Royalty Management Program

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This manual documents the procedures for the MMS auditors.

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Acting Chief, Rules and Publications Staff

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This manual replaces the *Audit Procedures Manual,* Release 1.0 in its entirety.

Audit Manual

Royalty Management Program

Release 2.0

MMS
U.S. Department of the Interior
Minerals Management Service
Royalty Management Program

Audit Manual

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Release 2.0

January 16, 1998

Written by:

Compliance Coordination Office

Prepared by:

American Management Systems
Operations Corporation, Inc.

under Contract No. 14-35-0001-30550

U.S. Department of the Interior
Minerals Management Service
Royalty Management Program

The use of trade names does not constitute endorsement by the U.S. Department of the Interior.

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Abbreviations

ACT	automated custody transfer
AD/PMI	Associate Director for Policy Management Improvement
AD/RM	Associate Director for Royalty Management
ADR	Administrative Dispute Resolution
AFMSS	Automated Fluid Minerals Support System
AFS	Auditing and Financial System
AIRS	Automated Inspection Records System
ALMRS	Automated Land and Minerals Records System
APD	Application for Permit to Drill, Deepen, or Plug Back
API	American Petroleum Institute
ARC	adjustment reason code
BIA	Bureau of Indian Affairs
BIS	Business Information System
BLM	Bureau of Land Management
BS&W	basic sediment and water
Btu	British thermal unit
CA	communitization agreement
CCN	case control number
CD	certificate of deposit
CFR	Code of Federal Regulations
CLN	cross-lease netting
CLS	cross-lease selling
COPAS	Council of Petroleum Accountants Society
COTR	Contracting Officer's Technical Representative
CPA	Certified Public Accountant
CPE	continuing professional education
CRD	Common Reference Data
CTS	Case Tracking System
CVD	Compliance Verification Division
DAD-C	Deputy Associate Director for Compliance
DCS	Debt Collection Section
DMD	Data Management Division
DOI	Department of the Interior
DPAI	Detailed Production Accountability Inspections

email	electronic mail
EOR	enhanced oil recovery
EVB	Economic Valuation Branch
FBIL	audit exceptions
FCN	finding control number
FERC	Federal Energy Regulatory Commission
FEV	full economic value
f.o.b	free on board
FOIA	Freedom of Information Act
FMIF	Facility and Measurement Information Form
FOGRMA	Federal Oil and Gas Royalty Management Act of 1982
FRC	Federal Records Center
GAGAS	generally accepted Government auditing standards
GBIL	Federal late payment
I&E/PV	Inspection and Enforcement/Production Verification
IBLA	Interior Board of Land Appeals
IMHI	Independent Measurement/Handling Inspections
INC	Incident of Noncompliance
IOC	Initial Operating Capability
IPAA	Independent Petroleum Association of America
kWh	kilowatt hours
LOC	letter of credit
LVS	Liquid Verification System
MATS	MMS Appeals Tracking System
Mcf	thousand cubic feet
MIF	Mine Information Form
MMBtu	million British thermal units
MMcf	million cubic feet
MMS	Mineral Management Service
MRO	Monthly Report of Operations
MOU	memorandum of understanding

NGL	natural gas liquid
NGLP	natural gas liquid product
NPS	net profit share
NPSL	net profit share lease
NTL	notice to lessee
O&M	operations and maintenance
OCS	Outer Continental Shelf
OCSIS	Outer Continental Shelf Information System
OCSLA	Outer Continental Shelf Lands Act of 1953
OE	Office of Enforcement
OGOR	Oil and Gas Operations Report
OGVB	Oil and Gas Valuation Branch
OIG	Office of Inspector General
OMM	Offshore Minerals Management
PAAS	Production Accounting and Auditing System
PASR	Production Allocation Schedule Report
PI	Petroleum Information Corporation
PIF	Payor Information Form
POP	percentage of proceeds
RATS	Royalty Audit Tracking System
RFD	Reports and Financial Division
RSFA	Royalty Simplification and Fairness Act
RIK	royalty-in-kind
RMP	Royalty Management Program
ROI	return on investment
ROR	rate of return
RPS	Rules and Publications Staff
RQS	RMP Query System
RVD	Royalty Valuation Division
SAS	statements on auditing standards
SICD	State and Indian Compliance Division
SMFR	Solid Minerals Facility Report
SMOR	Solid Minerals Operations Report
SMVB	Solid Minerals Valuation Branch
SOR	statement of reasons
STATSS	State and Tribal Support System
TIMS	Technical Information Management System
TS	Treasury Security

VSD	Valuation and Standards Division
UDC	Ute Distribution Corporation
USGS	United States Geological Survey
WAN	wide area network

Contents

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1. About This Manual

The Minerals Management Service (MMS), Royalty Management Program (RMP) provides revenue collection services for Federal and Indian leases. This manual contains technical guidance and procedures for conducting audits to determine if the revenues were paid timely and accurately.

1.1 Who Must Use this Manual

If you are an RMP auditor, a State or Tribal auditor funded by Section 202 or 205 monies, or a Certified Public Accountant (CPA) under contract with RMP, you must follow the procedures in this manual when auditing Federal and Indian mineral revenues. Any exceptions to these procedures must be approved by the appropriate audit manager:

- RMP auditors must obtain approval from their respective Division Chief.
- State and Tribal auditors must obtain approval from the Chief, State and Indian Compliance Division (SICD).
- Contract CPAs must obtain approval from their respective Contracting Officer's Technical Representative (COTR).

1.2 Maintenance

Please forward suggested changes or enhancements to this manual to the Compliance Coordination Office for review and approval. Approved changes and enhancements will be forwarded to the Rules and Publications Staff (RPS) and incorporated into future revisions of the manual. All revisions must be approved by RMP and are published by RPS.

1.3 Security Restrictions

No security restrictions apply for this manual. It contains neither classified material nor information covered by the Privacy Act.

2. Audit Overview

The RMP mission is to collect, verify, and distribute in a timely manner mineral revenues from Federal and Indian lands. RMP collects about $4 billion annually in mineral rents, bonuses, and royalties. The goal of the RMP audit program is to ensure that these payments are accurate and that payors comply with applicable mineral laws and regulations. To accomplish this goal, we have developed several methods to select audit candidates. Accomplishment of the goal depends on resource availability and program priorities.

Residencies and other major payors. By focusing on a relatively small number of major payors, we cover about 87 percent of total revenues. These audit candidates include:

- Residencies at 11 major payor companies,
- About 100 other major payor companies, and
- Companies paying at least $250,000 in royalties on Indian allottee leases.

Randomly selected payors. We randomly select approximately 30 companies—other than major payors—for audit annually. This strategy makes all payors subject to possible audit.

State- or Tribe-selected payors. States and Tribes, as audit partners, select payors within their geographic areas for audit. We supplement resources on these audits to cover all lease activity of a particular company for a specific period.

Noncompany. We audit important areas other than payors to cover cross-company activities. Examples are gas plants, unit or communitization agreements, transportation systems, and nonstandard Indian leases.

Contract settlements. We audit settlements of disputed purchase/sales contracts because of their large royalty potential.

Indian leases. In addition to the Indian royalty coverage obtained through company-based audits, we audit leases referred by Indian customers and leases specifically selected.

2.1 Types of Audits

You will perform several types of audits depending on the purpose of the assignment and the source of the request. These include:

- Company audits
- Issue audits
- Referrals
- Litigation support
- Negotiated settlement support

Other activities include non-audit reviews, which are not addressed in this manual but are appropriate enforcement tools.

2.1.1 Company audits

Company audits include a review of the company's (1) management controls, (2) production and royalty accounting systems, and (3) royalty payments on specific leases. Two approaches to company audits—by lease or by attribute—are described below.

Lease audits. When a company's lease universe is small, you may perform lease audits.

- Select leases that represent each major area in which the company is involved; for example, offshore oil and gas, onshore oil and gas, Indian oil and gas, and other mineral operations.
- Select leases that have traditional problem issues such as allowances and dual accounting on Indian leases.
- From the remaining lease universe, use a random selection process.

This approach may be used for companies with a few leases or with homogeneous groups of a few leases in a large universe.

Attribute audits. For companies with larger lease universes, you may perform attribute audits or a combination of attribute and lease audits.

- Stratify the company's lease universe and select leases from homogeneous groups. For example, divide the lease universe into homogeneous groups representing products and transaction codes. Subdivide these groups by lease types such as offshore oil and gas, onshore oil and gas, Indian oil and gas, and other mineral operations. For each lease type, homogeneous groups include volumes, values, royalties, allowances, tax reimbursements, direct pay to Indians, and any other areas of involvement.

- Select leases from trend-analysis reports to include with the homogeneous groups. The leases selected depend on the universe and your professional judgment. For example, a stratified selection of 5 leases from several homogeneous groups may approximate 85 percent coverage of the universe.

- Select leases randomly and from trend-analysis reports to test the accounting system and management controls.

  – All leases in the universe have the same chance of being selected for an audit when randomly selected. Some leases may be selected from more than one homogeneous group that stratifies the universe. For example, one lease may be randomly selected for volume, royalty, and allowances, but not for value or tax reimbursements. The total universe should be stratified after you have selected leases either randomly or by trend-analysis in all homogeneous groups.

NOTE Always substitute replacement leases when leases originally selected for audit cannot be reviewed adequately or do not satisfy the requirements of the audit strategy.

  – When your audit of the accounting system and management controls—using selected leases within a homogeneous group—shows no significant deficiencies, accept the universe as being reported correctly. For example, when tests of Indian oil volumes do not reveal significant deficiencies, accept the remaining Indian oil volumes in the company's universe as being properly reported. This clears only the reported Indian oil volumes.

– Use this approach early in the audit to identify systemic problems and deficiencies that apply to the universe. You attain comprehensive compliance by issuing system-wide orders to correct the deficiencies.

Several companies can be involved in lease activities affecting royalty payments. For example, a company may operate and pay on a lease, only operate a lease, or only pay on a lease. When several companies are involved in lease operations, you usually limit the audit scope to the company under audit. If you identify disparities involving other companies, you should document the audit leads for use in selecting future audit targets.

2.1.2 Issue audits

Issue audits cover multiple leases involved in a narrow but high-risk aspect of royalty determination.

Net profit sharing leases. Net profit sharing leases are one of our most important issue audits. Special mineral lease agreements for production from Outer Continental Shelf (OCS) and Indian lands provide for net profit sharing from lease operations. These agreements differ significantly from standard royalty calculations because they require special accounting procedures for capital accounts and allowable expenditures. These agreements require special auditing techniques to verify the accuracy of net profit determinations and pay-out periods for development and operating costs.

- Because OCS net profit sharing leases usually involve major oil and gas companies, residency teams and other major payor audits provide primary audit coverage for OCS net profit sharing leases. See chapter 11 for more information on OCS net profit sharing leases.

- Audit teams responsible for the major Indian payor companies provide audit coverage of Indian joint venture agreements. See “Joint venture agreements” on page 13-3 for more information on Indian joint venture agreements.

- Audit resources are allocated for Bureau of Indian Affairs (BIA) referrals to resolve royalty issues on Tribal and allotted net profit sharing leases. See “Net profit share agreements” on page 13-4 for more information on Indian net profit sharing leases.

Other high-risk elements. You can effectively address other issues through reviews of specific elements, such as:

- Transportation (pipelines),
- Gathering and processing allowances (gas plants),
- First-production royalty payments,
- Plant product pricing, and
- Royalty-in-kind.

2.1.3 Referrals

Referrals are an integral part of the audit workload. Most referrals are the result of one of the following:

- Exception processing completed by the Auditing and Financial System (AFS) and the Production Accounting and Auditing System (PAAS).
- Discrepancies discovered by the Bureau of Land Management (BLM), BIA, Tribes, allottees, or other audit offices.

These discrepancies may include incorrect value reported or used as royalty basis, incorrect reported volumes, improper deductions for allowances, or improper use of product on a lease.

Other MMS offices, governmental agencies, and Tribes and allottees initiate requests for review of irregularities because the alleged irregularity is beyond the scope of their work.

The State and Indian Compliance Division (SICD) initially receives referrals and assigns them to audit offices in the following priority:

1. Applicable State or Tribe,
2. Lakewood Compliance Division or the next applicable audit division if there is an ongoing or scheduled audit involving the referral.

The audit office acknowledges receipt of the referral, provides a target completion date to the requestor, and notifies the requestor when the audit is completed.

All referral reviews are limited to the specific issue causing the irregularity. If you discover other irregularities during the review, you must initiate an audit lead sheet.

2.1.4 Litigation support

You may provide technical assistance on royalty issues to various legal offices such as the MMS Appeals Division, the Solicitor's Office, and the U.S. Department of Justice. These activities include:

- Giving testimony and technical advice at depositions conducted by plaintiff attorneys.
- Responding to discovery actions using previously compiled data.
- Gathering statistical data and preparing position papers to defend the Government's position in appeals and litigation.
- Completing or reviewing recalculated royalties resulting from legal decisions.

2.1.5 Negotiated settlement support

Companies disagreeing with royalty enforcement documents, such as orders to pay and perform, sometimes seek to negotiate a settlement to resolve those issues. You may participate as a member of or contributor to a settlement negotiating team.

The audit representative on the settlement team is usually an audit manager. The audit manager may supplement team resources as necessary to conduct settlement activities and appoint auditors to explain, justify, defend, and participate in negotiating audit issues and orders. See chapter 26 for more information on the negotiated settlement process.

2.2 Audit Phases

The following are the phases of an audit:

- Initiation
- Entrance conference
- Preliminary survey
- Audit plan development
- Detailed testing
- Enforcement and resolution
- Reporting
- Closure
- Coordination

2.2.1 Initiation

At or near the beginning of a new fiscal year, general notification letters are sent to entities selected for comprehensive audits. When you initiate an audit, you issue a more detailed engagement letter to the auditee—the entity to be audited including any affiliates and subsidiaries. An engagement letter should:

- Be issued at least 60 days before the start of the audit to provide maximum advance notice;

- Identify each audit participant;
- State the objectives and period covered by the audit;
- Identify the time and date of the entrance conference and the number of auditors attending;
- Identify the number of auditors in the audit team and the dates and lengths of their onsite visits;
- Request adequate working space for the auditors;
- Request the name of the auditee contact and address to be used for data requests and any assessment action that may arise;
- Identify the audit coordinator, if one is designated, whom the auditee may contact for questions about the engagement letter; and
- Identify auditee records that will be reviewed during the audit.

2.2.2 Entrance conference

The entrance conference is an initial meeting between the audit participants and auditee officials to establish a mutual understanding of the ground rules for conducting the audit. To the extent resources and schedules permit, all audit participants should attend the entrance conference. Both the audit participants and the auditee should designate audit contacts and specify their duties. The audit participants should thoroughly explain the audit process and how important audit data is gathered, including any coordination requirements of the MMS, State, or Indian audit coordinator. The coordinator or a designee must also provide audit process training during the entrance conference.

2.2.3 Preliminary survey

During the preliminary survey, you gather and review background information on the auditee. You determine the audit universe and review and evaluate the auditee's internal accounting systems. You use the information developed during this stage to determine the scope of the audit, make sample selections, and develop steps for the detailed audit program. See chapter 6 for more information on conducting a preliminary survey.

2.2.4 Audit plan development

During audit plan development, you establish the scope of the work to be performed, select the leases and period to be reviewed, and develop detailed audit steps. You also identify and request any assistance that may be required from other offices to allow for necessary lead time. You should contact the appropriate audit office by telephone or e-mail first to ensure that the information you seek is available from that particular office. The telephone call or email message may be sufficient to obtain assistance from some audit offices. Other offices may require a written request for assistance to the appropriate Division Chief. The request should specifically define the assistance required and the urgency of a response. If the assistance cannot be provided within the necessary time frames, the requested office will notify you so that you can explore other methods for obtaining the required information. See chapter 6 for more information on developing an audit plan.

2.2.5 Detailed testing

In detailed testing, you perform the audit steps identified in the audit program and gather evidence. You may expand or contract the audit steps depending upon information gathered during the audit. You should continually evaluate whether to expand or decrease audit steps to ensure proper use of resources. Develop and document issues thoroughly so that corrective actions may be initiated. Extrapolation and interpolation techniques, when agreed to by both parties, are accepted methods for quantifying royalty underpayments and overpayments disclosed during detailed testing. Always use applicable regulations for the period under audit and document discrepancies involving other companies for referral. The RMP intranet library contains numerous examples of audit programs.

2.2.6 Enforcement and resolution

During the enforcement and resolution stage, you prepare issue letters, orders for payment, orders to perform, orders for records, subpoenas, appeal reports, and notices of noncompliance. You also review and evaluate the auditee's responses to these documents. See chapter 26 for more information on enforcement procedures.

The enforcement documents, Issue Letter, Order to Pay, Order to Perform, etc., serve as the audit report. Therefore, the documents must contain the required elements of a report, which include the scope of the audit, findings and conclusions, auditee's responses, and a statement that the audit was performed using generally accepted Government audit standards (GAGAS).

Generally, the enforcement document is all the reporting that is required. However, in the event of an audit where no enforcement documents are issued or in the case of an assisted audit, a summary letter to the auditee or assisting office may become necessary. The summary letter should explain the scope and results of the audit (including resolved and unresolved issues in the case of an assisted audit), include a GAGAS statement, and a statement thanking the auditee or assisting office for their efforts and/or cooperation. Resident auditors must also, at the auditee's request, issue an annual interim summary letter that specifies the audit period covered, lists outstanding data requests, discloses both resolved and unresolved audit findings by issue, and identifies closed issues. See chapter 24 for more information on the format and content of enforcement documents and summary letters.

2.2.7 Coordination

Audit offices are established geographically, with each office responsible for assignments within its geographic area. Coordination between offices is important to ensure the audit mission is accomplished efficiently. For example, during an audit you may note a discrepancy committed by a company under the jurisdiction of another audit office. Documenting this lead on an audit lead sheet provides a uniform and consistent method for referring important and timely audit information to other audit offices.

3. State and Tribe Participation

MMS enters into agreements with States and Tribes to conduct audits of Federal and Indian leases.

Funded agreements. The Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) authorized the Secretary of the Interior to enter into cooperative agreements with States and Tribes under section 202 and to delegate audit authority to States under section 205.

- **Section 202**. Under a cooperative agreement, a State or Tribe is permitted to conduct inspections, audits, and investigations of activities on Federal or Indian lands. The State or Tribe is reimbursed up to 100 percent of the costs directly required to carry out the agreed-upon activities.

NOTE

The Federal Oil and Gas Royalty Simplification and Fairness Act of 1996 (RFSA) (110 STAT 1717) declared FOGRMA Section 202 no longer applicable to Federal lands effective September 1, 1996. However, FOGRMA does still apply to Indian lands.

- **Section 205**. Under a delegation of audit authority, a State is permitted to conduct inspections, audits, and investigations of all Federal and Indian lands within the State if MMS has obtained the prior permission of the Tribe or allottee involved. The State is reimbursed for 100 percent of costs necessary to carry out the delegated activities.

NOTE

RSFA enlarged FOGRMA Section 205 delegations to States to include—in addition to conducting audits, inspections, and investigations—receiving and processing production and financial reports; correcting erroneous report data; performing automated verification; and issuing demands, subpoenas, and orders to perform restructured accounting for all Federal land within a State, effective September 1, 1997.

Unfunded agreements. In addition to funded agreements, MMS enters into unfunded joint audits and agreements with States and Tribes. This type of agreement is flexible and allows for modifications to meet the specific needs of the State or Tribe. For example, the State and Indian Compliance Division (SICD) and a Tribe may each provide an auditor to conduct joint audits. Under this arrangement, both parties are responsible for ensuring that the audit is properly conducted and completed within a reasonable time. Other agreements allow for audit participation but are used primarily for data exchanges.

3.1 Duties

Audit participant, audit coordinator, and SICD duties were initially defined in a memorandum dated February 24, 1992, entitled “Audit Coordination and Correspondence Responsibilities.” These duties were expanded by an Audit Subcommittee Report to the Royalty Policy Committee dated May 1996 entitled “Recommendations to Improve Royalty Audits” and the subsequent audit action plan.

3.1.1 Audit participants

Audit participants are those audit groups who dedicate time and resources to conduct an audit. Nonparticipants are those audit groups who have leases in the audit universe but do not dedicate time and resources to an audit. Therefore, only audit participants may claim an allocation of the audit findings as accomplishments.

Information gathered during an audit is available to all participants. Each participant's work papers are the responsibility of that participant. Duties of audit participants include:

- Establishing contact with the audit coordinator.
- Participating in the entrance and exit conferences when possible.
- Participating in the system review (recommended).
- Preparing the audit plan.
- Preparing issue letters for findings identified by participants.
- Preparing summary letters.
- Drafting orders to pay and orders to perform.
- Meeting scheduled deadlines.

3.1.2 Audit coordinator

An audit coordinator for the consolidated work plan is selected based upon such factors as the number of leases, audit resources, royalties at risk, and location of the audit. The audit coordinator can be from a State, a Tribe, or MMS. At resident audit sites, the audit participants may request the resident team leader to be the audit coordinator. The audit coordinator is selected and audit participants are notified before audit work starts.

Duties. Duties of the audit coordinator, depending on the needs of the audit participants, may include:

- Notifying all participants before establishing or changing the scheduled audit start date.
- Contacting each audit group to verify participation at the beginning of an audit.
- Preparing and sending an engagement letter identifying the audit participants, the number of auditors, and the timing of onsite visits.

- Preparing an agenda for the entrance conference covering the following subjects:
  - Audit process.
  - Audit coordinator's duties.
  - Auditee contact for issue letters and enforcement documents.
  - Identification and handling of confidential information.
  - Data requests customized to use participant or auditee identifiers.
  - Auditee contact for data requests.
  - Walkthrough of the auditee's accounting system.
  - Initial data-gathering activities.
- Conducting the entrance conference.
- Scheduling office space for the initial field visit.
- Performing or updating a management control review.
- Coordinating data requests at residencies.
- Preparing issue letters for findings identified by the coordinator.
- Coordinating and communicating findings among participants.
- Preparing orders for records or subpoenas.
- Preparing demand letters and orders to pay and perform for findings identified by the coordinator. For State and Tribal participants, see "Issuing orders to pay and perform" on page 3-7.
- Coordinating compliance activities. For example, when participants select test leases, the audit coordinator may contact other MMS offices to coordinate ongoing compliance activities on the leases selected for the audit.

- Referring disputes. If a disagreement between the audit participants cannot be resolved, the audit coordinator refers the problem to the appropriate audit manager.
- Notifying the auditee when the field work is completed. See the April 22, 1991, memorandum entitled "Policy Guidance Regarding Audit Field Work Complete."
- Conducting the exit conference.

3.1.3 State and Indian Compliance Division

SICD provides technical assistance to audit participants when requested. The SICD role is to:

- Provide ongoing audit coordination between the States, Tribes, and MMS.
- Sign orders to pay and perform prepared by the States and Tribes.

NOTE RSFA will allow appropriately delegated States to issue orders directly effective September 1, 1997.

- Review and distribute enforcement documents and appeal field reports prepared by the States and Tribes.
- Coordinate annual work plans submitted by States and Tribes with work plans submitted by MMS field offices.

The SICD/Indian Audit Team (IAT) conducts audits of Indian allottee issues.

3.2 Coordination Procedures

State and Tribal audits must meet the same standards as those performed by Federal auditors. See chapter 4 for more information on auditing standards. In addition, cooperative audit efforts require exceptional coordination and communication to succeed.

3.2.1 Developing annual work plans

The Compliance Coordination Office establishes a preliminary annual work plan. The work plan is based upon the type and number of producing mineral leases in each jurisdiction and referrals from internal and external sources.

This preliminary work plan is then issued to all audit organizations for a decision on whether to participate. Participation decisions are based on revenues at risk, budget constraints, and other factors.

Participants finalize their work plans to MMS to confirm their audit participation commitments during the fiscal year. SICD conducts an annual audit planning and coordination meeting with State, Tribal, and MMS audit managers to confirm audit work plans. MMS then issues a consolidated work plan identifying audit candidates and participating audit groups.

3.2.2 Segmenting audit participation

Timely audits of royalty payors are critical. Cooperative efforts with States and Tribes must be carefully coordinated to ensure that audit resources are fully used and audit objectives are achieved.

A payor audit covers all leases in an audit period. The leases are divided among those States and Tribes participating in the audit. Coverage is expanded by having States and Tribes audit those leases within their jurisdiction. MMS auditors generally cover Outer Continental Shelf (OCS) leases, allotted Indian leases, and Federal and Tribal leases, as necessary, when the involved State or Tribe chooses not to participate. To avoid duplication of effort, MMS carefully coordinates assignments among State, Tribal, and MMS audit offices.

Participants select leases, wells, and sales months to be audited in their jurisdiction. Each participant shares information and data—excluding proprietary information—with other participants. Any systematic or procedural findings or audit leads are immediately made available to the audit coordinator who shares the information with all affected participants.

3.2.3 Requesting data

Before requesting data from an auditee, participants must make a good faith effort to obtain the information from MMS and other Department of the Interior (DOI) agencies, such as the Bureau of Land management (BLM) and the Bureau of Indian Affairs (BIA). Participants should check with the audit coordinator to determine if there are any special procedures to be followed before submitting data requests to the auditee. In some instances, all data requests must be submitted by the audit coordinator. Subpoenas for records must be issued when all other means to obtain records fail. If an MMS audit office is a participant in the audit, the MMS participant issues the subpoena. If no MMS office participates, SICD issues the subpoena. See chapter 9 for more information on access to auditee records.

