobil Producing Texas & New Mexico Inc.'s (MPTM) pipeline, West Texas Pipeline, and Sheep Mountain Pipeline.

The Minerals Management Service (MMS) reviewed the information you submitted, and we have approved, subject to future audit, 1986 transportation allowances as outlined in the enclosed Findings and Conclusions. The procedures for determining your tentative 1987 transportation allowances are also outlined in the enclosed Findings and Conclusions.

When submitting the data for a transportation allowance, you must include copies of all current sales contracts or any subsequent amendments covering disposition of your interest in the production from the lease. Also, you should list the names and addresses of other working interest owners on whose behalf you are tendering royalty payments. The MMS will then forward a copy of the transportation allowance letter to each of the listed companies. This should reduce the number of separate allowance requests. For those working interest owners who are reporting and paying royalties on their own behalf, a separate transportation allowance must be requested.

You have the right to appeal this decision in accordance with 30 CFR 290. Please refer to the appeals procedure enclosure.

If there are any questions, please call (303) 231-3395.

Sincerely,

William H. Feldmiller

William H. Feldmiller
Chief, Royalty, Valuation and
Standards Division

2 Enclosures

CONTAINS COMPANY PROPRIETARY
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MOBIL PRODUCING TEXAS & NEW MEXICO INC.

ROYALTY MANAGEMENT PROGRAM
ROYALTY VALUATION AND STANDARDS DIVISION
Findings and Conclusions
on
McElmo Dome Transportation Allowances

BACKGROUND

Carbon dioxide (CO_2) is produced from the McElmo Dome Unit in Montezuma County, Colorado. Shell Western E&P Inc. (SWEPI) is the operator of the unit. Mobil Producing Texas & New Mexico Inc. (MPTM) is a working interest owner in the McElmo Dome Unit. The CO_2 is transported through the Cortez Pipeline to oil fields in west Texas where it is used in enhanced oil recovery projects. The Cortez Pipeline is owned by the Cortez Pipeline Company, of which MPTM, SWEPI, and Conoco Inc. are parent owners.

By letter dated March 16, 1987, MPTM requested approval of transportation allowances pertaining to CO_2 production transported from the McElmo Dome Unit to the following delivery points: McElmo Creek Unit; East Vacuum Unit; Central Basin Pipeline; Seminole-San Andres Unit; Willard Unit; Denver Unit; South Wasson Clearfork Unit; Mahoney Unit; Wellman Unit; Dollarhide Unit; Denver City Delivery Station (located on the Sheep Mountain Pipeline); and Denver City CO_2 Delivery Station (located on the Cortez Pipeline). The Denver City Delivery Station and the Denver City CO_2 Delivery Station are designated by MPTM as separate delivery points. The transportation allowances are discussed by pipeline segments which include the following: The Cortez Pipeline; MPTM's pipeline; West Texas Pipeline; and Sheep Mountain Pipeline.

FINDINGS

The Cortez Pipeline

- The MPTM requested a 1986 transportation allowance for CO_2 transported through the Cortez Pipeline from the McElmo Dome Unit to various units in west Texas. The Cortez Pipeline is owned by the Cortez Pipeline Company, of which MPTM, SWEPI, and Conoco Inc. are parent owners. The MPTM submitted a copy of the "Cortez Pipeline Company Letter Tariff" which charges MPTM \$0.39/Mcf for CO_2 transported through the Cortez Pipeline.

- The MMS's decisions dated March 29, 1984, and December 31, 1986, approved the costs incurred in the Cortez Pipeline Tariff, with the exception of

United States Department of the Interior

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

IN REPLY REFER TO:

AD/PSO/RIB 6-047-2c
Mail Stop 3062

JUL 12 1996

Mr. Jack J. Grynberg
President
Grynberg Petroleum Company
5000 South Quebec, Suite 500
Denver, Colorado 80237-2707

Dear Mr. Grynberg:

This is a followup to our April 8 and June 3, 1996, partial responses to your March 18 Freedom of Information Act (FOIA) request.

We are providing an additional nine-page document as responsive to your request. We are still consulting with several of the parties who submitted the information in the documentation you requested, and expect to complete our response by August 1.

We will enclose a bill for the cost to fulfill your request with our final response.

If you have any questions, please contact me at (303) 231-3013.

Sincerely,

Gregory K. Kann
Freedom of
Information Act Officer

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income tax, as a transportation allowance for the shipment of CO_2. The approved "tariff calculation" procedure allowed certain transportation charges assessed by Cortez Pipeline Company in accordance with a 1941 Pipeline Consent Decree. All components of the tariff were allowed to be deducted from the value of CO_2 with the exception of State and Federal income taxes. The SWEPI and MPTM are appealing the issue regarding the income taxes.

The MPTM's Pipeline

- Deliveries to the Seminole-San Andres, Willard, Wellman, and Mahoney units are via the Cortez Pipeline and MPTM's pipeline segment. A pipeline segment and pump connecting the Cortez Pipeline and Sheep Mountain Pipeline is operated by MPTM. The MPTM's pipeline segment extends from the Allred Station, located near the Cortez Pipeline, to the Denver City Delivery Station, located on the Sheep Mountain Pipeline. The MPTM provided actual cost data for their 1986 transportation allowance for CO_2 transportation from the Allred Station to the Denver City Delivery Station, and to the Wellman, Mahoney, and Willard units. Therefore, a 1986 allowance will be approved. Thereafter, MPTM should submit actual cost data for each year by April of the following year.

- The transportation costs submitted by MPTM for its pipeline segment are broken into four major components: Depreciation, Expenses, Interest, and Throughput. By letter dated December 31, 1986, MMS approved a 1985 allowance for MPTM's pipeline. The "Pipeline Capital Investment Depreciation Schedule" contained in the December 31, 1986, approval was utilized in the 1986 allowance calculation. (See Attachment 1.)

- The MPTM has used a 10 percent salvage value in calculating depreciation. The Conservation Division Manual (CDM) states ". . . unless otherwise justified by the lessee, a salvage value of 10 percent should be applied to tangible items when determining the depreciable investment cost to be used in allowance calculation. . . ." The MMS bases all allowable depreciation on the actual, out-of-pocket costs incurred for real property and equipment integral to the pipeline. The undepreciated investment for the beginning of 1986 is X-4 All the cost categories represent MMS-acceptable pipeline capital expenditures.

- The MPTM's submittal details the costs MPTM considers to be pertinent to the expense item of the transportation allowance calculation.

- The transportation allowance costs submitted by MPTM are broken into nine major groups: Operating Labor; Maintenance Labor; Operating Supplies,

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Utilities, and Fuel; Services Purchased; Maintenance Supplies; Trucks and Tractors; Overhead; Indirect Expenses; and Ad Valorem Taxes.

- The MMS's policy is to allow actual overhead costs limited to 10 percent of operating costs. The MPTM's overhead costs exceeded 10 percent of the allowable operating costs. Therefore, MPTM's overhead costs are limited to X-4 (See Attachment 2).

- The MPTM's category descriptions for operating and maintenance costs and indirect expense items represent MMS-acceptable pipeline expenses. The services purchased are within MMS-acceptable operation costs.

- The CDM allows certain operating expenses in the calculation of a transportation allowance. Section 647.5A.3B states in part:

  "Operating costs are those nondepreciable expenditures required to operate and maintain the pipeline system and shall be limited to the lesser of the following values: actual operating costs or 10 percent of the undepreciated initial or adjusted investment cost as of the beginning of the year for which the operating costs are being computed."

- The total MMS-allowable operating costs for MPTM's pipeline do not exceed 10 percent of the undepreciated investment at the beginning of 1986.

- Taxes (except income taxes) are allowed by MMS as an expense item. Only those taxes attributive to the pipeline will be allowed. The MPTM's request included a total figure of ad valorem taxes allocated to their pipeline segment.

- The MPTM submittal provided actual throughput for 1986. These figures represent CO_2 transported in MPTM's pipeline segment to the Seminole-San Andres, Willard, Wellman, and Mahoney units.

Sheep Mountain Pipeline

- A portion of MPTM's McElmo Dome CO_2 production is transported to the Seminole-San Andres Unit via the Cortez Pipeline, MPTM's pipeline segment, and Sheep Mountain Pipeline. The MPTM requested a transportation allowance for CO_2 production transported through the Sheep Mountain Pipeline.

- Amerada Hess Corporation (AHC) is an undivided interest owner of 30 percent of the southern segment of the Sheep Mountain Pipeline System which begins in New Mexico and extends to the Seminole-San Andres Unit, Gaines County, Texas. The arm's-length "Carbon Dioxide Transportation Agreement" was negotiated between MPTM and AHC on February 13, 1984, to transport MPTM's

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portion of CO_2 Production from the Denver City Delivery Station, located on the Sheep Mountain Pipeline to the Seminole-San Andres Unit. The MPTM is charged a transportation fee of X-4 /Mcf of CO_2 measured at the delivery station on the Sheep Mountain Pipeline.

West Texas Pipeline

- The MPTM requested a 1986 transportation allowance for CO_2 transported through the West Texas Pipeline. The arm's-length "Carbon Dioxide Transportation Contract" was negotiated between MPTM and Big Three Industries, Inc. on April 18, 1986, to transport MPTM's portion of CO_2 production from the Denver City CO_2 Delivery Station, located on the Cortez Pipeline, to the South Wasson Clearfork Unit. The MPTM is charged a transportation fee of X-4 per month. The monthly charge is adjusted by an adjustment multiplier as detailed in Section 6.2 of the transportation agreement. The MPTM submitted figures for July 1986 through December 1986. The information submitted by MPTM contained monthly charges to MPTM from Big Three Industries, Inc.

- The MPTM requested a transportation allowance of X-4 /Mcf for CO_2 transported to the Dollarhide Unit through the West Texas Pipeline. The arm's-length transportation agreement was negotiated on September 9, 1985, between MPTM and Big Three Industries, Inc.

- The CDM, Section 647.5C.3 states in part:

  "Allowances will be granted to cover transportation costs incurred in moving production through pipelines owned by parties other than the lessee. The allowance will be limited to . . . actual charges to the lessee for transporting production, pursuant to an arm's-length contract."

- The CDM, Section 647.5.3C states in part:

  "Generally, if the lessee/operator is transporting production under an arm's-length agreement by the only mode available to him, then these costs may be allowed even though they may be higher than other modes of transportation."

The Cortez Tariff No. 2

- The MPTM requested a 1986 allowance for a transfer charge for the movement of CO_2 through a gathering system from the Yellow Jacket Junction to the junction of Cortez Gathering System and the Hovenweep Central Facility Pipeline. The MPTM submitted a copy of the "Cortez Pipeline Company Letter Tariff No. 2" which charges MPTM $0.05/Mcf for the movement of CO_2 from non-Hovenweep Facility sources through the gathering system located within the McElmo Dome Unit boundary.

° At 43 CFR 3162.7, "Measurement, disposition and protection of production," Section (a) reads as follows:

> "The lessee shall put into marketable condition, if economically feasible, all oil, other hydrocarbons, gas and sulphur produced from the leased land."

° Section 647.3A of the CDM, states in part:

> "The lessee is obligated to place lease production in marketable condition without deduction of costs for measuring, compressing or otherwise conditioning the gas for market. Under no circumstances will royalty be computed on less than the gross proceeds accruing to the lessee from the sale of leasehold production."

° Notice to Lessees and Operators No. 1 (NTL-1), "Procedures for Reporting and Accounting for Royalties," under Section III, "Gas and Associated Liquids Production, Sales, and Royalty Requirements," states:

> "Under no circumstances will the royalty value be computed on less than the gross proceeds accruing to the operator from the sale of such leasehold production. Gross proceeds include, but are not limited to, tax reimbursements and payments to the operator for gathering, measuring, compressing, dehydrating, or performing other services necessary to market the production. Likewise, no deduction will be allowed for the cost which an operator incurs by reason of placing the gas in a marketable condition as an operator is obligated to do so at no cost to the lessor."

° The preceding statement is primarily concerned with gross proceeds. However, in defining the term, gathering gas is considered part of the activities for which the operator is responsible, at no cost to the lessor.

CONCLUSIONS

The Cortez Pipeline

° The Cortez Pipeline "tariff calculation" procedure to arrive at a value deduction for transportation costs proposed by MPTM is acceptable, with the exception that, for royalty purposes, State and Federal income taxes are not to be considered in computing transportation costs. Accordingly, State

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and Federal income taxes should be eliminated before transportation costs are computed.

- This method of determining the 1986 transportation allowance for the Cortez Pipeline should be used for calculating the tentative 1987 transportation allowance for this pipeline segment.

The MPTM's Pipeline

- The MPTM's pipeline transportation allowance will be computed annually based on actual allowable costs, consistent with the MMS's established policy. The MPTM should submit actual cost data for each year by April of the following year.
- The pipeline operating and maintenance costs represent MMS-acceptable operating costs. All compression-related operating and maintenance costs, however, will be disallowed.
- The MMS's policy is to require actual overhead costs (not to exceed 10 percent of the allowable costs) in computing a transportation allowance. The MPTM's overhead cost exceeded 10 percent of the allowable costs and limited MPTM's overhead figure.
- Attachments 1 and 2 detail all costs allowed by MMS for MPTM's pipeline. Attachment 1 is a copy of the depreciation schedule for MPTM's pipeline approved by letter dated December 31, 1986. Attachment 3 details the calculated 1986 allowance for MPTM's pipeline. For this pipeline segment, the approved 1986 transportation allowance will be used for the tentative 1987 transportation allowance.

The Sheep Mountain Pipeline

- The MMS's policy is to grant transportation allowances to cover transportation costs incurred in moving production through pipelines not owned by the lessee. Therefore, the transportation cost of X-4 /Mcf charged to MPTM, pursuant to an arm's-length agreement, for transporting CO_2 production through the Sheep Mountain Pipeline is an acceptable transportation allowance.
- For the Sheep Mountain Pipeline, the approved transportation allowance will be used during 1986. The actual fee charged to MPTM in 1987 by AHC should be used as the approved cost for this pipeline segment during 1987.

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The West Texas Pipeline

- The transportation fee of X.4 per month adjusted by an adjustment multiplier charged to MPTM, pursuant to an arm's-length agreement, for transporting CO_2 production through the West Texas Pipeline to the South Wasson Clearfork Unit is an acceptable transportation allowance. The approved allowances are for July 1986 through December 1986 and are the actual monthly charges. The actual monthly fee charged to MPTM in 1987 by Big Three Industries, Inc. should be used as the approved costs for this pipeline segment during 1987.

- The transportation cost of X.4 'Mcf charged to MPTM, pursuant to an arm's-length agreement, for transporting CO_2 production through the West Texas Pipeline to the Dollarhide Unit is an acceptable transportation allowance. For this pipeline segment, the approved transportation allowance will be used during 1986. The actual fee charged to MPTM in 1987 should be used as the approved cost for this pipeline segment during 1987.

The Cortez Tariff No. 2

- Pertinent regulations and NTL-1 clearly state that the lease operator has the responsibility and obligation to place the gas (CO_2) in marketable condition. The lease operator is obligated to perform necessary field gathering operations; therefore, the gathering charges under the Cortez Pipeline Tariff No. 2 are not deductible in computing Federal royalty.

- The MPTM's request for gathering charges to be approved as a transportation allowance is denied. Gathering costs are not allowed as a deduction from Federal royalty.

Limitation of the Transportation Allowances

- To determine the transportation allowance for each delivery point, MPTM should calculate the sum of the approved transportation allowances for the pipeline segments to each delivery point.

- The 1986 allowance which MPTM may deduct will be the lesser of the approved allowance (the sum of the approved 1986 transportation allowances for the pipeline segments to each delivery point) or 50 percent of the value of the CO_2 at the sales point.

- The 1987 allowance which MPTM may deduct will be the lesser of the tentatively approved 1987 transportation allowance (the sum of the approved and tentatively approved 1987 transportation allowances for the pipeline segments to each delivery point) or 50 percent of the value of the CO_2 at the sales point.

Attachment 1

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MOBIL PRODUCING TEXAS & NEW MEXICO INC.

Mobil CO_2 Transportation Allowance
Pipeline Capital Investment Depreciation Schedule

(1) Allowance Year	(2) Capital Invest.	(3) Undep. Invst. Beg. of Year	(4) Depreciation	(5) Undep. Invst. End of Year	(6) Return on Invest.
1985	X-4				
1986					
1987					
1988					
1989					
1990					
1991					
1992					
1993					
1994					
1995					
1996					
1997					
1998					
1999					
2000					
2001					
2002					
2003					
2004					
2005					

X-4

(1) 20-year, straight-line depreciation, 10 percent salvage value.

(2) Allowable pipeline capital investment.

(3) Remaining undepreciated investment at beginning of year.

(4) Annual depreciation X-4 ÷ 20).

(5) Undepreciated investment, beginning of year minus annual depreciation.

(6) Undepreciated investment, beginning of year times prime interest rate of 10.75 percent.

Attachment 2

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Operating Expenses, MPTM CO_2 Pipeline - 1986

Pipeline O&M[1]

Ad Valorem Tax[2]

Actual Operating Costs

Overhead (limited to 10 percent allowable operating costs)

Total MMS-Allowable Operating Expenses[3] (limited to lesser of actual operating expenses or 10 percent undepreciated investment)

X-4

---

[1] and [2] Figures from MPTM's submittal dated March 16, 1987.

[3]The MPTM's actual operating expenses did not exceed 10 percent of the undepreciated investment.

Attachment 3

CONTAINS COMPANY PROPRIETARY
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Transportation Allowance Calculation, MPTM CO_2 pipeline - 1986

$$\text{Transportation Allowance} = \frac{\text{Depreciation(D)}^{1} + \text{Operating Expenses(E)}^{2} + \text{Return on Investment(I)}}{\text{Throughput}}$$

— X — 4 ———[3]

Seminole-San Andres Unit	X — 4	/Mcf
Willard, Wellman, and Mahoney Units	X — 4	/Mcf

---

[1]Depreciation and return on investment figures from Attachment 1.

[2]Operating expenses from Attachment 2.

[3]The MPTM submitted a breakdown of costs which includes 80 percent applied to the Seminole-San Andres Unit and 20 percent to the Willard, Wellman and Mahoney units.

(172)

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225
Mail Stop 653

IN REPLY REFER TO:

MMS-RVS-OG:87-0095

MAY 22 1987

Memorandum

To: Chief, Division of Appeals

Through: Program Analyst (Litigation)

From: Chief, Royalty Valuation and Standards Division

Subject: Appeal by Mobil Producing Texas and New Mexico Inc. Concerning McElmo Dome Unit CO_2 Transportation Allowances

By letter dated February 3, 1987 (copy attached), Mobil Producing Texas and New Mexico Inc. (MPTM) filed an appeal to a Minerals Management Service (MMS) decision dated December 31, 1986 (copy attached). The December 31 decision approved transportation allowances pertaining to carbon dioxide (CO_2) production transported from the McElmo Dome Unit in southwestern Colorado to the Denver Unit, the Seminole-San Andres Unit, and the Wellman Unit, all of which are located in west Texas. The MPTM requested an additional 30 days in which to submit its Statement of Reasons in support of the appeal. By letter dated February 24, 1987, MMS's Royalty Valuation and Standards Division (RVSD), approved MPTM's request and granted additional time until March 7, 1987, to submit the Statement of Reasons in support of the appeal.

BACKGROUND

Carbon dioxide (CO_2) is produced from the McElmo Dome Unit in Dolores and Montezuma Counties, Colorado. Shell Western Exploration and Production Inc. (SWEPI) is the operator of the unit. The MPTM is a working interest owner in the McElmo Dome Unit. The CO_2 is transported through the Cortez Pipeline to oil fields in west Texas where it is used in enhanced oil recovery projects. The Cortez Pipeline is owned by the Cortez Pipeline Company, of which MPTM, SWEPI, and Conoco, Inc. are parent owners.

By decision dated December 31, 1986, MMS approved transportation allowances for the following pipeline segments: the Cortez Pipeline; MPTM's pipeline; and the Sheep Mountain Pipeline. The MMS-approved "tariff calculation" procedure for the Cortez Pipeline allowed certain transportation charges assessed by the Cortez Pipeline Company in accordance with a 1941 Pipeline Consent Decree. All components of the Cortez Pipeline Tariff were allowed to be deducted from the value of CO_2 prior to determining royalty with the exception of Federal and State income tax. The MMS-approved transportation allowance for MPTM's pipeline was computed based on actual allowable costs for the pipeline segment. The Sheep Mountain Pipeline transportation allowance was based on an arm's-length agreement to cover transportation costs incurred in moving production through pipelines not owned by the lessee. The MPTM filed an appeal dated February 3, 1987, to MMS's decision of December 31, 1986. The MPTM's appeal addressed six issues in which it contends that MMS was in error in its December 31, 1986, decision. Five of the issues pertain to the transportation allowance granted for MPTM's pipeline and one of the issues pertains to the Cortez Pipeline Tariff. These issues are:

1) General Argument. The MMS's decision approved transportation allowances for CO_2 production transported from the McElmo Dome Unit based on information in the Conservation Division Manual (CDM). The MPTM argues that the CDM takes the form of a directive and materially modifies existing regulations and is not lawfully in effect since the CDM was not promulgated and published in compliance with 5 U.S.C. § 552.

   The MPTM's appeal stated that no notice or justification has been given for procedures which, if applied, could substantially affect MPTM's liability to the United States for royalties accruing with respect to the McElmo Dome Unit. The MPTM further states that ". . . since the CDM was not promulgated and published in a manner consistent with Section 552 of the Administrative Procedures Act, policy guidelines therein, to the extent adverse to MPTM, should be deemed void."

RVSD's Response

Onshore oil and gas regulations do not specifically address royalty requirements for transportation deductions for CO_2 production. The Code of Federal Regulations (CFR), 30 CFR 206.103, "Value Basis for Computing Royalties," provides (in part) that ". . . due consideration being given to the highest price paid for a part or for a majority of production . . . to the price received by the lessee, to posted prices, and to other relevant matters." "Other relevant matters" were considered by MMS. As a matter of fact, "other relevant matters" is the only regulatory authority for the approval of transportation allowances. The CDM was the procedural guide issued by the Conservation Division of the United States Geological Survey (USGS), predecessor to the MMS. The CDM provides the guidelines for determining the reasonable costs incurred by the lessee in transporting onshore production to the nearest sales outlet. The guidelines include transportation costs "as one of the relevant matters" in establishing value for royalty purposes.