3.2.4 Issuing orders to pay and perform

If an enforcement order is warranted, the State or Tribal participant drafts and sends an order to SICD for issuance.

NOTE RSFA will allow appropriately delegated States to issue orders directly effective September 1, 1997.

MMS audit office participants follow normal procedures for issuing orders. An order should contain all the elements of a finding—condition, criteria, cause, and effect—and address the auditee's response to the finding. All findings must be identified by month, MMS 10-digit lease number, and applicable payor code number. See "Enforcement Documents" on page 24-2 for more information on orders to pay and perform.

3.2.5 Preparing appeal field reports

When requested, participants prepare field reports responding to arguments raised by an appellant. Participants respond only to arguments related to audit issues they developed. The field report is in memorandum form and addressed to the Chief of the Appeals Division.

Field reports are sent to the Appeals Division through SICD. State and Tribal participants should forward field reports to SICD for processing within 60 or 120 days after the State or Tribe's receipt of the appellant's final arguments. See chapter 27 for more information on the appeals process.

3.2.6 Writing enforcement documents

All enforcement documents issued contain sufficient detail to support collection of the findings. See chapter 24 for more information on audit reports.

4. Auditing Standards

You, as a Federal auditor, must comply with auditing standards contained in the publication entitled, *Government Auditing Standards* (June 1994)—commonly known as the Yellow Book. These standards, established by the Comptroller General of the United States, are broad statements of auditors' responsibilities and are included as basic audit criteria for Federal executive departments and agencies in Office of Management and Budget Circular No. A-73, Audit of Federal Operations and Programs (June 20, 1983).

MMS policy requires that Yellow Book standards be used when conducting royalty audits. In addition, MMS regulations at 30 CFR 228.102 and 229.123 (1996) require that audits conducted under cooperative agreements and delegations of authority comply with Yellow Book standards.

4.1 Types of Audits

The Yellow Book classifies audits under two general types:

- Financial audits, including financial statement and financial-related audits.

- Performance audits, including economy and efficiency, and program audits.

Royalty audits have characteristics of both financial and performance audits. In a typical royalty audit, you review the practices and procedures relating to the computation and payment of royalties due on minerals removed from Federal and Indian leases. All royalty audits are subject to the general standards for conducting financial and performance audits in chapter 3 of the Yellow Book. Further, royalty audits are covered in the Financial Related Audits section 4.40 and section 5.37 of the Yellow Book, which states in part, "...Auditors should follow the field work standards, for performance audits...and auditors should follow the reporting standards for performance audits."

4.2 General Standards

General standards apply to performance audits.

Qualifications. The staff assigned to conduct an audit should possess adequate professional proficiency for the tasks required. Work experience and training are important criterion when making personnel assignments in the audit process.

As a Federal auditor, you must complete, every 2 years, at least 80 hours of continuing professional education (CPE) credits. At least 20 credits must be completed in each year of the 2-year period. At least 24 of the 80 hours must be directly related to Government auditing. See the memorandum, dated April 27, 1990, entitled "Continuing Professional Education (CPE) Requirement for Auditors and Other Evaluators," for CPE requirements specific to RMP and examples of acceptable training programs.

Independence. In all matters relating to audit work, the audit organization and the individual auditors, whether Government or public, should be free from personal and external impairments to independence, should be organizationally independent, and should maintain an independent attitude and appearance.

As a Federal auditor, you must maintain actual and perceived independence so that your opinions, conclusions, judgments, and recommendations will be impartial and be viewed as impartial by knowledgeable third parties. In considering independence, you must appraise not only your own attitudes and beliefs, but also whether there is anything about your situation that might lead others to question your independence.

NOTE

If you encounter a situation that may be perceived as a conflict of interest, discuss the problem with your supervisor or call the MMS Ethics Counselor immediately for advice.

Due professional care. Due professional care should be used in conducting the audit and preparing related documentation.

This standard imposes a responsibility to observe generally accepted Government auditing standards (GAGAS). GAGAS incorporate the American Institute of Certified Public Accountants' statements on auditing standards (SAS) and prescribe several additional standards. The Yellow Book cites specific SASs applicable to fieldwork and reporting.

Quality control. Each audit organization conducting audits in accordance with these standards should have an appropriate internal quality control system in place and undergo an external quality control review.

RMP auditors perform "peer" reviews to insure that our audit offices follow Yellow Book standards and internal audit policy and procedures. Some of the important concepts of the peer reviews are as follows:

- Review frequency—Audit supervisors are reviewed once every 2 years. State and Tribal audit programs under 202/205 contracts are reviewed once every 2–3 years.
- Size of review team—The peer review team consists of two auditors, at least one of which is a Federal employee.
- Qualifications of reviewers—Participants must be at least journeyman-level auditors. All participants must have attended a course on the Yellow Book and the internal control review process within the past 3 years.
- Review criteria—Participants use a standard review checklist, and all resulting documentation is accumulated and retained in accordance with Government guidelines.
- Review results—The review results are furnished orally and in writing to the audit supervisor before the review team's departure from the review site. The report is short and designed to benefit the audit group reviewed.
- Reports to RMP management—An annual report is issued to RMP management and includes information on the number of reviews performed and the problem areas identified.

4.3 Field Work Standards

Some of the field work standards applicable to royalty audits are as follows.

Planning. Audit work is to be adequately planned.

Supervision. Staff are to be properly supervised. This includes timely supervisory review of workpapers and active involvement of audit supervisors in the conduct of the audit.

Compliance with laws and regulations. When laws, regulations, and other compliance requirements are significant to audit objectives, auditors should design the audit to provide reasonable assurance about compliance with them.

Management controls. Auditors should obtain an understanding of management controls that are relevant to the audit. When management controls are significant to audit objectives, auditors should obtain sufficient evidence to support their judgments about those controls.

Evidence. Sufficient, competent, and relevant evidence is to be obtained to afford a reasonable basis for the auditors' findings and conclusions. A record of the auditors' work should be retained in the form of work papers. Work papers should contain sufficient information to enable an experienced auditor having no previous connection with the audit to ascertain from them the evidence that supports the auditors' significant conclusions and judgments (financial and performance audits). See chapter 5 for more information on RMP work paper standards.

4.4 Reporting Standards

Some of the reporting standards applicable to royalty audits are as follows:

Form. Auditors should prepare written enforcement documents (for example, orders to pay or perform) communicating the result of each audit.

Timeliness. Auditors should appropriately issue the enforcement documents to make the information available for the timely use by management, legislative officials, and other interested parties.

Enforcement documents. Auditors should report:

- The audit objectives, scope, and methodology;
- Significant audit findings and, where applicable, auditors' conclusions;
- That the audit was made in accordance with GAGAS;
- All significant instances of noncompliance and all significant instances of abuse that were found during or in connection with the audit—auditors should report illegal acts directly to the Office of Enforcement;
- The scope of their work on management controls and any significant weakness found during the audit;
- The views of responsible officials of the audited program concerning auditors' findings and conclusions.

See chapter 24 for more information on RMP enforcement documents.

Findings presentation. The enforcement document should be complete, accurate, objective, convincing, and as clear and concise as the subject permits.

Distribution. Written enforcement documents are to be submitted by the audit organization to the appropriate officials of the auditee and to the appropriate officials of the organization requiring or arranging for the audits, including external funding organizations, unless legal restrictions prevent it.

5. Work Paper Standards

The Yellow Book, discussed in chapter 4, requires all Government auditors to prepare work papers that contain:

1. The objectives, scope, and methodology of the work performed, including any sampling criteria used;

2. Documentation of the work performed to support significant conclusions and judgements, including descriptions of transactions and records examined that would enable an experienced auditor to examine the same transactions and records; and

3. Evidence of supervisory review of the work performed.

In addition to the Yellow Book standards, you must use the preparation and review procedures described in this chapter for all RMP audit work papers.

5.1 Definition of Work Papers

Audit work papers document evidence obtained or developed, methods and procedures followed, and conclusions reached during an audit. A work paper may be one page or many, and may come in many forms, such as:

- Detailed worksheets prepared by hand or on a computer.
- Documents obtained from the auditee.
- Letters generated by your office or other audit offices.
- Computer printouts or diskettes of royalty history.
- Records of meeting and telephone conversations.
- Copies of leases and agreements.
- Enforcement documents.

- Relevant correspondence.
- Audit programs.

Audit work papers serve several purposes. The most important are to:

- Provide a record of information and evidence developed in support of findings, conclusions, and recommendations.
- Present information that will enable supervisors to manage assignments and evaluate performance.
- Allow others to review the quality of audit work.
- Create a permanent file that will be useful for planning and carrying out subsequent assignments.

To properly document an audit and minimize errors and omissions, you should promptly record all relevant information in your work papers.

5.2 General Requirements

There are four general requirements for work paper preparation; they must be:

1. **Complete**. Work papers must be complete and accurate in order to provide proper support for findings and conclusions. Work papers should explain or show how the work accomplished the audit program objective (especially for no findings).

2. **Understandable**. Work papers should be clear, concise, and understandable without supplementary oral explanations. Persons using the work papers should be able to readily determine the work paper purpose, the nature and scope of the work completed, and your conclusions. Conciseness is important, but clarity and completeness should not be sacrificed to save time or paper.

   Oral information may be recorded verbatim but is most often paraphrased for use in a report. Record your understanding or interpretation of what was said or meant and confirm your understanding with other participants in the conversation.

3. **Neat**. Work papers must be legible and as neat as practicable to decrease the time spent in review, enforcement document writing, and referencing.

4. **Relevant**. Information in work papers should be restricted to matters that are important and relevant to the audit objectives. Well-planned and organized audit programs, effective instruction by supervisors, and a statement of purpose ensures that the information accumulated is properly tied to the audit objectives.

   The cost of preparing work papers is an important part of the total cost of an audit. Work paper cost is justified by the value of the information collected. Accumulating and retaining unnecessary work papers can hamper the management of an assignment and complicate storage and filing. Unnecessary work papers can also cause important information to be overlooked.

   While interviewing auditee personnel or examining files, you may become aware of material that is not directly relevant to current objectives but might become relevant as the assignment progresses. To avoid accumulating excessive detail in the work papers, take brief notes on the material and retain them in informal files until their relevancy can be determined. Information that is clearly related to the subject of the report, even though it was not included in the report, should be included in the work papers.

5.3 Format and Content

The following are guidelines for work paper format and content.

1. Use approved word processing and spreadsheet software to prepare work papers.

2. Use good judgement to avoid making unnecessary copies.

3. Document only one subject on each work paper to avoid confusion and filing complications.

4. Use only one side of the worksheet. If it is absolutely necessary to write on the back, make an appropriate note that you have done so.

Write the information so that the reader does not have to turn the file upside down to read it.

5. Avoid excessively thick individual work paper files because they are difficult to handle and deteriorate rapidly with use.

6. Record the following information on the cover of each work paper file:

   - Audit assignment name and case number.
   - Auditee name.
   - Index symbol or number of the file itself or the work papers contained therein.
   - Subject matter.
   - Name of auditor(s) preparing the audit work papers.
   - Federal records management retention number (1802-01 for audit files and 1802-02 for appeal files).

7. Each work paper should contain the following:

   - Title or heading that describes the content.
   - Index number.
   - If continuation sheets are used, a notation that the sheet is part of a group (for example, 1 of 3, 2 of 3, 3 of 3).
   - Date of preparation.

NOTE The Yellow Book no longer requires that each work paper be signed by the preparer.

8. Work papers should be specific in documenting:

   Automated Work Papers:

   a. Document the application name.

   b. Any automated procedures.

   c. The name of the file.

   d. Copy of the disk in the work papers.

   e. Formulas in performing computations.

   f. Documentation of the method of data capture.

   g. The source of documents

   h. Data elements identified.

   i. Retrieval techniques defined.

   Sampling method:

   a. A universe.

   b. If downloaded, documents describing the download process.

   c. Sample size.

   d. Type of sampling method.

9. Each work paper series (covering one review step) should contain the following:

   - **Purpose** of the work performed on the work paper. Describe how the work paper helps to achieve the audit objectives, why the work paper was prepared, and what it is intended to show. The purpose should be responsive to the audit plan. If the work paper cannot be related to the audit plan, the work paper may not be needed. Purpose statements do not have to be elaborate. In some cases the phrase, “to document discussion,” may be adequate.

- **Source** of information appearing on the work paper. Include the company name, the department, and the title of the person from whom the document was obtained. When an auditee document is involved, the work paper should state why and by whom the document was prepared and the date of preparation, if it is not apparent from the document itself.

- **Scope** of the work performed. Scope is the boundary of the audit. In this section, explain the relationship between the lease universe and what was audited; identify organizations, geographic locations, and periods covered; document the kinds and sources of evidence; and explain any problems with the evidence.

- **Conclusions** summarize the results of work performed. Draw conclusions by analyzing and interpreting the information in the work papers. Conclusions should be concise, to the point, and responsive to the objectives of the audit. Conclusions should also be fully supported by the information in the work papers, and they should not be ignored or left incomplete by using citations such as “N/A,” “Information Only,” or “See Above.”

In some cases a scope and conclusion may not be necessary; for instance, when a copy of a document or report is mounted on the work paper and no analysis is made. Also, a scope and conclusion would not be necessary for an audit report or a summary mounted on a work paper.

10. If you use audit symbols, prepare a legend explaining the symbols on each work paper section.

11. Cross-index work papers to other related work papers and to the audit program. Effective cross-indexing often reduces the need for duplication of data and facilitates supervisory review and report preparation.

12. Independently verify the accuracy of all calculations, percentages, totals, cross-footing, and other mathematical computations in schedules, tabulations, and exhibits. Independent verification may be waived for computer-generated calculations and data; however, logic or mathematical formulas used in the calculations should be independently verified. Math and source verify all schedules to the documents used to prepare the schedules.

5.4 Indexing and Organizing Work Papers

No standard indexing system can be prescribed for work papers because of the diversity of assignments. A simple, logical index that best meets the needs of the assignment and facilitates identifying, storing, and locating files is best. In addition, a table of contents is helpful in organizing work papers.

The following are possible indexing methods.

- The indexing system may correspond to the audit program numbering system.
  - For small, less complex audits, a two-point indexing system should be adequate. A two-point indexing system has a work paper section and a page number, for example, A-1.
  - For larger, more complex audits, a three- or four-point indexing system may be necessary. A three- or four-point indexing system corresponds to the audit program. The first two or three digits indicate the specific audit step and the last digit is the page number in that group of work papers, for example, A-1-b-3.
- The indexing system may be organized by reporting element (such as production volume, value, and royalty rates) or by function (production accounting, cash disbursements, and property control), depending on the type of audit.

Example 1 shows a general index outline for a coal audit. Example 2 shows a general index outline that might be used for a company audit involving oil and gas leases.

The importance of an efficient system of indexing cannot be overemphasized. An index that is simple yet logical will promote efficiencies in handling work papers and in writing summaries and reports. Regardless of the method used, you should consider the ease with which assignments can be divided among staff members and the ease with which data can be located when choosing an indexing system.

Example 1 Work Paper File Index—Coal

ABC Coal Company Company Audit—Federal Coal Leases Audit Period 10/1/87–12/31/92	
Clean Copy of Order	A
Clean Copy of Issue Letter	A
Indexed Copy of Order	B
Indexed Copy of Issue Letter	B
Correspondence, Meeting Notes, Telecon, Etc. (Separate File with Sub-index)	C
Audit Program	D
Reviewer Notes, Referencer's Notes	E
Work Paper Summary	F
Audit Work Papers	
Review of MMS Reports with Reconciliations to ABC Sales Summaries — Sub-indexed	G
Production/Inventory Tests	H
Sales/Invoice Tests	I
Contract Cost Component Review/Scale Recalibrations	J
Coal Valuation as Recalculated Between Leases	K
Review of Reclamation Reports and Federal Excise Tax Returns	L
Document Copies (4014s, SMOR-As, 9-373s and ABC Sales Summaries) Sub-indexed	M

Example 2 Work Paper File Index—Oil and Gas

ABC Oil Company
Company Audit—Federal and Indian Oil and Gas Leases
Audit Period 10/1/87—12/31/92

Enforcement Documents	A	
Enforcement Documents—Final		A-1
Enforcement Documents—Referenced		A-2
Correspondence	B	
Engagement Letter		B-1
Issue Letter		B-2
Appeals	C	
Auditee Appeal		C-1
Field Report		C-2
Audit Program	D	
(The remaining letters of the alphabet may be used as necessary to meet the needs of the specific audit.)	E-Z	

5.5 Work Paper Summaries

Pertinent information collected during an assignment is of little value unless it is analyzed, organized, and correlated. You can accomplish this by preparing concise and convincing work paper summaries. Summaries present the essence of the work performed, the results achieved, and the conclusions reached in the supporting work papers.

Well-prepared work paper summaries should accomplish the following:

1. Force timely and critical analysis of evidence obtained and work completed, identify additional work requirements, and serve as a summary of the work performed. In many instances, the summaries provide the basis for positions taken in the final enforcement document.

2. Tie groups of related work papers together; provide an orderly and logical flow to the work papers; facilitate reviews of work segments; and depending upon the depth and coverage, resolve possible questions after work is completed.

3. Acquaint new auditors with the precision required when analyzing information, and the clarity, conciseness, readability, and organization required when preparing reports.

4. Facilitate the drafting of enforcement documents, issue letters, and orders to perform and pay. With a foundation of well-prepared summaries, preparing the enforcement document should be a smooth and logical process.

Because of the diverse nature and scope of assignments, each summary should be tailored to the needs of the work segment. Although no specific format or style is prescribed, each summary should lend itself to the preparation of enforcement documents.

5.5.1 Contents

Multiple level work paper summaries are not required. Each audit step does not require a lengthy narrative (e.g., purpose, scope, and conclusion). If the purpose of the document is obvious, a purpose, scope, and conclusion are not needed.

Each summary should concisely state what you have accomplished in relation to what was intended and provide a factual summary of the evidence. If you were unable to do certain work that was intended, describe why the work was not performed. Identify the sources of summary information. In the scope, state the major steps performed, what comparisons were made, and what data was reviewed. State conclusions in relation to the audit objectives. Conclusions should be supported by the work performed, the results obtained, and the information developed. Recommendations for corrective action should follow logically from the conclusions.

Although usually narrative presentations, summaries may also include tabulations and schedules. Summaries should analyze in appropriate depth all pertinent facts, deal with alternative issues, and lead to convincing conclusions.

5.5.2 Review

In preparing and reviewing summaries, you and the team supervisor should ensure that all areas have been covered. The data needed for effective enforcement documents should be complete and cross-indexed to underlying details, and the logic should be sound. All inconsistencies in the evidence should be examined, revised, or explained. When working at remote audit sites, work paper summaries should be prepared at the audit site and reviewed by an appropriate team supervisor. This provides opportunities to correct any inconsistencies while the personnel and data are still readily available. After the team supervisor's review, the completed summary should:

- Present facts fairly and convincingly.
- Support amounts, dates, names, facts, and other data in the work papers.
- Maintain a proper perspective.
- Consider necessary corrective actions.
- Avoid exaggeration, overly categorical positions, overreaching on technical subjects, broad endorsements, and presenting opinions as facts.
- Include favorable comments where warranted.

Problems with enforcement document preparation frequently originate from poor analysis and summaries of underlying evidence.

5.6 Supervisory Review

Active and timely supervisory involvement with the audit is required. The team supervisor should review work papers during each lease audit, contract settlement, or other assignment. The team supervisor should review each page. A statement at the front of the audit file or section of the audit stating that the audit file or section was reviewed, including the reviewer’s signature and the date, is all that is necessary to record the review. Supervisors are required to critique the work papers and obtain corrections if they are not satisfactory. After the auditor corrects the work papers, the supervisor signs and dates the page and assumes the same responsibility for the work papers as the auditor.

5.7 Safeguarding Work Papers

Work paper files, including draft enforcement documents and computer diskettes, should be safeguarded to protect them from theft or destruction and to prevent unauthorized disclosure. Confidential, privileged, or proprietary information received and used by MMS employees and Government contractors must be protected from unauthorized disclosure. The following memoranda provide specific information on using and releasing proprietary data:

- “Priority Processing of Freedom of Information Act Requests,” dated February 24, 1993.
- “Guidance and Procedures for Handling Requests for Royalty Management Program Proprietary Data/Records,” dated February 27, 1995.

NOTE

Work papers created by State or Tribal auditors under section 202/205 contracts are Federal records subject to the Privacy Act of 1974 and the Freedom of Information Act. The MMS Freedom of Information Act (FOIA) Officer in consultation with the RMP FOIA Officer make the final decision on whether these records may be released.

To ensure that work papers, enforcement documents, and computer diskettes are accessible only to authorized persons and protected from theft or destruction, you should follow these procedures:

1. Do not leave work papers, computer diskettes, and draft enforcement documents unattended during the day in places where they might be accessible to unauthorized persons. Normally, MMS offices are considered secure; however, in some instances, you may need to secure unattended work papers while working in the office. An example is when your office conference room is being used to give a training class or presentation to industry personnel and the participants have access to the office. The same would be true for building maintenance personnel or service technicians if they are working unattended for an extended period of time.

2. Lock work papers, computer diskettes, and draft enforcement documents left overnight at the work site in either security cabinets or containers with Government locks.

3. Lock work papers, computer diskettes, and draft enforcement documents out of sight in the trunk of an automobile, rather than on the seat or floor. Use good judgement in situations where extreme heat or cold might damage computer diskettes.

At locations outside of the office, the senior audit official is responsible for ensuring that all necessary safeguards are employed.

5.8 Records Retention

Work papers are retained in the audit office for at least 2 years after the case is closed or cut off.

NOTE

The Records Management Handbook lists two types of audit records—audit files and appeal files. Audit files are generally considered closed or cut off when the audit report is issued. Appeal files are generally considered closed or cut off when the appeal is settled. Unfortunately, it is nearly impossible to separate audit files and appeal files, so most audit offices consider the entire case as closed or cut off when the appeal period passes without an appeal or the appeal is settled.

The records may be shipped to the Federal Records Center (FRC) 2 years after the cut-off date. Federal records are destroyed 7 years after the cut-off date, while Indian records are retained indefinitely.

If the subject of the files is still controversial or of current interest near the end of the 7-year period, you should retrieve work papers from the FRC and store them in the audit office until the matter is settled. The audit manager determines how long work papers should be retained when highly controversial matters, Congressional investigations, or unsettled issues are involved.

When work papers are retained through agreements with States or Tribes, at State or Tribal offices, the retention period is at the discretion of the designated State or Tribal official; however, the period cannot be less than 7 years from the cut-off date.

Managers may also elect to retain work papers for 7 years or longer at an audit site. Although this is generally done for work papers at residencies, it may be done for nonresidency companies if deemed appropriate.

Retain work papers for recurring company audits until the subsequent company audit has begun. This allows an opportunity to review leases and prior audit issues.

General reference material can be retained at the job site for the duration of the assignment and as long as the material is considered useful. Material should be screened periodically, and obsolete material should be disposed of.

6. Developing an Audit Plan

You must survey an auditee's business activities to develop an appropriate audit plan. The preliminary survey and management control review includes:

- Examining the auditee's ownership structure for evaluating arm's-length and non-arm's-length transactions.
- Examining the auditee's policies, practices, and procedures for calculating royalties on Federal and Indian leases.
- Identifying general and background information necessary to define the direction and scope of the audit.
- Identifying and analyzing the lease universe.

During a survey, emphasis is on testing the auditee's management controls for accounting and production information from its origin to the royalty report. This review may be a basis for selecting the audit sample.

Work paper files for the preliminary survey and management controls review are created during the initial audit. The work papers identify the auditee's business activities, royalty accounting and reporting procedures, and all Federal and Indian leases the auditee operates, pays royalties on, or has an interest in. These files are kept and updated in subsequent audit periods when practical.

6.1 Background and Lease Inventory

The following steps provide general guidance for obtaining sufficient background information to understand an auditee's business practices. Additional steps can be added based upon circumstances and professional judgement.

STEP 1. Document the reason for selecting the auditee and period to be examined.

Examples are:

- The auditee was randomly selected.
- The auditee is a major payor audited on a recurring basis.

STEP 2. Review prior audits performed by MMS or others. Items to look for include previous findings and unresolved issues.

STEP 3. Review exception processing results to determine if the auditee has a trend of problems. Contact other RMP divisions to determine if there are any ongoing issues or outstanding referrals (for example, valuation, allowance, reporting errors, refund requests).

STEP 4. Determine if State and Tribal auditors are participating in the audit. If so, determine specifically what areas the States and Tribes are auditing; for example, solids, oil and gas, royalty-in-kind, attributes, or other areas.

STEP 5. Review copies of audit reports—performed by the auditee, joint venture partners, or other Federal agencies—covering your audit period.

STEP 6. Investigate the background of the auditee, its affiliates, and its subsidiaries through Pennwell's U.S.A. Oil Industry Directory or other appropriate sources. Copies of Pennwell's directory are maintained in each audit division.