2) Operating Costs. The MPTM's appeal stated that ad valorem taxes allowed by MMS as an expense item for MPTM's pipeline should not be considered in calculating operating costs since such taxes are not a cost of producing CO_2. The MPTM also challenges the limitation of operating costs to the lesser of the actual operating costs or 10 percent of the undepreciated initial investment.

The MPTM cites the CDM Section 647.5A.3B, which states in part:

> "Operating costs are those nondepreciable expenditures required to operate and maintain the pipeline system and shall be limited to the lesser of the following values: actual operating costs or 10 percent of the undepreciated initial or adjusted investment cost as of the beginning of the year for which the operating costs are being computed."

The MPTM states that the ad valorem taxes comprise X.4 percent of the total operating costs which are not established nor controlled by MPTM. In addition, MPTM argues that the limitation of operating costs to the lesser of the actual operating costs or 10 percent of the undepreciated initial investment results in discrimination against the owners of the Cortez Pipeline since no limitation is placed on producers who are not owners of the Cortez Pipeline.

RVSD's Response

The MMS's policy is to include ad valorem taxes attributable to the pipeline as an allowable operating cost. The CDM, Section 647.5A.3B, allows taxes (except income taxes) as an operating expense item. The CDM, Section 647.5A.3B, also specifies the limitation of operating costs to the lesser of the actual operating costs or 10 percent of the undepreciated initial or adjusted investment cost for producer-owned and operated pipelines.

3) Rate of Return on Investment. The MPTM appeal stated that the prime interest rate used to calculate the rate of return on investment for MPTM's pipeline should have been 11.25 percent, as published in the Wall Street Journal on January 2, 1985. The MPTM further argues that MMS's use of the prime interest rate is unreasonable since such rate reflects short-term cost of money to bank's most favored customers and can fluctuate within a year.

   The MPTM recommends that the rate of return should be established by MMS and should be published in the Federal Register in February of each calendar year. To be consistent with industry practice, MPTM requests that MMS calculate the rate by multiplying: "i) the average of the twelve (12) rates for twenty-year Treasury Bills published in the Wall Street Journal on the first publication date of each month of the preceding calendar year by ii) one hundred fifty percent (150%)."

RVSD's Response

The MMS's policy is to use the prime interest rate as published in the Wall Street Journal in effect at the beginning of the year for which the initial allowance is granted. The CDM, Section 647.5A.3A, provides that "the prime interest rate in effect at the time of initial allowance approval should be used." The prime interest rate published in the Wall Street Journal on January 2, 1985, was 10.75 percent, rather than 11.25 percent as cited by MPTM. However, this rate reflects the interest rate in effect for December 31, 1984. The prime interest rate published in the Wall Street Journal on January 3, 1985, reflecting the rate in effect for January 2, 1985, was 10.75 percent (see attachment). Therefore, the 10.75 percent prime interest rate used by MMS to calculate the allowable return on the depreciated investment was appropriate and in accordance with MMS's policy.

4) Compression Expenses. The MPTM's appeal stated that the disallowance of compression expenses for MPTM's pipeline segment is unreasonable since MMS fails to recognize that such expenses are production, operating, or maintenance in nature. The MPTM further argues that unusual operational circumstances exist at the McElmo Dome Unit; therefore, MPTM should be allowed to deduct compression related expenses for the purposes of calculating the transportation allowances.

   The MPTM cites the Financial Accounting and Reporting by Oil & Gas Producing Companies, Financial Accounting Standards Board (Statement No. 19) which states that "if unusual physical or operational circumstances exist, it may be more appropriate to regard the production function as terminating at the first point at which oil, gas or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal." The MPTM maintains that standard accounting practice allows compression related expenses to be deducted as a production cost. The MPTM points out that no market exists for CO_2 at the McElmo Dome Field; therefore, all CO_2 must be transported to remote locations. Costs associated with this transportation should be allowed since compression is the only method in which to transport the CO_2 to the Sheep Mountain Pipeline.

RVSD Response

Compression costs are not allowed as a deduction from Federal royalty. The CDM, Section 647.3A, Notice to Lessees and Operators No. 1 (NTL-1), and 43 CFR 3162.7 provide 2 that the lessee is obligated to place lease production in marketable condition without deduction of costs for compressing the gas for market. Decisions by the Director, Geological Survey, and a supporting court decision, The California Company v. Secretary of the Interior, August 10, 1961, have upheld the principle that the lease operator is obligated to perform necessary field gathering, dehydration, and compression operations. The court made the distinction between "transportation" of gas and "conditioning" of gas and accepted the Secretary's definition of production as "gas conditioned for market."

5) Allowable Limitation. The MPTM states that the transportation allowance ceiling limitation of 50 percent of the royalty value of the CO_2 at the

sales point does not recognize current market conditions. This limitation pertains to the approved transportation allowances for the Cortez Pipeline, MPTM's pipeline, and Sheep Mountain Pipeline to each delivery point. The MPTM further provides that product prices have decreased considerably during the past few years, while MPTM's operating costs have increased or remained constant.

RVSD Response

The CDM, Section 647.5.3E provides that under no circumstances should the transportation costs exceed 50 percent of the products fair market value at the market competitive sales point. The RVSD allows the reasonable actual transportation costs as proper deductions in computing royalties. However, RVSD must comply with established regulations, guidelines, and procedures. Therefore, the MMS's decision dated December 31, 1986, cites the 50 percent limitation on transportation deductions for CO_2 moved to the marketing locations. The decision is based upon established procedures in the regulations and the CDM. However, the Secretary may grant relief from the 50 percent limitation provided the lessee can demonstrate unusual circumstances which warrant such action.

6) Federal Income Taxes. The Cortez Pipeline "tariff calculation" procedure allowed MPTM to deduct certain transportation charges assessed by the Cortez Pipeline Company in accordance with a 1941 Pipeline Consent Decree. All components of the tariff were allowed to be deducted from the value of CO_2 prior to determining royalty with the exception of Federal and State income tax. The MPTM appealed the exception of Federal and State income tax as a cost of transportation.

   The MPTM's appeal stated that the tariff rate does not include Federal income tax since the tariff rate calculated under the 1941 Consent Decree would be considerably higher than \$0.39/Mcf based on current output. In addition, MPTM adopts SWEPI's Statement of Reasons in support of SWEPI's appeal dated October 9, 1986.

RVSD's Response

The RVSD upholds its previous position with regard to Federal and State income taxes. In Williams' Oil and Gas Law, Vol. 3, § 604.6(b) clearly defines which costs may be considered as a cost of operation; "the current cost of operation has been held to include taxes (other than income taxes) payable by the owner of the working interests." In addition, in Matzen v. Hugoton Production Co., (321 P.2d 576), the Supreme Court of Kansas upheld evidence which established that "from an accounting standpoint, income tax is a sharing of profits, not a cost; that in cost accounting, income tax is never used as a factor in determining cost of operation, cost of sales, nor of any other item." The RVSD recommends that income tax should not be allowed as part of the cost of transportation as claimed by MPTM.

CONCLUSIONS

- For all reasons stated above, RVSD recommends that the transportation allowances approved in MMS's decision dated December 31, 1986, be upheld.
- The RVSD disagrees with all six issues presented by MPTM in support of the appeal. Therefore, RVSD recommends MPTM's appeal be denied.

William H. Feldmiller

William H. Feldmiller

3 Attachments

(39)

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY REFER TO:

Mail Stop 653

MMS-RVSD-OG

Memorandum

To: Deputy Associate Director for Valuation and Audit

Through: Chief, Royalty Valuation and Standards Division

From: Chief, Oil and Gas Valuation Branch
Royalty Valuation and Standards Division

Subject: Appeal by Mobil Producing Texas and New Mexico, Inc. Concerning McElmo Dome CO_2 Transportation Allowance (MMS-87-0194-O&G)

The Director's decision dated October 30, 1987 (copy attached), was issued in response to Mobil Producing Texas and New Mexico, Inc.'s (Mobil) appeal of a Royalty Valuation and Standards Division (RVSD) order dated December 31, 1986 (MMS-RVS-OG:85-0889). The October 30 decision remanded the issue concerning the rate of return applicable to the transportation allowance to RVSD for recalculation. In the October 30 decision, the Director determined that RVSD should have calculated the rate of return based on the prime interest rate in effect at the time of the initial allowance approval as stated in section 647.5A.3A. of the Conservation Division Manual (CDM).

Since Mobil's transporation allowance was approved on December 31, 1986, the Director concluded that RVSD erred in using the prime rate in effect on January 1, 1985. The RVSD believes that the Director should have upheld RVSD's original decision regarding the rate of return. By memorandum dated January 26, 1988 (copy attached), RVSD recommended to the Director that this issue regarding the recalculation of the rate of return for Mobil's transporation allowance be reconsidered. By memorandum dated February 25, 1988, the Director determined that ". . .if particular CDM provisions are deemed inappropriate, action should be taken to amend or update those provisions and/or the relevant regulations . . . ." The Director found no basis for reconsideration of the decision regarding the issue of the rate of return.

The CDM section 647.5.3E states, "If the application is timely received (normally within 30 days from the date of first sales, unless a later date is justified), then the allowance when approved should be retroactive to the date of first sales." The CDM further states that if the application is not timely received, then any allowance should be denied for the period prior to the receipt of the allowance request. A literal interpretation of this section is that Mobil's transportation allowance would not have been approved for any period prior to October 1985 because the application was not received within "30 days from the date of first sales." However, MMS's policy is to approve transportation allowances retroactively to the first production month for which royalty is due.

The October 30 and February 25 decisions that determined that RVSD should have calculated the rate of return ". . . based on the prime interest rate in effect at the time of the initial allowance approval . . ." was also a literal interpretation of the CDM. The RVSD believes that to use the prime interest rate in effect on the date the RVSD order was approved (signed) is inappropriate. The MMS's policy is to use the prime interest rate in effect on the first day of the deduction period for which the allowance has been approved by MMS, even if approved retroactively. This policy has been consistently applied by RVSD. Therefore, RVSD requests that this issue regarding the recalculation of the rate of return for Mobil's transportation be readdressed.

If you have any questions, please contact Theresa Walsh at extension 3395.

John L. Price

John L. Price

2 Attachments

McElmo 1985

25

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY REFER TO:

Mail Stop 653

MMS-RVS-OG:85-0889

ENCLOSURE CONTAINS COMPANY PROPRIETARY INFORMATION FOR RELEASE ONLY TO MOBIL PRODUCING TEXAS & NEW MEXICO INC.

Mobil Producing Texas & New Mexico Inc.
Attention: Mr. Hector Casas
Nine Greenway Plaza - Suite 2700
Houston, Texas 77046

Gentlemen:

By letter dated October 28, 1985, you requested approval of transportation allowances pertaining to CO_2 production transported from the McElmo Dome Unit in southwestern Colorado to the Denver Unit, the Seminole San Andreas Unit, and the Wellman Unit all of which are located in west Texas.

The information you submitted has been reviewed. We have approved, subject to future audit, 1985 transportation allowances as outlined in Attachment 4 to the Findings and Conclusions.

The allowances approved for 1985 are to be used as the tentative allowances for production during calendar year 1986 and until the next annual adjustment. Pertinent data for calculation of the actual 1986 transportation allowances must reach our office by April 1, 1987.

When submitting the data for a transportation allowance, you must include copies of all current sales contracts or any subsequent amendments covering disposition of your interest in the production from the lease. Also, you should list the names and addresses of the other working interest owners on whose behalf you are tendering royalty payments. The Minerals Management Service (MMS) will then forward a copy of the transportation allowance letter to each of the listed companies. This should reduce the number of separate allowance requests. For those working interest owners who are reporting and paying royalties on their own behalf, a separate transportation allowance must be requested.

Enclosed is a copy of our Findings and Conclusions showing the basis for our approval of the transportation allowances.

You have the right to appeal this decision. Please refer to the enclosure for the royalty adjustments and appeals procedure.

If there are any questions, please call (303) 231-3395.

Sincerely,

Thomas J. Blair

for William H. Feldmiller
Chief, Royalty Valuation and
Standards Division

2 Enclosures

THIS DOCUMENT CONTAINS COMPANY PROPRIETARY INFORMATION FOR RELEASE ONLY TO MOBIL PRODUCING TEXAS & NEW MEXICO INC.

ROYALTY MANAGEMENT PROGRAM
ROYALTY VALUATION AND STANDARDS DIVISION

Findings and Conclusions on McElmo Dome Unit CO_2 Transportation Allowances

BACKGROUND

Carbon dioxide (CO_2) is produced from the McElmo Dome Unit in Montezuma County, Colorado. Shell Western E & P Inc. (SWEPI) is the operator of the unit. Mobil Producing Texas & New Mexico Inc. (MPTM) is a small share working-interest owner in the McElmo Dome Unit. The CO_2 is transported through the Cortez Pipeline to oil fields in west Texas where it is used in enhanced oil recovery projects. The Cortez Pipeline is owned by the Cortez Pipeline Company, of which MPTM, SWEPI, and Conoco are parent owners.

By letter dated October 28, 1985, MPTM requested approval of transportation allowances for CO_2 production transported from the McElmo Dome Unit in southwestern Colorado to the Denver Unit, the Seminole San Andreas Unit, and the Wellman Unit all of which are located in west Texas. Minerals Management Service (MMS), by letters dated December 26, 1985, and May 7, 1986, requested additional information on the data submitted in the October 28 request.

The MMS will require MPTM to establish CO_2 value for McElmo Dome CO_2 delivered to each unit based on the arm's-length CO_2 sales and purchase contract(s) in existence for each unit. By letter dated August 8, 1986, MMS requested MPTM to submit a proposed valuation procedure for the establishment of value(s) for royalty purposes, of CO_2 disposed under any contracts covering disposition of MPTM's portion of CO_2 from the McElmo Dome Unit. A royalty valuation procedure for CO_2 production from the McElmo Dome Unit will be established by MMS pending receipt of MPTM's proposed valuation procedure. The transportation allowances for CO_2 production from the McElmo Dome Field will be addressed separately from the valuation procedure as agreed upon in the September 11, 1986, meeting between representatives from Royalty Valuation and Standards Division (RVSD) and Dean Lee (MPTM). This approval will address the transportation allowances for CO_2 production from the McElmo Dome Unit to the Denver Unit, the Seminole San Andreas Unit, and the Wellman Unit. In the Findings and Conclusions, the transportation allowances are discussed by pipeline segments which include the following: the Cortez Pipeline; MPTM's pipeline; and the Sheep Mountain Pipeline.

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FINDINGS

The Cortez Pipeline

- The MPTM has requested a 1985 transportation allowance for CO_2 transported through the Cortez Pipeline from the McElmo Dome Unit to the Denver Unit in Yoakum and Gaines Counties, Texas. The MPTM submitted a copy of the "Cortez Pipeline Company Letter Tariff" which charges MPTM $0.39/Mcf for CO_2 transported through the Cortez Pipeline. The Cortez Pipeline Company is a general partnership owned by SWEPI, MPTM, and Conoco. The Cortez Pipeline Company owns a 500 mile, 30-inch pipeline ultimately capable of transporting approximately 1,000,000 Mcf/day of CO_2.

- The MMS's decision of March 29, 1984, approved the costs incurred in the Cortez Pipeline Tariff, with the exception of income tax, as a transportation allowance for the shipment of CO_2 to the Denver Unit. The approved "tariff calculation" procedure allowed certain transportation charges assessed by Cortez Pipeline Company in accordance with a 1941 Pipeline Consent Decree. All components of the tariff were allowed to be deducted from Federal royalty with the exception of state and Federal income tax. Shell is appealing the issue regarding income tax.

MPTM's Pipeline

- Deliveries of CO_2 to the Seminole San Andreas Unit are via the Cortez Pipeline and the Arco-operated Sheep Mountain Pipeline. A pipeline segment and pump connecting these two pipelines is operated by MPTM. The MPTM's pipeline segment extends from the Allred Station, located on Cortez Pipeline, to the Denver City delivery station, located on the Sheep Mountain Pipeline, and to the Wellman Unit. The MPTM initially submitted an estimated transportation cost of ¢X.4/Mcf for MPTM's pipeline segment. However, by letter dated May 29, 1986, MPTM provided actual cost data for their 1985 transportation allowance for CO_2 transportation from the Allred Station to the Denver City delivery station and the Wellman Unit. Therefore, a 1985 allowance will be approved. Thereafter, MPTM should submit actual cost data for each year by April of the following year.

- The transportation allowance costs submitted by MPTM for its pipeline segment are broken into four major components: Depreciation, Expenses, Interest, and Throughput. Each major component will be discussed separately in detail.

Depreciation

- The MPTM has used a 10 percent salvage value in calculating depreciation. The CDM states, " . . . unless otherwise justified by the lessee, a salvage value of 10 percent should be applied to tangible items when determining the depreciable investment cost to be used in allowance calculation. . . ."

- As stated above, MMS bases allowable depreciation on the actual, out-of-pocket costs incurred for real property and equipment integral to the pipeline. The MPTM's request shows as-spent capital on the pipeline of X-4 . This figure represents costs incurred for constructing the pipeline. All the cost categories represent MMS-acceptable pipeline capital expenditures.

Expenses

- The CDM allows certain operating expenses in the calculation of a transportation allowance. Section 647.5A.3B states in part:

  "Operating costs are those nondepreciable expenditures required to operate and maintain the pipeline system and shall be limited to the lesser of the following values: actual operating costs or 10 percent of the undepreciated initial or adjusted investment cost as of the beginning of the year for which the operating costs are being computed."

- The MPTM's submittal details the costs MPTM considers to be pertinent to the expense item of the transportation allowance calculation. The MPTM's actual operating costs exceeded 10 percent of the undepreciated initial investment. Therefore, the total MMS-allowable operating expenses used in the calculation of the transportation allowance for MPTM's pipeline was 10 percent of the undepreciated initial investment.

- The transportation allowance costs submitted by MPTM are broken into nine major groups: Operating Labor; Maintenance Labor; Operating Supplies, Utilities and Fuel Purchased; Services Purchased; Maintenance Supplies; Sales and Use Taxes; Other Direct Expenses; Indirect Expenses; and Ad Valorem Taxes. On September 15, 1986, Mr. Charles Shirley, a representative of MPTM was contacted by Ms. Theresa Walsh (RVSD). The operating expenses were discussed in detail and are within the criteria of MMS-allowable costs. The following is a discussion of the expense groups.

- O & M Costs -- The operating and maintenance (O & M) labor are comprised of direct wages paid to employees while engaged in maintaining, operating, or repairing the line. The O & M supplies are comprised of capital expenditures for miscellaneous parts associated with repair and maintenance of the pipeline. The category descriptions for O & M costs represent MMS-acceptable pipeline expenses.

- Services Purchased -- Services purchased are comprised of electrical and other energy purchase costs necessary for operation of pumps. These services are within MMS-acceptable operating costs.

- Direct and Indirect Expenses -- The direct expense includes foreman expense, insurance, and taxes on pipeline and equipment, etc. It is MMS's policy to allow actual overhead costs limited to 10 percent of operating costs. The MPTM's indirect expense (overhead) is less than 10 percent of allowable operating costs. Therefore, MPTM's overhead figure is acceptable.

- Ad Valorem Taxes -- Taxes (except income taxes) are allowed by MMS as an expense item. Only those taxes attributable to the pipeline will be allowed. The MPTM's request included a total figure of ad valorem taxes allocated to their pipeline segment.

Interest

- The CDM Section 647.5A.3A states in part:

  "Unless otherwise justified, the prime interest rate in effect at the time of initial allowance approval should be used as the rate of allowable return on the depreciated investment. Once established, the rate will be continuous (fixed) over the life of the pipeline."

  It is MMS's policy to use the prime interest rate, as published in the Wall Street Journal, in effect at the beginning of the year for which the initial allowance is granted. This rate then remains fixed for the remainder of the 20-year expected life of the project. The interest rate on January 8, 1985, was 10.75 percent. This rate will be used for calculating the allowable return on the depreciated investment.

Throughput

- The MPTM submittal provided actual throughput for 1985. These figures represent CO_2 transported in MPTM's pipeline from the Allred Station to

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the Denver City delivery station and from the Allred station to the Wellman Unit.

Calculation of MPTM's CO_2 Pipeline Transportation Allowance

- Attachment 1 is the MMS-computed, 20-year depreciation schedule. An investment figure of X-4 a salvage of 10 percent and a prime interest rate of 10.75 percent were used as discussed above.

- Attachment 2 provides a summary of the MMS-allowable costs and the 10 percent overhead calculation.

- In accordance with MMS's practice and policy, the 1985 transportation allowances for MTPM's pipeline are calculated as shown in Attachment 3. The approved allowance rates based on allowable actual costs are X-4 /Mcf for CO_2 transported to the Denver City delivery station and /Mcf transported to the Wellman Unit.

Sheep Mountain Pipeline

- A portion of MPTM's McElmo Dome CO_2 production is transported to the Seminole San Andreas Unit via the Cortez Pipeline, MPTM's pipeline, and the Sheep Mountain Pipeline. The MPTM requested a transportation allowance for CO_2 production transported through the Sheep Mountain Pipeline to the Seminole Andreas Unit.

- Amerada Hess Corporation (AHC) is an undivided owner of 30 percent of the southern segment of the Sheep Mountain Pipeline System which begins in New Mexico and extends to the Seminole San Andreas Unit, Gaines County, Texas. The arm's-length "Carbon Dioxide Transportation Agreement" was negotiated between MPTM and AHC on February 13, 1984, to transport MPTM's portion of CO_2 production from the Denver City delivery station, located on the Sheep Mountain Pipeline to the Seminole San Andreas Unit. The MPTM is charged a transportation of \$0.035/Mcf of CO_2 measured at the delivery station on the Sheep Mountain Pipeline.

- The CDM, Section 647.5.3C states in part:

  "Generally, if the lessee/operator is transporting production under an arm's-length agreement by the only mode available to him, then these costs may be allowed even though they may be higher than other modes of transportation."

- The CDM, Section 647.5C.3 states in part:

  "Allowances will be granted to cover transportation costs incurred in moving production through pipelines owned by parties other than the lessee. The allowances will be limited to . . . actual charges to the lessee for transporting production, pursuant to an arm's-length contract."

CONCLUSIONS

The Cortez Pipeline

- The Cortez Pipeline "tariff calculation" procedure to arrive at a value deduction for transportation costs proposed by MPTM is acceptable, with the exception that, for royalty purposes, state and Federal income tax are not to be considered in computing transportation costs. Accordingly, state and Federal income tax should be eliminated before transportation costs are computed.

MPTM's Pipeline

- The MPTM's pipeline transportation allowance will be computed annually based on actual allowable costs, consistent with the MMS's established policy. The MPTM should submit actual cost data for each year by April of the following year.

- The pipeline O & M costs (including power necessary to operate the pipeline) represent MMS-accepted operating costs. All compression-related O & M costs, however, will be disallowed.

- Only those ad valorem taxes attributable to the pipeline will be allowed.

- It is MMS's policy to require actual overhead costs (not to exceed 10 percent of the allowable costs) in computing a transportation allowance. The MPTM's overhead costs did not exceed 10 percent of the allowable costs; therefore, the overhead figure is acceptable.

- The allowable return on the depreciated investment will be based on the prime interest rate in effect at the beginning of the year for which the initial allowance is granted. This rate was 10.75 percent on January 8, 1985.

- Attachments 1 and 2 detail all costs allowed by MMS for MPTM's pipeline. Attachment 3 details the calculated 1985 allowance for MPTM's pipeline.

The Sheep Mountain Pipeline

- It is MMS's policy to grant transportation allowances to cover transportation costs incurred in moving production through pipelines not owned by the lessee. Therefore, the transportation cost of $0.035/Mcf charged to MPTM, pursuant to an arm's-length agreement, for transporting CO_2 production through the Sheep Mountain Pipeline is an acceptable transportation allowance.

- Attachment 4 details the MMS-approved transportation allowances for CO_2 transported from the McElmo Dome Unit to the following delivery points; the Denver Unit, the Seminole San Andreas Unit, and the Wellman Unit. The 1985 transportation allowances are broken into pipeline segments to each of the units.

- The CDM, Section 647.5.3E states, "Under no circumstances should transported costs exceed 50 percent of the product's fair market value at the market competitive sales point."

- The 1985 allowances which MPTM may deduct will be the lesser of the approved allowance (the sum of the approved transportation allowances for the pipeline segments to each delivery point) or 50 percent of the value of the CO_2 at the sales point.

Attachment 1

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Mobil CO_2 Transportation Allowance
Pipeline Capital Investment Depreciation Schedule

(1) Allowance Year	(2) Capital Invest.	(3) Undep. Invst. Beg. of Year	(4) Depreciation	(5) Undep. Invst. End of Year	(6) Return on Invest.
1985	X-4				
1986					
1987					
1988					
1989					
1990					
1991					
1992					
1993					
1994		X-4			
1995			X-4		
1996				X-4	X-4
1997					
1998					
1999					
2000					
2001					
2002					
2003					
2004					
2005					

(1) 20-year, straight-line depreciation, 10 percent salvage value.

(2) Allowable pipeline capital investment.

(3) Remaining undepreciated investment at beginning of year.

(4) Annual depreciation —X-4—

(5) Undepreciated investment, beginning of year minus annual depreciation.

(6) Undepreciated investment, beginning of year times prime interest rate of 10.75 percent.

Attachment 2

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1985 Operating Expenses, MPTM CO_2 Pipeline

Pipeline O & M[1]	$158,140.47
Ad Valorem Tax[2]	$211,020.62
Actual Operating Costs	$369,161.09
Overhead (limited to 10% allowable operating costs)	X-4
Total Operating Expenses[3]	X-4
Undep. Investment beginning of year	$1,857,770.00
Total MMS-Allowable Operating Expenses (limited to lessor of actual operating expenses or 10% of undep. investment)	$185,777.00

1 and 2 Figures from MPTM's submittal dated May 29, 1986.

3 MPTM's actual operating expenses exceeded 10 percent of undepreciated investment.

Attachment 3

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Transportation Allowance Calculation, MPTM CO_2 Pipeline 1985

$$\text{Transportation allowance} = \frac{\text{Depreciation}^{1}(D) + \text{Operating expenses}(E)^{2} + \text{Return on investment}(I)}{\text{Throughput}}$$

X.4

Allred Station
to Wellman Unit

Allred Station to Denver
City Delivery Station

X.4

---

1 Depreciation and return on investment figures from Attachment 1.

2 Operating expenses from Attachment 2.

3 MPTM submitted a breakdown of costs which included 80 percent applied to the Seminole San Andreas Unit and 20 percent applied to the Wellman Unit.

Attachment 4

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1985 MMS-Approved Transportation Allowances

Period	Segments	Allowance ($/Mcf) Denver Unit	Seminole-San Andreas Unit	Wellman Unit
1/1/85 - 12/31/85	McElmo Dome Unit to Denver Unit/Allred Station (Cortez Pipeline)	$0.390000/Mcf	$0.390000/Mcf	$0.390000/Mcf
	Allred Station to Denver City Delivery Station (MPTM Pipeline)	---		
	Allred Station to Wellman Unit	---	x-y	
	Denver City Delivery Station to Seminole San Andreas Unit - (Sheep Mtn. Pipeline)	---		
Total allowance*		$0.390000/Mcf	x-y	

* The 1985 allowance which MPTM may deduct will be the lesser of the sum of the approved allowance for the pipeline segments to each unit or 50 percent of the value of CO_2 at the sales point.

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY
REFER TO:

Mail Stop 653

MMS-RVS-OG:85-956

JUN 28 1985

CONTAINS COMPANY PROPRIETARY
INFORMATION FOR RELEASE ONLY
TO ARCO AND EXXON

ARCO Oil and Gas Company
Rocky Mountain District
Attention: W. H. McMillian
P. O. Box 5540
Denver, CO 80217

Exxon Company, U.S.A.
Southwestern/Rocky Mountain Division
Attention: R. R. Hickman
P. O. Box 1600
Midland, TX 79702-1600

Gentlemen:

By letter dated June 14, 1985, Atlantic Richfield Company submitted an amended application for the establishment of an allowance for costs associated with the transportation of CO_2 from the Sheep Mountain Unit, Huerfano County, Colorado, to points of sale in West Texas. This application amends a previous application dated December 27, 1984, and includes the Exxon Corporation as a partner with ARCO in the application for an allowance for transportation costs.

The application refers to guidelines in the Conservation Division Manual (Geological Survey) Part 647.5, "Transportation Allowances," as a basis for the establishment of an allowance for transportation costs. Attached to the application were Exhibits I and II which described the basic transportation allowance formula and the cost components comprising the basic elements of the formula. The components listed were capital charges, operating and maintenance expenses, overhead, electric power, abandonment expenses, ad valorem taxes, and interest on unamortized investment.

MMS has reviewed your submittal and determined that additional information is required on each component before MMS can thoroughly understand the costs involved and can properly evaluate the application.

The following is a description of each cost category provided by ARCO and a description of the additional information requested by MMS:

1. Capital Charges

Provided by ARCO:

Expenditures 1983 Dollars; Pipeline and Associated Compression; X-4

MMS Request:

A breakdown of capital charges by pipeline segment (i.e., for 20" and 24" pipeline sections); within each segment a list of major capital expenditures by category -- item description, date of purchase, original cost, salvage value, depreciable life, and depreciation method; a schematic diagram of entire Sheep Mountain Pipeline (Colorado to Texas) depicting pipeline sizes, ownership, meter points, sales points, branches, purchasing units, and mileage.

2. Operating and Maintenance Expense

Provided by ARCO:

Direct expenses attributable to the operation and maintenance of the pipeline and associated compression, exclusive of well-related charges and noncompression-related drillsite and central office expenses.

MMS Request:

A description of individual categories of operating expenses, costs by category, and the methods of derivation, where applicable, by category (e.g., labor costs for pipeline operation, utilities, materials, ad valorem taxes, rent, supplies, maintenance parts, maintenance labor, etc.)

3. Overhead

Provided by ARCO:

X.4 percent of operating, ad valorem taxes, and power costs on pipeline and compression equipment.

MMS Request:

A breakdown, by cost category, as they appear in ARCO's record books; a justification of flat X.4 percent rate; and a detailed explanation of the inclusion of "compression equipment" as overhead.

4. Electric Power

Provided by ARCO:

All electric energy purchased to drive compressors and ancillary equipment to deliver a marketable product at the required pressure.

MMS Request:

A comprehensive list of items requiring electricity and costs associated with each item; the relationship, if any, of electric power to capital and operating costs; a description of "ancillary equipment"; a justification of using electricity to power compressors -- explanation of where compressors are located, why they are located there; and a breakdown of the electric costs to power compressors and ancillary equipment.

5. Abandonment Expenses

Provided by ARCO:

The total costs of removal and restoration are included at an estimated X.X percent of original cost for both pipeline- and compression-related items. The allocation to each year is based on a straight line method of recoupment of the estimated total future cost.

MMS Request:

A rationale for necessity of pipeline removal and associated costs; a justification of zero salvage value of pipeline upon removal; a justification of the X.X percent rate; and an explanation of "compression-related items" and how abandonment applies to "compression-related items."

6. Ad valorem taxes

Provided by ARCO:

The allocation to each year is Y.Y percent of the uninflated, undepreciated initial investment in pipeline and compression, as the weighted average of all three states (Colorado, New Mexico and Texas).

MMS Request:

A breakdown of ad valorem taxes for each state instead of weighted average.

7. Interest on Unamortized Investment

Provided by ARCO:

✓

The cost of facilities and working capital is equivalent to debt. The approach used herein is to apply the investment weighted average prime rate during construction to the unamortized investment at the beginning of the year. The weighted average prime rate is 15.45 percent.

MMS Request:

Cite the source of the prime rate figure and date and provide an explanation of what the prime rate applies to (i.e., does it apply to working capital in addition to undepreciated investment).

8. <u>Exhibit II, (Q) Total Pipeline Throughput (BCF): 567.8</u>

MMS Request:

A breakdown of actual monthly throughputs to date through each segment of the pipeline (i.e., 20" and 24" segments); monthly estimates of throughput through 1989; and the capacity of 20" pipeline and 24" pipeline at existing and planned future pressures.

In addition to the above-requested information, we will need contract and sales price information on 100 percent of the CO_2 leaving Sheep Mountain Unit. MMS has received four (4) contracts for the sale of CO_2 from ARCO to various parties in West Texas. MMS requests ARCO to submit any other sales price information or contracts relating to any other sale of ARCO's 50-percent share of CO_2 from Sheep Mountain (i.e., to the Sable San Andreas Unit).

MMS also requests Exxon to submit any and all information regarding the sales of its 50-percent share of CO_2 from Sheep Mountain to buyers in Texas, including information regarding affiliate sales or transfers.

Any proprietary information submitted by ARCO and Exxon will be safeguarded as required by law.

During a meeting between MMS, ARCO, and Exxon, on June 25, 1985, various aspects were discussed of the valuation, for royalty purposes, of CO_2 at Sheep Mountain Unit. One issue raised during discussion was a "large capital investment" due in 1988 in regard to the Sheep Mountain Unit. Please advise of the complete details on this issue.

During the June 25 meeting, it was tentatively planned to meet again on July 30, 1985, at 1:00 p.m., at the Denver Federal Center to further discuss the transportation cost deductions requested by ARCO and Exxon and any questions ARCO and Exxon may have regarding additional information requested by MMS.

Please feel free to contact us at (303) 231-3546 if there are any questions in the meantime.

Sincerely,

William H. Feldmiller

William H. Feldmiller
Chief, Royalty Valuation
and Standards Division

(43)

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY REFER TO:

Mail Stop 653

MMS-RVS-OG:84-906

APR 4 1985

ENCLOSURE CONTAINS COMPANY PROPRIETARY INFORMATION FOR RELEASE ONLY TO CONOCO

Conoco, Inc.
Attention: T. R. Painter
907 North Poplar
Casper, WY 82601

Gentlemen:

By letter dated October 22, 1984, you requested that MMS approve Conoco's "production reporting sequence" for carbon dioxide (CO_2) produced from the McCallum Unit in Jackson County, Colorado. Attached to your letter were copies of an Application for the Establishment of Royalty Values (Form 9-1926), a diagram of field facilities, and the sales agreement dated June 2, 1983.

The CO_2 is produced from the Dakota-Lakota zone through two facilities; one crediting production to the Dakota-Lakota, the other crediting production to the Morrison Participating Area "production bank." The "production bank" serves as a monitor on the CO_2 volume which originated from the Morrison Formation, and is now being recovered from the Dakota-Lakota zone.

The Bureau of Land Management (BLM) has jurisdiction over unit operations and production reporting for the McCallum Unit. You are advised to request approval of your "production reporting sequence" for the McCallum Unit from the appropriate BLM District Office in Craig, Colorado.

Although MMS no longer requires the submittal of Form 9-1926 for the establishment of royalty value, we interpret your October 22, 1984 submission as a request for advice on valuation for royalty purposes.

Under provisions of the sales agreement, dated June 2, 1983, CO_2 is liquefied at a plant on the McCallum Unit by Liquid Carbonic Corporation. Liquid Carbonic owns and operates the plant; however, Conoco retains ownership of the CO_2 until the plant tailgate. At that point, Liquid Carbonic purchases the CO_2 for a base price specified in the agreement. The price paid there varies annually, depending on market prices obtained by Liquid Carbonic for its liquid CO_2 in defined sales regions.

Article 2. of the sales agreement provides that Liquid Carbonic will pay "up-front" money to Conoco to be credited against the first purchase of CO_2. The agreement also contains provisions for price reductions tied to CO_2 stream quality.

Please be advised that the base price received by Conoco under its arm's-length agreement is acceptable for royalty purposes; provided that royalty is never based upon less than the gross proceeds accruing to Conoco from the sale of the CO_2. The price should be reported and royalty computed on Form MMS-2014 on an Mcf basis. The quality provision of your arm's-length contract is acceptable to MMS.

MMS should be paid its royalty share of the "up-front" money paid to Conoco by Liquid Carbonic as advanced royalty to be recouped from later royalty payments. MMS considers this a part of the gross proceeds which have been received by Conoco. If royalty payment has already been made, please disregard.

Royalties are also due on any tax and/or royalty increase reimbursements received by Conoco. These are also gross proceeds upon which royalty is due.

You have the right to appeal in accordance with the provisions of Title 30, Code of Federal Regulations Part 290. Enclosed is a copy of the Appeals Procedure.

Also enclosed is your Form 9-1926 and a copy of our Findings and Conclusions.

If you have any questions regarding this matter, contact us at (303) 231-3546.

Sincerely,

William H. Feldmiller

William H. Feldmiller
Chief, Royalty Valuation and
Standards Division

Enclosures (3)

cc: Bureau of Land Management
455 Emerson St.
Craig, CO 81625

CONTAINS COMPANY
PROPRIETARY INFORMATION
FOR RELEASE ONLY TO CONOCO

ROYALTY MANAGEMENT PROGRAM
ROYALTY VALUATION AND STANDARDS DIVISION

Findings and Conclusions
on
Valuation of CO_2 Produced by
Conoco at the McCallum Unit, Colorado

Background

- By letter dated October 22, 1984, Conoco, Inc. requested that the MMS review attached materials and approve Conoco's "production reporting sequence" for carbon dioxide (CO_2) produced from the McCallum Unit in Jackson County, Colorado. The attached materials were an Application for the Establishment of Royalty Values (Form 9-1926); a diagram of field facilities; and a contract with Liquid Carbonic Corporation, dated June 2, 1983, for the sale of CO_2.

- Conoco is operator of the McCallum Unit.

- Conoco produces raw CO_2 from the Dakota-Lakota zone, and transports it by two supply lines (high pressure and low pressure) to a liquefaction plant at the McCallum Unit where it is put into marketable condition. Liquid Carbonic, as owner of the plant, liquefies the CO_2 and purchases it after the liquefaction process. Conoco retains full ownership of the CO_2 until the tailgate of the plant.

- The contract calls for a price of $ X-4 per ton (approximately $ X-4 per Mcf at X-4 psia and 60°F) for the finished product. The price will vary annually depending on market prices obtained by Liquid Carbonic for its liquid CO_2 in defined sales regions.

- Any vent gases left over from processing will be returned to Conoco. These gases will be run through a separator to remove any existing condensate. The remaining gas will be compressed and reinjected into the Dakota-Lakota zone.

- From September 1976 to December 1983, Conoco injected a total of X-4 Mcf of Morrison Formation CO_2 into the Dakota-Lakota Well No. 2. This had been reflected in the submittal of Forms 9-329 for the Morrison Participating Area.

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- As instructed in the Unit Agreement, this gas must be credited to the Morrison Formation as it is withdrawn from the Dakota-Lakota Well No. 2.

- Under the proposed arrangement, CO_2 is produced from both the Dakota-Lakota Well No. 2 (high pressure) and the existing Dakota-Lakota Battery (low pressure). Production allocated to the Dakota-Lakota Well No. 2 will be credited to the Morrison Formation until the allocations cumulate a total of 7-4 Mcf. Production allocated to the Dakota-Lakota Battery will be credited to the Dakota-Lakota zone.

Findings

- According to the Corporate Affiliation Directory of 1984, Conoco, Inc. of Houston, Texas, has no corporate affiliation with Liquid Carbonic Corporation, of Chicago, Illinois.

- No CO_2 pipelines exist nearby the McCallum Unit; therefore, Liquid Carbonic has created the only market for CO_2 in the area.

- The "Option Agreement," executed June 1, 1984, Item 2., provides that "Liquid Carbonic agrees to pay Conoco X-4 ($ X-4) by wire transfer to a bank account specified by Conoco within two (2) business days from the date that this Option Agreement is fully executed. It is agreed that if Liquid Carbonic exercises the option to activate the Agreement, Liquid Carbonic will be issued a credit of X-4 ($ X-4) by Conoco to be applied against the first purchase of CO_2 under the Agreement."

- The contract contains provisions for decreased prices in the event(s) any hydrocarbons, other than methane, exceed specified levels or if the carbon dioxide content falls below 91.5 percent of the volume of the gas stream.

- The contract contains a standard provision for tax and/or royalty increase reimbursements (up to 50 percent of the increase) by the buyer (Liquid Carbonic) to the seller (Conoco).

- The BLM/MMS Memorandum of Understanding (MOU) as revised May 22, 1984, specifies BLM as responsible for the receipt of Monthly Reports of Operation, Form 3160-6 (formerly Form 9-329), for those leases which are not currently under the Production Accounting and Auditing System (PAAS). The McCallum Unit leases are not currently being handled under PAAS.

Conclusions

- Conoco should be advised to request approval of the "production reporting sequence" for the McCallum Unit from the appropriate BLM District Office in Craig, Colorado.
- The base price of $ X-4 per ton received by Conoco under its arm's-length contract is acceptable for royalty purposes. The price reduction provisions are accepted as part of the arm's-length contract.
- The liquefaction and handling of CO_2 at the McCallum plant are considered by MMS as operations necessary to place the CO_2 in marketable condition; hence, no processing allowance can be approved.
- Conoco should be advised that royalty is due on the $ X-4 "up-front" money, as this sum is to be applied against the first purchase of CO_2.
- Conoco should be advised that royalty is due on any tax and/or royalty increase that may be received as "gross proceeds" by Conoco as a Federal lessee.

Sheep Mtn

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY REFER TO:

MMS-RVS-OG:85-0011
M.S. 653

FEB 1 1985

ATTACHMENT CONTAINS COMPANY PROPRIETARY INFORMATION
FOR U.S. GOVERNMENT USE ONLY

Memorandum

To: Chief, Office of State and Tribal Program Support

Through: Chief, Royalty Compliance Division

From: Chief, Royalty Valuation and Standards Division

Subject: Request for Determination of CO_2 Value, Sheep Mountain Unit, Colorado

By letter dated December 31, 1984, you requested MMS to review a contract for the sale of carbon dioxide (CO_2) produced from the Sheep Mountain Unit in Huerfano County, Colorado. The contract is between Atlantic Richfield Company (ARCO), as seller, and —X-Y— as buyer, for sales in the Denver Unit in West Texas.

You requested answers to two questions:

1. On what value should Federal royalties be based?

2. Should ARCO be allowed to adjust the value of Colorado production based upon West Texas oil prices?

MMS is currently working with ARCO to establish a value, for royalty purposes, of CO_2 produced from the Sheep Mountain Unit. MMS will keep the State of Colorado informed as to the progress of this determination. Briefly, MMS believes that CO_2 produced from the Sheep Mountain Unit, transported, and sold by ARCO to buyers in West Texas should be valued, for royalty purposes, by a method similar to the McElmo Dome "net-back" procedure previously established by MMS.

MMS believes that CO_2, as it exists in Colorado, has little or no market value by which MMS can determine royalty. Because the sole value of this CO_2 lies in its ability to enhance oil production, the value of CO_2 in terms of West Texas oil prices is appropriate.

Attached is a copy of our "Findings and Conclusions" which answers your questions in more detail. If you have any questions regarding this matter, please contact us at FTS 326-3546.

Bill Feldmiller

William H. Feldmiller

Attachment

Cobb

CONTAINS COMPANY
PROPRIETARY INFORMATION
FOR U.S. GOVERNMENT USE ONLY

ROYALTY MANAGEMENT PROGRAM
ROYALTY VALUATION AND STANDARDS DIVISION

Findings and Conclusions
on
Office of State and Tribal Program Support Request
on
Sheep Mountain CO_2 Valuation

Background

- By letter dated December 31, 1984, the office of State and Tribal Program Support (STP) requested that MMS review a contract for the sale of carbon dioxide (CO_2) produced from the Sheep Mountain Unit in Huerfano County, Colorado.

- The contract, dated January 27, 1983, is between Atlantic Richfield Company (ARCO), as seller, and X-4 , as buyer, for sales in the Denver Unit in West Texas.

- ARCO is a working-interest owner in the Denver Unit.

- According to the letter of December 31, 1984, the ARCO X-4 contract provides for a sales price that is equal to the sum of the transportation charge (X-4 per Mcf) and the commodity price (X-4 X-4 as of December 1, 1982). The transportation charge remains constant over the life of the contract; however, the commodity price is adjusted quarterly based on West Texas oil prices.

- STP requested answers to two questions:

  1. On what value should Federal royalties be based?

  2. Should ARCO be allowed to adjust the value of Colorado production based upon West Texas oil prices?

Findings

- The contract between ARCO and X-4 dated January 27, 1983, is cancelled and is replaced by a contract dated May 9, 1984.