STEP 7. Where applicable, review the annual report and Form 10-K for each audit year. Note such information as location of operations, affiliates, subsidiaries, joint ventures, and acquisitions or sales.

STEP 8. Review the auditee's organization charts and request an explanation of significant changes during the audit period. Determine the company's departmental or division responsibilities.

STEP 9. Obtain all active payor codes and leases for the audit period from MMS computer sources (Business Information System [BIS], Auditing and Financial System [AFS], and Production Accounting and Auditing System [PAAS]).

STEP 10. Reconcile the lease universe by comparing the MMS list with the auditee's list of leases for which the auditee was lessee, operator, or payor. Include leases acquired or sold during the audit period.

STEP 11. Once the universe is reconciled, stratify the leases by attributes, such as:

- Lease type (for example, Outer Continental Shelf [OCS], State, and Indian Tribal, allotted, or nonstandard).
- Product (for example, oil, gas, and solid minerals).
- Billing system type (for example, fixed royalty rate, variable royalty rate, and net profit share).
- Compensatory royalties.
- Gathering reimbursements.
- Leases in States that require ad valorem or severance taxes.

STEP 12. Identify leases and associated systems by specific characteristics. This step is very useful if an order to perform is issued, because the leases covered by the order will already be grouped. Characteristics include:

- Previous audit selection or prior audit findings.
- Indian direct pay.
- AFS/PAAS exceptions.
- Section 6, section 8, and section 8(g) leases.
- Processing plants.
- Transportation systems.
- Percentage-of-proceeds contracts.
- Unit or communitization participation.
- Royalty rate (cents-per-ton or ad valorem rate on coal leases).
- Audit referral.

STEP 13. From the RMP Query System (RQS), compile royalty payment data for the lease universe by year to identify payment trends that may be useful in selecting samples.

STEP 14. From RQS and auditee records, identify all products produced and sold from Federal and Indian mineral leases.

STEP 15. From the auditee, find out what facilities were owned or operated by the auditee including processing plants, refineries, coal washing facilities, and transportation systems. Determine if any Federal and Indian leases are associated with the facilities.

After you have obtained the necessary information, prepare a summary of the auditee's background and lease history. Assess the impact of your findings on the scope of the audit.

6.2 Management Controls Reviews

Determining how much time and effort to expend on a management controls review requires considerable professional judgement. For example, small companies may have virtually no controls because only one person, perhaps even the owner, performs all royalty-related tasks. A control review of such a company may be wasted effort and can be offset by increasing the number of transactions reviewed during your audit. In contrast, an extremely large company may employ thousands of personnel who perform tasks unrelated to Federal and Indian royalties. In these situations, you must limit your systems and controls review to relevant operations. Another important factor in performing internal controls and systems reviews is timing. If the period you are auditing occurred 6 years ago, an exhaustive review of current management controls may not be relevant.

The following steps provide general guidance for reviewing policies and procedures used to calculate and pay royalties on Federal and Indian leases. Steps may be added or deleted based on circumstances and professional judgment.

STEP 1. Review and document the auditee's production and revenue accounting procedures and controls. If your audit office maintains permanent files on the auditee, you need only document significant changes. Prepare a detailed system narrative with related flow charts as necessary. A detailed internal control review is optional, and should not be required in most cases. Our goal is to understand the accounting process from source of production to royalty reporting.

STEP 2. Evaluate and test the auditee's systems and controls specifically related to:

- Minimum and advance royalty and rent payments. Determine the department responsible for monitoring these payments and whether the system is automated or manual.
- Production volumes. Identify production departments and determine how production information is reported and monitored. If different departments account for production and sales volumes, determine if the records are periodically reconciled. If not, evaluate controls to ensure correct reporting.
- Sales volumes. Determine how the auditee verifies sales volumes reported by the purchaser (for example, run ticket recalculation, independent gas chart audits, comparison of weigh tickets to customer billings).
- Commingled production. Document how the auditee allocates production to individual leases. For oil and gas leases, allocations are probably based on well tests. For solid mineral leases, allocations may be based on scales, meter or fluid measuring devices, or mine surveys.
- Unit/communitization allocations.
- Mineral valuation. Determine if valuation is based on purchaser remittance statements, contract pricing, cents-per-ton for coal leases, or other methods. Determine if there is a system to compare revenue from purchaser remittances (gross proceeds) to contract pricing. Pay special attention to the auditee's procedures for non-arm's-length valuation and Indian leases.
- Transportation, processing, and washing allowances. Determine the type of allowances taken and the department responsible for calculating and filing the forms. Determine if the auditee's policy and practice is to report these allowances separately on the Form MMS-2014 or to net the allowances in royalty value.
- Indian direct pay. Analyze a sample of direct pay leases for accuracy to test the auditee's direct pay procedures.
- Oil and gas section 6 leases. Test the auditee's policies and procedures by reviewing a sample of Form MMS-2014 entries for transportation deductions (transaction code 11), royalty-in-lieu (transaction code 37), and excess royalty payments (transaction code 38) on section 6 leases.

- Recoupment of overpaid royalties. Test recoupment procedures for overpaid royalties on offshore leases (section 10 requirements), onshore Federal leases, and Indian Tribal and allotted leases (transaction codes 50 and 51 for recoupments).
- Payment of compensatory royalty.
- Royalty-in-kind.
- Reporting first production and shut-in wells for oil and gas.

STEP 3. Review and document the auditee's policy and practice for paying royalties on the following issues:

- Dual accounting.
- Tax reimbursements.
- Takes versus entitlements.
- Federal Energy Regulatory Commission (FERC) Order 94 receipts.
- Contract settlements.
- Majority pricing.
- FERC Order 636.
- Stripper well royalty rate reduction.
- Nonstandard or variable royalty rates.
- Non-arm's-length-transactions.
- Cessation of production without approval.
- Federal Black Lung excise tax, abandoned mine land fees, and State severance tax allowances on coal leases.

STEP 4. Review the auditee's chart of accounts. Identify all general ledger, subsidiary, and suspense accounts that could contain Federal or Indian revenue. Analyze the accounts to determine if any Indian or Federal revenue flows through nonroyalty or suspense accounts.

After you have completed the management controls review, document any systemic problems that might cause incorrect royalty payments. Factor the results into your audit scope.

6.3 Audit Plan Development

Prepare an audit plan that incorporates the results of the preliminary survey, systems review, and lease stratification. Examples of audit plans may be found in the RMP intranet library. The plan should address the following:

1. Nature of the audit (major payor audit, referral, residency company, or random, and period of examination).

2. Participation of others (State and Tribal auditors or field inspectors).

3. Extent of testing required. The extent of testing is based on a combination of factors, such as the evaluation of the lease universe, accounting procedures, royalty payment policies and practices, prior audit coverage, and type of issues (referrals, exceptions, or known problems).

4. Sample criteria and selection (stratified, all balances over $1,000, judgmental with specified sampling parameters, random, or percent of royalties covered).

5. Justification for the type and method of tests to be used.

6. Sample items for detailed testing (leases, sample months, processing plants, mines, transportation allowances, volumes, values). When making the sample selection consider the following factors:

    a. Scope of prior audits.

    b. Composition of lease universe.

    c. Allotted and Tribal leases.

    d. State and Tribal participation.

    e. Follow-up on referrals from other organizations.

    f. Revenue coverage.

7. Resource requirements for the audit, including:

   a. Staffing needs.

   b. Technical assistance (Bureau of Land Management [BLM], OCS operations, Royalty Valuation Division [RVD]).

   c. Travel requirements (locations, time frame, and budget).

   d. Special reporting requirements (BLM and Bureau of Indian Affairs [BIA] referrals).

7. General Lease Audit Plan

This chapter provides a general overview of a lease audit plan. The objective of a lease audit is to determine if royalties were reported and paid in compliance with applicable laws, regulations, and lease terms. This general plan allows you to insert additional audit steps based on your professional judgement and the circumstances in each audit. You are encouraged to apply originality within reason to complete your audit efficiently and competently. Other types of audit plans such as those for company audits, transportation systems, royalty-in-kind, unit agreements, and others can be found in the RMP intranet library.

NOTE

RMP policy is to obtain audit records from Government sources whenever possible before approaching the auditee.

Most of the following documents can be obtained from internal Government sources:

- Lease document and assignments.
- Operating agreement and designation of operator.
- Unit and communitization agreements.
- Lease plots.
- Transportation and processing allowance forms.
- Lease inspection reports.
- Business Information System (BIS) lease reference information and production and payment history.

The following documents should be requested from the auditee:

- Purchaser statements.
- Contracts.

- Imbalance statements.
- Run tickets (if the survey indicates volume or gravity problems).
- Well tests.
- Allocation reports.
- Bonuses.
- Premiums.

Using the information obtained above, determine the:

1. Rent and minimum royalty lease requirements.
2. Rent and minimum royalty paid.
3. Proper royalty measurement point.
4. Volume produced.
5. Volume sold.
6. Valuation of sales volume.
7. Royalty due compared to royalty paid.

In this process, you should always consider approved allowances, allocations, lease use, and special valuation requirements. Do not duplicate the review efforts of other internal MMS organizations.

7.1 Volume

In verifying volumes, you should perform a comparison of reported produced (operations reports), metered (company volume statements) and reported gross royalty volumes.

- Verify proper measurement methods (gravity and pressure base, measurement point, commingling approval, etc.). For example, you may request inspection reports from the appropriate BLM office or, if none are available, request that BLM perform a meter inspection.

- Identify and reconcile missing volumes.
- Identify lease use and determine if allowable under lease terms.

Additional audit steps may be necessary if:

- The audited lease is involved in a unit agreement.
- The lease is involved in an imbalance situation.
- Other payors of lease production are involved.
- The lease is an Outer Continental Shelf Lands Act (OCSLA) Section 6 lease.

7.2 Value

Verify contract pricing against gross proceeds and reported values. Consider any special valuation issues, such as:

- Wet versus dry conversions. British thermal unit (Btu) wet/dry conversion formulas are:
  - 0.9826 X dry Btu = wet Btu
  - 1.0177 X wet Btu = dry Btu
- Spot market pricing.
- Approved allowances.
- Federal Energy Regulatory Commission (FERC) Order 94.
- FERC Order 636.
- Section 6 valuation requirements.
- Percentage-of-proceeds (POP) contract valuation.

Consider any unusual circumstances such as:

- Bonuses.
- Premiums.
- Contract settlements.

7.3 Royalty Due and Paid

After verifying volume and value, calculate royalties due the Federal Government based on lease terms. Additional audit steps may be necessary if:

- The lease is a Schedule B competitive lease. See “Lease Terms” on page 12-3 for more information on Schedule B leases.
- The audited lease is a step or sliding scale royalty lease. See chapter 12 for more information on step and sliding scale leases.
- The auditee’s royalty system is designed for a 1/8 standard royalty distribution (for example, the software cannot handle a 20 percent royalty rate without manipulation).
- Royalty rates were reduced—either temporarily or permanently—because of stripper well incentives.

Compare your calculation of royalties due to actual royalties paid. If royalties were underpaid, document the auditee’s calculation and determine if the error is systemic and will affect other leases.

8. Data Sources

You have access to several excellent internal and external sources of audit data.

8.1 Internal MMS Data Sources

Internally, RMP uses two comprehensive, automated systems to effectively fulfill its accounting responsibilities for Federal and Indian leases and agreements.

1. The Auditing and Financial System (AFS) is a revenue accounting system that accounts for revenues and related information from payors.

2. The Production Accounting and Auditing System (PAAS) is a production accounting system that collects production and disposition information submitted by operators of leases, agreements, facility measurement points, and gas plants.

Although the two systems operate independently, information in the two systems is systematically compared in an exception processing routine called the AFS/PAAS Comparison. Royalty-bearing sales volumes reported to PAAS are compared to sales volumes reported to AFS. Differences above certain thresholds are analyzed and reconciled.

For audit purposes, AFS and PAAS can provide useful reporting and payment information to identify problem-reporting areas. You should contact the Compliance Verification Division (CVD) and request a list of outstanding exceptions when you begin your audit. Other automated systems contain offshore lease and inspection data and audit tracking information.

8.1.1 AFS

AFS accounts for Federal and Indian mineral lease revenues. Detailed information about the AFS system is included in the following handbooks:

1. *Oil and Gas Payor Handbook*.

    a. Volume I contains detailed reporting instructions for the Form MMS-4025, Payor Information Form.

    b. Volume II contains detailed reporting instructions for the Form MMS-2014, Report of Sales and Royalty Remittance.

    c. Volume III contains product valuation information plus transportation and processing allowance information.

2. *Solid Minerals Payor Handbook*. This handbook provides payors information and instructions on how to prepare and submit data on the Payor Information Form and to report sales and remit payments to AFS using the Report of Sales and Royalty Remittance.

8.1.2 BIS

In April 1988, MMS/RMP introduced the State and Tribal Support System (STATSS) to provide royalty and financial data to States, Tribes, and the Bureau of Indian Affairs (BIA). With this information, they could monitor monies collected and distributed by MMS. The system was secured so that these groups could view only the information that related to their leases.

MMS's rapid growth, coupled with the desire to improve the services provided to the States and Tribes, resulted in the development of a major upgrade to STATSS. In January 1992, the Business Information System (BIS) was introduced.

BIS ultimately tied together the AFS, PAAS, former Bonus and Rental Accounting System, and Common Reference Data (CRD) database. The huge BIS database now provides royalty and production historical data to the States, Tribes, BIA, Bureau of Land Management (BLM), and MMS field sites from Washington, D.C., to Anchorage, Alaska.

BIS provides royalty data from October 1983, production data from May 1988, and lease and financial data from April 1992. Access to this data is available through a series of menu-driven inquiry screens with various choices of output; for example, screen prints, download to computer, or paper report. Details on specific reference, royalty, production, lease, and financial data available in BIS and how to access the information is available in the *BIS Users Manual* (Release 1.0 dated April 19, 1994).

8.1.3 AFS exception processing modules

Exception processing is an automated system employed by MMS at its Lakewood offices consisting of a series of exception processing modules that identify noncompliance with reporting and payment requirements. Interest associated with audit findings is also assessed by this system.

Examples of exception processing modules include:

1. Underpayment of rent or minimum royalty.

2. Use of incorrect royalty rates.

3. Unauthorized recoupments of Outer Continental Shelf (OCS) royalty overpayments.

4. Improper deduction of severance taxes from Indian leases.

5. Improper recoupment of overpayments on Indian leases.

6. Invalid adjustments.

7. Late payment interest.

8. Allowances claimed above regulatory limits.

Reporting and payment adjustments identified by exception processing modules can be seen on various reports available through BIS.

8.1.4 PAAS

PAAS maintains production and disposition activity on mineral lease sites. Detailed information about the PAAS system is included in the following handbooks:

1. *PAAS Reporter Handbook—Lease, Facility/Measurement Point, and Gas Plant Operators.* A detailed reference manual for all OCS reporters, those onshore reporters that have elected to report production on the Oil and Gas Operations Report (OGOR), and gas plant reporters.

2. *PAAS Onshore Oil and Gas Reporter Handbook.* detailed reference manual for those onshore reporters reporting production on the Monthly Report of Operations (MRO, Form MMS-3160).

3. *PAAS Solid Minerals Reporter Handbook.* A detailed reference manual for solid minerals reporters to use to report production on the Solid Mineral Operations Report (SMOR).

8.1.5 RQS

The RMP Query System (RQS) provides general access to RMP sales, production, and reference data through a graphical user interface. RQS is composed of four parts: graphs, reports, custom queries, and queries.

- Graphs allow users to display royalty data for a selected period of time in a bar graph format. It provides the capability to drill down through additional graphs, each displaying lower levels of detail.

- Reports provide users the ability to execute predefined reports. The query function also provides users with the ability to export data to other applications, print reports, save reports in multiple formats to disk, or send reports using electronic mail (email).

- Custom queries allow users to create a report with the data and in the format of their choice by selecting report criteria and selecting fields to display on the report.

- Saved queries provide users the ability to execute saved custom queries using original or modified selection criteria.

8.1.6 MATS

The MMS Appeals Tracking Systems (MATS) is a system containing all the information related to a specific appeal made by a lessor or payor regarding an MMS policy or ruling. This system allows the user to search for and view specific information regarding appeals, to update this information, and to add appeals. The information contained in this system will identify who has made the appeal, how much has been appealed, and when the appeal was filed.

The system is windows-oriented and allows the user to scroll vertically or horizontally using the scroll bars or arrows. Many fields contain selection lists accessible by double-clicking the field area. When performing a search, the user is prompted for the appropriate criteria. The information within a specific appeal is necessary for a query to search for the desired data.

8.1.7 RATS

The Royalty Audit Tracking System (RATS) was replaced by the Compliance Tracking System (CTS). Historical information is available at the respective audit division.

8.1.8 CTS

The Compliance Tracking System (CTS) is a client/server, online, centralized system designed to assist in planning and assigning resources and tracking the status and results of audits. Through CTS, you are able to track money received from an audit, provide historical data about previous findings related to an auditee and estimate resources needed to complete an audit. CTS is designed for use by personnel at various field locations, State and Indian offices, and compliance groups. Eventually, users will be able to access CTS from 5 compliance offices and 11 oil companies through the wide area network

(WAN); 17 State and Indian offices through the WAN; and about 20 remote locations through dial-up connections.

CTS is accessed through the RMP Desktop. Each case and subcase is owned. The owner can be someone other than a team leader or area supervisor, although team leaders and area supervisors are co-owners with the same rights as an owner. An owner may grant update rights to a case or subcase to another person. Each person is assigned an access level. The access levels are:

MMS 1	– view all case and subcase information
	– create personal timesheets
	– update cases and subcases as granted
	– view personal workplan
MMS 2	– own a subcase
	– update personal workplan
	– grant rights to owned subcase
MMS 3	– own a case
	– grant rights to owned case
	– approve timesheets
MMS 4	– site administrator
MMS 5	– all Divisions/STRAC administrator

The CTS folders contain four divisions of data that form the basis for CTS.

1. **Case Folder** contains basic information on each case control number (CCN). This folder contains the case information, subcases, results, participants, and letters for that CCN.

2. **Subcase Folder** contains the subcase information, results on leases, and subcase letters.

3. **Time Folder** contains details on hours expended by all employees each month. This folder is essentially a timesheet file, and all data is historical.

4. **Workplan Folder** contains the supervisor's and individual auditor's planned time to accomplish assigned work. The workplan establishes estimated start and completion dates for each assignment.

8.1.9 OCSIS

The Offshore Minerals Management's (OMM) Outer Continental Shelf Information System (OCSIS) has been replaced with the Technical Information Management System (TIMS). Please refer to the next section.

8.1.10 TIMS

OMM's TIMS was designed to replace OCSIS for all OMM regions. TIMS is a massive database of scientific and technical information built around a corporate database philosophy with fully networked access. TIMS includes data and reports on leasing activities, environmental studies, land use and reserve estimation, and drilling and production operations, as well as spatial data for generating maps.

Additionally, an interactive information exchange exists between PAAS and TIMS in each region, providing all the necessary information to update the CRD database for wells, meters, and leasing. In return, PAAS provides TIMS with production information, disposition information, inventory information received on Oil and Gas Operations Reports (OGORs), and allocation information received on the Production Allocation Schedule Report (PASR), for later release to the public.

Databases that may be useful in your audits include:

- Company information
- Lease management
- Well activity
- Inspections
- Meters and verification
- Units
- Production history

Direct access to TIMS for all regions is available to all of RMP. Authorization must be obtained from the TIMS/RMP Coordinator, and then access directly from your desktop can be provided by your local area network (LAN) administrator.

8.2 External Data Sources

You can use various information sources outside MMS to gather useful data for your audit. The following sections contain brief descriptions of these data sources.

8.2.1 BLM's ALMRS

BLM maintains the Automated Land and Mineral Records System (ALMRS), which provides the legal description, ownership history, and use information about the nation's Federal lands. ALMRS data is accessible to MMS personnel and other Federal, State, or local agencies. Within MMS, ALMRS data is accessible from computer terminals located in the Accounting and Reports Division, Reference Data Branch. BLM is currently redesigning ALMRS to enhance its informational capabilities. The redesign is in its initial stage called "Initial Operating Capability" (IOC) and will be implemented in individual BLM offices in phases.

8.2.2 BLM's AIRS

BLM also maintains the Automated Inspection Records System (AIRS), which contains well and inspection data.

AIRS will be replaced in fiscal year 1997 by the Automated Fluid Minerals Support System (AFMSS). AFMSS will contain basic well information for onshore wells such as lease or agreement, operator, status, and location. Related data will include approvals and incidents of noncompliance. BLM will add MRO data based on transmissions from RMP. Future enhancements include allowing industry to submit data electronically.

8.2.3 Dwights

Dwights is a commercial, subscription source of historical monthly volumes (barrels of oil and Mcf of gas) for all major oil and gas producing areas in the U.S., as well as Federal offshore waters. Updated monthly, production volumes are available on a monthly or annual basis, and as an aggregated, cumulative total for each property. Related information is generally provided for each well or lease including:

- pressure tests from completion to current date for most gas wells,
- oil well tests, and
- descriptive information such as American Petroleum Institute (API) number, operator, field, location, lease name, and engineering data.

You can access the Dwights database by modem.

8.2.4 Petroleum Information Corporation

Petroleum Information Corporation (PI) is a commercial, subscription source of detailed information on more than 2.4 million well completions, including oil, gas, dry, service, and reentry wells. PI's production database contains monthly and annual historical production volumes, test data, water volumes, and cumulatives for most States. PI is updated monthly and is accessed by modem.

9. Access to Records

A critical element in audit execution is timely access to auditee records. These records include supporting documentation for production, revenue, and royalty accounting. Delays in requesting or receiving records adversely affects your ability to complete audits in a timely manner.

9.1 Laws, Regulations, and Other Criteria

Statutory record keeping requirements for oil and gas leases and the authority to conduct audits are contained in the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA), Sections 103 (30 U.S.C. 1713) and 107 (30 U.S.C. 1717).

NOTE

Record keeping requirements for Federal oil and gas leases were amended by the Royalty Simplification and Fairness Act (RSFA), section 4. Effective for production after August 31, 1996, lessees must maintain royalty records for 7 years from the date the royalty obligation became due (the last day of the calendar month following the month in which oil or gas is produced). MMS is barred from obtaining records after this period unless the lessee signed a tolling agreement extending the period, MMS issued a subpoena before the limitation period, the lessee misrepresented material facts to evade paying royalties, or MMS issued an order to perform a restructured accounting before the limitation period expired.

Regulatory requirements for record access and maintenance for Federal and Indian oil, gas, solid mineral, and geothermal leases are contained in 30 Code of Federal Regulations (CFR) 212.51 (1996), 212.200 (1996), and 212.351 (1996), respectively. Regulations require the record holder (lessee, operator, or revenue payor) to maintain all records pertaining to

Federal and Indian lease production prior to August 31, 1996, for 6 years after the records are generated unless the record holder is notified in writing that the records must be maintained until the record holder is released by written notice of the obligation. The regulations further authorize MMS access to all records pertaining to compliance with royalty obligations under Federal and Indian leases.

In addition to regulatory requirements, mineral lease and agreement terms often include provisions that specify the right of the Secretary of the Interior to access and audit accounts and records. All leases should be carefully reviewed for applicable provisions.

The record keeping and access sections of mineral agreements negotiated under the Indian Minerals Development Act of 1982 (25 U.S.C. 2101 et seq.) vary and should be reviewed carefully. Some agreements incorporate language from the Council of Petroleum Accountants Society (COPAS) of North America Bulletin No. 3 (October 1980) that provides for a 2-year records access and audit period. Unless the agreement expressly differs from Federal regulations governing records retention and access, Federal regulations apply.

9.2 Record Gathering Process

You will routinely make written requests for information from payors, operators, lessees, gas plants, purchasers, and others.

Auditees furnish significant quantities of accounting records, contracts, reports on field operations, and other data during the course of an audit. Documentation standards require you to retain all data requests and auditee responses in the audit files.

When auditees refuse access to records, you may need to issue a subpoena for the records. Civil penalties may apply to those auditees who, after due notice, fail to provide access to required records or fail to comply with an order to provide information required by statute, rule, regulation, or lease terms.

To ensure a consistent and timely process for obtaining records, you should follow the general guidelines outlined below. However, you should always consider the specific circumstances of each audit when establishing response times.

- Engagement letters notifying auditees of the types of records needed and the expected time frames for the audit should be given to the auditee at least 30–60 days before the audit begins.
- Data requests for specific documents should allow a 15-day compliance period unless, in your judgement, a longer or shorter period is justified.
- Before issuing a request for records previously reported to any bureau or agency of the Department, you must make a good faith effort to obtain the records from the bureau or agency.
- Subpoenas or orders to provide records are issued for all data requests not timely satisfied. RMP policy on issuing subpoenas is contained in an April 26, 1991, memorandum entitled, “Use of Subpoenas to Obtain Records During Audit.” Examples of subpoenas can be found on the RMP intranet library.

NOTE

Effective with production after August 31, 1996, (RSFA, Section 115(d)(2)), a subpoena cannot be issued unless you have requested the records in writing from the lessee or its designee, and the lessee:

– failed to respond within a reasonable time period, or

– denied access to the records in writing, or

– unreasonably delayed producing the records.