- ARCO has three additional contracts for the sale of CO_2 in West Texas: X-4 All four contracts presently provide for a sales price that is equal to the sum of a transportation charge of X-4 plus a base commodity price of X-4 (to be adjusted quarterly based on West Texas oil prices).

- The contracts mentioned above cover the sale of ARCO's 50-percent share of CO_2 produced from the Sheep Mountain Unit. ARCO has an agreement with Exxon Corporation whereby Exxon purchases the other 50 percent of the production from Sheep Mountain. At this time, no other information is available regarding the sale of CO_2 to Exxon.

X-4

- MMS has determined by letter dated March 29, 1984, that the CO_2 produced from the McElmo Dome shall be valued, for royalty purposes, using a "net-back" procedure. This is accomplished by (1) establishing the fair market value of the CO_2 at the Denver Unit, (2) deducting therefrom the cost of transporting the gas from the McElmo Dome Unit to the Denver Unit, and (3) adding thereto any other reimbursements that may be received as "gross proceeds" by X-4 as a Federal lessee.

X-4

- MMS determined that all the elements of the Cortez Pipeline Tariff, with the exception of income tax, were allowable deductions from the cost of transporting CO_2 from McElmo Dome to West Texas, for royalty purposes. X-4 is currently appealing the issue of income tax.

Conclusions

- MMS believes that CO_2 produced from the Sheep Mountain Unit, transported, and sold by ARCO to buyers in West Texas should be valued, for royalty purposes, by a method similar to the McElmo Dome "net-back" procedure.

- MMS is in the process of determining a value for CO_2 produced from Sheep Mountain. MMS will keep the State of Colorado informed as to the progress of this determination.

- MMS believes that CO_2, as it exists in Colorado, has little or no market value by which MMS can determine royalty. Because the sole value of this CO_2 lies in its ability to enhance oil production, the value of CO_2 in terms of West Texas oil prices is appropriate.

12/8/87

(14)

ISSUE PAPER

CARBON DIOXIDE COMPRESSION

Issue

Should MMS allow compression costs in the computation of the transporation allowance for carbon dioxide (CO_2) production?

Introduction

Compression has been considered by MMS as necessary to place lease production in marketable condition. Compression has been required to be performed at no cost to the lessor and, consequently, the costs of compression have not been allowed as a deduction when calculating Federal royalty. However, the point at which compression occurs is significant to the issue. Compression costs to place the product in marketable condition have not been allowed, but compression costs critical to transporting the product along the pipeline may be allowable. If this policy is accepted and compression costs critical to transporting the production along the pipeline are allowed, they could be allowable costs in the computation of the transportation allowance for CO_2 production. This paper will examine the function of the compression and the points at which compression occurs and recommend that certain compression costs be allowable transportation costs.

Historical Background

- Until the early 1980's, there was no market demand for CO_2 and compression was only at issue with natural gas. With the advent of major CO_2 projects in the Rocky Mountain region, the compression costs became a factor in determining the value of CO_2 for royalty purposes.

- Valuation decisions on three major CO_2 cases have been issued by MMS regarding the value of CO_2 for royalty purposes. In all of the decisions MMS has continued its policy of disallowing the costs of compression as a deduction in the computation of the value for royalty purposes.

- The first decision specific to CO_2 was issued by MMS on March 29, 1984, to Shell Western E&P, Inc. (SWEPI) for CO_2 produced from the McElmo Dome Unit (MMS-RVS-OG:83-0374). This decision approved the use of the calculation method in the Cortez Pipeline tariff, with the exception of the inclusion of income tax, to determine a transportation allowance for shipment of CO_2 to west Texas. The "tariff calculation" procedure approved for the Cortez Pipeline was based on the 1941 Pipeline Consent Decree methodology. The SWEPI appealed the exclusion of income taxes as a cost of transportation. The Director's decision in response to SWEPI's appeal, dated August 6, 1986 (MMS-84-0013-MISC), concurred with MMS's exclusion of income tax and ordered SWEPI to pay additional royalties based upon the methodology required by MMS. The issue of compression of CO_2 was not specifically addressed in the SWEPI decision, however, no compression costs were allowed for compressing CO_2 at the McElmo Dome Unit.

- A second major case involving CO_2 was issued by MMS on February 12, 1985, to Amoco Production Company for CO_2 produced from the Bravo Dome Unit (MMS-RVS-OG:84-0802). This decision reiterated MMS's position that pertinent regulations, Director's decisions, and the <u>California Company v. Udall</u> court decision require that the lessee place the leasehold gas production into marketable condition. The Bravo Dome Unit valuation decision recognized that, according to the lease terms and regulations, the term 'gas' includes carbon dioxide. Thus, the Federal lessee was held responsible for all costs involved in compressing the carbon dioxide at the Bravo Dome Unit. Transportation allowances were not involved in the valuation of the CO_2 from this unit.

- A second decision dated January 6, 1987, was issued to Amoco

(MMS-RVS-OG:85-0544) reaffirming that no deductions may be taken for the gathering, compression, and/or dehydration costs involved in placing CO_2 into marketable condition.

- A decision was issued on the third major case to Mobil Producing Texas and New Mexico Inc. (MPTM) (MMS-RVS-OG:85-0889), concerning the transportation of CO_2 produced at the McElmo Dome Unit. All costs submitted by MPTM regarding the transportation allowance for MPTM's pipeline were considered MMS-acceptable costs subject to certain limitations. In this decision it was stated that all compression costs would be disallowed, however, no costs were specifically identified by MPTM in its submittal as compression costs. This decision was appealed by MPTM. In the field report dated May 22, 1987 (MMS-RVS-OG:87-0095), provided to the Division of Appeals, MMS reiterated the policy that compression costs are not allowed as a deduction when calculating Federal royalty.

- The Director's decision in response to MPTM's appeal, dated October 30, 1987, concurred with MMS's order regarding compression costs and stated "This issue has been appealed numerous times, and the Department of the Interior (Department) has consistently held that the costs of gathering, dehydrating, and compression of gas produced on a Federal lease may not be deducted when computing the royalty value against which the royalty rate is applied."

- In addition to the Bravo Dome and McElmo Dome Projects, MMS has issued a draft decision to Arco Oil and Gas Company (ARCO), and Exxon regarding CO_2 production from the Sheep Mountain Unit. This draft decision has continued the policy of denying deduction of compression costs.

- The MMS did a review of the Department and Interior Board of Land Appeals (IBLA) decisions regarding the allowance of compression costs as a deduction in the computation of value for royalty purposes. The review involved searching MMS's database system for Director, U.S. Geological Survey, and IBLA decisions. Two decisions regarding compression costs were obtained from the review of the database. Both decisions were signed by the Assistant Secretary of Indian Affairs. Decision (MMS-87-0009-IND), dated September 29, 1987, denied a deduction for compression costs in determining the royalty value of gas produced on an Indian lease. In this case, Wellhead Enterprises, Inc. constructed a gas gathering and compression system that gathered gas on the lease. It was necessary to compress the gas so that gas would be accepted into the pipeline. The compression was determined to be necessary to place production in marketable condition. The other decision (87-0088-IND), dated August 20, 1987, denied a "tariff volume" requested as part of the transportation allowance. In this case, the pipeline company retained 2 percent of the gas transported for periodic compression of gas. The tariff volume constituted an offlease use of gas which was calculated in a theoretical basis using meters other than those officially recognized by the Bureau of Land Management. The MMS determined that royalties are due on the "tariff volume" as affirmed by the Secretarial Decision. This decision did not specifically disallow compression costs but rather determined the volume upon which the transportation allowance should be applied.

Compression Costs

° In order for MMS to determine whether compression costs should be allowed in the computation of the transportation allowance for CO_2 production, the function of the compression and the point at which compression occurs must be considered in the following situations:

1. The compression of CO_2 is performed in the field to condition production for initial delivery into the pipeline to meet purchaser specifications under a sales contract.

- The applicable regulations have consistently required that the lessee place the products from the leased lands into marketable condition. Marketable condition includes measuring, gathering, compressing and otherwise conditioning the production for the market. The lease products should be in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area. This includes the requirement that production be at a pressure sufficient to enter the pipeline. Although production may or may not actually be sold to a purchaser in the field, the compression of the production for initial delivery into a pipeline has been considered by MMS as necessary to place lease production in marketable condition. Compression performed to condition production for initial delivery into a pipeline is clearly addressed in the applicable regulations, NTL's and guidelines as necessary to place production in marketable condition to be performed at no cost to the lessor.

2. Compression of CO_2 is performed along the transportation pipeline as a transportation function.

- To date, MMS has not issued any decisions specifically allowing compression costs as <u>transportation</u> <u>costs</u>. However, if the compression was found to a transportation function, MMS may allow such costs as part of the allowable transportation costs. For example, the costs of compressors located along the transportation pipeline route where the primary function is to keep production moving through the pipeline may be considered by MMS as allowable transportation costs if a distinction can be made between compression performed along the transportation pipeline as a transportation function and compression performed to place production in marketable condition.

- Making this distinction may raise complicated issues such as, at which point should compression be considered transportation costs. The costs of compressors located along the transportation route where the primary function is to keep production moving through the pipeline could clearly be construed as transportation costs since the compression is performed to maintain the pressure at all points along the pipeline. Compression performed where the primary function is to get production from one pipeline into another pipeline system (after initial delivery from the field) could also be considered as transportation costs since the compression is necessary to move the production into another pipeline leading to the sales point.

3. Compression is performed in the field and/or at the inlet of the processing plant.

° When a gas stream is processed and CO_2 is one of the gas plant products, MMS's policy is that an allowance for compression costs cannot be allowed irrespective of whether the compression is performed at the field, at a processing plant, or at both the field and central processing plant.

° As discussed above, compression performed in the field to condition the production for initial delivery into a pipeline has been considered by MMS as necessary to place lease production in marketable condition. Allowing compression costs in the computation of a transportation allowance raises another issue as to whether compression should be allowed at the inlet of a processing plant when compession has already performed in the field as well. To date, MMS has not issued any decision specifically allowing compression at the inlet of the processing plant as part of the processing allowance, however, when compression is performed in the field and compression is also performed at the inlet of a processing plant, MMS may consider allowing compression costs at the inlet of a processing plant as part of the allowable processing deduction since this compression is performed after initial delivery in the field. For example, when lease production is processed and the sales point is remote from the production field, the production must be transported long distances, therefore, compression is performed in the field and at the inlet of a processing plant. Thus, when compression is performed in the field and at the inlet ~~of a processing plant, MMS may consider allowing compression costs at the~~ inlet of a processing plant as part of the processing allowance since this compression is performed after initial delivery in the field and is a function of the processing of the gas stream at the plant.

° However, when compression is not performed in the field but compression is performed at the inlet of a processing plant, no allowance is allowed for compression at the inlet of a processing plant since this compression must eventually be performed to condition production for initial delivery into a pipeline. In this case, the compression serves the same purpose as the commpression that is performed in this field. Therefore, the MMS considers this compression at the inlet of a processing plant as necessary to place production in marketable condition to be performed at no cost to the lessor.

4. Lease production is processed and recompression is performed at the tailgate of a processing plant.

° When the lessee chooses to process lease production and processing lowers the pressure of the production, no allowance for recompression is allowed since the recompression is considered by MMS as necessary to place lease production in marketable condition to meet purchaser specifications under a sales contract. The regulations at 30 CFR 206.106 (1987) and 206.152 (1987) state that ". . . no allowance shall be made for boosting residue gas or other expenses incidental to marketing." Recompression at the tailgate of a processing plant is not considered a function of the processing of the gas stream and, therefore, no processing deductions are allowed for recompressing the production at the tailgate of a processing plant.

- When the lessee sells production and retains the right to process and execises that right, the compression of production performed in the field to condition production for initial delivery into the pipeline is considered by MMS as necessary to place production in marketable condition. Also, when the lessee retains the right to process its gas, no processing deductions are allowed for recompressing the production at the tailgate of a processing plant.

McElmo Dome CO_2 Project

- In the case of MPTM's McElmo Dome CO_2 Project, CO_2 is compressed and enters the transporation pipeline at the McElmo Dome Unit. The MPTM did not request that these compression costs be included in the calculation of the transportation allowance. Compression of CO_2 that occurred within the McElmo Dome Unit was considered by MMS as a cost of placing lease production in marketable condition, thus, no allowance was granted for these compression costs.

- The costs submitted by MPTM to MMS for the computation of MPTM's transportation allowance did <u>not</u> specifically identify any cost as compression costs. In follow-up discussions with MPTM, however, it has been stated that the costs submitted by MPTM <u>did</u> contain compression costs. The costs included were for compression occurring along MPTM's pipeline in order to get CO_2 into the higher pressured Sheep Mountain Pipeline to continue moving the production to the sales point.

SUMMARY

- The applicable regulations, NTL's, and guidelines clearly address that compression to place production in marketable condition are not allowed as a deduction when calculating Federal royalty.

- Although MMS has not issued any decisions allowing compression costs as a deduction when calculating Federal royalty, MMS's policy is that if compression was found to be performed as a transportation function, MMS may allow such costs as part of the allowable transportation costs.

- Compression costs considered by MMS to be part of the cost of placing production in marketable condition at no cost to the lessor include the following situations:

    1. Any compression of CO_2 performed in the field to condition production for initial delivery into the pipeline;

    2. Compression performed at the inlet of a processing plant, provided that no compression is performed in the field; and

    3. Recompression performed at the tailgate of a processing plant.

- Compression performed after initial delivery in the field that are critical to transporting the product along the pipeline may be allowable in the computation of the transportation allowance for CO_2 production. These compression costs include the following situations:

    1. The costs of compressors located along the transportation route when the primary function is to keep production moving through the pipeline; and

    2. The costs of compressors located along the transportation route where the primary function is to compress CO_2 into another pipeline system in order to continue moving the production to the sales point.

- Compression performed at the inlet of a processing plant may be considered allowable by MMS as in the computation of the processing allowance provided that compression is also performed in the field.

- In MPTM's McElmo Dome Project, any compression performed at the McElmo Dome Unit for initial delivery into the pipeline is considered by MMS as necessary to place production in marketable condition at no cost to the lessor.

- The primary function of the compression for transporting CO_2 production through MPTM's pipeline is to compress CO_2 into another pipeline in order to continue moving the production to the sales point. To date, MPTM has not specifically identified which costs submitted to MMS were compression costs for MPTM's pipeline.

RECOMMENDATIONS

- The MMS should continue its policy that compression costs for placing production in marketable condition are not allowed as a deduction from the value of CO_2 upon which royalty is due.

- The MMS should allow compression critical to transporting the product along the pipeline as MMS-allowable transportation costs in the computation of the transportation allowance for CO_2 production. (See above MMS-allowable transportation costs.)

- The MMS should allow compression costs at the inlet of a processing plant as allowable costs in the computation of the processing allowance provided that compression is also performed in the field.

- Compression costs submitted by MPTM for the computation of MPTM's transportation allowance would be accepted by MMS as transportation costs if the compression is critical to moving the production from MPTM's pipeline into the Sheep Mountain pipeline as a transportation function.

- The MMS recommends that MPTM submit additional information specifically identifying the compression costs submitted by MPTM for the computation of MPTM's transportation allowance.

- The MMS would not recommend the recalculation of the transportation allowance for the McElmo Dome Project if all of the compression costs are identified as transportation costs since all costs previously submitted by MPTM regarding the transportation allowance for MPTM's pipeline were considered MMS-acceptable costs at the time of approval.

BRAVO DOME

(45)

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY
REFER TO:

MMS-RVS-O&G-84-802
M.S. 653

1 NOV 1984

Memorandum

To: Bravo Dome CO_2 File

From: Petroleum Engineer, Oil and Gas Valuation Branch

Subject: Meeting in Santa Fe, New Mexico on Bravo Dome CO_2

On Tuesday, October 23, 1984, I attended a meeting sponsored by the New Mexico State Land Office concerning the valuation of carbon dioxide (CO_2) sold from the Bravo Dome Unit in northeastern New Mexico. Attending the meeting were representatives from the State of New Mexico, Amerada Hess, Amoco, Exxon, and other oil companies.

The primary purpose of the meeting was to discuss a September 17, 1984, letter from the Taxation and Revenue Department to Amerada Hess. The main issues discussed in the letter dealt with allowable deductions from the sale value of carbon dioxide. Costs relating to gathering, dehydration, and compression were requested to be deducted from the sales value by Amerada Hess in a previous letter and were being addressed in the September 17 letter.

Amerada Hess requested a 15-year depreciation of the plant facilities (relating to dehydration and compression), however, the State required a 30-year depreciation. The State decided at the meeting that a 15-year depreciation was allowable if supported by sufficient evidence. Amerada Hess stated that such data would be submitted.

Next, Amerada Hess questioned the State if they would reconsider their position on not allowing expenses related to the gathering facilities and interest on unamortized investment or interest cost on investment. The State said they would review such proposals if Amerada Hess submitted more details, however, they were unlikely to alter their position.

In summary, it appears the State is willing to allow the four types of deductions (relating to dehydration and compression) stated in their September 17, 1984 letter, including a 15-year depreciation on the plant facilities. The State is not, apparently, going to allow any deductions relating to gathering expenses.

After the meeting, I met with Gary Carlson, Assistant Land Commissioner for Natural Resources for the State of New Mexico. I questioned him about the State's position in regard to gathering allowances in light of the language agreed to in the Bravo Dome Unit Agreement. He reasserted the State's firm position on denying gathering deductions from the State's royalty share. He stated that further correspondence with Amerada Hess is needed, and that we would be contacted about future correspondence. I told Gary that I would attempt to forward to him copies of our McElmo Dome and Sheep Mountain CO_2 valuation decisions.

Larry Cobb

Larry Cobb

Exxon's "LaBarge Proposal"

Issue

Approval of processing and transportation allowances, and approval of extraordinary processing cost allowance under the revised gas royalty valuation regulations.

Background

The attached diagram shows the relative location of operations in the LaBarge area.

By decision dated October 29, 1984, Royalty Valuation and Standards Division (RVSD) made the following determinations regarding Exxon Company U.S.A.'s (Exxon) application to include all processing and transportation costs in royalty calculations on gas attributable to Federal leases within the Graphite, Lake Ridge, and Fogarty Creek Federal Units, LaBarge area, Sublette County, Wyoming.

(1) The costs of the field dehydration facility and the costs to build and operate the pipeline from the field to the Shute Creek plant are not deductible in computing Federal royalty;

(2) Processing costs can be approved for the associated products removed and sold (to a maximum of 66-2/3 percent) but no portion of the processing costs can be applied to the value of the methane; and

(3) The costs required to transport carbon dioxide, methane, or sulfur, to the first sales point downstream of the plant are deductible (to a maximum of 50 percent of the value of the product).

On November 29, 1984, Exxon filed an appeal with the Director, Minerals Management Service, (MMS) from the RVSD decision. On January 18, 1985, Exxon filed a "Request for Special Exception Relief" with the Secretary of the Interior.

By decision MMS-RVS-0066-O&G dated January 7, 1986, the Director upheld the RVSD decision, with the exception that a transportation allowance for the pipeline constructed from the field to the Shute Creek plant was authorized.

Exxon appealed the Director's decision to IBLA (86-626) where a decision is now pending. The remaining issues are MMS's decisions to disallow:

(1) The costs of field dehydration; and

(2) Any processing costs for methane at the Shute Creek plant.

Exxon Proposal

At a meeting on March 15, 1988, Exxon representatives proposed the following cost allowances and exceptions for LaBarge royalty valuation in accordance with the revised gas royalty valuation regulations:

Transportation Allowance

The actual reasonable costs up to 75 percent of the methane, carbon dioxide, sulfur, and nitrogen product values, in proportion to the value of the volumes sold. A transportation allowance is requested for the dehydration facility, the "feed gas" pipeline, the sulfur transportation facilities and the CO_2 pipelines.

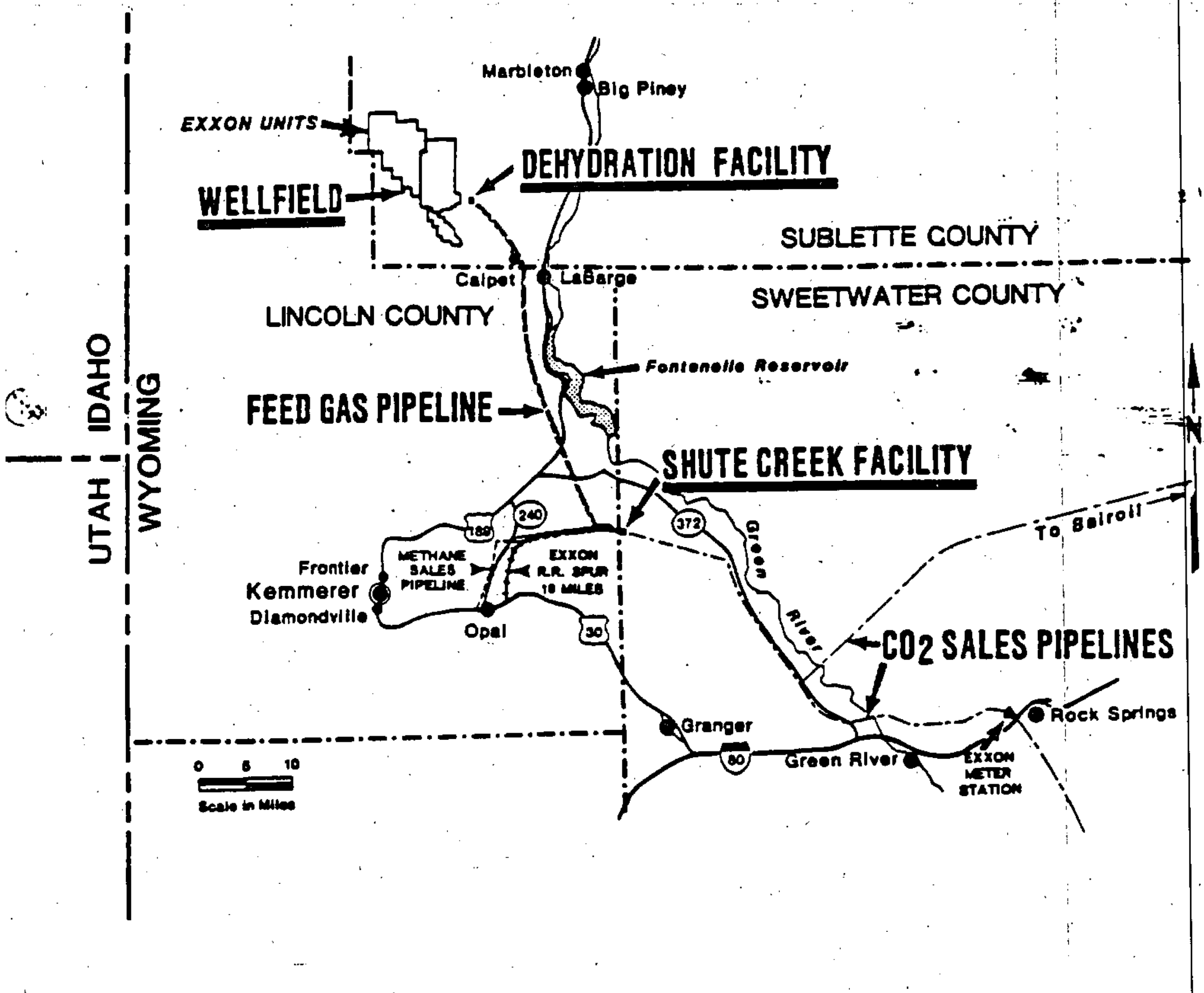
Processing Allowance

The actual reasonable costs of all Shute Creek processing facilities up to 95 percent of the carbon dioxide, sulfur, and nitrogen values, in proportion to the value of the volumes sold.