Subpoenas must be issued by either the Secretary of the Interior, the Assistant Secretary of the Interior, the Director of MMS, or the highest State official having ultimate authority over the collection of royalties from leases on Federal lands within a State. The responsibility cannot be delegated to a lower level.

- You must provide a Notice of Noncompliance to enforce orders for records to the Office of Enforcement no later than 15 days after the date the auditee is required to supply records.
- The Office of Enforcement usually issues a Notice of Noncompliance within 15 calendar days after receipt.

9.3 Records Security

You must maintain adequate physical security over audit work papers and data received from the auditee. See “Safeguarding Work Papers” on page 5-12 for more information.

Auditees may request that audit team members sign a confidentiality agreement before the audit begins. Confidentiality agreements with individual auditees are not necessary. Various laws protect the confidentiality of information provided to the Federal Government. These laws include:

- Trade Secrets Act (18 U.S.C. 1905)
- Outer Continental Shelf Lands Act (OCSLA) (43 U.S.C. 1352(c))

Regulations (43 CFR 2.11) implementing the Freedom of Information Act (5 U.S.C. 552) for the Department of the Interior also protect the confidentiality of proprietary information. In addition, the Yellow Book requires you to use due care to protect information provided by auditees (see “Field Work Standards” on p. 4-4). A sample letter informing an auditee that a confidentiality agreement is not necessary can be found on the RMP intranet library.

10. Offshore Leases

Offshore Minerals Management (OMM) manages Federal offshore oil and gas leases. OMM conducts lease sales in which interested parties bid on tracts within the sale area. Under conventional bidding procedures, bids must be accompanied by funds sufficient to cover at least 20 percent of the bid offered. The remaining 80 percent—together with the first-year rental fee—is due when the bid is accepted. OMM may reject any bid that does not represent fair market value of the estimated resources on the tract.

The oil and gas lease grants the lessee exclusive right to drill for and produce oil and gas from the lease area within a specified period. In general, an offshore lease has a primary term of 5 years. Under certain conditions, there may be an 8 to 10 year primary term. Lease rights extend past the primary term for as long as commercial production occurs or a suspension of production exists.

Lease operations must conform to all regulations and operating orders issued by the Government. These regulations and orders cover platform design and safety, environmental, drilling, production plans, and the construction and operation of pipelines to carry production from the field to onshore facilities. Throughout drilling and production operations, OMM and the Coast Guard conduct on-site field inspections to ensure compliance with operating orders and regulations.

10.1 Laws

The authority for managing oil and gas operations stems from the authority to manage public property vested in Congress by the Constitution. Congress has delegated its authority through specific legislation.

Jurisdiction over offshore lands is divided between the Coastal States and the Federal Government. The States manage the mineral resources off their immediate coasts. OMM manages the mineral resources in the area under Federal jurisdiction, commonly referred to as the Outer Continental Shelf (OCS).

The formal division of responsibility has evolved gradually. As interest in offshore resources increased, questions arose regarding the jurisdictional boundaries between Coastal States and the Federal Government. In 1947 and 1950, the U.S. Supreme Court upheld the position of the Secretary of the Interior, that the Federal Government, not the States, possessed full power over the lands and natural resources in the submerged land areas seaward of the coasts of the United States (U.S. v. California, 332 U.S. 19, decided June 23, 1947, and U.S. v. Texas, 339 U.S. 707, decided June 5, 1950).

In response to public concerns about the ownership and development of offshore resources, Congress enacted several laws that provide the framework for regulating and managing the exploration, development, and production of oil, gas, and other minerals of the seabed beyond the area managed by the Coastal States.

10.1.1 The Submerged Lands Act

The Submerged Lands Act of May 22, 1953, (43 USC 1301-1315) granted the Coastal States jurisdiction over a belt of submerged lands seaward of their coastlines to a distance of 3 geographical miles. A greater distance from shore—about 9 geographical miles or 3 marine leagues—was granted to Texas and Florida (west coast only) because these states had established their jurisdiction over the larger area before achieving statehood. The Submerged Lands Act reaffirmed that natural resources of the seabed and subsoil beyond those granted to Coastal States would be subject to the jurisdiction of the Federal Government for the benefit of the entire Nation.

10.1.2 OCS Lands Act

The OCS Lands Act (OCSLA) of August 7, 1953, as amended in 1978, (43 USC 1331-1356) authorized the Secretary of the Interior to grant mineral leases and to prescribe regulations governing oil and gas activities on OCS lands. The OCSLA established the importance of developing the mineral resources of the continental shelf in an expeditious and orderly manner. The act also recognized the need for conducting oil and gas operations safely using technology and procedures intended to minimize the likelihood of blowouts, fires, spills, and interference with other uses of the offshore waters.

The act was amended by the OCSLA Amendments of 1985 (43 USC 1801-1866). Included in those amendments are the following provisions:

1. The distribution of a portion of the receipts from the leasing of OCS mineral resources to Coastal States. As provided under section 8(g) of the act, 27 percent of the receipts from Federal leases located wholly or partially within a 3 nautical mile zone adjacent to the State's seaward boundary is to be distributed to affected Coastal States. The funds may be used for the mitigation of adverse economic and environmental effects related to the development of such resources.

2. A schedule for the distribution of funds in the section 8(g) account to affected Coastal States of revenues received as a result of leasing activity from September 1978 through October 1, 1985; and a formula for the distribution of additional payments for leasing activity occurring after October 1, 1985.

10.1.3 Federal Oil and Gas Royalty Management Act of 1982

The Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) (30 USC 1701-1757) ensures that all oil and gas originating from Federal lands, Indian lands, and on OCS are properly accounted for under the direction of the Secretary of the Interior.

10.2 Other Leasing Authority

Other authorities associated with the management of offshore leases are regulations, orders, notices to lessees, and conditions of approval.

10.2.1 Regulations

OMM administers the provisions of OCSLA, as amended, through regulations found at 30 CFR 250 (1996) et seq. These regulations govern OCS leasing and operations. In addition, the regulations provide for royalty payments, environmental studies, and consultation with appropriate Federal and State agencies to develop measures to mitigate adverse effects on the environment. Regulations pertaining to royalty management are found at 30 CFR 201 (1996), et seq.

10.2.2 OCS orders

OMM issued OCS Orders by Region (Gulf of Mexico, Atlantic, Pacific, and Alaska), which governed most day-to-day lease operations. The OCS orders established specific requirements for performing various types of oil and gas operations, which include drilling, production, well abandonment, pipeline transportation, gas venting and flaring, production measurement, records availability, and other important offshore oil and gas activities.

Although OCS orders were issued as separate documents, they are considered part of the regulatory framework. On April 1, 1988, MMS incorporated all the requirements in OCS orders into a single set of regulations codified in 30 CFR 250 (1996), et seq.

10.2.3 Notices to lessees and operators

Notices to lessees and operators (NTLs) are used to notify operators within a particular OCS region about changes in administrative practices or procedures for complying with rules, regulations, and lease stipulations. Offshore NTLs may be found on the MMS/OMM World Wide Web site.

10.2.4 Conditions of approval

Conditions of approval are often attached to approved permits, such as applications for permit to drill, deepen, or plug back (APD). These conditions range from administrative matters, such as the required frequency and number of reports, to technical or environmental conditions, such as requirements for the disposal of drilling mud. In all cases, they are specific conditions that explain a requirement in the regulations, lease stipulations, or OCS orders.

10.3 Special Lease Terms

Section 6 leases. Section 6 leases are offshore oil and gas leases issued by the State of Louisiana and maintained under section 6 of the OCSLA. Section 6 leases are considered Federal offshore leases; however, the original lease terms still apply. Differences in section 6 leases you should be aware of are as follows:

- **Excess royalty**. Many section 6 lease terms call for an additional royalty of 1/32, 1/48, or 1/64 on oil or gas and products. This excess royalty should be reported under transaction code 38 on Form MMS-2014.

- **Royalty in lieu of severance tax**. Originally, section 6 leases were State leases subject to State-assessed severance taxes. MMS collects royalties in lieu of severance taxes at the rate in effect at the time the lease was converted to a Federal lease in August 1953. Transaction code 37 is used on Form MMS-2014 to report the royalties due the Federal Government in lieu of the State severance tax. Increases in the State severance tax rate since 1953 do not increase the amount of royalties due the Federal Government.

NOTE

MMS does not collect royalties in lieu of State-assessed gathering taxes. The Louisiana Supreme Court declared State gathering taxes unconstitutional in Bell Oil Corporation v. Fontenot (238 La. 1002, 117 So.2d 571, 1959). Because the gathering tax was declared unconstitutional, it was never a part of the State law as it existed in 1953 when the leases were converted to Federal leases. The Federal Government has no royalty claim on gathering taxes.

- **Flaring, venting, and lease use**. Flaring, venting, or lease use deductions are not allowed on section 6 leases. Royalty is due on the full production volume.

- **Transportation allowances**. Leases issued by the State of Louisiana on the 1942 lease form contain lease terms that disallow deductions for gathering or transporting production to the purchaser. Oil and gas produced from leases issued on the 1942 form are not eligible for a transportation allowance.

Section 6 leases are no longer being issued. A list of section 6 leases can be found in the RMP intranet library.

Section 8 leases. Section 8 leases are offshore oil and gas leases issued by the Federal Government under section 8 of the OCSLA. Section 8 leases make up at least 95 percent of all existing offshore leases.

Section 8(g) leases. Section 8(g) leases are generally the same as section 8 leases, except part of the revenue is shared with the applicable Coastal State.

NOTE

The OCSLA section applicable to each offshore lease is recorded in the lower right quadrant of the Business Information Systems (BIS) Master Lease Data Screen in the OCS SEC/AREA/BLOCK field. The first three characters in this field will be either 06, 08, or 8G.

10.4 Unit Agreements

A unit is formed when two or more leases (or portions thereof) sharing a common pool or reservoir combine for joint operation in order to produce the reserves more efficiently. Unitization makes it economically feasible to undertake cycling, pressure maintenance, waterflood, or enhanced recovery to maximize the ultimate recovery from the reservoir.

A unit may be requested by the lessees or required by MMS for exploration, development, and production. Normally, unitization is based upon the MMS Model Unit Agreement unless good cause exists for variation. The unit agreement (or plan of development and operation) appoints an operator of the unit who is responsible for operations, preparation and submission of regulatory reports, and allocation of production and royalty volumes to the participating leases in accordance with the approved unit allocation schedule.

When a lease is in a unit, it is easier to audit the entire unit for total unit volume and then apply the lease's allocated portion to that volume. Audit guidelines for agreements may be found in the RMP Intranet library. If you find a discrepancy in volumes, you should prepare an audit lead sheet on the responsible payor.

11. OCS Net Profit Share Leases

Net profit share leases (NPSL) were issued under section 8(a) of the Outer Continental Shelf Lands Act (OCSLA). The OCSLA required that alternative bidding systems be established for Outer Continental Shelf (OCS) leases. The intent of the net profit share concept was to strike a balance between:

- Securing a fair return for the lease of Government lands, and
- Providing companies risk and investment incentives to develop OCS oil and gas tracts.

The following schedule is a comparison of traditional and NPS leases:

	Type of Lease	
	<u>Traditional</u>	<u>NPS</u>
Bid variable	Cash bonus	Cash bonus
Fixed components	Royalty rate Annual rental	NPS rate Capitol recovery factor Annual rental

Rather than paying a fixed royalty, the NPSL operator pays a fixed percentage of net profits—that is, revenues received from the sale of oil and gas minus the cost of production. Under this system, the lessee recovers expenses of exploration and development, plus a reasonable return on that investment, before paying the Government.

The traditional bidding system for OCS lease sales requires that leases be issued on the basis of a cash bonus bid. Subsequent payments to the Government are based on a fixed royalty rate and a fixed annual rent. The NPSL bidding system also employs a cash bonus bid variable and requires a fixed annual rent payment, but royalty payment is replaced by payment of a fixed share of net profits of no less than 30 percent.

Congress believed that using an NPS system would place greater emphasis on contingency payments and less reliance on the initial cash bonus for generating returns to the Government. The result was expected to be increased production of oil and gas, development of marginal fields, increased effective competition, the freeing of more funds for exploration, and increased total revenue to the public.

Originally, OMM issued approximately 200 NPSLs; however, only 24 are currently active (7 profitable, 12 nonprofitable, 5 nonproducing). No offshore NPSLs have been issued since the early 1980s.

11.1 Laws, Regulations, and Other Criteria

The following laws, regulations, and other criteria apply to OCS NPS leases:

- Outer Continental Shelf Lands Act, Section 8(a), as amended (43 U.S.C. 1331 et seq.).
- 30 CFR 220 (1996).
- 30 CFR 260.110(a)(4)(1996).
- Summary report on NPSL “Issues and Decisions” dated September 27, 1995, prepared by the Valuation and Standards Division. This report highlights issues and the resulting decisions encountered during previous NPSL audits.
- Council of Petroleum Accountants Society (COPAS) bulletins such as Bulletin 9 that covers accounting procedures for net profit share leases. Bulletins 2, 5, 8, 13, 16, and 22 cover joint offshore operations. Other COPAS bulletins on specific cost elements may also apply.

Review these documents carefully before beginning your audit.

11.2 Accounting and Auditing Requirements

The NPSL accounting system conforms with industry accounting practices to the extent possible. The result, in theory, minimizes confusion in accounting for expenses and revenues from operations, and reduces administrative costs to the lessee. Situations not covered by COPAS procedures or departures from industry practice require MMS approval.

An NPSL lessee or designated operator must file an annual report during the period from issuance of the NPSL until the first month in which production revenues are credited to the NPSL capital account.

- The lessee is required to maintain all cost and expenditure records from the nonproduction period until 36 months after first production revenues are credited to the capital account.

- The nonproduction period can last 10 years or longer.

After production revenues are credited to the capital account, the lessee must file a report for each NPSL, not later than 60 days following the end of each month. The lessee must establish and maintain the records necessary to determine:

1. The volume and disposition of production for each month.

2. The value of production for each month.

3. The amount and description of costs and credits to the NPSL capital account.

4. The amount and description of all costs of acquisition, construction, and operation of equipment and facilities furnished by the lessee and charged to the NPSL capital account.

5. The cumulative balance of costs and credits to the NPSL capital account.

6. The inventory of material.

NPSL lessees were given the opportunity to enter into an “Agreement on Offshore Net Profit Share Lease Recordkeeping.” The agreement offered the lessee the option of maintaining NPSL records for a minimum of 6 years after cessation of operations or supplying MMS with all records related to the lease on an annual basis until cessation of operations.

Regulations at 30 CFR 220.033 (a) (1996) allow the Department of the Interior (DOI) to initiate an audit within 36 months of the due date of the monthly statement to be audited or the date that the statement was mailed, whichever is later. The lessee has the right to deny a request to audit any period after the 36-month time limit. Because the 36-month period does not coincide with our 5-year audit cycle, it may be necessary to schedule interim audits to avoid expiration of the audit period.

Regulations at 30 CFR 220.033 (b) (1996) require that the MMS Director be notified when an NPSL audit is called by nonoperators. This requirement affords MMS the opportunity to participate in the audit. However, if we choose not to participate, these audit reports can be an excellent source of information and save a great deal of time when we begin our own audit.

11.3 NPSL Capital Account

A lessee must establish and maintain a capital account for each NPSL tract. The account includes charges for direct and allocable joint costs incurred during the term of the lease, overhead allowances, and allowances for capital recovery. The accrual basis account is credited with production revenues and other credits.

11.3.1 Direct and allocable joint costs

NPSL capital accounts may be directly charged or allocated the following costs:

- **Lease rental**.
- **Labor**. Salaries and wages of field employees, first level supervisors, and technical employees are allowable. Labor costs include travel expenses.

- **Material**. If material is purchased for use in NPSL operations, cost is the net price paid. If material is acquired by means other than purchase, or disposed of by any means, the classification becomes important.
  - Condition A (new): Priced at market price in effect on the date of movement.
  - Condition B (good used): Material transferred from the NPSL that is in sound condition and needs no reconditioning is priced at 65–75 percent of the current new price. Material transferred to the NPSL that is in good condition and needs no reconditioning is priced at 75 percent of the current new price.
  - Condition C and D (other used): Material not in serviceable condition and not suitable for its original function unless reconditioned is valued at 50 percent of the current new price or scrap value.

  Accurate material prices are often difficult to acquire. One very good source is the auditors who conducted any nonoperator audits of the NPSL.

- **Transportation**. These costs include transportation of employees and material. The cost of transporting material is limited to the distance between the lease and the nearest reliable supply store, recognized barge terminal, or railway receiving point where like material is normally available.

- **Contract services**. The cost of services and utilities provided under contract by outside parties and rental charges paid to outside parties for use of equipment are allowed subject to limitations. Contract services include professional consulting services and services of technical personnel. The cost of any contract service for research and development and feasibility studies are excluded. The Valuation and Standards Division (VSD) prepared a Summary Report of Net Profit Share Lease Issues and Decisions, dated September 27, 1995, which provides very helpful details about allowable and unallowable contract service costs.

- **Legal**. Costs of litigating against the Federal government, fines or penalties leveled by a Federal agency, and costs resulting from the lessee's violation of regulatory requirements or negligence are not allowable.

- **Equipment rental and facilities**. These costs include the use of lessee-owned equipment and facilities. Facilities include shore-base and offshore facilities and pipelines from the tract to shore-base production facilities that are not NPSL property.

- **Damages and losses**. Cost necessary to repair or replace NPSL property damaged by means other than the lessee's negligence are allowable. Any settlement from an insurance carrier must be credited to the account when received.

- **Taxes**. Allowable taxes include production, severance, excise, ad valorem, and municipal taxes. Income taxes, profit share payments, and taxes based upon income are not allowable.

- **Insurance**.

- **Communications systems**.

- **Ecological and environmental**. Payments for equipment and assistance in the event of oil spills or other environmental damage are allowable.

- **Dry or bottom-hole contributions**.

- **Abandonment**. Actual cost of abandonment is charged when incurred and not on an accrual basis. Costs incurred after cessation of production are not allowable.

11.3.2 Overhead allowance

The overhead allowance during the capital recovery period is 4 percent of direct and allocable joint costs. After the capital recovery period, the overhead rate increases to 10 percent. The overhead allowance is debited to the NPSL capital account.

Overhead cannot be charged on the value of lease rental, contract services, taxes, reinjected hydrocarbons, and credits for materials that are salvaged, returned, or used for the benefit of non–NPSL operations.

Scrutinize any charge to the capital account for jobs performed by an outside contractor, that is, contract services. These charges may not be properly classified as contract services in the capital account. Because contract services are not defined in the regulations, you must determine the actual amount of overhead incurred by the lessee. Generally, outside contractors incur all costs associated with a job—including overhead—and invoice the NPSL operator for direct cost, overhead, and profit. In most cases, applying an overhead rate to these charges duplicates overhead charges and overstates the capital account.

Reviewing the operating agreement helps determine how the working interest owners view overhead for the various cost elements of the NPSL project, such as major construction and drilling. Costs determined to be contract services in the operating agreement should also be considered contract services in NPSL operations.

The objective of an NPSL overhead rate is to recover the operator's actual overhead costs. Over-recovery of overhead costs is not allowable.

11.3.3 Capital recovery period

The capital recovery period begins when the lease is issued and ends when the earlier of the following events occurs:

- The lessee completes the last well on the first platform specified in the approved development and production plan.
- The NPSL capital account balance changes from a debit to a credit, that is, payout occurs.
- The lessee chooses to terminate the capital recovery period (the date may not coincide with termination of operations).

11.3.4 Allowance for capital recovery

The allowance for capital recovery is a calculated amount that allows a premium for the lessee's initial risk and a return on the investment made during the capital recovery period. The capital recovery factor is unique to each lease and is selected on the basis of cost and resource expectations. The cost base for the allowance for capital recovery for a particular month is the sum of:

- All direct and allocable joint costs; plus
- The value of contract services; plus
- The capital recovery period overhead; plus
- Production revenues and other credits received during the month.

The allowance for capital recovery is calculated by multiplying the cost base by the capital recovery factor. If the cost base is greater than zero, the allowance is debited to the capital account. If the cost base is less than zero, the allowance is credited to the capital account.

Charges or credits after the end of the capital recovery period are excluded from the calculation.

11.3.5 Net profit share

The NPSL tract reaches payout—revenues equal expenditures—when there is a credit balance in the capital account. This credit balance is the net profit share base.

The net profit share payment is calculated by multiplying the net profit share base by the net profit share rate. See the formula for calculating an NPSL payment in Example 1.

Example 1 Calculating an NPSL payment

Capitol recovery period

Capital account balance forward

Current month activity

Add:	Allowable direct and allocable joint costs Overhead allowance (4%) Allowance for capital recovery
Deduct:	Revenues and other credits

Capital account ending balance

Post-capitol recovery period

Capital account balance forward

Current month activity

Add:	Allowable direct and allocable joint costs Overhead allowance (10%)
Deduct:	Revenues and other credits

Capital account ending balance

If the capital account has a debit balance, that balance is carried forward as the next month's beginning balance.

If the capital account has a credit balance, the credit balance is the net profit share base for that month.

Calculation of net profit share payment

$$\text{NPS Base} \times \text{NPS Rate} = \text{NPS Payment}$$

11.4 Audit Steps

OCS NPSL audit steps can be found in the RMP Intranet library.

12. Onshore Leases

Through a lease document, a lessor grants a lessee the right to explore for and produce oil, gas, or solid minerals on Federal or Indian land in exchange for a monetary consideration, such as rent and royalty payments to the lessor. Leases on Federal and Indian lands are issued by the responsible surface management agency.

Lease administration consists of a variety of functions, including issuing leases, inspecting operations, enforcing lease terms and regulations, and maintaining official records. The Bureau of Land Management (BLM) performs these functions for most onshore Federal lands, even where other surface agencies—such as the Corps of Engineers and the U.S. Forest Service—have primary jurisdiction. On Indian lands, the functions are shared between BLM and the Bureau of Indian Affairs (BIA). The former inspects operations and enforces regulations. The latter issues or approves Indian leases (often called agreements or contracts), assists Tribes and allottees in enforcing lease terms, and maintains official records on these leases.

12.1 Laws

Congress enacted many laws establishing the responsibilities and authority of the Secretary of the Interior for onshore Federal and Indian leases. Among these are:

- The Minerals Lands Leasing Act of 1920 (30 U.S.C 181) and the following amendments:
  - 1935 Amendment (30 U.S.C. 185)
  - 1945 Amendment (Circular No. 1595)
  - 1946 Amendment (30 U.S.C. 181)
  - 1960 Amendment (30 U.S.C. 181)
- The Mineral Leasing Act for Acquired Lands of 1947 (30 U.S.C. 351 et seq.)

- The Allotted Indian Leasing Act of 1909 (25 U.S.C. 396)
- The Unallotted Indian Leasing Act of 1938 (25 U.S.C. 476)
- The Indian Mineral Development Act of 1982 (25 U.S.C. 2101)
- The Federal Oil and Gas Royalty Management Act of 1982 (30 U.S.C. 188)
- Notice to Lessees Numbered 5 Gas Royalty Act of 1987 (101 STAT 1719 et seq.).

12.2 Other Leasing Authority

Other authorities associated with the management of onshore leases are regulations and orders.

12.2.1 Regulations

Responsible agencies issue regulations to implement statutory requirements. Regulations for minerals and royalty management are found at 25 CFR for BIA, 30 CFR (1996) for MMS, and 43 CFR (1996) for BLM. Regulations pertaining to onshore and Indian royalty volume and value determinations are found at 30 CFR 202 and 206 (1996), while others can be found at 30 CFR 208, 210, 218, and 241 (1996). Additional regulations pertaining to Indian leases are found at 25 CFR 211, 212, 213, and 227 (1996).

12.2.2 Orders

The Secretary of the Interior delegates duties assigned to him to agencies within DOI through Secretarial Orders. Orders that established the involvement of BIA, BLM, United States Geological Survey (USGS), and MMS in the Federal and Indian lands management are outlined below.

- **Order No. 1112** dated September 4, 1936, assigned BIA responsibility for fiscal and administrative matters on Indian oil and gas leases except royalty accounting. It also assigned USGS accounting responsibility for Indian lease revenues and duties related to regulation of oil and gas operations on Indian leases.

- **Order No. 2505** dated December 30, 1948, assigned responsibility between BLM and USGS for administering onshore mineral leasing laws.

- **Order No. 2948** dated October 6, 1972, assigned responsibility to BLM for issuing mineral leases and assigned responsibility to USGS for approving and supervising oil and gas lease operations, and for all geologic, engineering, and economic value determinations including rentals and royalties.

- **Order No. 3071** dated January 19, 1982, established MMS and assigned MMS some functions formerly performed by USGS.

- **Order No. 3087** dated December 3, 1982, assigned all functions related to royalty and mineral revenue management, including collection and disbursement to MMS. The order assigned BLM all other onshore minerals management functions on nonIndian lands, including resource evaluation, approval of drilling permits and mining and production plans, inspection, and enforcement. All other mineral management functions on Indian lands were assigned to BIA. Amendment No. 1, dated February 7, 1983, assigned BLM a mineral management function on Indian lands, including resource evaluation, approval of permits and plans, inspection, and enforcement of regulations.

12.3 Lease Terms

Lease terms specify the royalty and rental rates and payment requirements. Section 2(d) of the standard Federal oil and gas lease and section 3(c) of the standard oil and gas mining lease for Indian lands provide that royalties on production are due and payable monthly on the last day of the month following the month of production. Except for leases issued subject to net profit share provisions, such as Indian nonstandard leases and agreements, an annual rental is due and payable in advance on the first day of each lease year prior to discovery of oil or gas on the lease. Read all lease terms carefully because some leases require rent payments during production and are not always available for offset.

Federal leases have four general royalty rate schedules:

1. Schedule A

   This schedule is applicable to noncompetitive leases issued after the 1946 act and provides for a 12 1/2 percent royalty on production.

2. Schedule B

   This schedule carries a step-scale royalty of 12 1/2 percent to 25 percent on oil and 12 1/2 percent or 16 2/3 percent on gas. This schedule is applicable to all leases issued between May 1945 and August 1946, and all competitive leases issued after the 1946 act. Leases issued between August 1935 and May 1945 also have this royalty schedule, except the maximum rate for oil is 32 percent when daily production exceeds 2,000 barrels per well.

3. Schedule C

   This schedule applies when a 20-year lease with a 5 percent royalty rate is exchanged or renewed. This schedule provides a step-scale royalty for gas. However, schedule C leases may be eligible for a 12 1/2 percent royalty determination.

4. Schedule D

   This schedule applies when a 20-year lease with a royalty rate other than 5 percent is renewed or exchanged. This schedule provides a sliding-scale royalty on oil of 12 1/2 to 33 1/3 percent or 12 1/2 to 25 percent, depending on the oil's gravity. Royalty on gas is either 12 1/2 or 16 2/3 percent. Schedule D leases may also be eligible for a 12 1/2 percent royalty determination.

Occasionally, an older lease may have royalty provisions other than those discussed above, and some of the older unitization agreements contain provisions that change lease royalty rates. Consequently, you should thoroughly review all lease terms and any agreements to which the lease may be committed.

Leases on Indian lands generally require payment of royalties on either 12 1/2, 16 2/3, or 20 percent of production, although variations do exist. The Indian Mineral Development Act of 1982, for instance, provided Tribes the opportunity to directly negotiate mineral agreements with energy and mineral companies. Under such agreements, Tribes may negotiate leases with unique royalty rates and methods of calculation. These and other nonstandard agreements may include provisions to receive economic benefits through net profit interest, joint venture, working interest sharing, production payments, or similar arrangements.

12.4 Pooling Agreements

The following sections contain an overview of onshore pooling agreements. Pooling agreements, that is, units and communitization agreements, can include any combination of Federal, Indian, State, and fee leases.

- Federal leases are on lands owned by the United States. These leases can be on either public domain or acquired lands.
- Allotted Indian leases are on lands owned by individual Indians in which the Tribe has no ownership interest. In a few rare instances, however, Tribes have purchased allotted lands for the benefit of the Tribe. See act of March 3, 1909; 35 statute 781-783; 25 USC 396; 25 CFR 212.
- Tribal Indian leases are on land owned by the Tribe, and the members of the Tribe have no individual interests. See Indian Mineral Leasing Act, May 11, 1938; 25 USC 396; 25 CFR 212.
- State leases are on lands owned by the State in which they are located.
- Fee (sometimes referred to as patented) leases are on lands owned by private individuals, including some Indians for which the U.S. does not act as trustee.

12.4.1 Communitization agreements

The objective of a communitization agreement (CA) is to develop separate Federal or Indian tracts that could not be developed independently because of an established well-spacing program. Spacing programs are usually based on State well-spacing orders. For example, a State's oil and gas commission may require that wells be spaced in no greater density than one well per section (640 acres). Communitized production is allocated to all committed tracts on the basis of surface acreage. All operations on Federal and Indian leases in a CA are approved by the authorized BLM officer.

12.4.2 Unit agreements

The objective of unitization is to develop and operate an entire structure or area (generally consisting of several leases) in the most efficient and orderly manner. Unitization agreements are usually entered into before exploration or production begins and generally cover all depths and formations.

Some leases included in an agreement may not receive any allocated production because no existing oil, gas, or other minerals are thought to underlie them. Leases or portions of leases that receive allocated production are included in what is called a participating area. Unitized lands may have several participating areas, each covering different geologic formations and depths. Leases that initially lie partially inside a unitized area are segregated and treated as two or more leases.

BLM State directors approve unit agreements. Unitization is usually done on a field-wide or reservoir-wide scale so that many lease types (State, Federal, Indian, or fee) are combined and treated as one recovery operation. The unitization or pooling clause in a lease authorizes combining two or more leases in return for a proportionate share of production.

Royalty on production under an exploratory unit agreement is normally allocated to each tract of unitized land within the controlling participating areas on the basis of the number of tract surface areas included within the participating areas, as compared to the total number of unitized surface acres within the participating area. For example, if a Federal lease of 100 acres and a fee lease of 60 acres were unitized, a well drilled anywhere on the 160 acres would result in an allocation factor of 62.5 percent for the Federal lease, computed as follows:

100 Federal acres ÷ 160 Participating Acres = 62.5%

If 200 barrels of oil are produced and sold from the unit during a month, the royalty for the Federal lease (royalty rate 12.5%) is calculated as follows:

200	barrels produced
x 62.5%	Federal lease allocation from unit
125	barrels allocated to Federal Lease
x $20	per barrel value
$2,500	value of Federal oil
x 12.5%	royalty rate for Federal lease
$ 312	Federal royalty

NOTE

Lease allocation factors change over time as a participating area expands. Lease allocations for specific periods may be obtained from the Business Information Systems (BIS) agreement database.

Oil and gas produced under unitized operations are allocated to the working interest owners of the unitized lands on the basis of the factors and formulas prescribed in the unit operating agreement.

Sometimes parties who did not agree to the pooling agreement receive a share of production, but only after a nonconsent penalty has been paid. Nonconsent parties refuse to participate in the costs of drilling a well on a unitized tract. In these cases, a penalty is imposed, which may be in terms of production, cash, or acreage. After the penalty has been satisfied—for example, 200 percent of the cost of drilling the well has been paid—the nonconsenting party may receive a share of production.

12.4.3 Royalty computations

Royalty is based on the volume of unitized substances allocated to each participating Federal or Indian lease or, when appropriate, on the total production and number of producing (countable) wells in a participating area. The value of such production is based on the gravity or British thermal unit (Btu) content of the total volume sold from the participating area during the month.

See chapter 2, section 6, of the *Oil and Gas Payor Handbook, Volume III* (07/21/93), for important information about computing royalties on agreement production.

12.4.4 Secondary and tertiary recovery

Older oil producing reservoirs within unit agreement areas often require special maintenance, such as reservoir pressurization, in order to continue producing economically. Gases such as carbon dioxide, natural gas, nitrogen, or steam are typically injected into the reservoir through injection wells to maintain the pressure of the producing reservoir and push the oil out. Water flooding is another technique commonly used. Also, natural gas liquids (NGLs) may be injected into the reservoir to facilitate the recovery of oil. These agreement areas thus become secondary or tertiary recovery units, also known as enhanced oil recovery (EOR) units, subject to BLM approval.

For injected fluids with a market value obtained outside of the unit area, the policy is to allow a credit for their value when they are recovered from the producing wells and sold. Similarly, for royalty bearing substances native to the reservoir that are produced and reinjected into the reservoir, no royalty is due until those substances are finally removed or sold from the unit. Reinjection must be included in the plan of development or operations approved by BLM.

13. Nonstandard Indian Leases

Many Tribes and individual Indians have negotiated agreements that govern the development and disposition of their mineral resources. These agreements are authorized by either the Indian Reorganization Act of 1934 (25 U.S.C. 461 et seq.) and the specific Tribal constitution or charter, or the Indian Mineral Development Act of 1982 (25 U.S.C. 2101 et seq.).

The 1982 Act provides Tribes specific authority to enter into negotiated mineral agreements with energy and mineral companies. Section 3(a) states:

> Any Indian Tribe, subject to the approval of the Secretary and any limitation or provision contained in its constitution or charter, may enter into any joint venture, operating, production sharing, service, managerial, lease or other agreement, or any amendment, supplement or other modification of such agreement (hereinafter referred to as a "Minerals Agreement") providing for the exploration for, or extraction, processing, or other development of, oil, gas, uranium, coal, geothermal, or other energy or nonenergy mineral resources—in which such Indian Tribe owns a beneficial or restricted interest, or providing for the sale or other disposition of the production or products of such mineral resources.

Section 3(b) states:

> Any Indian owning a beneficial or restricted interest in mineral resources may include such resources in a Tribal Minerals Agreement subject to the concurrence of the parties and a finding by the Secretary that such participation is in the best interest of the Indian.

Under the 1982 Act, a Tribe may negotiate an agreement to develop and dispose of both energy and nonenergy mineral resources in which the Tribe owns a beneficial or restricted interest. If all parties to such an agreement consent and the Secretary approves, an individual Indian may choose to include his mineral resources in an agreement negotiated by a Tribe.

The 1982 Act is very broad and encourages a Tribe to develop agreement provisions that will address its unique reservation circumstances and Tribal philosophy. The 1982 Act provides for agreements that govern the following:

- Development
  - Exploration
  - Extraction
  - Processing
  - Other
- Disposition
  - Sale
  - Other

With this legal authority, Tribes may negotiate leases that contain unique royalty and revenue provisions.

Before passage of the 1982 act, some Tribes entered into leases that contained variable or escalating royalty rates and revenue calculation methods that differed from those contained in standard leases. These leases may include provisions to receive economic benefits through net profit interest, joint venture, working interest sharing, production payments, or similar arrangements. These leases—and minerals agreements entered into under the 1982 act—are commonly referred to as nonstandard Indian leases and agreements.

Nonstandard leases and agreements may take many different forms. The lease or agreement could be 1) a standard lease with unique royalty rates or special provisions added through attachments or addendums, or 2) an agreement with a format completely different from the typical lease.

Some nonstandard leases, such as those involving the Ute Distribution Corporation (UDC), contain provisions that require UDC's portion of royalties and rents to be paid directly to the appropriate BIA agency. Only the portion of royalties and rents due the Tribe are paid to MMS. To account for total revenues paid on a UDC lease, you must sum the two payments.

13.1 Types of Leases and Agreements

In 1995, MMS accounted for approximately 75 producing and 49 nonproducing nonstandard leases and agreements. As Tribes seek to maximize revenues from their lands through unique agreements with commercial operators, a number of new nonstandard leases and agreements will likely be developed. Nonstandard Indian leases and agreements can generally be classified into three major groups, although other variations may also exist:

- Joint venture agreements.
- Net profit share (NPS) agreements.
- Unusual royalty terms or conditions.

Each of these categories are discussed in the sections that follow.

13.1.1 Joint venture agreements

A joint venture agreement is an agreement with another party to share in the development costs and revenues of a property. Joint ventures usually involve Indian properties developed by commercial oil and gas companies. Unlike most joint ventures between commercial companies, Tribes typically do not pay for costs during the development or preproduction phase. Instead, the operator accumulates the charges until production begins and then recovers the Tribe's share of cost out of revenues due the Tribe. In many cases, the interest in the property also changes after the operator recoups his initial investment. Because the Tribe receives a portion of the net revenues after allowable expenses, the Tribe's interest is actually a revenue share rather than a royalty based on gross proceeds.

13.1.2 Net profit share agreements

NPS agreements are similar to joint ventures because NPS agreements are also net revenue sharing arrangements.

A net profit share is typically an acquired interest that does not require any payment from the Tribe, but allows the operator to recover certain costs before revenue sharing begins. Costs may be entirely recovered before any payment is made to the Tribe or partially recovered as a deduction from proceeds over a period of time.

13.1.3 Unusual royalty terms or conditions

Some agreements may have unusual royalty terms or conditions, such as variable or conditional royalty rates, bonus or penalty payment terms, alternate payment methods, or alternate reporting frequencies. Some leases and agreements may include characteristics of one or more of the above groups; for example, an agreement in which the Tribe receives a standard royalty based on gross proceeds from sales, in addition to sharing in net revenues after deduction of capital and operating expenses.

13.2 Reporting Requirements

Reporting requirements in negotiated minerals agreements vary. Except for some leases converted to the Auditing and Financial System (AFS) in October 1983, MMS did not account for payments under most nonstandard leases and agreements before 1988. Lessees or operators were not required to report sales or payment information to MMS, and payments were remitted directly to the Tribe.

In March 1988, however, the MMS Director announced that MMS would assume accounting responsibility for nonstandard Indian leases and agreements (see note entitled "Accounting for Nonstandard Indian Leases" dated March 1, 1988). The payment and reporting requirements were prospective; consequently, historical information is not available in the MMS accounting systems. Information on payments prior to the implementation of the 1988 accounting procedures must be obtained directly from the appropriate Indian Tribe.

13.3 Audit Steps

Nonstandard Indian lease audit steps can be found in the RMP Intranet library.

14. Onshore Lease Management

The Secretary of the Interior designates which organizations within the Department of the Interior (DOI) administers the duties assigned to the Secretary by statutes. Secretarial delegations of authority generally occur in the form of Secretarial Orders.

Secretarial Order No. 3087, dated December 3, 1982, as amended, established minerals management responsibilities as follows:

- MMS is responsible for all royalty and mineral revenue management functions.
- Bureau of Land Management (BLM) is responsible for all other onshore mineral lease functions for nonIndian lands.
- BLM is responsible for certain mineral lease functions on Indian lands, including resource evaluation, approval of permits and plans, inspection, and enforcement of regulations.
- Bureau of Indian Affairs (BIA) is responsible for all Indian lease administrative functions.

Because mineral lease management functions are shared, BLM, BIA, and MMS must coordinate carefully. To achieve the common goal of excellent mineral accountability on all Federal and Indian leases, BIA, BLM, and MMS entered into a Memorandum of Understanding (MOU), dated September 6, 1991, that covers the following four functional areas:

- Information sharing and responsibilities, Indian minerals.
- Information sharing and responsibilities, Federal onshore minerals.
- Onshore production data, procedures for data management.
- Treatment of proprietary/confidential data.

14.1 Laws, Regulations, and Other Criteria

The laws, regulations, and other criteria associated with onshore minerals management activities are:

- Secretarial Order No. 3087, dated December 3, 1982, and Amendment No. 1, dated February 7, 1983.
- 43 CFR Subchapter B (1996).
- 25 CFR Subchapter I (1996).
- BLM, BIA, and MMS Memorandum of Understanding dated September 6, 1991.
- BLM Instruction Memorandum No. 94-17 dated October 8, 1993, entitled “Establishment of Interim Manual and Handbook Guidance for the Oil and Gas Inspection and Enforcement Strategy.”
- Washington Office Instruction Memorandum No. 92-91 issued January 3, 1992, entitled “Policy for Avoidable Lost Gas—Onshore Federal and Indian Oil and Gas Leases.”
- BLM Drainage Protection Procedures, Section 3160-2, BLM Manual, Release 3-276, dated November 4, 1992.
- BLM Instruction Memorandum No. 93-287 dated July 9, 1994, entitled “Application of the Statute of Limitation to Oil and Gas Drainage Cases.”
- BLM Instruction Memorandum No. 96-06 dated October 19, 1995, entitled “Lessee Liability for Oil and Gas Drainage that Occurred Prior to Lease Acquisition.”

14.2 Organizational Overviews

BLM. The BLM organization consists of a headquarters office in Washington, D.C., and a field organization that is composed of State offices with subordinate district and resource area offices. BLM's land and resource management programs are conducted in the field offices.

Each State office administers specified geographic areas containing one or more States. These offices are responsible for the following:

- Directing Statewide programs,
- Coordinating renewable and nonrenewable resource programs,
- Maintaining relations with the public and other organizations, and
- Evaluating the performance of the field-level organizations.

BLM maintains original lease case files at State offices and copies of leases at responsible district offices. Lease, unit, and communitization agreement files are generally available at the responsible district office. You should contact the appropriate State office for assistance locating and using BLM records. BLM Deputy State Directors can provide helpful information.

BIA. The BIA organization consists of a headquarters in Washington, D.C., and a field organization that consists of area offices with subordinate agency offices. BIA's minerals management functions are performed at the agency offices and include the following:

- Lease approvals,
- Assignment approvals,
- Lease records maintenance,
- Revenue disbursements to Indian royalty owners, and
- Lease cancellations. BIA also maintains the Branch of Energy and Mineral Resource Assistance in Denver, Colorado, to provide technical assistance on minerals management activities.

Agency offices are the official BIA offices of record. All Indian mineral lease records are maintained in the Real Property Management office of each agency. Individual lease files are maintained for each lease that is not unitized or communitized. When two or more leases are unitized or communitized, separate files are maintained for each agreement.

Although BIA administers some provisions of the mineral leasing regulations, BLM and MMS enforce most of the functions related to royalty management on Indian oil and gas leases. Assistance for mineral functions performed by BIA should be obtained from the appropriate BIA area office.

14.3 BIA and BLM Records

The following types of records are available at the various BLM and BIA offices:

- Lease documents, including lease modifications, relinquishments, terminations, extensions, expansion, and cancellations.
- Lease inspection and calibration reports.
- Lease assignments.
- Lease correspondence.
- Unit or communitization agreements and correspondence.
- Production reports.
- Operating reports.
- Mine engineer inspection reports.
- Mine plans and permits.
- Licenses and permits.
- Applications for relief from operating and production requirements.
- Applications for any modifications of royalty or rental requirements.
- Appeals.

14.4 BLM Functions

BLM functions include oil and gas and solid mineral lease inspections, well counts for variable royalty rate leases, drainage determinations, and maintenance of the Automated Land and Minerals Records System (ALMRS).

14.4.1 Oil and gas lease inspections

BLM Instruction Memorandum No. 94-17 dated October 8, 1993 sets forth the agency's inspection and enforcement strategy for onshore Federal and Indian oil and gas leases. BLM's goal is to ensure 100 percent compliance with the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) requirement to "...inspect at least annually each lease site producing or expected to produce significant quantities of oil or gas...or which has a history of noncompliance...."

BLM's inspection and enforcement activities include all the procedures used to monitor exploration and extraction operations. BLM field personnel inspect operations to ensure compliance with established requirements—laws; regulations; lease, license, or permit terms; onshore oil and gas orders; notices to lessee (NTL); and written orders—issued by authorized BLM personnel. Enforcement actions for noncompliance include notices of noncompliance, bond forfeiture, cessation of operations, lease cancellation, or monetary assessments and civil penalties.

Production accountability. BLM ensures production accountability by conducting two types of producing lease inspections: Detailed Production Accountability Inspections (DPAI) or Independent Measurement/Handling Inspections (IMHI).

- **DPAI**. A DPAI is a detailed review of production practices on a lease, unit, or communitization agreement. All items relating to production accountability, the environment, and public health and safety are reviewed during the inspection. BLM technicians perform an onsite inspection of oil and gas measurement activities and obtain production information—run tickets, chart integration reports, daily gauge reports, and seal records—from the operator. The information is reviewed and verified against the Monthly Report of Operations (MRO). Corrective actions are required from the operator if necessary, and the inspection is documented in the Automated Inspection Records System (AIRS) and on the hardcopy Production Inspection Form 3160-11. This type of inspection ensures that production is handled and measured correctly, and reported accurately based upon independent field observations.

- **IMHI**. An IMHI is an individual inspection activity conducted for specific measurement and handling actions such as site security. Two technical inspections must be completed for an IMHI. In addition, all IMHI inspections include observations for environmental concerns and compliance issues, and are documented in AIRS and on the hardcopy Production Inspection Form 3160-11. An IMHI may be upgraded to a DPAI if production accountability concerns are raised and a more in-depth inspection is necessary.

Records verification. In certain instances, BLM may also conduct a Records Verification Inspection over and above the DPAI or IMHI requirements. A Records Verification Inspection is an office review of a specific type of production record such as run tickets, meter calibrations reports, MRO reviews, and variable royalty rate determinations. If anomalies are found, then an IMHI or DPAI can be conducted.

You can request that BLM perform onsite inspections of a lease to confirm that the operator maintains adequate onsite security and that the location of all measurement points are compatible with BLM requirements. These inspections allow you to confirm the number of producing wells on a lease, determine the adequacy of measurement equipment, and ensure that required site facilities diagrams reflect current operations.

AIRS. BLM enters all lease production inspections in AIRS using the standard Production Inspection Form 3160-11. You should review this data before beginning your audit. The format for BLM narrative reports about production inspections varies between State offices and sometimes between field offices within a State office. You should contact the appropriate BLM State office, Division of Mineral Resources, for assistance in obtaining and using AIRS inspection information.

14.4.2 Solid mineral lease inspections

BLM is responsible for Inspection and Enforcement/Production Verification (I&E/PV) of all Federal and Indian solid mineral leases. Because production verification is one of the steps in a solid minerals audit, you should contact the responsible BLM office early in the audit to examine their production verification records. Inspection and production verification procedures vary, based on the type of solid mineral being mined and the mining method.

For all solid mineral leases, BLM regulations require that inspections be performed at least quarterly. However, there is a great deal of latitude in the regulations about what must be included in quarterly inspections. As a result, production verification inspections are often conducted only on an annual basis.

Regulations for Indian solid mineral leases do not specify the frequency of or requirement for production verification inspections, but make reference to BLM's authority and responsibility to conduct Federal lease production verification inspections. As with Federal solid mineral leases, Indian solid mineral leases vary widely, and the procedures and standards for conducting solid mineral lease inspections vary as well.

You should contact the appropriate BIA Energy and Minerals office as soon as you know the scope of your Indian solid minerals audit to provide as much time as possible to perform an inspection.

14.4.3 Avoidably lost gas determinations

BLM officially determines whether vented or flared gas is considered avoidably lost. No monetary obligation attaches to unauthorized vented or flared gas unless the gas is determined to have been avoidably lost. You may request from BLM an avoidably lost gas determination. BLM is responsible for issuing appealable orders stating that royalty on the value of the lost gas will be assessed to any operator found to have avoidably lost gas. BLM policies and procedures for avoidably lost gas determinations are found in Washington Office Instruction Memorandum No. 92-91 issued January 3, 1992.

After BLM resolves the avoidably lost issue, MMS assesses the amount of royalty on the lost gas depending upon BLM's determination.

Instruction Memorandum No. 92-91 specifies full value April 1, 1980, through October 21, 1984, and royalty value thereafter. MMS has sole responsibility for computing, billing, and collecting the amounts owed. The MMS policy for assessing royalty for avoidably lost gas is contained in a policy memorandum entitled “Avoidably Lost Gas Onshore,” dated July 25, 1986, from the Assistant Secretary for Land and Minerals Management.

14.4.4 Well counts on variable rate leases

The BLM, BIA, and MMS MOU specifies that BLM is responsible for the determining countable wells for variable royalty rate leases. The correct well count is essential to accurately compute the royalty rate on these leases. You may request BLM to provide a well count for variable royalty rate leases if you are either unable to determine the well count from available information or wish to confirm your well count. Send your requests for well count determinations to the appropriate BLM State office to the attention of the appropriate State Director.

14.4.5 Drainage determinations

As provided in 43 CFR 3100.2-2 and 3162.2(a) (1995), it is the responsibility of all Federal oil and gas lessees to drill and produce all wells necessary to offset or protect the leased lands from drainage, or to compensate the Federal Government for the loss of royalties through drainage. Drainage is the migration of hydrocarbons in a reservoir beneath two or more parcels of land resulting from the drilling of a well in the reservoir.

BLM field offices are responsible for determining whether drainage is occurring. A comprehensive summary of BLM’s guidelines, standards, and procedures for protecting leases and unleased public domain, acquired, and Tribal and allotted lands from loss of oil and gas by drainage and the resulting loss of royalty revenues is found in BLM Manual 3160-2 and BLM Handbook H-3160-2. Also, BLM Instruction Memorandums No. 93-287 dated July 9, 1993, and No. 96-06 dated October 19, 1995, are pertinent. The authority of BLM to assess compensatory royalty for drainage is discussed in Amoco Production Company, 129 IBLA 186 (1994) and CSX Oil & Gas Corp., 104 IBLA 188 (1988).

When BLM determines that compensatory royalty is due in accordance with the above cited regulations and with its own internal procedures, BLM notifies MMS in accordance with section 19B of BLM Manual 3160-2. A memorandum dated November 1, 1993, from the Deputy Associate Director for Audit contains MMS's procedures for processing compensatory royalty assessments.

15. Solid Minerals

According to *MMS Mineral Revenues 1994*, MMS administered 142 coal and 153 other solid minerals leases. Although less than 1 percent of all mineral leases, solid mineral leases generated $411 million or about 12 percent of the $3.5 billion total royalties collected.

Coal production, valued at $3.5 billion, was the major revenue source for solid minerals, providing $360 million of the $411 million collected. Coal leases are found in 11 States. Wyoming is by far the largest producer of Federal coal. Other major coal-producing States are Arizona, Colorado, Montana, New Mexico, and Utah. Indian coal leases made up nearly 20 percent of the total coal royalties collected.

Besides coal, MMS administers leases for fluorspar, limestone, phosphate, potash, sand-gravel, sodium, and sulphur. Some minerals that are normally not leasable—lead, zinc, copper, and gemstones—can also produce royalties when leases are issued on acquired or Indian lands. In 1994, the value of noncoal, solid minerals was $1.3 billion, generating approximately $51 million in royalties.