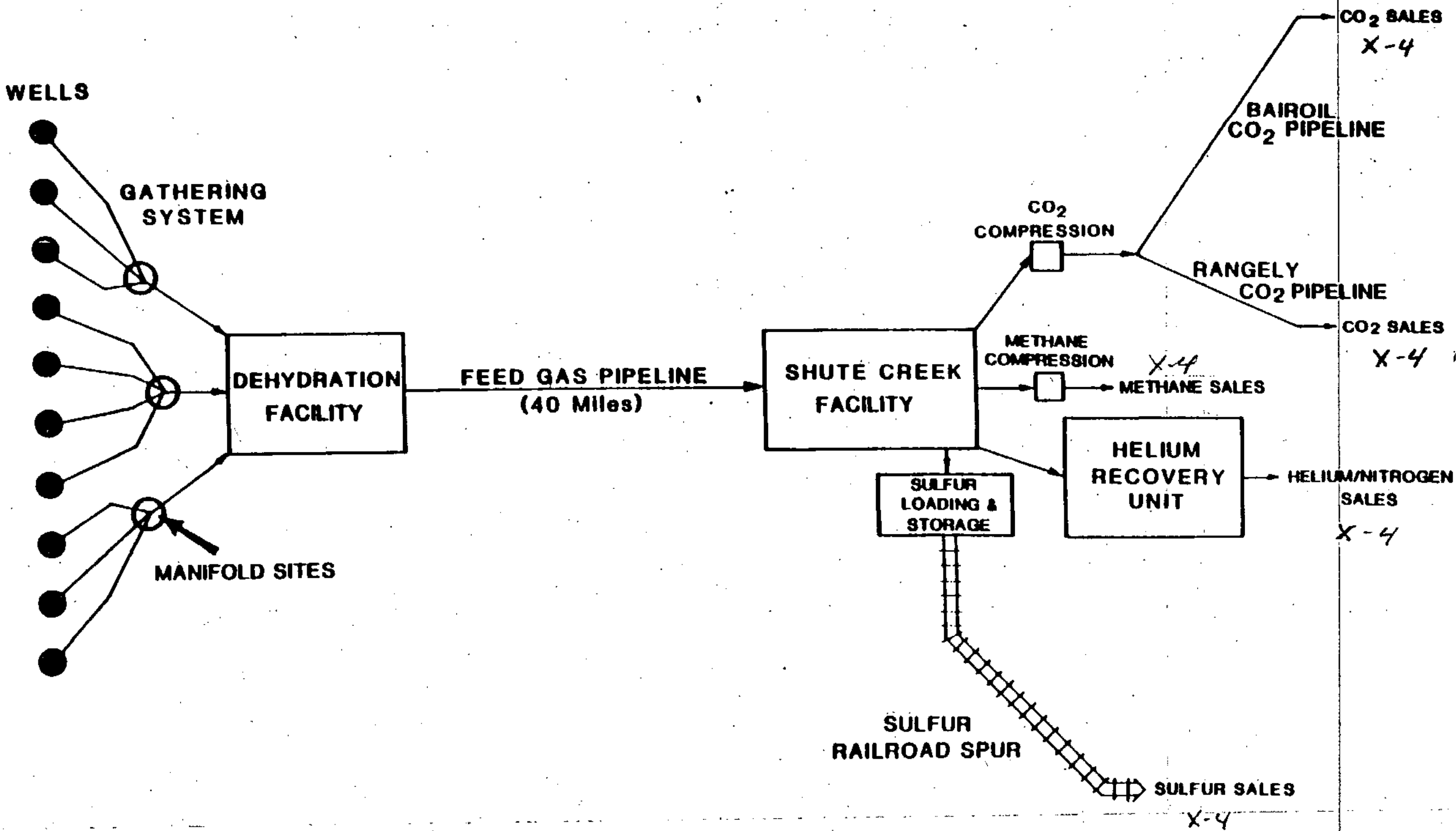
Extraordinary Cost Allowance

Exxon also requests an extraordinary cost allowance of up to 75 percent of the methane product value for those processing costs that exceed the 95 percent cost allowance for carbon dioxide, sulfur, and nitrogen.

LABARGE
FIELD AND FACILITY SITE LOCATION



LABARGE FLOW DIAGRAM



EXXON LA BARGE PROJECT--
ALTERNATE PROPOSAL

Purpose of Proposal:

- To provide an alternative to the primary valuation proposal provided by Exxon to MMS; would increase current royalty value and establish guaranteed minimum royalty value when costs high relative to revenue.

Methodology:

- All specified transportation and processing facilities eligible for transportation, ordinary processing, or extraordinary processing cost allowances.

- Allowance based on combined revenues from methane, CO_2, sulfur and nitrogen, and total processing/transportation costs.

- Cost allowance limited to lesser of total processing and transportation costs or 80 percent of gross proceeds (revenues).

- If processing and transportation costs greater than 80 percent of gross proceeds, then depreciable investment balance increased by adding costs exceeding 80 percent of gross proceeds; such added costs limited to maximum of 20 percent of gross proceeds.

- No depreciation taken until total processing and transportation costs excluding depreciation less than 80 percent of gross proceeds. Thereafter only a portion of depreciation taken until 80 percent of revenues exceeds total costs including depreciation. Then remaining undepreciated balance fully depreciated (straight line) over the remaining project life.

- Royalty value would be the greater of (1) 20 percent of revenues or (2) revenues less total cost deductions.

Results:

- Guaranteed minimum royalty of 20 percent of revenue.

- Increased royalty payments compared to primary proposal in early years.

- "Roll forward" of some costs not claimed as deductions in current year; less "permanent" loss of current-year costs than under primary proposal.

- Larger allowance components for depreciation in later years, and for return on investment throughout project life, than under primary proposal.

Conflicts with New Regulations:

- New regulations at 30 CFR §§ 206.157(b)(2) and 206.159(b)(2) permit allowances for non-arm's-length or no-contract situations based on lessee's actual costs for transportation or processing during the reporting period. No language, implicit or otherwise, permitting carry-forward of costs from previous periods.

- Same regulations state allowable capital costs are generally those for depreciable fixed assets which are integral part of transportation system or processing plant. No apparent justification for increasing depreciable balance by amounts representing operating, maintenance, or overhead costs, or return on investment. Nor is rate of return allowed on non-capital costs.

- New regulations allow straight-line depreciation based on life of equipment or life of reserves serviced. Thus, proposal to take no or partial depreciation until certain limits are met circumvents meaning of regulations--i.e., depreciation to be applied evenly over life of equipment or reserves, beginning at project inception. Proposal would result in inflated depreciation deductions in later years.

- Due to combined effects of increasing undepreciated balance by amount of "rolled-over" costs and taking limited or no depreciation in some years, the remaining depreciable balance, and hence the return on investment, would be higher throughout project life than otherwise allowable under the new regulations.

- Extraordinary cost provision of new regulations applies only to gas processing, and not to transportation. However, same procedures should be applied in calculating extraordinary cost allowances as for calculating ordinary ones.

"BASE VALUE"

.50 and .67 T&P 'CAPS'; NO EXTRAORDINARY COSTS; NO DEHY. OR WATER INJ. COSTS, NO COMPRESSION COSTS;
NO He TRANSPORTATION OR PROCESSING COSTS; T&P ONLY ON CO_2 VOLUME SOLD; ALLOC. ON VOLUME
NO TRANSPORTATION COSTS FOR CH_4 PLANT FUEL
(Data for Calendar Year 1987)

Product	Sales Volume	Post-Plant Transp. Costs	Plant Tailgate Value	% Volume (Excl. CH_4)	Proc. Costs Alloc. on Volume	67% Tailgate Value	Allow. Proc. Costs	Plant Inlet Value	Pre-Plant Transp. Alloc. on Volume	‡‡ [illegible]	Allow. Transp. Cost	Royalty Value
CH_4	34,492											
CO_2	54,392											
S	9,380											
N_2	44											
He	803											

X-4

X-4 proc. costs, excl. compr.
% CO_2 proc. & sold
X-4

X-4 n. CH_4 sales
n. plant inlet vol.
n. fuel gas pipeline costs

X-4

X-4 % CO_2 inlet gas
X-4

‡‡50% Sales Pt. Value Less Post-Plant Transportation Costs Previously Taken

***Regulations Would not Permit Reduction in Royalty Value to "0"

(All volumes in MMcf; all costs and values in 000's)

5/23/88

Scenario for Calculating
Federal Royalty on Gas
from Exxon's LaBarge
Processing Plant

- Transportation costs are allowed up to a limit of 50% of each product's value at the sales point. No transportation costs were eliminated by this limit.

- Processing costs are allowed up to a limit of 95% of each product's plant tailgate value, with plant processing costs allocated on the volume of each product in the incoming gas stream, excluding methane.

- Costs of processing helium, vented carbon dioxide and nitrogen volumes unsold are not shared in by the lessor. Helium from Federal lands is a non-royalty bearing product. Royalty is not required on volumes of carbon dioxide and nitrogen vented and/or unsold.

- Costs of compressing carbon dioxide and methane to meet market specifications are not allowed.

- Extraordinary costs are limited to the lesser of 50% of the methane tailgate value or the unrecovered processing costs attributable to the carbon dioxide, sulfur and nitrogen which are royalty bearing.

- Pre-plant transportation costs are allocated on the volume of each product in the incoming gas stream. Costs for transporting helium and vented and/or unsold carbon dioxide and nitrogen are not shared in by the lessor.

- Costs of dehydration of the gas stream for transportation are allowable, but no costs of the water disposal by injection are allowed.

"BASE VALUE"

.50 and .67 T&P 'CAPS'; NO EXTRAORDINARY COSTS; NO DEHY. OR WATER INJ. COSTS, NO COMPRESSION COSTS;
NO He TRANSPORTATION OR PROCESSING COSTS; T&P ONLY ON CO_2 VOLUME SOLD; ALLOC. ON VOLUME
NO TRANSPORTATION COSTS FOR CH_4 PLANT FUEL
(Data for Calendar Year 1987)

Product	Sales Volume	Post-Plant Transp. Costs	Plant Tailgate Value	% Volume (Excl. CH_4)	Proc. Costs Alloc. on Volume	67% Tailgate Value	Allow. Proc. Costs	Plant Inlet Value	Pre-Plant Transp. Alloc. on Volume	‡‡ [illegible]sp. [illegible]	Allow. Transp. Cost	Royalty Value
CH_4	34,492											
CO_2	54,392											
S	9,380											
N_2	44											
He	803											

X-4

X-4 = proc. costs, excl. compr.
= % CO_2 proc. & sold
X-4

X-4 ann. CH_4 sales
- ann. plant inlet vol.
- ann. fuel gas pipeline costs

X-4

X-4 % CO_2 inlet gas
X-4

‡‡50% Sales Pt. Value Less Post-Plant Transportation Costs Previously Taken

***Regulations Would not Permit Reduction in Royalty Value to "0"

(All volumes in MMcf; all costs and values in 000's)

.95 T&P 'CAPS'; NO EXTRAORDINARY COSTS; NO WATER INJ. COSTS, NO COMPRESSION COSTS; ALLOW DEHYDRATION COSTS;
NO He TRANSPORTATION OR PROCESSING COSTS; T&P ONLY ON CO_2 VOLUME SOLD; ALLOC. ON VOLUME
(Data for Calendar Year 1987)

Product	Sales Volume	Post-Plant Transp. Costs	Plant Tailgate Value	% Volume (Excl. CH_4)	Proc. Costs Alloc. on Volume	95% Tailgate Value	Allow. Proc. Costs	Plant Inlet Value	Pre-Plant Transp. Alloc. on Volume	‡‡Transp. Cost Limit	Allow. Transp. Cost	Royalty Value
CH_4	34,492											
CO_2	54,392											
S	9,380											
N_2	44					X-4						
He	803											

X-4 = proc. costs, excl. compr.
... = % CO_2 proc. & sold X-4

X-4 = % CO_2 inlet gas

‡‡95% Sales Pt. Value Less Post-Plant Transportation Costs Previously Taken

***Regulations Would not Permit Reduction in Royalty Value to "0"

(All volumes in MMcf; all costs and values in 000's)

.95 T&P 'CAPS'; NO EXTRAORDINARY COSTS; NO WATER INJ. COSTS, ALLOW DEHYDRATION COSTS;
NO He TRANSPORTATION OR PROCESSING COSTS; T&P ONLY ON CO_2 VOLUME SOLD; ALLOC. ON VOLUME
COMPRESSION COSTS ALLOWED
(Data for Calendar Year 1987)

Product	Sales Volume	Post-Plant Transp. Costs	Plant Tailgate Value	% Volume (Excl. CH_4)	Proc. Costs Alloc. on Volume	95% Tailgate Value	Allow. Proc. Costs	Plant Inlet Value	Pre-Plant Transp. Alloc. on Volume	‡‡Transp. Cost Limit	Allow. Transp. Cost	Royalty Value
CH_4	34,492											
CO_2	54,392										---	---
S	9,380											
N_2	44											
He	803											

X - Y

X-Y proc. costs, incl. compr.
total compr. costs; 11,131 = CO_2 compr. costs
% CO_2 proc. & sold

X-Y

X - Y = transp. costs, less water disposal
% CO_2 inlet gas
X - Y

‡‡95% Sales Pt. Value Less Post-Plant Transportation Costs Previously Taken

***Regulations Would not Permit Reduction in Royalty Value to "0"

(All volumes in MMcf; all costs and values in 000's)

EXXON PROPOSAL
(Data for Calendar Year 1987)

Product	Sales Revenue	Post-Plant Transp. Costs	Plant Tailgate Value	% Value (Excl. CH_4)‡	Proc. Costs Alloc. on Value	*Allow. Proc. Costs	Plant Inlet Value	Pre-Plant Transp. Alloc. on Value	**Transp. Cost Limit	Allow. Transp. Costs	Royalty Value
CH_4											
CO_2					X-4						
S											
N_2											

*95% Plant Tailgate Value Limit

‡After Deduction X-4 CH_4 Plant Tailgate Value for Extraordinary Cost -X-4-

**Based on X-4 Plant Inlet Value

(all volumes in MMcf; all costs and values in 000's)

EXXON PROPOSAL EXCEPT:

(1) ALLOW 50% T & 95% P COSTS; (2) NO COSTS FOR VENTED CO_2 OR He;
(3) NO COMPRESSION COSTS; (4) NO WATER WELL INJ. COSTS;
(5) ALLOCATE ON VOLUME;
(6) COMPUTE TRANSPORATION COSTS IN ACCORDANCE WITH REGULATIONS (NOT EXXON'S 2-SEGMENT SYSTEM)

(Data for Calendar Year 1987)

Product	Sales Volume	Post-Plant Transp. Costs	Plant Tailgate Value	% Volume Excl. CH_4	Proc. Costs Alloc. on Volume	Allow. Proc. Costs	Plant Inlet Value	Pre-Plant Transp. Alloc. on Volume	**Transp. Cost Limit	Allow. Transp. Costs	Royalty Value
CH_4	34,492	[illegible]	[illegible]	-							
CO_2	54,932										
S	9,380										
N_2	44										
He	803										
TOTAL:											

X-4

X-4 ' = total proc. costs except compression
% CO_2 proc. sold
X-4 9

‡After deduction of X-4 for extraordinary costs.

X-4

X-4 total costs except water inj.
% CO_2 plant inlet volume
; CO_2 processed and sold
X-4

**50% Sales Point Value Less Post-Plant Transportation Costs Already Taken

‡‡‡Regulations Would Not Permit Reduction in Royalty Value to "0"

(all volumes in MMcf; all costs and values in 000's)

EXXON PROPOSAL - EXCEPT ALLOCATE ON VOLUME
(Data for Calendar Year 1987)

Product	Sales Volume	Post-Plant Transp. Costs	Plant Tailgate Value	% Volume (excl. CH_4)	Proc. Costs Alloc. on Volume	*Allow. Proc. Costs	Plant Inlet Value	Pre-Plant Transp. Alloc. on Volume	**Tr[illegible] C[illegible] L[illegible]	Allow. Transp. Costs	Royalty Value
CH_4	34,492										
CO_2	54,392										
S	9,380										
N_2	44										

X-4

*[illegible] Plant Tailgate Value Limit

‡After Deduction 75% CH_4 Plant Tailgate Value for Extraordinary Costs X-4

**Based on X-4 Plant Inlet Value

(All volumes in MMcf; all costs and volumes in 000's)

EXXON PROPOSAL - EXCEPT NO COSTS ALLOWED FOR PROCESSING
OR TRANSPORTING VENTED CO_2 OR He
(Data for Calendar Year 1987)

Product	Sales Revenue	Post-Plant Transp. Costs	Plant Tailgate Value	% Value (Excl. CH_4)	Proc. Costs Alloc. on Value	**Allow. Proc. Costs	Plant Inlet Value	Pre-Plant Transp. Alloc. on Value	‡‡‡Transp. Cost Limit	Allow. Transp. Costs	Royalty Value
CH_4											
CO_2											
S											
N_2						X-4					
He											
TOTAL:											

X-4 = total proc. costs
% CO_2 proc. & sold
X-4

X-4 Plant Tailgate Value Limit

‡After deduction of X-4 extraordinary costs.

X-4 X-4

X-4 = % CO_2 plant inlet value
% CO_2 processed and sold
X-4

‡‡‡Based on 75% Plant Inlet Value

(all volumes MMcf; all costs and values in 000's)

EXXON PROPOSAL - EXCEPT NO COSTS ALLOWED FOR PROCESSING OR TRANSPORTING VENTED CO_2 OR He AND ALLOCATION ON VOLUME
(Data for Calendar Year 1987)

Product	Sales Volume	Post-Plant Transp. Costs	Plant Tailgate Value	% Volume Excl. CH_4	Proc. Costs Alloc. on Volume	**Allow. Proc. Costs	Plant Inlet Value	Pre-Plant Transp. Alloc. on Volume	***Transp. Cost Limit	Allow. Transp. Costs	Royalty Value
CH_4	34,492										
CO_2	54,932										
S	9,380										
N_2	44										
He	803										
TOTAL:											

X-4

------ = total proc. costs
X-4 % CO_2 proc. & sold

X-4 Plant Tailgate Value Limit

*After deduction of X-4 for extraordinary costs

X-4

X-4 Plant Inlet Volume
% CO_2 Processed and Sold
X-4

***Based on 75% Plant Inlet Value

(all volumes in MMcf; all costs and values in 000's)

EXXON PROPOSAL - EXCEPT
(1) ALLOW 50% T & 95% P COSTS; (2) NO COSTS FOR VENTED CO_2, He OR UNSOLD N_2
(3) NO COMPRESSION COSTS; (4) NO WATER WELL INJ. COSTS;
(5) ALLOCATE ON VOLUME;
(6) COMPUTE TRANSPORTATION COSTS IN ACCORDANCE WITH REGULATIONS (NOT EXXON'S 2-SEGMENT SYSTEM)
(Data for Calendar Year 1987)

Product	Sales Volume	Post-Plant Transp. Costs	Plant Tailgate Value	% Volume Processed Excl. CH_4	Proc. Costs Alloc. on Volume	Allow. Proc. Costs	Plant Inlet Value	Pre-Plant Transp. Alloc. on Volume	***Transp. Cost Limit	Allow. Transp. Costs	Royalty Value
CH_4											
CO_2					X-4						
S											
N_2											
He											
					X-4						
TOTAL:											

X-4 = total proc. costs excluding compression
% CO_2 processed and sold
X-4

X-4
= % N_2 processed & sold

†After deduction of X-4 for extraordinary costs (
X-4 Tailgate value is greater than the 'unrecovered' processing costs)

X-4 total costs excluding water inj.
% CO_2 plant inlet volume
CO_2 processed and sold
X-4

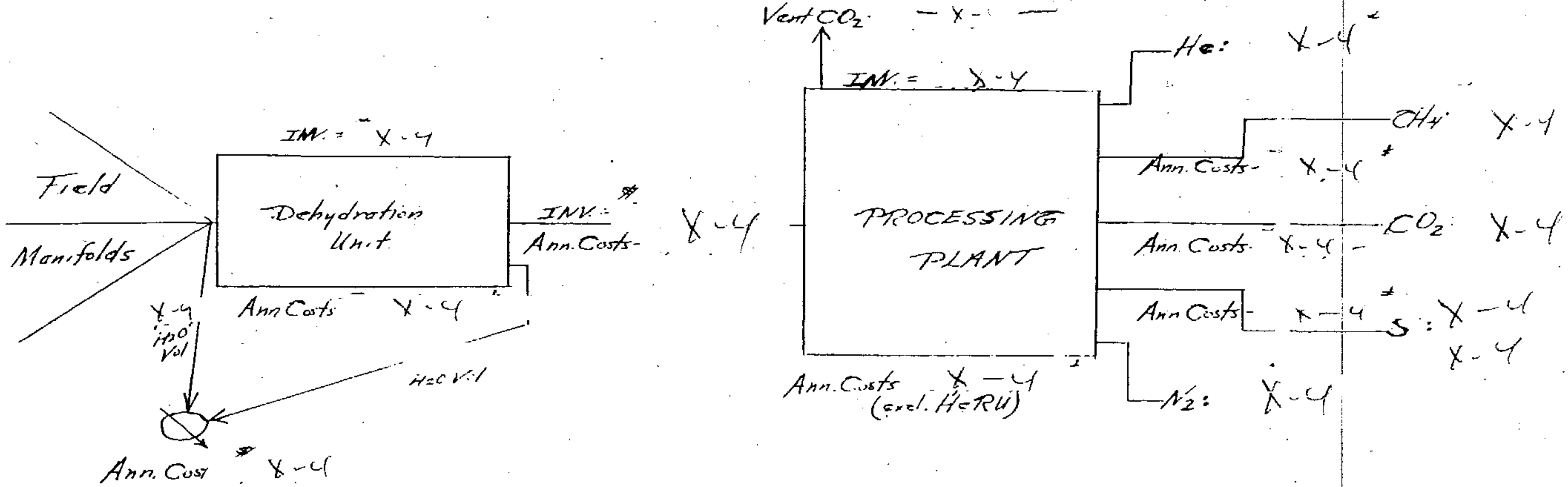
X-4 % N_2 plant inlet volume
% N_2 processed & sold
X-4

***50% Sales Point Value Less Post-Plant Transportation Costs Already Taken

‡‡‡‡Regulations Would Not Permit Reduction in Royalty Value to "0"

(All Volumes in MMcf; All Cost and Values in 000's)

La Barge Operation
1987 Data



Includes depreciation, return on inv., O&M & OH.

* Based on sales vol. info. from Bureau Mines (BM) & avg. price X-4 /Mcf from Exxon 9-30-87 rpt. to BM

United States Department of the Interior
MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY REFER TO:

MMS-RVS-OG-505
M.S. 653

OCT 29 1984

ENCLOSURE CONTAINS
COMPANY PROPRIETARY
INFORMATION FOR
U.S. GOVERNMENT USE ONLY

Certified Mail -
Return Receipt Requested

Exxon Company U.S.A.
Attention: P. W. Henderson
P. O. Box 1600
Midland, TX 79702

Dear Mr. Henderson:

By application dated March 23, 1984, reviewed at a meeting with MMS personnel on April 17, Exxon requests MMS approval to deduct manufacturing and transportation costs from royalty payments on gas attributable to Federal leases within three Federal units in the LaBarge area, Sublette County, Wyoming. The gas is composed of about 65 percent carbon dioxide and 22 percent methane with significant quantities of nitrogen, hydrogen sulfide and helium. A followup meeting was held on July 10 and the original application was thereafter supplemented with supporting information.

The gas is dehydrated in the fields before being transported approximately 50 miles via pipeline to the Shute Creek processing plant. The plant is located at Shute Creek as a result of information developed by an environmental impact statement and resultant recommendations by the United States Bureau of Land Management and the United States Forest Service. The plant products to be sold are methane, carbon dioxide, sulfur, and possibly helium and nitrogen if necessary arrangements are made with the United States Bureau of Mines. The methane will be sold at the plant. Initial carbon dioxide sales will be at Rock Springs, Wyoming. The sulfur will be transported about 16 miles to Opal, Wyoming.

In summary, you have requested that the costs of the following operations be deductible in computing Federal royalty:

(1) The capital and operating costs of the centralized dehydration facilities used to remove water from the gas prior to transportation to the Shute Creek plant.

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(2) The capital and operating costs of the pipeline which will transport gas from the centralized dehydration facilities to the Shute Creek plant.

(3) The capital and operating costs of the gas plant at Shute Creek.

(4) The capital and operating costs of the 16-mile railroad spur from Shute Creek to Opal.

You have also proposed that the requested manufacturing allowances apply to all plant products, including methane, and that the allowances be applied up to 100 percent of the value of the plant products if the costs are of that magnitude.

The total capital costs of the facilities are estimated to be about X.4 including X.4 for gas plant construction. Total annual operating costs are estimated to be about X.4 including for gas plant operating costs.

The basic issues are (a) whether all or part of the requested deductions are approvable in accord with the lease, regulations, court decisions and past MMS (USGS) practices; (b) whether processing deductions can be applied to all products sold; and (c) whether the normal limits on processing and transportation costs apply in this situation.

It has been determined that the costs of the field dehydration units and the gas transportation costs to the plant at Shute Creek are not deductible because the lessee is responsible for operational expenses resulting from environmental requirements imposed pursuant to the National Environmental Policy Act. The imposition of environmental requirements under NEPA cannot be the basis for a processing or transportation deduction in computing Federal royalty.

It has been determined that the gas plant costs are deductible because the processing required for the LaBarge gas is comparable to that done in a typical gas plant and the lease and regulations did not intend to preclude this process. It also has been determined that the approved processing cost deductions can be applied to the associated products sold, carbon dioxide, sulfur, and possibly nitrogen and helium (depending upon the terms of the helium disposition agreement). However, no portion of the processing costs can be applied to methane, the principal product, in accord with the regulations and consistent past practice and procedure.

In accord with past practices, the allowable costs will be applied, in total, to the total value of the associated products (i.e., all products except methane) sold to determine the allowable percentage to be used, with a maximum allowance of 66 2/3 percent.

The costs required to transport the carbon dioxide, methane, or sulfur (after being placed in marketable condition) to the first sale point are deductible. In accord with past practices, transportation costs are limited to 50 percent of the value of each product and applied separately to each product transported and sold.

An application based on estimated costs should be submitted to the MMS Transportation and Processing Branch for official approval in accordance with the information contained in attachments 2 and 3. At the time the application is to be prepared, please contact this office so that we might render additional assistance.

If you believe that relief from the two-thirds of value ceiling for processing costs and/or relief from the 50 percent of value ceiling for transportation costs is justified by convincing information, you may wish to consider the filing of an application with this office.

If you believe that royalty rate relief is justified, you may wish to consider the filing of an application for a royalty rate reduction with the appropriate Bureau of Land Management office pursuant to 43 CFR 3103.4-1. "Waiver, suspension or reduction of rental, royalty or minimum royalty."

You have the right to appeal any of the decisions in this letter in accordance with the provisions of Title 30, Code of Federal Regulations Part 290. Any appeal taken will be to the Director, Minerals Management Service, and the notice of appeal must be filed with

Minerals Management Service
Attention: Mr. William H. Feldmiller
Chief, Royalty Valuation and Standards Division
P. O. Box 25165, M.S. 653
Denver, CO 80225
Telephone (303)231-3184

within 30 days from the date of receipt of this letter.

A copy of your appeal should be forwarded to

Mr. Norman Hess
Appeals Division
Minerals Management Service
Mail Stop 623
12203 Sunrise Valley Drive
Reston, VA 22091
Telephone (703)860-7251

Sincerely,

William H. Feldmiller

William H. Feldmiller
Chief, Royalty Valuation and
Standards Division

Enclosures (4)
Plat
Transportation CDM
Processing CDM
Memo 12/8/78

CONTAINS COMPANY
PROPRIETARY INFORMATION
FOR U.S. GOVERNMENT USE ONLY

ROYALTY MANAGEMENT PROGRAM
ROYALTY VALUATION AND STANDARDS DIVISION

Findings and Conclusions on Exxon Company's Request to Deduct Costs Involved in Processing and Transporting Gas Produced from Three Federal Units, LaBarge Area, Sublette Co., Wyoming

Background - General

- Exxon Corporation (Exxon), as operator and working-interest owner in the Graphite, Lake Ridge, and Fogarty Creek Federal Units, LaBarge area, Sublette Co., Wyoming, has submitted an application requesting the deduction of costs involved in processing and transporting gas produced from the three Units when computing Federal royalties. Federal leases comprise a large percentage of the three Federal Units. Exxon holds leases on approximately 85 percent of the Federal lands.

- Gas production from the three Units is from the Madison formation below 15,000 feet. A typical reservoir analysis shows the gas content to be carbon dioxide (CO_2)-65.4 percent, methane (CH_4)-22 percent, nitrogen-7.5 percent, hydrogen sulfide-4.5 percent, and helium-0.6 percent. There are no liquid hydrocarbons produced.

- Exxon is constructing a gas processing plant at Shute Creek, about 50 miles from the field. The location of the plant is in accord with information developed by an environmental impact statement and resultant recommendations by the U.S. Bureau of Land Management and U.S. Forest Service. A centralized dehydration facility will be located in the field area to remove water before the gas is transported to the plant to preclude pipeline corrosion. The plant products to be sold will be CH_4, CO_2, sulfur, and possibly helium and nitrogen. The CH_4 will be sold at the plant. The CO_2 will be sold at Rock Springs, Wyoming. The sulfur will be transported about 16 miles by railroad to Opal, Wyoming (a spur on the main line of the Union Pacific railroad), which is the point of sale for the sulfur. Exxon advises that it is negotiating a helium disposition agreement with the U.S. Bureau of Mines. If that agreement is approved, potential sales of helium may make the marketing of liquefied nitrogen economically attractive as the nitrogen must be removed to make a saleable helium product.

- The producing fields are located in rugged terrain at a high elevation. After the first few wells were completed and the magnitude of the gas reserves were realized, environmental concerns by Federal agencies prompted preparation of an environmental impact statement. The primary concerns involved socioeconomics, wildlife, air quality and health and safety issues. As a result of information developed, the Bureau of Land Management and Forest Service jointly recommended a Shute Creek location for the gas processing plant.

- The attached diagram, "LaBarge Project Area", shows the relative location of the operations:

  (a) The centralized dehydration facility;

  (b) The 50-mile "dry gas" pipeline from the units to the processing plant at Shute Creek;

  (c) The Shute Creek processing plant;

  (d) The 16-mile railroad spur from Shute Creek to Opal on the main line of the Union Pacific railroad which is used to transport sulfur.

- The expected plant construction capital costs are about X·4 including an estimated contingency cost of X-4 Annual plant operating costs are estimated to be X·4 including X·4 for electrical power costs.

- The expected "transportation" capital costs are about X-4 including an estimated contingency cost of about Principal components are:

  Dehydration Facilities -
  Pipeline -
  Railroad spur -
  X-4

  Annual transportation costs are estimated to be X-4 including X·4 for electric power for the dehydration units.

- The Selexol portion of the plant removes the CO_2 and H_2S fractions from the inlet gas stream (System 41). The H_2S is stripped from the Selexol solution and processed in the Claus recovery unit (System 51). The CO_2 is stripped from the Selexol system. The gas separated from the CO_2-H_2S stream consists of methane, helium and nitrogen. The gases pass through dehydrators (System 42) to further decrease the dew point for cryogenic processing downstream.

- The Nitrogen Rejection Unit (System 43) is designed to separate the CH_4, N_2, and He gas mixture into two gas streams. One of the streams is CH_4, relatively pure enough to be saleable. The other stream is composed of nitrogen and helium. The nitrogen is separated and a small portion is used in the Selexol process to condition the Selexol solution prior to recirculation through System 41. In the event a helium disposition agreement is concluded with the Bureau of Mines and a market found for the helium, a facility would be constructed to separate the remainder of the nitrogen from the nitrogen-helium stream leaving pure helium. An attempt would be made to market the nitrogen.

Background - Exxon Legal Arguments

- Exxon cites California Company v. Udall, 296 F.2d 384 (D.C. Cir. 1961), the "Romere Pass" case, as "clearly implying that manufacturing costs do not fall within the marketing obligation and that the lessee is entitled to an allowance for such costs". Exxon states that, "The California Company decision was based in part on the Court of Appeal's determination that the exercise of the Secretary's discretion in denying allowances for conditioning costs should be upheld unless unreasonable. The case does not indicate that the disallowance of conditioning costs is mandatory, and, in fact, the court implies that it would be an abuse of discretion for the Secretary to deny allowances for manufacturing or transportation costs."

- Exxon cites the "Kettleman Hills", United States v. General Petroleum Corporation of California, 73 F. Supp. 225, case to affirm that there is no doubt that an allowance for manufacturing costs is mandatory and states that, "There is no question that a typical extraction plant which removes hydrocarbon liquids is a manufacturing operation, but it has been pointed out that the LaBarge Gas Plant is not such a typical plant." Exxon concludes that, "There is no basis in the reported cases for concluding that only the removal of natural gas liquids is entitled to a manufacturing allowance while an even more advanced and more costly manufacturing operation is not."

- Exxon cites 43 CFR 3103.3-1(c):

  "In determining the amount or value of gas and liquid products produced, the amount or value shall be net after the cost of manufacture. The allowance for cost of manufacture may exceed two-thirds of the amount or value of any product only with the approval of the Secretary."

Exxon concludes,

> (a) "The regulation does not limit the allowance to liquid products, recognizing that gases can be as much a product of a manufacturing process as liquids." and,
>
> (b) "...if the processes involved are, in fact, manufacturing processes and the amount of the costs involved is reasonable for such processes, the Secretary must approve the allowances requested, even if they exceed two-thirds of the value of the products."

- Exxon states the LaBarge gas stream "...does not happen to contain the particular substances covered by..." 30 CFR 221.14, and "...therefore, that regulation is not directly applicable to the LaBarge gas stream. Obviously, a regulation is needed which specifically addresses allowances for manufacturing costs in connection with products other than natural gas liquids, but the absence of such a regulation does not eliminate the lessee's right to such an allowance."

- Exxon cites the regulation 30 CFR 206.103, "Value basis for computing royalties", as one of the bases for approval of a manufacturing allowance. In particular, it refers to the phrase "and to other relevant matters" as one of the criteria to be considered when making a determination of value for royalty purposes.

- Exxon makes reference to Solicitor's Opinion A-29460, August 2, 1963, 70 I.D. 393, as being relevant to the subject case in that it noted that unusual and complex factors which result in unusually high costs should be considered as "other relevant matters" in determining the product value. Opinion A-29460 involved transportation allowances for barging costs from offshore oil and gas leases.

- Exxon cites an article entitled "Calculating the Landowner's Royalty" 28 Rocky Mountain Mineral Law Institute 803 (1983), which concluded that:

  > "The more expensive the operation and the greater the difference in the particular activity and the ordinary process of production, the more likely it is that a court will allow adjustments for costs incurred in determining the royalty due."

- Exxon cites the definition of "manufacturing process" in the draft "Guidelines for Valuation of Gas for Royalty Purposes" as applying to the LaBarge gas plant.

- Exxon cites an Interior Board of Land Appeals decision dated January 5, 1981, and the "Kettleman Hills" case as a basis for approval of costs of transporting gas from the field to Shute Creek and to any more distant locations in computing Federal royalty. It states that the "Kettleman Hills" case "is direct, controlling precedent for the principle that allowances are mandatory in connection with the transportation of gas by pipeline to a gas plant." Exxon states that it is entitled to allowances for the costs related to the pipeline, or, alternatively, such costs should be included as part of the actual costs of operating the gas plant.

Basic Issues

- Are all or part of Exxon's requested deductions approvable in accord with the regulations, instructions and past practices or are they a part of the expenses to be borne by the lessee?

- When multiple products are produced, does the MMS approved deduction for processing apply to all products sold?

- When multiple products are produced, should allowable costs be applied separately to each product?

- Do the normal limits on transportation and processing costs apply in this situation?

Findings

- The following pertinent language is found in a typical lease and the regulations:

  (a) Typical Schedule "B" and "C" lease:

  "In determining the amount or value of gas and liquid products produced, the amount or value shall be net after an allowance for the cost of manufacture. The allowance for cost of manufacture may exceed two-thirds of the amount or value of any product only on approval by the Secretary of the Interior."

  (b) 30 CFR 206.105 (221.50)

  "Royalty accrues on dry gas whether produced as such or as residue gas after the extraction of gasoline."

  (c) 30 CFR 206.106 (221.51)

"A royalty as provided in the lease shall be paid on the value of one third...of all casinghead or natural gasoline, butane, propane, or other liquid hydrocarbon substances extracted from the gas produced from the leasehold. The value of the remainder is an allowance for the cost of manufacture,...."

(d) 30 CFR 206.107 (221.52)

"The royalty on all drip gasoline...recovered from gas...without resort to manufacturing...shall be the same percentage as provided in the lease for other oil, except that such substance, if processed in a casinghead gasoline plant shall be treated for royalty purposes as though it were gasoline."

(e) 43 CFR 3162.7 - "The lessee shall put into marketable condition, if economically feasible, all oil, other hydrocarbons, gas, and sulphur produced from the leased land."

- Production costs are the responsibility of the lessee. The Manual of Oil and Gas Terms by Williams and Meyers defines a lessee as "The person entitled under an oil and gas lease to drill and operate wells, paying the lessor a royalty and retaining the remainder, often seven-eighths of the production costs out of his fraction, the lessor's fraction being free and clear of all such costs...." This lessor-lessee relationship has been long recognized in Federal regulation.

- The following pertinent language is found in the Conservation Division Manual:

  (a) 647.7.1 - "This chapter provides guidelines and procedures for determining manufacturing allowances where royalties for residue gas and associated liquids from onshore public domain,... leases...."

  (b) 674.7.3 - "Under no circumstances can royalty payments be made on a value less than the value of one-third of the extracted liquids and all of the residue gas."

- The following pertinent language is found in Notice to Lessees No. 1:

  "...Likewise, no deduction will be allowed for the cost which an operator incurs by reason of placing the gas in a marketable condition as an operator is obligated to do so at no cost to the lessor."

- The following pertinent language is found in the Conservation Division Manual regarding transportation allowances:

  (a) 647.5.3 - A relevant matter in establishing value is "reasonable costs...in transporting lease production to the nearest available market place or sales outlet....

  "...the posted price will be reduced by an amount...to cover the reasonable costs incurred in transporting marketable production from the lease to the nearest market place or sales point.

  "As used in this chapter, the term 'market place' means that point at which a reasonable product value can be established....

  "The term 'marketable condition', as used in this chapter, means clean crude oil, drip gasoline, or natural condensates, gas, natural gas liquids, and any other liquid or gaseous substances meeting normal arm's-length contract requirements for the area.

  "Under no circumstances should transportation costs exceed 50 percent of the product's fair market value at the nearest competitive sales point."

  (b) 647.5.H - "...a reasonable allowance for transporting wet gas to a processing plant may be granted, provided that the plant is not located in the field where the lessee's well is located."

- The following quote is from the <u>Continental v. U.S. 184 F.2d 802</u>:

  "It has been held that if there is no open market in the place where an article ordinarily would be sold, the market value of such article in the nearest open market less cost of transportation to such open market becomes the market value of the article in question."

  MMS applies this principle in computing Federal royalty.

- NTL-1, "Procedures for Reporting and Accounting for Royalties": states under Section III, "Gas and Associated Liquids Production, Sales, and Royalty Requirements":

> "Under no circumstances will the royalty value be computed on less than the gross proceeds accruing to the operator from the sale of such leasehold production. Gross proceeds include, but are not limited to, tax reimbursements and payments to the operator for gathering, measuring, compressing, dehydrating, or performing other services necessary to market the production. Likewise, no deduction will be allowed for the cost which an operator incurs by reason of placing the gas in a marketable condition as an operator is obligated to do so at no cost to the lessor."

- Since the passage of the National Environmental Policy Act (NEPA), developers of projects are required to meet certain environmental stipulations as a prerequisite to undertaking development. The costs of meeting these requirements are the responsibility of the lessee. The imposition of environmental requirements under NEPA cannot be the basis for deduction in computing Federal royalty.

- Decision by the Director, Geological Survey, and a supporting court decision, The California Company v. Udall, 296 F.2d, August 10, 1961, the "Romere Pass" case, (cited by Exxon) have upheld the principle that the lease operator is obligated to perform necessary field gathering, dehydration, and compression operations. The court made a distinction between "transportation" of gas and "conditioning" of gas and accepted the Secretary's definition of production as "gas conditioned for market." The court stated, "In the record before us, there is no evidence of a market for the gas in the condition it comes from the wells." There is no market for the LaBarge gas in the condition it comes from the wells. Therefore, there are conditioning costs that must take place at the lessee's expense.

- By memorandum dated December 8, 1978, the Acting Chief, Conservation Division, determined that if sulfur is sold following a gas sweetening process, a manufacturing deduction from sulfur royalty payments is authorized where the extraction costs are an integral part of the "whole manufacturing process."

- In the event a lease (unit) cannot be operated successfully, the Bureau of Land Management regulations make provision for obtaining economic relief in the royalty reduction provision, 43 CFR 3103.4-1.

Primary Considerations - Dehydration

- The following primary considerations apply in determining whether the dehydration costs are approvable:

(a) Locating the processing plant about 50 miles from the field is mandated by environmental considerations. The additional costs resulting from the imposition of environmental requirements under NEPA are expenses to be borne by the lessee. The royalty owner is not obligated to share in such costs.

(b) Dehydration is specifically mentioned in NTL-1 as one of the processes for which royalty is due under "gross proceeds" if the operator receives reimbursement (e.g., it is the responsibility of the operator).

(c) In the "Romere Pass" case the court held that the lease operator is obligated to perform dehydration operations to place the gas in marketable condition.

(d) The Selexol process used in the processing plant involves an aqueous solution. The field dehydration system is for transportation purposes only. Exxon has advised that there would be no difference in the cost of dehydration facilities at the plant location if the processing plant were located in the field.

Primary Considerations - "Dry Gas" Transportation

- The following primary considerations apply in determining whether the cost of transporting the gas about 50 miles to the processing plant is approvable.

  (a) Locating the processing plant about 50 miles from the field is mandated by environmental considerations. The costs resulting from the imposition of environmental requirements under NEPA are expenses to be borne by the lessee. The royalty owner is not obligated to share in such costs.

  (b) In The California Company v. Udall, the "Romere Pass" case, the court held that the lease operator is obligated to perform field gathering operations. Normally, the bringing together of gas from many wells or leases to a gas processing plant is "field gathering."

Primary Considerations - Plant Processing

- The following primary considerations apply in determining whether all or part of the Shute Creek gas plant processing costs are approvable.

  (a) The language in the lease and the regulations did not anticipate the type of gas stream or the processing procedures involved here.

(b) In accordance with pertinent decisions, the lessee has the responsibility to make a marketable product from the leasehold production. In the normal hydrocarbon stream, the principal product is methane. Present regulations and decisions address normal hydrocarbon stream processing.