15.1 Laws, Regulations, and Other Criteria

Solid mineral leases were authorized under the Mineral Lands Leasing Act of February 25, 1920, as amended (30 U.S.C. 181 et seq.) and the Federal Coal Leasing Amendments Act of 1975 (30 U.S.C. 201 et seq.). Audit criteria are found in the lease document and applicable regulations. The following is a list of pertinent regulations:

30 CFR 202	Subpart F, Coal Overriding Royalties (1996)
30 CFR 203	Subpart F, Coal Royalty or Rental Rate Reduction (1996)
30 CFR 206	Product Valuation (1996)
30 CFR 210	Forms and Reports (1996)

30 CFR 212	Records and Files Maintenance (1996)
30 CFR 216	Production Accounting (1996)
30 CFR 217	Audits and Inspections (1996)
30 CFR 218	Collection of Royalties, Rentals, Bonuses, and Other Monies Due the Federal Government (1996)
25 CFR 211	Leasing of Tribal lands for Mining (1996)
25 CFR 212	Leasing of Allotted Lands for Mining (1996)
43 CFR 3400	Coal Management (1996)
43 CFR 3451	Continuation of Leases: Readjustment of Terms (1996)
43 CFR 3483	Diligence Requirements (1996)
43 CFR 3485	Reports, Royalties, and Records (1996)
43 CFR 3500	Leasing of Solid Minerals Other Than Coal and Oil Shale (1996)
43 CFR 3510	Phosphate (1996)
43 CFR 3520	Sodium (1996)
43 CFR 3530	Potassium (1996)
43 CFR 3540	Sulphur (1996)
43 CFR 3550	Gilsonite (including all vein-type solid hydrocarbons) (1996)
43 CFR 3560	Hardrock Minerals (1996)
43 CFR 3570	Asphalt in Oklahoma (1996)
43 CFR 3580	Special Leasing Areas (1996)

43 CFR 3590	Solid Minerals (other than coal) Exploration and Mining Operations (1996)

If any lease provision or any provision of a Federal statute, treaty, or settlement agreement between the United States and a lessee is inconsistent with these regulations, then the statute, treaty, settlement agreement, or lease provision governs the inconsistency. Other internal sources for guidance in conducting solid mineral audits are:

- *Solid Minerals Payor Handbook* (February 27, 1997) and *AFS Payor Handbook—Solid Minerals*, chapter 10 (October 26, 1992).
- *Solid Minerals Training Course Materials* provided by BLM, (November 1989).
- *Auditor Training Manual* (July 1996).
- Dear Payor letters and MMS decisions provide interpretation of lease terms, laws, regulations, or MMS policy; therefore, a review of these sources is recommended before drawing any audit conclusion.
- MMS and Interior Board of Land Appeals (IBLA) decisions reprinted in *Gower Federal Services*.

15.2 State and Tribal Audit Authority

The Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) did not include solid minerals. Therefore, the Tribes and States under sections 202 and 205 of FOGRMA, respectively, did not have the authority to conduct audits of solid minerals. In 1992, FOGRMA was amended by the “Enrolled 1992 Appropriation Bill, H.R. 2686-12” to allow States and Tribes with FOGRMA sections 202 and 205 delegation to perform audits involving coal and other solid minerals.

15.3 AFS Forms

The following are Auditing and Financial System (AFS) forms and reporting requirements for solid mineral leases:

- **Report of Sales and Remittance, Form MMS-2014**. Submitted monthly to report royalties due. Before December 1, 1992, Federal and Indian solid mineral payors reported sales and royalty information on the Report of Sales and Remittance—Solid Minerals, Form MMS-4014.

- **Solid Minerals Payor Information Form, Form MMS-4030**. Used to establish a database of payor accounts, report any changes to the accounts, and identify the type of mine and solid mineral product produced.

- **Coal Washing Allowance Report, Form MMS-4292.** Used to establish an allowance to be deducted from royalty payments for the reasonable, actual cost of washing. Schedules 1a and 1b are used to report non-arm's-length costs.

NOTE

As of March 1, 1996, coal washing allowance forms are not required for Federal leases. Allowance forms are still required for Indian leases.

- **Coal Transportation Allowance Report, Form MMS-4293**. Used to establish an allowance to be deducted from royalty payments for the reasonable, actual cost of transportation. Schedules 1a and 1b are used to report non-arm's-length costs.

NOTE

As of March 1, 1996, coal transportation allowance forms are not required for Federal leases. Allowance forms are still required for Indian leases.

15.4 PAAS Forms

Any entity “directly associated” with a Federal or Indian minerals lease that is within an “approved mine plan” or in a producing status is subject to Production Accounting and Auditing System (PAAS) reporting requirements. Those “directly associated,” include operators of:

- Mines (including primary processing).
- Secondary processing facilities.
- Solid minerals storage facilities.
- Measurement points that measure the sale or transfer of production from Federal or Indian leases.

These entities must file the relevant reports listed in the sections below.

15.4.1 Reference reports

Reference reports provide static information related to mines or facilities. These reports establish and modify PAAS reporter identification data. After the initial submission, these reports are submitted only when information changes; for example, when a scale at a measurement point is replaced. The following are PAAS reference information forms, shown with a description of the responsible reporter:

- **Mine Information Form (MIF), Form MMS-4050**. Initially submitted by mine operators to identify the mine, mine operator, products recovered, and the Federal and Indian leases contained in an approved mine plan or in a producing status.
- **Facility and Measurement Information Form (FMIF), Form MMS-4051**. Submitted by mine operators who use measurement points or facilities that measure, process, or store Federal or Indian production before royalty determination. This form is submitted by the operator during system initialization and whenever a change in measurement point occurs.

15.4.2 Operations reports

Operations reports include mine or facility operations data such as production, disposition, sales, and inventory levels. These reports are submitted regularly for producing mines or facilities.

- **Solid Minerals Operations Report—Part A (SMOR-A), Form MMS-4059-A**. Submitted by mine operators responsible for reporting production from mines that include Federal or Indian leases in the approved mine plan. Submitted monthly unless authorized for a different reporting period.
- **Solid Minerals Operations Report—Part B (SMOR-B), Form MMS-4059-B**. Submitted monthly by mine operators reporting sales from a secondary processing or remote storage facility.
- **Solid Minerals Facility Report—Part A (SMFR-A), Form MMS-4060-A**. Submitted monthly by operators of secondary processing facilities processing Federal or Indian production.
- **Solid Minerals Facility Report—Part B (SMFR-B), Form MMS-4060-B**. Submitted monthly by operators of secondary processing or remote storage facilities receiving or disposing of Federal or Indian production.

15.5 Royalty Valuation Division

Contact the Royalty Valuation Division (RVD), Solid Minerals Branch, before starting an audit on solid minerals. The branch can provide criteria, specific valuation decisions for the company or mine, and technical assistance on mine tours and valuation issues. The branch monitors transportation and washing allowances and performs all data management functions including lease reference data, PAAS, and AFS maintenance. You should contact the Solid Minerals Branch instead of the Compliance Verification Division (CVD) for AFS/PAAS comparison results on solid mineral leases.

15.6 Coal Audits

Coal is a carbon-based mineral classified by four different ranks as follows:

1. Lignite, 4,000 through 8,300 British thermal unit (Btu)/lb

2. Subbituminous, 8,300 through 11,000 Btu/lb

3. Bituminous, 11,000 through 16,000

4. Anthracite, greater than 86 percent fixed carbon

The rank of the coal is very important in the determination of the value of the coal. Other relevant considerations in the determination of coal value are the impurities contained within the coal, such as, percent sulfur, percent moisture, and percent ash.

Coal audits involve auditing volume, value, and the royalty determination point. The most important component of the coal audit is auditing the value.

15.6.1 Volume

Produced volumes and sales volumes must be verified during an audit. Some differences between the two volumes may be attributable to inventories, commingled production from privately owned leases, or coal purchased from another mine for resale.

- **Produced volumes**. BLM does an annual production verification for each mine. Verification includes a comparison of the monthly reported production volumes with volumetric calculations prepared from a combination of survey maps and onsite measurements (volumetric survey). Ensure that the royalty determination point used for reporting purposes is the approved royalty determination point and that inspections are current. If the coal seam is regular in shape, that is, has no pinch-outs or other irregular underground formations, then the production verification can be substantially relied on to support volume testing. The production allocation method must be documented and supported by either copies of the BLM testing procedure or your own testing.

- **Sales volume**. Each state has a Bureau of Weights and Scales that inspects commercial scales. Weigh tickets should be generated at the time of loading or shortly after loading at a scale designed to weigh railroad cars. Sampling must be done at the time of loading to determine quality. Mining regulations explain how sampling is to be done. Also, coal contracts often specify minimum frequency of scale inspections and define the method to be used for quality testing. Weigh tickets and sampling results should be spot checked to customer billings to verify that the production accounting system is accurately transferring measurement and quality information to the billing system.

15.6.2 Value

Before 1989, coal valuation was defined using the term “gross value.” After 1989, the term changed to “gross proceeds” for consistency with oil and gas regulations. In the preamble to the 1989 coal regulations, MMS stated there was no difference between the terms “gross value” and “gross proceeds.”

- **Contract price**. The most important step in auditing coal is to obtain a copy of the coal sales contract and review it very carefully. The contract must be reviewed to determine the gross proceeds that accrue to the lessee. Gross proceeds include, but are not limited to, payments to the lessee for certain services such as crushing, sizing, screening, storing, mixing, loading, or treating. Also, included in gross proceeds, if specified in the contract, are reimbursement for royalties, taxes, and other fees.

  There are three types of coal contracts:

  1. Base price plus escalation,

  2. Cost plus, and

  3. Short-term.

  Contractual provisions between independent buyers and sellers govern the value of coal. Price may be simply stated in a pricing letter similar to gas spot sales. Or the contract may contain a detailed formula that includes factors for such things as severance tax; royalty; Btu content; sulfur content; labor cost; power cost;

capital cost; reclamation cost; inflation or deflation; or Wholesale Price Index for Diesel, Explosives, Tires, and Construction Machinery and Equipment.

- **Marketable condition**. There are five major markets for coal:

  1. Utility steam,
  2. Industrial fuel,
  3. Stoker coal,
  4. Lump coal, and
  5. Metallurgical coal.

  Each of these coal markets require the coal to be in a specific marketable condition. As stated in 54 Federal Register 1498, 1499 (1989):

  > ... the test of marketable condition relies on: (1) The market segment that coal is sold into; (2) the customary requirements of preparation or conditioning normally expected by that market segment; and (3) the typical level of preparation or conditioning by coal producers in that area. Therefore, under no circumstances will MMS accept the gross proceeds established under any sale of coal that does not meet the market's minimum requirement for marketable condition. Specifically, the sale of run-of-mine coal for steam coal utilization by an electric utility does not constitute coal in marketable condition. In this situation MMS will add to the gross proceeds the cost of those normal mining processes which are ordinarily the responsibility of the lessee. This provision is explicitly set forth at 30 CFR 206.257(h) (1996).

- **Retroactive price adjustments**. Coal audits include testing the timeliness of royalty payments. Many cost-plus coal contracts include adjustments based on consumer price indexes that are not known at the time the coal is sold; consequently, pricing adjustments take place as much as a year after the sale. MMS does not bill late-payment interest for pricing adjustments that could not have been determined before the date the adjustment was received. However, payments must be made in a timely manner after the adjustment is received, or interest will be assessed.

- **Exclusions for taxes and fees**. Before 1989, royalty on ad valorem coal leases was due on the gross proceeds accruing to the lessee regardless of the components used in pricing. From March 1989 through September 1990, the regulations permitted a lessee to deduct from gross proceeds Federal Black Lung taxes, Federal abandoned mine land fees, and production-related State and local severance taxes; however, Indian coal leases were not allowed these deductions. Since October 1990, no deductions from gross proceeds are allowed on Federal or Indian leases. No deductions were ever granted on cents-per-ton coal leases.

- **Allowances**. Transportation and processing (coal washing) allowances affect net royalty value. As of March 1, 1996, allowance forms on Federal leases are not required under 61 Federal Register 29 (1996).

  – **Transportation**. Transportation allowances are granted for the actual, reasonable cost of transporting coal off the mine site to a wash plant or to a remote point of sale. Coal transportation allowances are reported on Form MMS-2014 as a separate line.

  – **Coal washing**. Coal washing allowances are not common. All coal washing plants to date are operated at non-arm's-length. Coal washing involves sifting, vibrating, and emulsifying in vats to separate mineral pyrite, ash, shell, sand, and gravel from the coal. Coal washing is not a chemical treatment of coal, although chemicals may be used to separate the impurities. Coal washing allowances are reported on Form MMS-2014 as a separate line.

  Audit programs for non-arm's-length transportation and washing allowances are cost audits. In auditing arm's-length allowances, an invoice with the actual costs from the third-party should be obtained to support the allowance.

- **Oiling** (chemically treating coal for transportation). Sometimes purchasers require a mine to oil the coal before transporting. Oiling is generally done to meet local code restrictions on transporting coal near or around the purchaser's facilities. Any increase in value that results from oiling the coal is part of gross proceeds and any cost is considered a marketing cost. As such, no allowance is granted for the cost of oiling.

- **Non-arm's-length Pricing**. Pre- and post-1989 non-arm's-length valuation regulations are explained in an Royalty Valuation Division (RVD) Product Valuation Determination letter, dated January 9, 1992, Federal Lease M19-021209-0, Basin Cooperative Services. In non-arm's-length coal sales, the purchaser is generally either reselling the coal or using it to generate electricity. If the coal is used to generate electricity, the cost of the coal is reported to the Federal Energy Regulatory Commission (FERC) for the purposes of justifying a rate per kilowatt hour sold. (Coal regulations established in 1989 substantially adopted the same framework as for oil and gas.) Because MMS allows brokered sales and sales between joint venture owners, resales should be handled on a case-by-case basis with RVD's technical assistance.

- **Beneficiation**. Beneficiation is the process of changing the chemical or physical properties of coal, thereby producing a value-added product. Generally, royalties are paid on the value of feedstock coal in marketable condition that is transferred or sold prior to input to the beneficiation process. Therefore, the regulations at 30 CFR 206.257(b) (1996) would be used to value feedstock coal sold at arm's-length to a third party operating the beneficiation facility. For feedstock coal in marketable condition transferred intracompany or sold under a non-arm's-length contract to an affiliate or subsidiary, non-arm's-length valuation benchmarks at 30 CFR 206.257(c) (1996) would be used to value the feedstock prior to enhancement. Contact RVD for valuation guidance in cases where the beneficiated coal product (royalty has been paid on the feedstock coal) is blended with run-of-mine coal (royalty has not yet been paid on run-of-mine coal) prior to sale to the end user.

  Examples of coal beneficiation operations include: the Great Plains Coal Gasification Project in North Dakota that produces methane and other liquid chemical products; the ENCOAL mild gasification project located at Triton Coal Company's Buckskin Mine near Gillette, Wyoming, that produces both liquid and dry processed fuels; and FMC Wyoming Corporation's "form coke" plant near Kemmerer, Wyoming, that produces a dry product used in other chemical process applications. Other coal beneficiation projects designed to remove moisture from coal, thereby increasing Btu per pound, are under construction or are in planning stages in Montana, North Dakota, and Wyoming.

15.6.3 Royalty determination point and royalty rates

The designated point of sale is normally regarded as the point of royalty determination or point of royalty settlement as long as the coal is in marketable condition.

Because gross proceeds are normally determined under the terms of an acceptable coal supply agreement, the point of royalty quantity and quality measure are usually defined by the sales contract. The royalty determination point for non-arm's-length sales is determined jointly by BLM and RVD.

- **Cents-per-ton**. Coal subject to fixed-rate, per-ton royalty terms is reported on Form MMS-2014 using Selling Arrangement Code 300. Royalty must be paid at the rate-per-ton specified by the lease on all coal tonnage sold, used by the lessee, transferred to an affiliate, avoidably lost, or otherwise discarded. No transportation or washing allowances can be taken on coal subject to cents-per-ton royalty.

- **Ad valorem**. Coal subject to a royalty based on a percent of gross proceeds accruing to the lessee from sale or disposition is reported on Form MMS-2014. The value of coal from ad valorem leases—or cents-per-ton leases that have been readjusted to ad valorem rates—is normally based on gross proceeds less any applicable transportation and washing allowances. Such allowances must be reported on a separate line from the gross proceeds.

15.6.4 Readjustments

A readjustment is a statutory provision allowing the Government to alter the terms and conditions of a lease at specific intervals. This is generally associated with changing cents-per-ton leases to ad valorem leases.

15.6.5 Rental and rental recoupment

Rent is due on most nonproducing Federal and Indian leases. Rental recoupment occurs when an advance rental payment is recouped from royalty on production. In this situation, the rent payment works like a minimum royalty payment guaranteeing a minimum amount is paid each year. Most new lease terms do not allow rental recoupment.

15.6.6 Advance royalty and minimum royalty

Advance royalty can be approved and paid in lieu of continued operation. Most minimum royalty payments become due on nonproducing leases after 4 to 6 years. Leases with provisions for the payment of advance royalty or minimum royalty due in advance frequently have specific reporting requirements. Most advance royalty or minimum royalty payments are not recoupable.

15.6.7 Contract settlements

In a memorandum dated October 15, 1993, the Associate Director for Royalty Management stated that the May 3, 1993, Dear Payor letter on contract settlements also applied to coal, although coal contract settlements many times had different circumstances than gas contract settlements. Coal contract settlements can involve the typical elements of past pricing, buyout, and buydown. But coal contracts have provisions to pay minimum quantity payments such as capacity payments, deficiency payments, minimum quantity guarantees, and delay payment components as part of the price.

15.7 Other Solid Minerals

The following sections contain information specific to solid minerals other than coal.

15.7.1 Volume

The principles discussed in the preceding sections also apply to other solid minerals. Because the regulations are so general, however, understanding the lease terms is important. Leases for solid minerals other than coal are usually more explicit regarding royalty requirements. Sales, purchase, and processing agreements frequently provide detailed information affecting the calculation of volume and value for royalties. Lease terms often specify reporting, rate, valuation, and other requirements not generally found in the regulations. Leases may also provide terms on several different solid minerals; for example, copper leases may discuss other solid minerals that are generated during the smelting process, and ferrophosphorous is a secondary product of phosphate with a high vanadium content. References to other agreements may also be found in the lease and must be considered in the audit.

15.7.2 Value

In general, the calculation of value for royalty purposes for other solid minerals is:

Sale or contract unit price × number of units sold = gross value

- **Contract price**. Contractual transactions between the lessee and the purchaser govern the value of the commodities produced from the lease and are considered bona fide transactions unless the value of the transaction is based in whole or in part upon considerations other than the value of the commodities.

- **Allowances**. Transportation and processing allowances can be granted that affect net royalty value.

- **Processing allowances**. Processing allowances for certain minerals—lead, zinc, and copper—may be deducted for smelting, refining, and handling costs when royalties are based on the refined metal. Processing allowances are not permitted for mining and concentrating costs necessary to produce the ore concentrate.

  For sodium and potassium products, processing allowances may be deducted for the costs of purchased reagents that become chemically combined with the primary product to produce secondary products. A processing allowance may be deducted on sodium and potassium only when the royalty is based on the value of the secondary product. Normally, sodium and potassium royalty is reported by primary product bulk sales and, accordingly, no processing allowances are allowed. Where sodium and potassium products are sold in packaged or bagged form and royalty is reported on that basis, a processing allowance may be taken for the costs of bagging and tagging, provided that the value basis may not be reduced to an amount less than the price received for like-quantity products sold in bulk form.

No processing allowances are allowed for phosphate. Processing allowances for other leasable minerals, such as uranium, is generally contingent on lease terms.

- **Transportation allowances**. Transportation allowances are deductions for the reasonable, actual costs to transport lease production to a point of sale that is distant from the mine, plant, or other customary point of shipment to market. Transportation allowances cannot be deducted for the cost of haulage in and about the mine, including mine support facilities and associated mineral processing facilities. Normally, the lessee’s actual costs are the basis for an allowance; however, in reviewing the reasonableness of allowances, the free on board (f.o.b.) mine sale values will be compared with f.o.b. destination sale values less the cost of transportation. Shipper rebates based on transporting bulk quantities are royalty bearing because the rebates reduce the cost to transport the product. The allowance should be reported on the Form MMS-2014 as a separate line and should not be netted in the price.

15.7.3 Royalty rates

- **Sodium and potassium**. Royalty provisions for sodium and potassium production from Federal and Indian lands can vary considerably. Most royalty rates for sodium and potassium leases are generally 2 to 5 percent of the gross value of the product at the point of shipment to the market. The point of shipment is generally the recovery and processing plant or the refinery, whether on or off the lease.

- **Lead/zinc/copper**. Most Federal lead, zinc, and copper leases stipulate that royalties are calculated as a percentage of the gross value of minerals mined and milled at the point of shipment to market. The point of shipment is commonly the mill, and the mill products are called mineral concentrates.

- **Phosphate**. Indian leases in Idaho and leases in the western phosphate fields require royalties be paid on a percentage of the indexed 1979 phosphate value rather than on actual gross value. Also, royalties are due on associated and related minerals that may include ferrophosphorous slag, calcium silicate slag, and precipitator dust, which are by-products of the elemental phosphorous process. See the MMS Director's decision dated May 8, 1996, Monsanto Company, MMS-93-0957-MIN.
- **Uranium**. Royalty provisions for uranium production vary according to lease terms. Most common royalty rates are expressed as a percentage of the value of produced uranium ore, called dry tons. Value is determined by either the gross proceeds of any unprocessed uranium ore sales or by complex schedules that determine the value per pound of triuranium octaoxide (U_3O_8) contained in the ore. Because uranium royalties are based on the value of the product contained in the ore, the point of royalty determination occurs before any processing facility. Royalties paid on associated molybdenum—and some other byproducts produced with the uranium—are based on sales of the processed product.

15.7.4 Readjustments

Generally, phosphate and gilsonite leases are subject to readjustment at the end of each 20-year period following the effective date of the lease. Sodium and potassium leases are generally issued for a term of 20 years subject to a preferential right of the lessee to renew for a 10-year term at the end of the initial term and at the end of each 10-year period thereafter.

15.7.5 Minimum royalty

Most Federal and Indian mining leases contain minimum royalty provisions. Some sodium, potassium, and phosphate leases require that minimum royalties be adjusted annually using an index. Many Indian leases require month-by-month payment of advance minimum royalties. If lease terms do not specify otherwise, minimum royalties are due at the end of the month immediately following the end of the lease year.

15.7.6 Advance rental royalty

Generally, sodium and potassium compounds and related-products leases provide for the payment of rental at the rate of 25 cents-per-acre for the first calendar year, 50 cents-per-acre for the second through the fifth years, and $1 per-acre for the sixth and each succeeding year during the life of the lease. The rental is due and payable annually on or before January 1.

15.7.7 Advance royalty

Generally, sodium and potassium compounds and related-products leases are conditioned upon the payment of royalties specified in the lease and fixed in advance, but not less than 2 percent of the quantity or gross value of the output.

NOTE

RMP's Exception Processing Modules analyze rent, rent recoupment, and advance and minimum royalty. Exercise judgement on how extensively these areas need to be included in the audit plan.

16. Geothermal Resources

Geothermal resources are all products of geothermal processes, steam, hot water, hot brine, heat, and associated energy and byproducts. Byproducts are any minerals—exclusive of oil, hydrocarbon gas, and helium—found in solution or developed in association with geothermal fluids that are:

- Valued at less than 75 percent of the value of the geothermal energy, or
- Because of quantity, quality, or difficulties encountered in extraction and production, not of sufficient value to warrant extraction and production by themselves.

Byproducts include commercially demineralized water. Sulfur is a commonly recovered byproduct in the United States, and much of it is treated as hazardous waste.

Geothermal resources have diverse uses largely dictated by temperature. Lower temperature resources are used in domestic, agricultural, and industrial processes, while higher temperature resources are predominantly used to generate electricity.

16.1 Laws, Regulations, and Other Criteria

The Geothermal Steam Act of 1970 (30 U.S.C. 1001 et seq.) authorizes the Department of the Interior (DOI) to issue geothermal leases on Federal lands only. The act excluded issuance of geothermal leases on Indian lands. Geothermal resources on Indian lands are covered by Indian minerals agreements entered into under the Indian Mineral Development Act of 1982 (25 U.S.C. 2101-2108). See also 25 CFR Part 225 (1996).

Current regulations for geothermal resources became effective January 1, 1992, and are found in 30 CFR Parts 202 and 206 (1996). MMS prepared specific valuation and reporting guidelines consistent with the regulations and issued the *Geothermal Payor Handbook* on December 27, 1996.

16.2 Royalty Due

Royalty is due on geothermal resources sold or used, or susceptible to sale or use. Royalty valuation of Federal geothermal resources is authorized in the Geothermal Steam Act of 1970 (30 USC 1001 et seq.), which provides for royalty payments to the Government based on the value of geothermal resources.

Royalty is also due on any geothermal resource avoidably lost, wasted, or drained, and on any insurance received for unavoidably lost production. Royalty is not due on unavoidably lost production, reinjected fluids, or production used in the operation of a powerplant or lease.

The lease establishes the minimum royalty payment. If royalties paid are less than the minimum royalty, the lessee must pay the difference on or before the expiration of the lease year.

16.3 Valuation

The valuation method is dependent upon resource usage and disposition. Uses include:

- Electrical generation—those fluid geothermal resources, such as steam, hot water, and hot brines, used to generate electricity.
- Direct use—those fluid geothermal resources, such as warm to hot water, used directly in processes such as commercial space heating, greenhouse heating, and industrial and agricultural operations requiring process heat.
- Byproduct recovery—those recovered minerals found in solution or developed in association with geothermal fluid production.

Disposition of the resources will be under the following situations:

- Arm’s-length sales.
- Non-arm’s-length sales.

- Used by the lessee's own powerplant for generation and sale of electricity, referred to as "no sales."

Volume measurements used to report sales of geothermal resources can be hundreds of gallons, thousands of pounds, millions of British thermal units (Btu), and kilowatt hours (kWh). Sulfur, a common byproduct, must be reported in long tons (2,240 pounds). The lessee is not required to report quality measurements for geothermal resources but must retain quality measurement records for audit and valuation.

16.4 Electrical Generation

If geothermal resources are sold under an arm's-length contract, the price established in the contract is acceptable for royalty purposes. The sales contract must reflect total consideration, direct or indirect, passing between buyer and seller. Total consideration is the equivalent of gross proceeds, and the value used for royalty purposes can never be less than gross proceeds. MMS may require the lessee to certify that the arm's-length contract reflects all of the consideration that has passed between buyer and seller.

Gross proceeds received under an arm's-length contract must reflect reasonable value. Indications that value is not reasonable are:

- Misconduct by or between the seller and buyer, or

- The lessee did not market production for the mutual benefit of the lessee and lessor.

When gross proceeds do not reflect a reasonable value, MMS requires the lessee to use "no sales" benchmarks for valuation.

Value of geothermal resources must be based on the highest price a lessee can receive through legally enforceable claims under its contract. Contract revisions or amendments must be in writing and signed by the parties involved.

16.4.1 Non-arm's-length sales

Valuation for non-arm's-length sales is determined by the first of three applicable benchmarks:

1. Gross proceeds received under the non-arm's-length contract, provided gross proceeds are not less than the minimum value. Minimum value is the lowest-priced, available, arm's-length contract for sales of geothermal resources to the affiliates' same powerplant. If gross proceeds are less than the minimum value, value is determined by the weighted average of gross proceeds under arm's-length contracts for the sale of significant quantities of geothermal resources to the same powerplant.

2. The value determined by the geothermal netback procedure where value is equal to gross proceeds for sale of electricity less reasonable, actual costs of generating and transmitting electricity.

3. A value determined by any other reasonable method approved by MMS in which the lessee demonstrates that the first two benchmarks are not workable.

For non-arm's-length and "no sales" valuations, the lessee must notify MMS in writing and identify the valuation method used including any supporting documents. The notification is a one-time reporting requirement, effective until the valuation method changes.

Value can never be less than gross proceeds when geothermal resources are sold. The lessee is required to place geothermal resources in marketable condition and to deliver geothermal resources to the powerplant at no cost to the Federal lessor. Where gross proceeds have been reduced by the purchaser for providing services that are the responsibility of the lessee, gross proceeds must be increased by the amount of the reduction before the royalty computation.

16.4.2 No sales

For “no sales” valuation, value is determined by the first applicable of three possible benchmarks:

1. Weighted average of the gross proceeds established in arm’s-length contracts for the purchase of significant quantities of geothermal resources to operate the same powerplant.

2. The value determined by the netback procedure.

3. A value determined by any other reasonable method approved by MMS in which the lessee demonstrates that the first two benchmarks are not workable.

16.5 Direct Use

For geothermal resources used in direct-use processes and sold under an arm’s-length contract, valuation is determined by gross proceeds. Two conditions must be satisfied:

1. The sales contract must reflect the total consideration transferred either directly or indirectly from buyer to seller. MMS may require the lessee to certify that the arm’s-length contract includes all of the consideration, whether direct or indirect, paid by the buyer for the geothermal resource.

2. Gross proceeds received under the arm’s-length contract must reflect reasonable value. If you determine that gross proceeds do not reflect reasonable value (a) because of misconduct by or between the contracting parties, or (b) because the lessee has not fulfilled the obligation to market production for the mutual benefit of both lessee and lessor, valuation must be performed under “no sales” benchmarks.

16.5.1 Non-arm's-length sales

Non-arm's-length sales of geothermal resources occur when the producer sells the geothermal production to its direct-use affiliate. The producer receives gross proceeds from a non-arm's-length transaction. These gross proceeds must be compared to other valuations, preferably arm's-length, to accept the royalty value reported by the lessee. The value for non-arm's-length sales of direct-use resources is determined by the first applicable of three possible benchmarks.

1. **Gross proceeds**. This benchmark is dependent upon existing arm's-length sales of geothermal resources to the lessee's affiliated, direct-use facility. Gross proceeds under the non-arm's-length contract that are equal to or greater than the minimum value are acceptable. Minimum value is defined as gross proceeds received from the lowest-priced, available, comparable, arm's-length contract for sales of geothermal resources to the producer's affiliated, direct-use facility.

   If gross proceeds received under a non-arm's-length contract are less than the minimum value, or if there are no comparable arm's-length contracts available, the value is determined by the weighted average of gross proceeds from arm's-length contracts for the sale of significant quantities of geothermal resources to the same direct-use facility. In determining the weighted average, gross proceeds are the contract prices. The definition of significant quantities depends upon the particular circumstances, because significant for one producer may be insignificant for another.

   If the direct-use affiliate purchases only geothermal production from the producer and there are no comparable arm's-length sales, or the direct-use affiliate does not purchase significant quantities of geothermal resources under arm's-length transactions, then valuation must be determined under the second benchmark.

2. **Alternative fuel method**. The alternative fuel method is the equivalent value of the least expensive, reasonable, alternative fuel that could be used by the affiliate for heating in a direct-use process. Because value can never be less than gross proceeds received from the sale of the geothermal resources, value becomes the greater of gross proceeds received under the non-arm's-length contract or the alternative fuel method.

Under the alternative fuel method, the formula for calculating geothermal value is:

alternative fuel method $\times$ thermal energy displaced

Alternative fuel value is the local market price in dollars per million Btu (MMBtu). Thermal energy displaced is the amount of the alternative fuel, in MMBtu, the lessee would have used in the direct-use process in place of the geothermal resource.

For further guidance—including formulas, definitions, and examples—consult chapter 6 of the draft *Geothermal Payor Handbook* (December 27, 1996), which covers alternative fuel valuation. If the alternative fuel method is not reasonable, valuation must be determined using the third benchmark.

3. **Other valuation benchmark**. To use this benchmark, the lessee must prove that the first two benchmarks cannot be used. The lessee must propose an alternative valuation method and receive approval from MMS. The approval remains in effect until the producer chooses a different valuation method. The lessee must provide written notification to MMS for any change in valuation methods along with a description of the valuation method and supporting documents.

16.5.2 No sales

"No sales" of direct-use resources occur when the lessee uses the geothermal production in its own direct-use facility. The value of the "no sales" resource is determined by the first applicable of three possible benchmarks.

1. Weighted average of arm's-length gross proceeds. This benchmark is dependent upon the existence of arm's-length purchases of geothermal resources from outside sources to operate the direct-use facility. The weighted average of gross proceeds from the arm's-length contracts determines the value. Gross proceeds are the equivalent of contract prices. The volume of outside geothermal resources purchased must be of a significant quantity. The acceptability of the arm's-length contracts is determined by considering the effective date, duration, terms, volume purchased, and any other factors having an effect on the value of the resource.

If significant quantities of geothermal resources are not purchased under arm"s-length contracts from outside sources, valuation will be determined using the second benchmark.

2. The alternative fuel method.

3. A value determined by another reasonable method because the first two benchmarks are not workable.

The lessee must notify MMS if the valuation method is one of the "no sales" benchmarks. The notification must describe the procedure used and include supporting documents. The notification remains in effect until the valuation method changes. The lessee must provide written notification of any change in valuation methods.

16.6 Geothermal Netback Valuation

Geothermal netback valuation is used under the second non-arm's-length and "no sales" valuation benchmarks where there are no comparable arm's-length contracts to establish value. Two conditions determine whether the netback value is applicable:

1. A contractual sale of electricity exists, and

2. The lessee or lessee's power-generating affiliate uses the geothermal resource to generate and sell electricity.

The existence of a sales contract is important because the electricity value is established by the sales contract. If the electricity value cannot be established, netback valuation cannot be used.

This section covers the basic concepts and formulas for computing the netback value. For further guidance—including formulas, definitions, and examples—consult chapter 4 of the *Geothermal Payor Handbook* (December 27, 1996), which covers netback valuation. Direct any questions related to audit of geothermal resources to the Royalty Valuation Division (RVD).

16.6.1 Netback value formula

The geothermal netback value formula is as follows:

electricity value – (transmission and generating deductions)

Transmission deductions are the lessee's actual cost of transmitting electricity from the powerplant to the point of sale. Generating deductions are the lessee's actual costs associated with constructing and operating the powerplant.

16.6.2 Netback value basic steps

The basic steps for computing netback value are as follows:

1. Obtain the annual transmission cost rate and the annual generating cost rate. These rates are normally calculated at the beginning of the deduction period.

   Deduction periods, also called reporting periods, are the 12 months during which annual cost rates are effective. Annual deduction periods begin with the month the:

   a. Transmission line is placed into service,

   b. Powerplant is placed into service, or

   c. Lessee's annual corporate accounting period begins.

   Annual cost rates consist of two components—combined operations and maintenance (O&M) expenses and capital-related costs. The lessee has the option of claiming capital-related costs as either (a) depreciation and a return on undepreciated capital investment or (b) a return on capital investment.

   The selection of capital related-costs determines how the annual cost rate is computed—the depreciation method or the return-on-investment method. The return-on-investment method can be selected only for transmission lines placed into service on or after March 1, 1988. Once a method has been selected, the lessee needs approval from RVD to switch to an alternative method.

If the annual cost rate was computed using the depreciation method, then the annual transmission line cost rate and the annual generating cost rate are calculated using the following formula:

$$\text{Cost Rate (\$/kWh)} = \frac{E+D+I}{F}$$

E = annual O&M expenses

D = annual depreciation of gross capital investments

I = annual return on undepreciated capital investment

F = annual kWh of delivered or interconnect electricity—estimated for the first deduction period (transmission line rate only), or

F = annual kWh of plant tailgate electricity —estimated for the first deduction period (generating cost rate only)

If the annual cost rate is computed using the return-on-investment method, then the annual transmission line cost rate and the annual generating cost rate are calculated using the following formula:

$$\text{Cost Rate (\$/kWh)} = \frac{E+R}{F}$$

E = annual O&M expenses

R = annual return on gross capital investments

F = annual kWh of delivered or interconnect electricity—estimated for the first deduction period (transmission line rate only), or

F = annual kWh of plant tailgate electricity—estimated for the first deduction period (generating cost rate only)

Real estate costs may be eligible for a return-on-investment, but RVD must approve the costs before including them. The conditions that must be met are (a) the purchased land is not on a Federal geothermal lease, and (b) the necessity for the land purchased can be demonstrated. Only that portion of real estate costs necessary for the powerplant site can be included.

Using the depreciation method to calculate the generating cost rate, the real estate costs are added to the annual undepreciated capital balance to compute the return on the undepreciated capital investment. Using the return-on-investment method, the real estate costs become part of the gross capital investment.

2. Obtain the monthly transmission and generating deductions.

Transmission and generating deductions are based on annual cost rates that are computed as dollars per kilowatt hour (\$/kWh). The cost rates are applied to monthly electricity measurements so that deductions equal:

Annual cost rate (\$/kWh) × Measured electricity (kWh) for that month

Transmission deductions consist of either or both of (a) arm's-length wheeling charges or (b) transmission line deductions.

Arm's-length wheeling charges are fees charged by a third party to wheel the electricity to the sales point. If the electricity gets commingled with electricity generated from other powerplants, the lessee must allocate the wheeling charges in proportion to the amount of electricity transmitted by each powerplant.

Transmission line deductions are the product of the annual transmission line cost rate and monthly delivered or interconnect electricity. The transmission line must directly serve the powerplant using Federal geothermal production. The transmission line deduction equals:

Annual cost rate (\$kWh) × Monthly delivered electricity (kWh)

Monthly delivered electricity is the amount of electricity delivered to the purchaser at the sales point. Interconnect electricity occurs where the lessee's transmission line interconnects with another third party transmission line to wheel electricity to the sales point. In this situation, the amount of electricity delivered at the interconnect is used in the calculation.

Generating deductions are the product of the annual generating cost rate and monthly plant tailgate electricity. The generating deduction equals:

Annual cost rate ($kWh) × Monthly plant tailgate electricity (kWh)

Plant tailgate electricity is the amount of electricity generated by the powerplant and includes any generated electricity returned to the lease for lease operations.

The transmission and generating deductions must coincide, and the deduction period cannot be changed without MMS approval. Deductions cannot reduce the value to zero. MMS policy does not allow the combined transmission and generating deductions to exceed 99 percent of electricity value. Minimum royalty requirements remain in force and are not reduced or eliminated by transmission or generating deductions.

Transmission and generating deductions and cost rates are subject to MMS review, audit, and adjustment. The lessee is required to maintain all data and records that support the transmission and generating deductions.

3. Obtain the monthly value of geothermal resources used in the powerplant.

   The electricity value for one month is computed by subtracting the transmission and generating deductions from the gross proceeds for that month's sale of electricity. This value represents the netback value of all geothermal resources at the powerplant inlet, regardless of the source.

4. Obtain the allocation of the monthly value to Federal leases as necessary.

   The netback formula determines the value of all geothermal resources used by the powerplant, regardless of the source. If geothermal resources were obtained from more than one lease, the lessee must allocate the value to each lease, and BLM must approve the basis for allocation. The simplest methods are the:

   a. Proportion of measured lease production, or

b. Allocation schedule from the unit or communitization agreement.

5. Obtain the netback quantities and values of delivered electricity reported by the lessee on Form MMS-2014.

   Sales quantity is equivalent to the delivered electricity allocated to the lease. Sales value is equivalent to the netback value for the geothermal production allocated to the lease. Sales quantity multiplied by the lease royalty rate determines the royalty quantity, and sales value multiplied by the lease royalty rate determines the royalty value.

6. Obtain the lessee's supporting documents and computations for that deduction period's cost rates, netback values, and generating and transmission deductions based on actual costs for that deduction period.

   Actual costs and deductions are determined at the end of the annual reporting period. The lessee recalculates monthly royalty amounts and submits corrected Forms MMS-2014 to reflect the adjustments. If royalty was underpaid, the lessee must pay the difference plus interest. If royalty was overpaid, the lessee may take a credit.

16.7 Byproduct Valuation

Byproduct valuation is determined by disposition:

- Sales under an arm's-length contract.
- Sales under a non-arm's-length contract.
- No sales—includes use and disposition.

Byproduct sales are minimal. For more information, consult the *Geothermal Payor Handbook* (December 27, 1996) or call RVD.

17. Valuation Policies

Calculating royalties due the Government is often a complex process that depends on the facts of each sale. The following are some issues that require special attention.

17.1 Take-or-Pay

A take-or-pay clause in a gas purchase contract requires the purchaser to take or pay for failing to take the minimum annual volume of gas that the producer-seller has available for delivery. The purchaser is required to pay the purchase price for the take quantity specified, whether or not taken.

In most instances where a volume of gas is paid for but not taken, the purchaser—over a defined period of time—can “make up” the deficient volume by taking gas above the minimum required in the contract and not have to pay for it. If a paid-for volume of gas remains at the end of the prescribed make-up period, the paid-for volume of gas can no longer be made up, and the amount paid for it cannot be recouped by the purchaser.

Royalty due. The principal issue of take-or-pay clauses is whether take-or-pay payments are a portion of the total consideration accruing to the lessee for the disposition of production upon which royalty is due. The resolution of the issue rests with the determination of whether take-or-pay payments are attributable to future production, and only if that production actually occurs.

Take-or-pay payments, if recoupable, are viewed as attributable to future production; therefore, royalty on that future production is not due until such time as that production occurs. Value is determined under the regulations in effect at the time of production. If make-up deliveries do not occur, no royalty is due on any take-or-pay amounts retained by the lessee.

Policy. Take-or-pay policy is contained in a “Dear Payor” letter dated November 8, 1988, issued by the Associate Director for Royalty Management. This policy implemented a Fifth Circuit Court of Appeals decision, dated August 17, 1988, on Diamond Shamrock Exploration Corporation vs. Hodel, Nos. 87-3195 and 87-4069.

Contract Settlements. Contract settlements are discussed in chapter 22.

17.2 Production-Related Cost Recovery

On May 15, 1991, the United States Court of Appeals for the Fifth Circuit, in Mesa Operating Limited Partnership v. U.S. Dept. of the Interior, 931 F.2d. 318 (5th Cir. 1991), cert. denied—U.S.—,112 S.Ct.934, 117 L.Ed.2d 106 (1992), decided that the Department of the Interior (DOI) acted properly and within its authority in requiring Federal and Indian lessees to pay royalties on reimbursements received from purchasers for certain production-related costs under the authority of section 110 of the Natural Gas Policy Act, 15 U.S.C. 3320, and the Federal Energy Regulatory Commission (FERC) Order No. 94 and related orders (FERC 94 payments). Only a few royalty payors have not settled this issue with MMS as of the date of this publication.

17.3 FERC Order 636

On April 8, 1992, FERC issued FERC Order 636. Prior to the implementation of Order 636, pipeline companies purchased the gas. The price pipelines offered to sellers generally bundled transportation costs together with costs for other component services. With the issuance of Order 636, costs for transportation, which were previously lumped together, are now separated.

Natural gas is now marketed under an Order 636 environment where producers can sell directly to end users, such as industrial facilities, local distribution companies, and other large consumer groups. Most of these sales occur in pools downstream of the producing fields along interstate transmission lines or in market hubs where many interstate lines interconnect.

Interstate pipeline companies are barred under Order 636 from participating directly in marketing aspects but still perform virtually all transportation from the producing regions to the consuming regions. Producer pipelines still perform much of the field gathering to interstate trunklines.

Pricing has changed under Order 636, as producers or marketers now provide services once performed by interstate pipelines. These services include firm and interruptible transportation, storage, swing supply, capacity release, market hub services, and pipeline imbalance resolution.

The proposed Order 636 regulations identify costs that are allowable as part of transportation, including firm demand charges, commodity charges, wheeling costs, and other FERC-instituted charges. Under the proposed regulation, no allowance may be taken for costs associated with marketing the gas. Marketing costs including storage, aggregator fees, and intrahub title transfer fees are nonallowable.

On July 31, 1996, MMS published the proposed Order 636 regulations in the Federal Register. These regulations provide payors and auditors guidance on which of the FERC Order 636 unbundled components are allowable for transportation allowance calculation purposes.

The Department also required MMS to perform an analysis of the impact the rule will have on Indian royalties. The analysis of the rule and a copy of the proposed rule was posted on MMS's World Wide Web page. MMS proposes to make the changes to the transportation allowances effective May 18, 1992, the effective date of Order 636. Until the rule is finalized, please refer to the Royalty Valuation Division's (RVD) internal guidance memorandum dated February 24, 1995, when addressing questions on allowances for the transportation of gas and related amendments to the gas valuation regulations.

17.4 Major Portion Analysis

Major portion analysis is used to establish the value of production from certain Indian gas leases for royalty purposes. In these situations, consideration is given to the highest price paid for a major portion of production of like-quality gas in the same field or area. Like-quality gas is gas of similar chemical, physical, and legal characteristics.

17.4.1 Laws, regulations, and other criteria

Authority for major portion analysis on Indian leases is found at 30 CFR 206 (1996). In all cases, you must read the lease terms to determine the requirement for major portion analysis.

17.4.2 Audit steps

You should contact RVD to determine if a major portion price was calculated for certain Tribes/allottee associations and whether the payor was billed or has settled this issue with MMS for certain time periods. By memorandum dated July 15, 1996, RVD provided major portion prices for all current major portion projects to the various compliance division offices. These prices have also been provided in automated form.

17.5 Dual Accounting

Dual accounting is used to establish the value of gas production from Indian and certain Federal oil and gas leases. In these situations, the value of wellhead gas is compared to the value of processed gas, that is, residue gas plus extracted liquid value. Royalty is paid on the higher value but is never less than gross proceeds.

17.5.1 Dual accounting requirements

Dual accounting is required for four situations:

1. The lessee (or lessee's affiliate who receives lessee's gas under a non-arm's-length contract) processes the lessee's gas, and the residue gas is not sold under an arm's-length contract.

2. Prior to November 1, 1991, the lessee sells gas under a percent-of-proceeds (POP) contract, and the residue gas is not sold under an arm's-length contract.

3. On or after November 1, 1991, the lessee sells gas under a non-arm's-length POP contract, and the residue gas is not sold under an arm's-length contract.

4. All Indian leases where dual accounting is specified in the lease document (by direct reference to dual accounting or by reference to regulations that require dual accounting) and:

   a. The gas is actually processed; or

   b. The gas is eventually processed, even if the gas is sold at the wellhead under an arm's-length contract with no gas processing provisions.

17.5.2 Dual accounting valuation requirements

For Indian leases, lessees must comply with the major portion requirements established by the regulations and leases terms in addition to the dual accounting requirements. However, regardless of the valuation method used, value can never be less than the gross proceeds accruing to the lessee, less applicable allowances.

As specified in 30 CFR 206.155(a) (1996), the value of gas sold under dual accounting is the greater of:

1. The combined values of the residue gas and gas plant products, less applicable transportation and processing allowances, plus the value of any drip condensate recovered downstream from the point of title transfer without resorting to processing; or

2. The value of the unprocessed gas.

Section 4.1 (unprocessed gas) and 4.2 (processed gas) of the *Oil and Gas Payor Handbook—Volume III, Product Valuation* provide specific valuation guidance.

17.5.3 Theoretical dual accounting

In situations where dual accounting is required but the information needed to determine the residue and/or the gas plant product value are not available to the lessee, a dual accounting procedure based on theoretical calculations may be used. This method is referred to as theoretical dual accounting.

For Indian leases, no allowances are permitted in the dual accounting computations, unless an allowance form has been properly filed. The theoretical dual accounting procedure is found in section 4.4.2 of the *Oil and Gas Payor Handbook—Volume III, Product Valuation* and in the Dear Payor letter dated July 27, 1992.

17.6 Percentage-of-Proceeds Contracts

A POP contract is an agreement for the sale of gas prior to processing in which the value of the unprocessed gas is based on a percentage of the proceeds the purchaser received for the sale of residue gas and gas plant products attributable to processing the lessee's gas. A contract that allows the producer to retain some of the products "in-kind" is not a POP contract.

POP contract valuation is an area of confusion among payors because the regulatory requirements for the valuation of Federal royalties often differs from normal royalty valuation processes.

Payors are required to notify MMS of an existing POP contract by submitting a Payor Information Form (PIF) for which MMS assigns a unique code. The unique code is identified in the Business Information Systems (BIS) data by the selling arrangement code series 770. See the Dear Payor letter dated January 3, 1994, on the subject of unique POP contract selling arrangements.

Prior regulations. Before November 1, 1991, all gas sold under a POP contract was valued as processed gas under 30 CFR 206.153 (1996). All lessees were required to file for transportation and processing allowances during this period.

Current regulations. Effective November 1, 1991, gas sold under an arm's-length POP contract is valued as unprocessed gas under 30 CFR

206.152 (1996). Lessees with Federal leases are not required to file for or claim an allowance on the Form MMS-2014. However, lessees with Indian leases are required to file allowances forms.

Gas sold under a non-arm's-length POP contract continues to be reported as processed gas. Lessees are required to file the appropriate allowance forms prior to the time or at the time an allowance is claimed on the Form MMS-2014.

The processing allowance under a non-arm's-length POP contract is based on the actual plant costs under the contract.

Processing costs under non-arm's-length situations are limited to two-thirds of the value of the gas plant products. However, the lessee may request an exception to the two-thirds limitation.

The minimum value of unprocessed gas sold under an arm's length POP contract after November 1, 1991, is 100 percent of the value of the residue gas at the tailgate of the plant. This minimum value is a wellhead value.

- The minimum value may not be further reduced for any costs associated with transporting the gas from the field to the plant.

- Consistent with all other Federal and Indian gas valuation, royalty is due on no less than the gross proceeds accruing under the lessee's POP contract.

Because of these various regulations, you must pay close attention to the date of sale and the processed or unprocessed status, as well as purchaser affiliation.

17.7 Royalty-in-Kind

Royalty-in-kind (RIK) contracts are those in which the Federal or Indian lessor takes its royalty share in production rather than in value. Oil RIK sales delivered to small refiners under 30 CFR Part 208 (1996) are reported on the Form MMS-2014 as transaction code "06." The RIK Section verifies the reported volume against Production Accounting and Auditing System (PAAS) reports, and prepares an invoice to the refiner for reimbursement.

In most Federal and Indian agreements, the lessor may take his/her share of the production in kind, rather than allowing the lessee to market the production.