(c) In accord with the regulations and consistent with past practice and procedure, royalty is due on 100 percent of the residue gas (methane is normally the principal product of a typical gas plant). The lease and regulations clearly provide that any deduction from royalty for costs of processing applies to the "products produced" or to "liquid hydrocarbon substances extracted."

(d) Processing costs can be deducted on the associated products which are sold, such as carbon dioxide and sulfur, in accord with the principle set forth in the Acting Chief's memo dated December 8, 1978, up to a maximum of two-thirds (unless the Secretary of the Interior is petitioned for and approves a higher amount) of the value of the associated products processed and sold.

(e) The consistent practices and procedures of MMS and its predecessors have been to combine all processing costs in gasoline plants and to apply the total costs against the total value of the extracted liquid hydrocarbons, up to a maximum of 66 2/3 percent. The Secretary has authority to approve a processing allowance in excess of 66 2/3 percent.

(f) Exxon will not need unit compression facilities during the early life of unit production as flowing wellhead pressures will be adequate to pass the gas through the dehydrators and dry gas gathering lines arriving at the plant inlet with at least 1,050 psi. The plant pass-through pressure drop will necessitate compression of the saleable methane prior to entering the methane sales line. Compression of carbon dioxide gas sales will probably be necessary to transport the CO_2 to Rock Springs, Wyoming. Compression costs necessary to compress and inject either methane or CO_2 into the transmission line is not being requested by Exxon and will be excluded from any processing allowance considerations by MMS.

Primary Considerations - Transportation

- The following primary considerations apply in determining whether any transportation costs beyond the plant outlet are applicable in determining royalty:

(a) MMS policy permits deduction of costs required to transport lease products which have been placed in marketable condition from the lease, unit or communitization agreement or other designated point in the field or at a plant to the point of first sale.

(b) The point of sale of methane probably will be at the outlet ("tailgate") of the Shute Creek plant. The point of sale for carbon dioxide will be at Rock Springs, Wyoming.

(c) Exxon states that there currently is no prospect for developing a market at the Shute Creek plant site for the sulfur produced in the plant, and it will be necessary in marketing the sulfur to transport it by rail car at least as far as Opal, Wyoming. Allowances for costs related to building and operating the 16-mile rail spur are to be considered.

(d) The Conservation Division Manual provides that transportation costs may not exceed 50 percent of the product's fair market value at the sales point. This is a policy restriction imposed by the Director, U.S. Geological Survey (now the Director, Minerals Management Service) and can be modified by that official in a particular case, when justified by convincing information.

Conclusions

- The costs of the field dehydration facility are not deductible because water removal here is for pipeline safety purposes (to prevent corrosion). The pipeline is required because the Shute Creek plant was located about 50 miles from the field to satisfy environmental considerations. The lessee is responsible for all operational expenses resulting from adherence to environmental requirements. In addition, the operator is responsible for the costs of the field dehydration facility in accord with pertinent regulations, NTL-1, and the "Romere Pass" court decision. Costs associated with dehydration at the Shute Creek plant are deductible processing costs.

- The costs to build and operate the pipeline from the field to the plant are not deductible because the lessee is responsible for all operational expenses resulting from adherence to environmental requirements.

- The requested processing costs for the associated products removed and sold can be considered for approval. The processing required for LaBarge gas is comparable to that done in a normal plant and it is logical to conclude that the lease and regulations did not intend to preclude inclusion of this process even though processing of gas such as that produced at LaBarge was unknown at the time the documents were written. It is concluded that the principle set forth in the Acting Chief's December 8, 1978 memo can logically be extended to include associated products sold (in this case carbon dioxide, helium and possibly nitrogen) in addition to sulfur.

- The approved processing cost deductions will be applied to the associated products which are sold. No portion of the processing costs can be applied to the value of the methane removed and sold. MMS considers methane to be the principal product. Methane is considered to be that part of the gas stream that the lessee is obligated to place in marketable condition at no cost to the lessor.

- In accord with consistent past practices, the allowable costs will be applied in total to the total value of the associated products sold, to a maximum of 66 2/3 percent. Exxon can petition MMS (as a delegated authority of the Secretary of the Interior) for a greater percentage deduction if it has convincing information to show it to be justified in this case.

- The costs required to transport the CO_2, methane or sulfur which have been placed in marketable condition to the first sale point are deductible in computing Federal royalty. Transportation costs are applied separately to each product transported and sold. The limit on transportation costs is 50 percent of the value of the product. This is a policy limit imposed by the predecessor agency to the Minerals Management Service. It is assumed that the Director, Minerals Management Service, can approve an increase in such percentage if Exxon provides convincing information to show that it is justified.

- If Exxon believes that royalty relief is justified in this situation, it may file an application requesting that the two-thirds ceiling on processing deductions and/or the 50 percent ceiling on transportation deductions be liberalized or waived and/or it may file an application for royalty rate reduction with the appropriate BLM office pursuant to 43 CFR 3103.4-1, "Waiver, suspension or reduction of rental, royalty, or minimum royalty".

MMS-2014 Reporting Requirements

For purposes of royalty reporting, all "original" royalty lines (e.g., Transaction Code 01--Royalty Due, shall show values at the point of first sale rather than being net after deduction of transportation and processing costs. All deductions taken for transportation costs (Transaction Code 11) and for processing costs (Transaction Code 15) shall be reported against the appropriate original royalty line. The net of the "original" line and the value at the lease. Therefore, rather than one reporting line per lease, there may be one "original" line plus a processing deduction line and/or a transportation deduction line for each lease.

Enclosed is a sample MMS-2014 illustrating the reporting requirements for methane, carbon dioxide and sulfur production for a hypothetical lease. For purposes of illustration, the following assumptions were made:

- The delivered price of methane at the Shute Creek plant is $4.00 per Mcf.

- The delivered price of carbon dioxide at Rock Springs, Wyoming, is $1.50 per Mcf.

- The delivered price of sulfur at Opal is $60.00 per ton.

- The total approved processing deduction for the associated products is 66 2/3% of the value at the plant.

- The total cost of transporting carbon dioxide from the plant to Rock Springs, Wyoming, is $.90 per Mcf. The total approved transportation deduction is $.75 per Mcf, or 50 percent of the value at the sales point.

- The total approved transportation deduction for shipment of sulfur to Opal is $20.00 per ton.

- The royalty rate is one-eighth.

Form MMS-2014 Revised 12/82
Previous editions are obsolete and may not be used

SAMPLE FORM MMS-2014
(FOR ILLUSTRATION PURPOSES ONLY)

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

REPORT OF SALES AND ROYALTY REMITTANCE

OIL AND GAS

OMB 1010-0022
(Exp. March 31, 1986)

Page ____ of ____

For MMS Use Only

REPORT MO./YR. 0 8 8 4

PAYOR'S NAME Exxon Corporation

ADDRESS P.O. Box 2180

CITY/STATE Houston, TX ZIP 77001

PAYOR CODE

3 FEDERAL [X] OR INDIAN [ ]

3a PAYOR-ASSIGNED DOCUMENT NUMBER

5 RESERVED FOR PREPARER'S USE	6 ACCOUNTING IDENTIFICATION (AID) NUMBER	7 PRODUCT CODE	8 REG PRICE CODE	9 SELLING ARR CODE	10 SALES MONTH/YEAR	11 TRANS CODE	12 ADJ. REAS CODE	13 SALES QUANTITY	14 QUALITY MEASUREMENT	15 CALC METH	16 SALES VALUE	17 ROYALTY QUANTITY	18 ROYALTY VALUE	19 PAYMENT METHOD CODE
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20 PAGE TOTAL

21 REPORT TOTAL

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: PUBLIC LAW 97-451 PROVIDES CIVIL AND CRIMINAL PENALTIES FOR FALSE OR INACCURATE REPORTING. Failure to report as required under the terms of the lease, permit, or contract may result in suspension of operations or other enforcement actions.

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 oil and gas from leases on Federal and Indian lands. MMS will use this information to maintain and audit lease accounts.

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 ____ Date ____

31 Name of preparer ____ Telephone ____

DEPARTMENT of the INTERIOR
news release

Minerals Management Service

Michael L. Baugher (303) 231-3162
Susan Hall (202) 343-3983

For Release: October 19, 1988

DEPARTMENT OF THE INTERIOR DISALLOWS LABARGE REQUEST
FOR EXTRAORDINARY ALLOWANCES

Assistant Secretary of the Interior J. Steven Griles announced today that the Minerals Management Service (MMS) is not granting the special and extraordinary cost allowances requested by Exxon USA for its LaBarge project gas operations in western Wyoming.

"Federal regulations require companies to pay a royalty on the value of products obtained from federal leases and provide for deductions of certain processing and transportation costs," said Griles. "MMS has granted Exxon's requested allowances for reasonable actual costs associated with the LaBarge facilities, as required by law, but has denied the company additional relief requested under the extraordinary cost allowances provision of the Department's product value regulations."

The extraordinary cost allowance provision adopted earlier this year was meant to apply to federal lease operations involving expensive processing technologies that may exceed normal industry costs, such as frontier technology. Griles has directed that MMS consult with industry and States to develop criteria regarding extraordinary cost allowances.

"Until such criteria are adopted, it would be premature to approve extraordinary cost allowances for any project," Griles said.

Exxon initiated discussion of the subject with the Department in 1984, before the LaBarge project was started. In January 1985 the company formally requested exception relief under the old product valuation regulations. That request was denied by MMS in January 1986, and is currently under appeal to the Interior Board of Land Appeals. When new product valuation regulations became effective in March 1988, Exxon applied for the extraordinary allowances provided for in those regulations.

-DOI-

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
WASHINGTON, DC 20240

JAN 7 1986

MMS-84-0066-O&G	: Fogarty Creek, Graphite, and Lake Ridge Federal Units, Sublette County, Wyoming
Exxon Company, U.S.A.	: Appeal from Order Relating to Deductions Based on Processing and Transportation Costs
Appellant	: Reversed in Part

Statement of Facts

This is an appeal filed by Exxon Company, U.S.A. (Exxon), under the regulations in 30 CFR Part 290. Exxon is appealing an October 29, 1984, order by the Chief, Royalty Valuation and Standards Division (RVSD), Minerals Management Service (MMS), disallowing certain proposed deductions based on processing and transportation costs relating to gas production under Federal leases in the Fogarty Creek, Graphite, and Lake Ridge Federal Units, Sublette County, Wyoming.

These three units embrace a total of 39,850 acres of which 37,930 acres are federally owned. Exxon holds leases covering approximately 31,600 acres of the Federal lands included in these units.

The Riley Ridge area contains an estimated 17.5 trillion cubic feet of recoverable gas at depths exceeding 15,000 feet. This appeal concerns gas in the Riley Ridge gas field to the extent that such gas lies in the Madison Formation within the three units.

The gas mixture found in the Madison Formation within these units typically contains: carbon dioxide (65.4 percent), methane (22 percent), nitrogen (7.5 percent), hydrogen sulfide (4.5 percent), and helium (0.6 percent). Each of these components constitutes a gas which, with the exception of helium, is subject to the provisions of the controlling leases and the governing regulations at 30 CFR Part 206 and 43 CFR Part 3103. Helium is not a leasable mineral but it will be produced and sold by Exxon under a separate agreement with the United States.

Most natural gas streams contain predominantly hydrocarbons, some water, and relatively small quantities of various contaminants. Essentially, these gas streams are marketed after a few simple processing steps designed to remove the water and contaminants. As noted above, the Riley Ridge gas stream is made up principally of carbon dioxide with only about 22 percent methane, and no other hydrocarbons in significant quantities. The selective separation of the various components of the Riley Ridge gas stream requires a series of relatively complex manufacturing processes.

Exxon is presently constructing a gas processing plant at Shute Creek. Exxon describes the Shute Creek gas processing plant as the "largest, most complex and most costly gas manufacturing facility of its kind ever built in the United States." Current plans are to complete the first phase of plant construction and to begin processing gas from the Fogarty Creek, Graphite, and Lake Ridge unit areas in 1986. The wells, field facilities, and plant are expected to cost $1.017 billion dollars.

Exxon's development plans provide for the construction of field dehydration facilities on each unit. The production from each unit would be gathered at the wells by pipelines leading to the field dehydration plants.

The power supply needed to operate dehydration facilities is one of the most significant components of operating costs. Normally, lease-use gas is utilized as a power source. As previously noted, unlike a typical gas stream, the Riley Ridge raw gas stream is not high in hydrocarbons and is not combustible. For this reason, an independent source of energy will be required to fuel the field dehydration facilities being constructed by Exxon on the three units involved in this appeal.

The dried gas stream will be transported to the Shute Creek gas processing plant where it will be separated into its component parts (i.e., carbon dioxide, methane, nitrogen, hydrogen sulfide (sulfur), and helium).

Due to environmental considerations, the Shute Creek Plant was sited about 40 miles from the well field. The plant's distance from the field requires construction of 54 miles of pipeline leading from the dehydration plants to the Shute Creek gas processing plant.

Present expectations are that gas and the products processed at Shute Creek will be disposed of as follows:

(1) Methane will be sold at the tailgate of the Shute Creek gas processing plant;

(2) Sulfur will be transported by rail to a point of sale at Opal, Wyoming;

(3) Carbon dioxide will be transported by pipeline to a sale point in Rock Springs, Wyoming;

(4) Helium will be sold in accordance with the helium sales agreement between Exxon and the Bureau of Mines; and

(5) A customer for the nitrogen has not been found as yet.

According to Exxon, the Riley Ridge gas stream has no market value prior to the separation of the various component gases, and the nearest market for methane will be at the tailgate of the processing plant. The nearest market for the sulfur will be at Opal, Wyoming, and for carbon dioxide, at Rock Springs, Wyoming. For helium and nitrogen, the nearest market is expected to be at the tailgate of the Shute Creek plant.

By a letter dated March 23, 1984, Exxon transmitted a document entitled "LaBarge Project-Royalty Cost Allowances for Transportation and Gas Processing Facilities-Exxon Company, U.S.A." to RVSD with a request that, in connection with the determination of the royalties due under the Federal oil and gas leases committed to the Fogarty Creek, Graphite, and Lake Ridge unit areas, Exxon be permitted to deduct the following transportation and processing costs:

(1) The capital and operating costs of the three field dehydration plants where water is removed from produced gas prior to the transmission of the gas to the Shute Creek gas processing plant.

(2) The capital and operating costs of the pipelines which will transport the dehydrated gas stream from the three field dehydration plants to the Shute Creek gas processing plant.

(3) A deduction based on the capital and operating costs of the Shute Creek plant as applied to 100 percent of the value of the gas and products (including methane).

(4) The capital and operating costs for a 16-mile railroad spur built to transport sulfur from the Shute Creek gas processing plant to Opal, Wyoming.

The October 29, 1984, decision by the RVSD denied a deduction from royalty value based on the cost of the field dehydration units and the cost of transporting the production to Shute Creek. A deduction based on the processing costs at Shute Creek was approved up to a maximum of 66-2/3 percent of the value of all associated products (excluding methane which was found to be the principal product). The RVSD also approved a deduction based on the cost of transportation for carbon dioxide, methane, or sulfur from Shute Creek to the point of first sale subject to a ceiling of 50 percent of the value of each product. Such value will be computed separately with respect to each product transported and sold.

Exxon appealed the denial of a deduction from the royalty base grounded on the costs of: (1) the field dehydration units, and (2) the pipeline to Shute Creek. Exxon also appealed the exclusion of methane from the product value base used to determine the deductibility of manufacturing costs.

In support of its appeal, Exxon alleges that a lessee under a Federal lease is entitled to deduct manufacturing costs in calculating royalties. Exxon states that 43 CFR § 3103.3-1(c) does not limit the manufacturing allowance to liquid products since gases can be as much a product of a manufacturing process as liquids. (Statement of Reasons (SR) at page 5.)

In the case of the Shute Creek manufacturing facility, the manufacturing costs exceed the combined value of the products other than methane. Thus, in Exxon's view, the manufacturing allowance must be extended to the value of the methane. (SR 8)

Insofar as the transportation cost allowances are involved, Exxon's application is purportedly grounded (SR 3) on:

> * * * the well established principle that a lessee under a federal lease is entitled to an allowance for the cost of transporting production from the lease * * * to * * * the nearest available market, including the location where the gas stream is processed prior to sale. * * *

In Exxon's opinion, environmental requirements which increase the lessee's costs do not change the category within which these costs would otherwise fall. (SR 9) Thus, according to Exxon, the transportation cost allowance should cover field dehydration costs which arise solely because of the necessity of transporting the production to Shute Creek. (SR 3) Essentially, Exxon regards the field dehydration facilities as an integral part of the transportation to the Shute Creek plant.

In this connection, Exxon emphasizes that the dehydration in the field is not performed to meet a pipeline purchaser's specifications or to make the gas stream marketable. Exxon alleges that the dehydration of the gas at the field dehydration plants is intended to prevent corrosion in the gas pipelines running between the field and the Shute Creek processing plant. According to Exxon, the three dehydration plants will exceed in both scale and complexity the dehydration facilities ordinarily used to dry natural gas for pipeline sales.

Exxon further alleges that, even in the absence of the field dehydration units, the gas would be dehydrated sufficiently at Shute Creek to meet the purchaser's specifications. (SR 13)

Exxon characterizes the sour gas pipeline (SR 11) "as either a part of the gas plant operation, with its costs being included in the manufacturing allowance, or as a transportation line to the nearest available market, with a separate transportation allowance." In this regard, Exxon alleges (SR 12):

> Transportation of the sour gas in a pipeline to Shute Creek is closely associated with the manufacturing costs incurred in connection with the plant itself. The relocation of the plant to a more distant location was requested by the Government for environmental and socioeconomic reasons and had the effect of increasing the cost of the manufacturing operation to the extent of the added cost of transporting the sour gas to the Shute Creek plant site. Thus, the cost of the sour gas pipeline is an allowable item in accordance with the * * * [principle] that transportation to the gas plant is a part of the gas plant costs. * * *

In addition, Exxon states (SR 2) that the propriety of the limitation of the manufacturing cost deduction to 2/3 of the value of the products is dependent on the inclusion of methane in the allowance. Therefore, Exxon purports to reserve "the right to a release of the 2/3 limitation as to the products other than methane after the disposition of this appeal * * *." Exxon also purports to reserve "the right to appeal the application" of the 50 percent limitation as regards transportation of any product insofar as the application of the limitation "prevents the recovery of the royalty share of transportation costs." (SR 3)

The regulations found in 30 CFR § 206.105, 30 CFR § 206.103 and 43 CFR § 3103.3-1 provide as follows in pertinent part:

> 30 CFR 206.103 Value basis for computing royalties.
>
> The value of production, for the purpose of computing royalty, shall be the estimated reasonable value of the product as determined by the Associate Director due consideration being given to the highest price paid for a part or for a majority of production of like quality in the same field, to the price received by the lessee, to posted prices, and to other relevant matters. Under no circumstances shall the value of production of any of said substances for the purposes of computing royalty be deemed to be less than the gross proceeds accruing to the lessee from the sale thereof or less than the value computed on such reasonable unit value as shall have been determined by the Secretary. In the absence of good reason to the contrary, value computed on the basis of the highest price per barrel, thousand cubic feet, or gallon paid or offered at the time of production in a fair and open market for the major portion of like-quality oil, gas, or other products produced and sold from the field or area where the leased lands are situated will be considered to be a reasonable value.
>
> 30 CFR 206.105 Royalty on gas.
>
> The royalty on gas shall be the percentage established by the terms of the lease of the value or amount of the gas produced.
>
> (a) Royalty accrues on dry gas, whether produced as such or as residue gas after the extraction of gasoline.
>
> (b) If the lessee derives revenue on gas from two or more products, a royalty normally will be collected on all such products.

> (c) For the purpose of computing royalty, the value of wet gas shall be either the gross proceeds accruing to the lessee from the sale thereof or the aggregate value determined by the Secretary of all commodities, including residue gas, obtained therefrom, whichever is greater.
>
> 43 CFR 3103.3-1 Royalty on production.
>
> * * * * *
>
> (c) In determining the amount or value of gas and liquid products produced, the amount or value shall be net after the cost of manufacture. The allowance for cost of manufacture may exceed two-thirds of the amount or value of any product only with the approval of the Secretary.

Notice to Lessees and Operators (NTL) No. 1, Procedures for Reporting and Accounting for Royalties, provides as follows in relevant part:

> * * * Under no circumstances will the royalty value be computed on less than the gross proceeds accruing to the operator from the sale of such leasehold production. Gross proceeds include, but are not limited to, tax reimbursements and payments to the operator for gathering, measuring, compressing, dehydrating, or performing other services necessary to market the production. Likewise, no deduction will be allowed for the cost which an operator incurs by reason of placing the gas in a marketable condition as an operator is obligated to do so at no cost to the lessor. [Emphasis added]

The Conservation Division* Manual provided at section 647.5.3E:

> * * * Under no circumstances should transportation costs exceed 50 percent of the product's fair market value at the nearest competitive sales point.

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*By Secretarial Order No. 3071, dated January 19, 1982, as amended May 10, 1982, all minerals management functions previously exercised by the Conservation Division, U.S. Geological Survey, were transferred to the Department's Minerals Management Service. By Secretarial Order No. 3087, dated December 3, 1982, as amended February 7, 1983, the onshore, nonroyalty management functions of the Minerals Management Service were transferred to the Department's Bureau of Land Management.

Conclusions and Order

1. Section 17 of the Mineral Leasing Act (30 U.S.C. 226) authorizes the Secretary of the Interior "to require the payment of * * * royalty [based] on the 'value of the production.'" California Company v. Udall, 296 F.2d 384, 387 (D.C. Cir. 1961). Under section 17, "The Secretary * * * possesses considerable discretion for determining what is the 'value' of production." Amoco Production Co., 78 IBLA 93, 96 (1983), appeal pending, Amoco Production Co. v. Clark, CV 84-0916 (W.D. La.).

In the exercise of his statutory discretion, the Secretary has decided that royalties must be based on the value of the production after it has been placed in a marketable state.

> The premise for the Secretary's decision * * * was that, since the lessee was obliged to market the product, he was obligated to put it in marketable condition; and that the 'production' was the product in marketable condition.
>
> California Company at 387.

Moreover, the cost of placing the production in a marketable condition must be borne by the lessee. Id. See also SR at p. 4.

The cost of dehydration of the gas production prior to sale is considered as part of the cost of marketing the production. See Kuntz, The Law of Oil and Gas, § 40.5, pp. 322, 324. Exxon concedes (SR 9) that environmental requirements do not affect the category within which costs fall. Thus, an allowance for the dehydration cost cannot be allowed irrespective of whether the dehydration is performed at field dehydration units, at a processing plant or, as here, at both field dehydration units and at a central processing plant due to environmental considerations dictating the siting of the processing plant. Accordingly, Exxon cannot deduct the cost of the dehydration at the field dehydration units.

2. A lessee is entitled to an allowance based on the cost of transporting the production to the nearest market. Shell Oil Co., 52 IBLA 15, 20 (1981). The uncontroverted record evidence is that the nearest market of the methane production is at the tailgate at Shute Creek. In addition, the record shows that the nearest market for the other produced gases is at or beyond the tailgate at Shute Creek. Accordingly, Exxon is entitled to a transportation allowance based on the construction and operating costs of the pipelines transporting the production from the field dehydration units to Shute Creek.

However, in accordance with established guidelines (see Conservation Division Manual § 647.5.3E), this allowance may not be greater than 50 percent of the separate value of the leased products at the nearest competitive sales point. These guidelines represent a lawful exercise of the Department's wide discretion to determine royalty values. See Amoco Production Co., supra.

In conformity with these guidelines, the United States has limited transportation allowances, granted to lessees under Federal oil and gas leases issued under the Mineral Leasing Act, to 50 percent of the value of the products at the nearest competitive sales point, and lessees have been paying royalties in accordance with such 50 percent allowance. This longstanding interpretation of the leases by the parties further supports the 50 percent limitation of the transportation allowance. 38 Am. Jur. 2d., Gas and Oil § 97, at page 564.

3. Where natural gas is processed to yield products other than methane, a deduction from the royalty value must be allowed as compensation for the cost of producing such additional products. United States v. General Petroleum Corporation, 73 F. Supp. 225, 254-255 (S.D. Ca. 1946) affirmed sub nom. Continental Oil Co. v. United States, 184 F.2d 802 (9 Cir. 1950). In

determining royalties, the Department's consistent practice has been to apply the processing costs against the value of <u>such additional products</u> up to a maximum of 66-2/3 percent. See e.g., <u>General Petroleum Corporation</u> at 256. By this appeal, Exxon seeks a processing allowance based on (a) 2/3 of the value of the additional products, plus (b) 2/3 of the value of methane.

It appears that methane is the most valuable single component of the gas stream. Under the circumstances, the separation of methane from the remaining products in the gas stream must be regarded as part of the process of conditioning the production into a marketable product. As previously discussed, this conditioning expense must be borne by the lessee. Exxon concedes that "historically" manufacturing allowances have not been applied "to the residue gas stream." It follows that Exxon is not entitled to a deduction based on the cost of processing the methane at Shute Creek. See 38 Am. Jur. 2d., <u>supra</u>.

Exxon notes that section 3103.3-1 of Title 43 provides that the amount or value of "gas and liquid products" shall be net after an allowance for the cost of manufacture. However, as the second sentence of section 3103.3-1 shows, such an allowance is limited to a deduction based solely on the value "of any product." For purposes of the allowance, the value of the "gas" cannot be considered. This construction of the regulation was upheld by the court in <u>General Petroleum Corporation</u>, <u>supra</u>. For these reasons, the value of methane may not be considered in determining Exxon's processing allowance.

4. Exxon indicates that the project may be uneconomic. The Department has procedures which make it possible to give relief in appropriate cases where a lessee's operations are uneconomic. See 43 CFR 3103.4-1. After

production begins, if Exxon should fall within the purview of these regulations, Exxon is entitled to apply for relief under prescribed procedures.

In view of the comprehensiveness of Exxon's Statement of Reasons, it is determined that oral argument is unnecessary.

In a letter dated January 18, 1985, addressed to the Secretary of the Interior, Exxon also made a request for special exceptions to the same items addressed in this appeal. Given that Exxon's request to the Secretary is similar in nature, a separate response is not anticipated.

This decision may be appealed to the Interior Board of Land Appeals pursuant to 30 CFR Part 290 and 43 CFR §§ 4.411 and 4.413. Copies of 43 CFR §§ 4.411 and 4.413 are enclosed for reference.

Wm D Bettenberg

Director

Enclosures

days after it was required to be filed and it is determined that the document was transmitted or probably transmitted to the office in which the filing is required before the end of the period in which it was required to be filed. Determinations under this paragraph shall be made by the officer before whom is pending the appeal in connection with which the document is required to be filed.

(b) *Transferees and encumbrancers.* Transferees and encumbrancers of land the title to which is claimed or is in the process of acquisition under any public land law shall, upon filing notice of the transfer or encumbrance in the proper land office, become entitled to receive and be given the same notice of any appeal, or other proceeding thereafter initiated affecting such interest which is required to be given to a party to the proceeding. Every such notice of a transfer or encumbrance will be noted upon the records of the land office. Thereafter such transferee or encumbrancer must be made a party to any proceedings thereafter initiated adverse to the entry.

(c) *Service of documents.* (1) Wherever the regulations in this subpart require that a copy of a document be served upon a person, service may be made by delivering the copy personally to him or by sending the document by registered or certified mail, return receipt requested, to his address of record in the Bureau.

(2) In any case service may be proved by an acknowledgment of service signed by the person to be served. Personal service may be proved by a written statement of the person who made such service. Service by registered or certified mail may be proved by a post-office return receipt showing that the document was delivered at the person's record address or showing that the document could not be delivered to such person at his record address because he had moved therefrom without leaving a forwarding address or because delivery was refused at that address or because no such address exists. Proof of service of a copy of a document should be filed in the same office in whic' [illegible] document is filed except that pa[illegible] service of a notice of appeal should be filed in the office of the officer to whom the appeal is made, if the proof of service is filed later than the notice of appeal.

(3) A document will be considered to have been served at the time of personal service, of delivery of a registered or certified letter, or of the return by post office of an undelivered registered or certified letter.

[36 FR 7186, Apr. 15, 1971, as amended at 36 FR 15117, Aug. 13, 1971]

§ 4.402 Summary dismissal.

An appeal to the Board will be subject to summary dismissal by the Board for any of the following causes:

(a) If a statement of the reasons for the appeal is not included in the notice of appeal and is not filed within the time required;

(b) If the notice of appeal is not served upon adverse parties within the time required; and

(c) If the statement of reasons, if not contained in the notice of appeal, is not served upon adverse parties within the time required.

(d) If the statement of standing required by § 4.412(b) is not filed with the Board or is not served upon adverse parties within the time required.

[36 FR 7186, Apr. 15, 1971, as amended at 47 FR 26392, June 18, 1982]

APPEALS TO THE BOARD OF LAND APPEALS

§ 4.410 Who may appeal.

(a) Any party to a case who is adversely affected by a decision of an officer of the Bureau of Land Management or of an administrative law judge shall have a right to appeal to the Board, except—

(1) As otherwise provided in Group 2400 of Chapter II of this title,

(2) To the extent that decisions of Bureau of Land Management officers must first be appealed to an administrative law judge under § 4.470 and Part 4100 of this title,

(3) Where a decision has been approved by the Secretary, and

(4) As provided in paragraph (b) of this section.

(b) For decisions rendered by Departmental officials relating to land selections under the Alaska Native

Claims Settlement Act, as amended, any party who claims a property interest in land affected by the decision, an agency of the Federal Government or a regional corporation shall have a right to appeal to the Board.

[47 FR 26392, June 18, 1982]

§ 4.411 Appeal; how taken, mandatory time limit.

(a) A person who wishes to appeal to the Board must file in the office of the officer who made the decision (not the Board) a notice that he wishes to appeal. The notice of appeal must give the serial number or other identification of the case and must be transmitted in time to be filed in the office where it is required to be filed within 30 days after the person taking the appeal is served with the decision from which he is appealing, or if publication of the decision in the FEDERAL REGISTER is made, within 30 days after publication of the decision in the FEDERAL REGISTER, whichever shall occur first. The notice of appeal may include a statement of the reasons for the appeal, a statement of standing if required by § 4.412(b), and any arguments the appellant wishes to make.

(b) No extension of time will be granted for filing the notice of appeal. If a notice of appeal is filed after the grace period provided in § 4.401(a), the notice of appeal will not be considered and the case will be closed by the officer from whose decision the appeal is taken. If the notice of appeal is filed during the grace period provided in § 4.401(a) and the delay in filing is not waived, as provided in that section, the notice of appeal will not be considered and the appeal will be dismissed by the Board.

[36 FR 7186, Apr. 15, 1971, as amended at 36 FR 15117, Aug. 13, 1971; 47 FR 26392, June 18, 1982]

§ 4.412 Statement of reasons, statement of standing, written arguments, briefs.

(a) If the notice of appeal did not include a statement of the reasons for the appeal, the appellant shall file such a statement with the Board (address: Board of Land Appeals, Office of Hearings and Appeals, 4015 Wilson Boulevard, Arlington, VA 22203) within 30 days after the notice of appeal was filed. In any case, the Board will permit the appellant to file additional statements of reasons and written arguments or briefs within the 30-day period after the notice of appeal was filed.

(b) Where the decision being appealed relates to land selections under the Alaska Native Claims Settlement Act, as amended, the appellant also shall file with the Board a statement of facts upon which the appellant relies for standing under § 4.410(b) within 30 days after filing of the notice of appeal. The statement may be included with the notice of appeal filed pursuant to § 4.411 or the statement of reasons filed pursuant to paragraph (a) of this section or may be filed as a separate document.

(c) Failure to file the statement of reasons and statement of standing within the time required will subject the appeal to summary dismissal as provided in § 4.402, unless the delay is filing is waived as provided in § 4.401(a).

[47 FR 26392, June 18, 1982]

§ 4.413 Service of notice of appeal and o[f] other documents.

The appellant must serve a copy of the notice of appeal and of any statement of reasons, written arguments, or briefs on the Regional or Field Solicitor having jurisdiction over the State in which the appeal arose, or upon the Associate Solicitor, Division of Energy and Resources, when the appeals are taken from decisions of the Director U.S. Geological Survey, or the Director, Bureau of Land Management, or the subject matter of the appeal involves mineral activities on the Outer Continental Shelf.

Address: Associate, Regional or Field Solicitor and States Served

Associate Solicitor, Division of Energy and Resources, U.S. Dept. of the Interior Washington, D.C. 20240—n/a

Regional Solicitor, Northeast Region, U.S. Dept. of the Interior, Suite 306, One Gateway Center, Newton Corner, MA 02158—Pennsylvania, Indiana, Michigan, Minnesota, Ohio, Illinois, West Virginia, Wisconsin, Delaware, New [illegible] New York, the

New England States, Maryland and Virginia.

Regional Solicitor, Southeast Region, U.S. Dept. of the Interior, 75 Spring Street, S.W., Suite 1328, Atlanta, GA 30303—Kentucky, Tennessee, North Carolina, South Carolina, Georgia, Florida, Alabama, Mississippi, Puerto Rico and the Virgin Islands.

Regional Solicitor, Rocky Mountain Region, U.S. Dept. of the Interior, P.O. Box 25007, Denver Federal Center, Denver, CO 80225—Colorado, Wyoming, Nebraska, Kansas, Iowa and Missouri.

Field Solicitor, U.S. Dept. of the Interior, P.O. Box 1538, Billings, MT 59103—Montana, North Dakota and South Dakota.

Regional Solicitor, Intermountain Region, U.S. Dept. of the Interior, Suite 6201, Federal Bldg., 125 South State Street, Salt Lake City, UT 84138—Utah.

Regional Solicitor, Pacific Southwest Region, U.S. Dept. of the Interior, 2800 Cottage Way, Room E-2753, Sacramento, CA 95825—California, Nevada, Arizona and Hawaii.

Regional Solicitor, Pacific Northwest Region, U.S. Dept. of the Interior, Lloyd 500 Bldg., Suite 607, 500 N.E. Multnomah Street, Portland, OR 97232—Oregon and Washington.

Field Solicitor, U.S. Dept. of the Interior, Box 020, Fed. Bldg. & Courthouse 550 West Fort St., Boise, ID 83724—Idaho.

Field Solicitor, U.S. Dept. of the Interior, P.O. Box 1042, Santa Fe, NM 87501—Oklahoma, Texas, New Mexico, Arkansas and Louisiana.

Regional Solicitor, Alaska Region, U.S. Dept. of the Interior, 510 L Street, Suite 408, Anchorage, AK 99501—Alaska.

and each adverse party named in the decision appealed from, in the manner prescribed in § 4.401(c), not later than 15 days after filing the document.

Failure to serve within the time required will subject the appeal to summary dismissal as provided in § 4.402. Proof of such service as required by § 4.401(c) must be filed with the Board (address: Board of Land Appeals, Office of Hearings and Appeals, 4015 Wilson Boulevard, Arlington, VA 22203), within 15 days after service unless filed with the notice of appeal.

[45 FR 56947, Aug. 26, 1980]

§ 4.414 Answers.

If any party served with a notice of appeal wishes to participate in the proceedings on appeal, he must file an answer within 30 days after service on him of the notice of appeal or statement of reasons where such statement was not included in the notice of appeal. If additional reasons, written arguments, or briefs are filed by the appellant, the adverse party shall have 30 days after service thereof on him within which to answer them. The answer must state the reasons why the answerer thinks the appeal should not be sustained. Answers must be filed with the Board (address: Board of Land Appeals, Office of Hearings and Appeals, 4015 Wilson Boulevard, Arlington, VA 22203) and must be served on the appellant, in the manner prescribed in § 4.401(c), not later than 15 days thereafter. Proof of such service as required by § 4.401(c), must be filed with the Board (see address above) within 15 days after service. Failure to answer will not result in a default. If an answer is not filed and served within the time required, it may be disregarded in deciding the appeal, unless the delay in filing is waived as provided in § 4.401(a).

ACTIONS BY BOARD OF LAND APPEALS

§ 4.415 Request for hearings on appeals involving questions of fact.

Either an appellant or an adverse party may, if he desires a hearing to present evidence on an issue of fact, request that the case be assigned to an administrative law judge for such a hearing. Such a request must be made in writing and filed with the Board within 30 days after answer is due and a copy of the request should be served on the opposing party in the case. The allowance of a request for hearing is within the discretion of the Board, and the Board may, on its own motion, refer any case to an administrative law judge for a hearing on an issue of fact. If a hearing is ordered, the Board will specify the issues upon which the hearing is to be held and the hearing will be held in accordance with §§ 4.430 to 4.439, and the general rules in Subpart B of this part.

HEARINGS PROCEDURES

HEARINGS PROCEDURES; GENERAL

§ 4.420 Applicability of general rules.

To the extent they are not inconsistent with these special rules, the general rules of the Office of Hearings and Appeals in Subpart B of this part are also applicable to hearings, procedures.

§ 4.421 Definitions.

As used in this subpart:

(a) "Secretary" means the Secretary of the Interior or his authorized representatives.

(b) "Director" means the Director of the Bureau of Land Management, the Associate Director or an Assistant Director.

(c) "Bureau" means Bureau of Land Management.

(d) "Board" means the Board of Land Appeals in the Office of Hearings and Appeals, Office of the Secretary. The terms "office" or "officer" as used in this subpart include "Board" where the context requires.

(e) "Administrative law judge" means an administrative law judge in the Office of Hearings and Appeals, Office of the Secretary, appointed under section 3105 of Title 5 of the United States Code.

(f) "State Director" means the supervising Bureau of Land Management officer for the State in which the particular range lies, or his authorized agent.

(g) "District manager" means the supervising Bureau of Land Management officer of the grazing district in which the particular range lies, or his authorized agent.

[36 FR 7186, Apr. 15, 1971, as amended at 36 FR 15117, Aug. 13, 1971]

§ 4.422 Documents.

(a) *Grace period for filing.* Whenever a document is required under this subpart to be filed within a certain time and it is not received in the proper office during that time, the delay in filing will be waived if the document is filed not later than 10 days after it was required to be filed and it is determined that the document was transmitted or probably transmitted to the office in which the filing is required before the end of the period in which it was required to be filed. Determinations under this paragraph shall be made by the office before whom is pending the appeal or contest in connection with which the document is required to be filed. This paragraph does not apply to requests for postponement of hearings under §§ 4.452-1 and 4.452-2.

(b) *Transferees and encumbrancers.* Transferees and encumbrancers of land, the title to which is claimed or is in the process of acquisition under any public land law shall, upon filing notice of the transfer or encumbrance in the proper land office, become entitled to receive and be given the same notice of any contest, appeal, or other proceeding thereafter initiated affecting such interest which is required to be given to a party to the proceeding. Every such notice of a transfer or encumbrance will be noted upon the records of the land office. Thereafter such transferee or encumbrancer must be made a party to any proceeding thereafter initiated adverse to the entry.

(c) *Service of documents.* (1) Whenever the regulations in this subpart require that a copy of a document be served upon a person, service may be made by delivering the copy personally to him or by sending the document by registered or certified mail, return receipt requested, to his address of record in the Bureau.

(2) In any case service may be proved by an acknowledgement of service signed by the person to be served. Personal service may be proved by a written statement of the person who made such service. Service by registered or certified mail may be proved by a post-office return receipt showing that the document was delivered at the person's record address or showing that the document could not be delivered to such person at his record address because he had moved therefrom without leaving a forwarding address or because delivery was refused at that address or because no such address exists. Proof of service of a copy of a document should be filed in the same office in which the document is filed.

(44)

TAXATION & REVENUE DEPARTMENT

P.O. Box 630, Santa Fe, New Mexico 87509-0630

September 17, 1984

Mr. Lyn Patterson
Amerada Hess Corporation
Post Office Box 2040
Tulsa, Oklahoma 74102

RE: Valuation of Carbon Dioxide
Bravo Dome Unit

Dear Mr. Patterson:

This letter is a follow-up to our letter of June 18, 1984, concerning the valuation of carbon dioxide for the purposes of oil and gas tax and state royalty payments. As you are aware, we had informed you that you could report provisionally based upon your suggested method of valuation, in order to allow us further time to study the matter and determine our position as to the method of valuation.

Our review of this matter has yielded the following results. It is our position that interest on unamortized investment, or interest cost on the investment cannot be justified as a cost related to the production and sale of carbon dioxide, and therefore will not be allowed as a deduction from the sales price. Additionally, the only allowable deductions for transportation allowed under the oil and gas accounting laws are the reasonable expense of trucking the product from the production unit to the first place of market. See § 7-29-4.5A(3) NMSA 1978. Accordingly, all costs associated with the gathering system and facilities are not allowable as a deduction from the sales value to determine the taxable value. Finally, although depreciation will be allowed as to the plant facilities, we do not believe it is proper to base the estimation on the plant life on the life of the Seminole oil field where the CO_2 will be used. It is anticipated that there will be additional markets for the CO_2 as time goes on. Accordingly, we believe that the proper basis for depreciation of the plant is the actual plant life itself. In the absence of engineering studies or other evidence concerning the life of the processing plant, we have chosen to estimate the life of the plant at 30 years, based upon our experience with natural gas processing plants. We remain open, however, to evidence of a different plant life, should you wish to present such evidence.

Based upon the above, the Taxation and Revenue Department and Commissioner of Public Lands have determined that the following method will be used in arriving at the gross value upon which taxes and state royalty are to be determined for carbon dioxide sales from the Bravo Dome Carbon Dioxide Unit:

Mr. Lyn Patterson
Cont'd. Page 2

From the tailgate price per MCF there shall be deducted the following cost adjustments per MCF:

1. Depreciation of the plant facilities based upon a 30-year life, using the straight line method of depreciation.

2. Direct expenses related to the plant facilities, being labor, benefits and direct overhead.

3. Electrical power purchased, directly relating to the plant facilities.

4. Chemicals and maintenance directly related to the plant facilities.

The following costs will not be allowed as deductions from the tailgate price per MCF:

1. All expenses related to the gathering facilities including depreciation, direct expenses, electrical power, chemicals, maintenance, and labor.

2. Interest on unamortized investment or interest cost on investment.

In accordance with the terms of our letter of June 18, 1984, please submit amended reports with the additional taxes and state royalty due together with a total cost of service schedule based upon the allowable adjustments.

Please feel free to call upon us should you have any questions regarding any of the above.

Very truly yours,

Vickie Fisher, Secretary
Taxation & Revenue Department

Jim Baca

Jim Baca
Commissioner of Public Lands

JR/cmo

McElmo Dome

(27)

United States Department of the Interior
MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY
REFER TO:

MMS-RVS-OG
MS-653

Memorandum

12 JUL 1984

To: McElmo Dome CO_2 File

From: Petroleum Engineer, Oil and Gas Branch

Subject: Staff Meeting on Shell's Appeal to Deduct Income Tax as a Transportation Cost

A meeting was held June 28, 1984, by RVSD members to discuss the merits for, and against, allowing income tax as a cost of transportation for federal royalty. Attending the meeting were: Bill Feldmiller, Tom Blair, Dave Hubbard, and the entire Oil and Gas Valuation Branch.

A wide range of opinions was unveiled--from the argument that income tax is assessed on a basis of profit only, and that federal royalty should not be affected by a company's profit margin--to the argument that a company must figure income tax as a cost of doing business when planning future projects.

The Conservation Division Manual does not allow income taxes to be deducted as a transportation cost for producer-owned/operated systems; however, no legal basis has been found to support this position. MMS does allow, (as a matter of policy) income tax when transportation costs are incurred under arm's-length contracts of FERC tariff.

We determined that this issue must be considered in two distinct situations: (1) the point of sales is at the beginning of the pipeline, but the point of valuation is at the terminus, and (2) both the points of sale and valuation are at the terminus; i.e., the pipeline is producer-owned.

In the first situation, income tax is a cost of doing business and such costs are included in a tariff or an arm's-length contract. Actual costs, such as income tax, are incurred by the payor and are therefore allowed as deductible. We concluded that Shell's McElmo Dome CO_2 pipeline transportation costs fall in this category and that their full tariff rate, including income tax, should be allowed to be deducted from federal royalty.

In the second situation, it is current MMS policy to not allow income tax to be deducted from federal royalty. However, further study is needed to determine why this policy exists, and if it should continue.

Larry Cobb

Larry Cobb