The lessor assumes responsibility for disposing of his/her share of the production. If the point of delivery to the purchaser is not at the lease, the lessor also assumes responsibility for arranging transportation of his/her production to the point of delivery. In this situation, you should verify that the royalty share of the production is correct; royalty oil or oil received in exchange for such royalty oil was refined by the RIK contractor as required in 30 CFR 208.9(c); payments are in line with the sales agreement; and, if off-lease delivery is involved, the transportation charges are correct.

17.8 Determining Gross Proceeds

The minimum acceptable value for royalty purposes is based on the total gross proceeds accruing from the disposition of production. The determination of gross proceeds can be a relatively straightforward or a very complex process, depending upon whether the disposition of production involves an arm’s-length or a non-arm’s-length transaction.

Arm’s-length gross proceeds is an amount usually based on the consideration transferred between independent purchasing and selling parties in accordance with the pricing provisions of a sales contract. The consideration can be in the form of a payment or services performed. Auditors should look for additional consideration associated with placing the product in marketable condition. Marketing is the responsibility of the lessee and is not allowable as a deduction from royalty value.

Non-arm’s-length gross proceeds is an amount usually determined by comparing a lessee-assigned value for the disposition of production to other market-based transactions using a series of regulatory benchmarks. The analysis of non-arm’s-length transactions can be very complex and involve several affiliated entities and internal transfers within the corporate structure of a company. Production can be transferred from the producing entity of a company to a marketing entity of a company that in turn enters into exchange or buy/sell agreements to better market or refine the production. The auditor must fully evaluate these varied and complex transactions and the royalty values assigned by the lessee to properly determine royalty value.

Detailed gross proceeds audit steps are contained in a variety of audit programs that can be found in the RMP Intranet library. Additionally, an audit training manual entitled *Auditing Crude Oil Premiums* includes guidelines and examples addressing various gross proceeds scenarios.

17.9 Royalty Valuation Division

RVD provides royalty valuation technical support for all mineral production from Federal and Indian lands by:

- Preparing and issuing royalty valuation determinations and approving transportation and processing allowance exceptions.
- Providing product valuation advice and assistance on accounting, economic, geologic, and engineering issues raised by industry, Indian Tribes and allottees, States, RMP, and other Government agencies.
- Collecting and assimilating technical information to support allowance determinations appealed by industry.
- Developing, maintaining, interpreting, and enforcing product valuation regulations, guidelines, and transportation and processing allowance determination procedures.
- Providing payor, regulatory, and outreach training.

RVD provides an important service through responding to requests for technical guidance. You may make a formal request or an informal telephone call or send an electronic mail (email) request for valuation or policy guidance. The request should specifically identify the issue for consideration. You must provide all pertinent information in the memo, telephone call, or email message to assist RVD in analyzing the issue.

18. Measuring Production

Production can be measured for royalty purposes from a single lease or after mixing production from several leases. If production is measured from a single lease before mixing, the measured volume is the volume upon which royalty is due. That volume is then multiplied by the royalty rate—for example, 1/6, 1/8, sliding scale, and step scale—to determine either the volume to be taken in-kind or, after application of royalty value per unit, the royalty dollars due. The royalty point may or may not be the sales point.

Production volumes are measured on the lease or at a central gathering point, generally at an oil terminal or at the inlet of a gas processing plant. Purchaser statements often show these volumes as “block” volumes made up of production from more than one lease, but not identified to individual leases. In commingling situations, you need a method for allocating volumes to leases under audit. Many times, the operating producer will have in-house allocations already completed, identifying the individual lease volumes. In most cases, you must verify the accuracy of the allocations by acquiring the source data—well tests and meter listings—used to make the allocations. If the auditee is not the lease operator or if no auditee allocations are available, you must also verify the accuracy of allocated volumes reported on the MMS Form-2014. Several chapters in this manual contain volume and measurement-related subjects:

- Chapter 7 contains steps for auditing oil and gas production volumes.
- Chapter 14 contains information on Bureau of Land Management (BLM) meter and well inspections that can be used to verify the accuracy of reported volumes.
- Chapter 15 covers volume issues found with solid minerals.

18.1 Oil Measurement

Two types of run ticket measurements are automatic custody transfer units (ACT) and tank measurement tickets. Each type of ticket is discussed below.

18.1.1 Automatic custody transfer unit tickets

ACT units are metering units that quantitatively and qualitatively measure liquid hydrocarbons for sales. The term “transfer” is a contractual term and not necessarily related to royalty consideration. Always refer to agreement terms to determine royalty considerations; for example, in buy/sell or exchange situations.

ACT unit measurement allows a continuous flow of oil production and provides the automatic control of storage, measurement, and transfer of oil into the purchaser’s pipeline or storage facilities. Using meter counters, the measurement facility monitors the oil as it passes into the purchaser’s facilities and produces “opening” and “closing” meter readings. The difference between these two readings is the amount of oil that passed through the meter. You must adjust the gross meter reading to determine net adjusted barrels. These adjustments are listed below.

Gravity. A quality adjustment is made to the posted price per barrel of oil based on oil gravity compared to water gravity at sea level. Gravity is determined by periodic sampling and is listed on the run ticket.

Meter provings. ACT meters are “proven” at defined intervals throughout the year. A meter proving involves calibrating the meter to determine the accuracy of the meter readings. Most meters are not exact at one unit of measurement for one barrel of oil because of various factors such as manufacturing processes, weather, and wear and tear. Calibration determines how far to one side or the other the meter is off. This proving should be completed by an independent contract company. The resulting meter-proving report lists a meter-proving factor (examples, .998 or 1.004). You should request meter proving reports from the auditee and ascertain whether the reported meter factor coincides with the meter factor shown on the ACT run ticket. Multiply the verified factor by the metered barrels to determine the adjusted sales barrels.

Basic sediment and water (BS&W). An acceptable impurity or BS&W level is set for a stipulated percent. BS&W monitors automatically check the BS&W content of the oil and recirculate any unacceptable oil back through the system until the BS&W level is at an acceptable percentage. The BS&W factor is listed on the run ticket. The difference between the opening and closing readings is adjusted by the BS&W factor. For example, the BS&W factor, 2/10 percent, equates to .0020 of BS&W in the oil. The meter reading should be multiplied by the inverse .998 to produce adjusted run barrels.

Temperature compensation. Oil volumes are corrected to 60 degrees Fahrenheit to compensate for temperature. Some ACT tickets are already temperature compensated and so noted on the face of the ticket. Others are not temperature compensated and will require you to apply a temperature compensation factor.

Meter security. Most ACT tickets list opening and closing seal numbers on the bottom of the tickets. These seal numbers are individual numbers pressed into each disposable metal piece used to seal the meter. When the seal is broken for meter reading or testing, a new seal with its own seal number is installed. By tracking these numbers, especially if compared to prior and post run ticket seal numbers, you can determine if there has been any unauthorized access to the meter.

18.1.2 Tank measurement or run tickets

In a tank measuring system, oil is gathered through lines to the lease tanks, commonly called the “tank battery.” Each tank in the battery is assigned a tank number and the tank is “strapped.” Tank strapping is a method by which an independent contract company measures the individual tanks and determines the volume capacity for each, listing the volume measurements in 1/4-inch measurements. For example, a strapped tank with the oil level at 3 feet 6 1/4 inches would have an oil volume of 226.27 barrels. Tank volumes differ, and every tank will have its own strapping due to manufacture, construction, and age differences. These strappings or tank tables provide equivalent barrels for feet, inch, and fraction-of-an-inch measurements shown on the run tickets. You must have access to the strappings to correct run ticket measurements.

Tank gauging. Tank gauging is a method of determining the volume released from a tank by measuring the height of the liquid surface before and after the run. The height of a liquid surface is converted to a volume by using tank tables that provide a volume for a given liquid depth. When a run is performed on a tank, an opening reading in feet, inch, and fraction-of-an-inch is recorded. After the run is completed, this process is repeated to determine the residual amount in the tank. The difference between these two readings is the uncorrected gross run barrels. Gross barrels must be adjusted by several factors to determine corrected net run barrels. The two tank gauge readings and correction factors are documented on the run ticket.

Basic sediment and water (BS&W). The BS&W factor is noted on the run ticket. The difference between the opening and closing readings will be adjusted by this BS&W factor. For example, the BS&W factor 2/10 percent equates to .0020 of BS&W in the oil, and the meter reading should be multiplied by the inverse (.998) to produce adjusted run barrels.

Gravity and temperature compensation. Gravity and temperature are sampled and reported on the run ticket. Because standard measurements are made at 40 degrees gravity and 60 degrees Fahrenheit, you need to make compensation calculations to correct measured gross barrels to the proper temperature and gravity. Refer to the Petroleum Measurement Tables, Volume Correction Factors, Volume I, compensation tables 5A and 6A. Instructions on how to use the tables are in the front of the book. Using the methods outlined, you can derive and apply a temperature compensation factor to the meter reading to determine adjusted run barrels.

18.2 Commingled Production

Mixing production from two or more leases before royalty measurement is called commingling. Commingling occurs onshore and offshore generally for economic reasons. Commingling allows tanks and sophisticated sales and royalty measurement units to be placed on one central platform or shore location rather than on each lease. Also, measuring separated condensate under pressure for allocation and reinjecting into the gas pipeline for transportation to shore is more economical than bringing condensate to atmospheric pressure, measuring it, and then putting it into the gas stream.

Commingled volume must be allocated to each commingled lease to determine royalty volume for each lease. To allocate a commingled royalty volume to two or more leases, the production from those leases must be measured individually before commingling to establish an allocation factor. The measurement can be either indirect (well test) or direct (continuous meter).

- During a well test, an individual well flows separately to a test separator. After full-well-stream separation, the oil, water, and gas are metered continuously for 4 to 8 hours. The production rate for each stream component is determined for the test period and considered constant for the period between tests. The product of a tested rate and production time equals the theoretical volume produced by a particular well during a given production period. The sum of the well test volumes for all wells on a lease is the total allocation volume of the lease.

- In a continuous meter test allocation, the total production from the lease is continuously metered to determine the allocation volume of the lease.

The percentage of a commingled royalty volume allocated to a particular lease is equal to the percentage of the total volume that lease represents. For example, royalty volume (VR) = 1,000 barrels.

Lease	Allocation volume	Allocation percent	Allocated volume
1	200	200/800=25%	250
2	200	200/800=25%	250
3	400	400/800=50%	500
	800		1,000

Well tests are used to allocate royalty volume to a commingled lease and to each individual well on the lease.

Because product value is a function of quality as well as volume, the gravity of oil production and the British thermal unit (Btu) value of gas production must be associated with volume. When production is measured without commingling, the quality is simply the quality of the production measured. When commingling occurs, a commingled gravity—the composite gravity of mixed production—is allocated to each lease.

18.3 Field Inspections

Measurement facilities (meters and tanks) are inspected for compliance with requirements set forth as a condition for approval. Inspections are completed by BLM engineering technicians. When a field inspection uncovers a discrepancy between what is required and what actually exists, an Incident of Noncompliance (INC) is issued. This requires the operator to correct the discrepancy within 7 days of the INC report. You should request copies of BLM inspection reports and any INCs for the audit period, and determine if all items of noncompliance have been resolved.

18.4 Offshore Liquid Verification System

The Offshore Minerals Management (OMM), Gulf of Mexico Region, developed a Liquid Verification System (LVS) that calculates meter factors and run ticket net volume. The run ticket net volumes are compared to volumes reported to the Production Accounting and Auditing System (PAAS) for all leases. LVS began in May 1989 with about 10 percent of the royalty measurement points verified. By January 1990, production from 93 percent of the active royalty measurement points was verified. Discrepancies that exceed 1,000 barrels and 5 percent of produced volume are sent to RMP for resolution; therefore, depending on the audit period, you may not need to verify oil run tickets.

18.5 Gas Measurement

For royalty purposes, gas should be measured at the wellhead unless BLM has approved an off-lease measurement site. Gas from more than one lease can be commingled (discussed at section 18.2). The calculation of wellhead volumes from commingled volumes is similar to those used for commingled oil production.

Once the wellhead volume has been determined, the basic gas valuation formulas are as follows:

Volume × Btu × Contract Price = Gross Value

Gross Value × Royalty Rate = Royalty Value

- **Volume**. Volumes are measured in thousand cubic feet (Mcf) and are listed at certain pressure bases. For offshore leases, MMS requires gas to be reported at 15.025, while onshore leases must be reported at 14.73. You may encounter situations in which a volume has not been measured at the correct pressure base. To convert volume to the correct pressure base, use the following formula:

$$\frac{\text{Pressure base you are converting to}}{\text{Pressure base you are converting from}} \times \text{Volume}$$

Example:

$$\frac{\text{14.73 Correct pressure base/onshore leases}}{\text{14.65 incorrect pressure base}} \times \text{Volume}$$

- **Btu**. Btu is the heating value of the gas. Btus are also carried at a pressure base.

- **MMBtu**. An MMBtu (one million Btu) is the product of the volume multiplied by the Btu. Both the volume and the Btu should be at the same pressure base. As the volume pressure base increases, the volume decreases; as the Btu pressure base increases, the Btu numeric value increases. This inverse relationship guarantees that no matter what pressure base volumes and Btus are shown on the purchaser statement, MMBtus will always agree, as in the example below:

Pressure		14.65		14.73		15.025
Mcf		1200		1193		1170
Btu	×	1.012	×	1.018	×	1.038
MMBtu		1214		1214		1214

19. Transportation Allowances

Unless production is sold at the wellhead, lessees are permitted to deduct from royalty payments the reasonable, actual costs incurred for transporting oil, condensate, and gas from the lease or common storage point to the nearest available marketplace or sales outlet. See "Value" on page 15-8 for information on allowances for transporting solid minerals. Most pipelines are producer-owned or third-party-owned. Normal gathering expenses incurred by a producer on the lease, unit, or field in which the production is located are not allowable transportation costs. Transportation costs cannot be deducted when prohibited by lease terms. All transportation costs that reduce royalty value are subject to review, audit, and adjustment.

Before March 1988, MMS regulations required lessees to obtain prior approval from MMS before deducting transportation allowances from royalties due. Revised regulations effective March 1988 changed the requirement to filing an allowance form before deducting an allowance. Allowance regulations were revised again in March 1996 (61 FR 5448, February 12, 1996) to discontinue forms-filing requirements for Federal leases beginning with calendar year 1995. See the "Dear Payor" letter dated March 11, 1996.

NOTE Indian leases remain subject to forms-filing requirements in the 1988 regulations.

19.1 Regulations

The product value regulations, effective March 1988, contain specific regulatory provisions for pipeline transportation costs. The appropriate regulations are:

- Federal and Indian Oil—30 CFR 206.104 (1996)
  30 CFR 206.105 (1996)

- Federal and Indian Gas—30 CFR 206.156 (1996)
  30 CFR 206.157 (1996)

19.2 Allowable Costs

Allowable transportation costs for producer-owned and third-party-owned pipelines are discussed below.

19.2.1 Producer-owned pipelines

Allowable rates per barrel or million cubic feet (MMcf) for moving production through pipelines owned by the producer are calculated using one of the following formulas:

- Depreciation method

  $[E + D + ROI(U)] \div F$

- Return on depreciable capital investment method

  $[E + (IDV^{*} \times ROR)] \div F$

  * This formula applies only to facilities first placed in service after March 1, 1988.

Legends of the formula elements are:

E = Actual transportation costs during the reporting period, including operating, maintenance, and overhead expense.

D = Depreciation for the reporting period. The lessee may elect to use either a straight-line depreciation method based on the life of equipment, on the life of the reserves that the transportation system services, or a unit of production method. Equipment shall not be depreciated below a reasonable salvage value.

ROI(U)= Return on undepreciated capital investment. A cost equal to the undepreciated capital investment in the transportation system multiplied by the rate of return.

IDV = Initial capital investment in the transportation system.

ROR = The rate of return is the monthly average Standard and Poor's BBB bond industrial rate for the company's reporting period. The company's reporting period is found on Forms MMS-4110 and MMS-4295, Oil and Gas Transportation Allowance Reports.

F = Total barrels of liquids or Mcf of gas moved through the pipeline (including production from fee and State lands) in the reporting period.

NOTE

The lessee may elect to use one depreciation method for the allowable rate. The lessee may not change to an alternate depreciation method without approval. In addition, the transportation factor may not exceed 50 percent of the value of the product without approval.

Investment costs. Investment costs are those costs for depreciable real property, equipment (including costs to deliver or install), and other facilities. Investment costs are limited to those items that are an integral part of a pipeline (downstream from the point of measurement on the lease) and should not include lease equipment items. Normal gathering expenses incurred by a lessee or operator on the lease or unit are not allowable. Items generally considered lease equipment are separators, treaters, storage tanks, dehydrators, water knockouts, heaters, meters, automated custody transfer (ACT) units, meter sheds, vapor recovery units, surface and subsurface pumping equipment, and circulating pumps.

Operating costs. Operating costs are those nondepreciable expenditures required to operate and maintain the pipeline system. Allowable operating costs downstream from the point of lease measurement may include but are not limited to expenses for:

- Direct wages paid to employees and supervisors when engaged in maintaining, operating, or repairing the line.
- Capital expenditures for miscellaneous replacement parts associated with pipeline repair and maintenance.
- Chemicals injected in the main line solely for purposes of protecting, cleaning, or inhibiting deposits.
- Electrical or other energy purchase costs necessary to operate pumps, heaters, etc.
- Indirect costs in the following categories are operating costs:
  - Insurance costs such as hazard, liability, workman's compensation, and other insurance.
  - Taxes such as Social Security, property taxes, etc. (Income taxes are not an allowable expense.)
  - Reasonable district and division overhead.

19.2.2 Third-party-owned pipelines

Pipelines owned by third parties may incur transportation costs to move production through pipelines. Transportation costs are limited to the lesser of tariffs established by State or Federal regulatory agencies or the actual charges to the producer for transporting the production. The transportation factor may not exceed 50 percent of the value of the product without approval.

19.3 Audit Procedures

The following procedures are designed to audit pipeline transportation costs used to reduce royalties on oil, condensate, or gas. These are general procedures to be performed and are not all-inclusive. You may eliminate or develop additional audit steps for unusual circumstances.

19.3.1 Obtain background information

Obtain the following documents before beginning your audit:

- For sample months, Forms MMS-2014 or MMS SRHs (Royalty Detail) reports on which transportation costs were deducted.
- Any Royalty Valuation Division (RVD) approval letters for transportation deductions exceeding the 50 percent limit.
- Forms MMS-4110 and MMS-4295 (and schedule 1), Oil and Gas Transportation Allowance Reports, for calendar years before 1995. This allowance information can be found in the Business Information System (BIS).
- Commingling letters identifying the point of royalty determination and any other information about the point of sale. Transportation allowances are generally not allowed after the point of sale.

19.3.2 Producer-owned pipelines

As a general rule, obtain the producer’s actual cost information for transportation related to audit transactions.

For producer-owned pipelines, verify the elements of the formula for calculating pipeline rates discussed previously. Elements in the transportation cost formulas for producer-owned pipelines should be reviewed as follows:

1. Depreciation

    a. Determine the company's method of calculating depreciation. There are two acceptable methods for determining depreciation that the lessee may elect to use.

        (1) Straight line depreciation based on the life of the equipment or the life of the reserves that the transportation system services.

        (2) Unit-of-production depreciation method.

    b. After an election of a depreciation method is made, the lessee may not change methods without MMS approval.

    c. A change in ownership of a transportation system does not alter the depreciation schedule established by the original transporter/lessee for purposes of the unit rate calculation. With or without a change in ownership, a transportation system shall be depreciated only once.

    d. Determine the depreciable life of the pipeline.

    e. Verify that the items being depreciated are directly related to the pipeline.

    f. Verify that plant investment costs do not include nondepreciable items, such as pipeline right-of-way.

    g. Select a sample of investment costs and trace to the company's records and supporting detail (such as invoices) to ensure the costs were actually incurred.

2. Return on investment

    Include the undepreciated capital investment costs.

3. Initial depreciable investment

   Include the initial capital investment in the transportation system when using the alternate formula. This item applies only to facilities first placed in service after March 1, 1988.

4. Rate of return

   The reporting period rate of return is the monthly average industrial rate as published in Standard and Poor's Bond Guide as of the first month. The rate shall be redetermined at the beginning of each subsequent reporting period. The company's reporting period is found on Forms MMS-4110 and MMS-4295, Oil and Gas Transportation Allowance Reports.

5. Annual operating costs

   a. Review direct wages paid to employees and supervisors to ensure the expenses were incurred while engaged in maintaining, operating, or repairing the pipeline.

   b. Review expenditures for miscellaneous replacement parts. Determine if the parts were for repair and maintenance of the pipeline.

   c. Verify that chemicals charged to the pipeline account were injected solely for purposes of protecting, cleaning, or inhibiting deposits in the main pipeline.

   d. Review expenditures for electrical or other energy purchase costs. Determine if these costs were necessary for the operation of pumps, heaters, or other equipment associated with the pipeline. A memorandum dated October 8, 1992, entitled, "Royalty Liability for Production Used on or for the Benefit of a Lease," provides several examples of production used for the benefit of a lease and explains the royalty implications of each.

   e. Review intangible and other direct costs such as insurance and taxes.

   f. Select a sample of operating and maintenance costs and trace to the company's records and supporting details (such as invoices) to ensure that costs were actually incurred.

6. Volumes

   a. Trace the barrels or Mcf transported through the line to the company's supporting records and ensure that any volumes transported from fee and State leases are included. The deduction for transportation costs is determined based on the lessee's cost of transporting each product through each individual transportation system.

   b. Where more than one product in a gaseous phase is transported, the allocation of costs is prorated in the ratio of the volume of each product (excluding waste products that have no value). The lessee may propose a cost allocation method on the basis of values.

7. Recalculate the transportation costs in unit values after making any required adjustments to costs or transported volumes. Compare the recalculated unit values to unit values calculated by the company.

8. Document any differences. Determine the effect any differences have on transportation allowance deductions taken by the company by comparing the recalculated transportation costs to the deductions reported on Forms MMS-2014 or MMS SRH (Royalty Detail) reports for sample months.

19.3.3 Third-party-owned pipelines

Transportation costs incurred transporting a product through third-party-owned pipelines should be reviewed as follows:

1. Obtain a copy of supporting documentation (contract, invoice, or tariff) used by the company to support its transportation costs. Review the tariff document provided by the company for any unallowable costs, that is, gathering, dehydration, and any other costs that should be borne by the lessee.

2. Determine if the company is deducting transportation costs on its invoices. Verify the sales values from the invoice to the reported sales value on the Form MMS-2014. Transportation costs must be reported as a separate line entry on Forms MMS-2014 unless MMS approves a different reporting procedure.

3. Document any irregularities.

20. Processing Allowances

Processing allowances are granted for costs incurred to extract liquids from a natural gas stream and fractionate into products. Allowances may be deducted from the value of gas plant products to determine royalties due. When gas is processed at a plant owned in part by the lessee or its affiliate, the cost of processing is determined from the costs of owning and operating the plant. See “Value” on page 15-8 for information on solid mineral processing allowances.

20.1 Gas Processing Plants

Gas processing plants separate the inlet wet gas stream into residue gas, desirable liquid components, and impurities. The wet gas stream is composed of the following elements—plus impurities such as sulfur, hydrogen sulfide, carbon dioxide, nitrogen, and water—in these approximate percentages:

- Methane 80.0%
- Ethane 7.0%
- Propane 6.0%
- Isobutane 1.5%
- Butane 2.5%
- Pentanes plus 3.0%

Processing consists of two phases: extraction and fractionation. Extraction separates the wet gas stream into residue—the methane gas commonly used to heat homes—and raw make or natural gas liquids (NGLs). Fractionation separates the raw make into liquid products. Both phases may take place in the same or separate facilities.

Gas plants provide a variety of services to bring natural gas production to a marketable state. These can include:

- Gathering.
- Compression.
- Separation from crude and condensate.
- Desulfurization.
- Dehydration.
- Extraction of NGLs.
- NGL fractionation and storage.
- A combination of these services.

Depending upon the type of services provided and the contractual arrangements between the plant and the producers, the plant may derive profits from:

- Sales of NGLs extracted.
- Sales of natural gas liquid products (NGLPs) fractionated.
- Sales of residue natural gas.
- Processing fees charged the producers.
- A combination of the above.

20.1.1 Extraction

The extractor is a plant that extracts liquid constituents in wet gas. In many cases, the wet gas stream receives some manner of treatment before entering the extractor. For example, lease facilities include a separator for removal of condensate and a dehydrator. The dehydrator is required whether or not the gas is processed. When the gas comes out of the ground, it contains a certain amount of water. The water must be removed so that it will not freeze or cause corrosion to the pipeline.

The extractor receives wet gas and runs it through an inlet separator, also known as a scrubber. This inlet separator removes any condensate not removed at the lease. Royalty is due on scrubber condensate.

Regardless of the extraction process used—absorption, adsorption, or refrigeration—all extraction plants have three basic steps in their operation:

1. The inlet or unprocessed gas is passed through a separator to remove the condensate and free water.

NOTE Some portion of the unprocessed gas may "bypass" the plant.

2. The separator gas is sent through the processing equipment where NGLs are removed.

3. The residue gas from the processing operation is sent through a dehydrator where any water is removed. The gas is compressed and delivered to the pipeline purchaser.

Extraction plants yield two basic products, residue gas and NGLs. The NGLs may be sold as a composite NGL stream or they may be fractionated into separate NGLPs.

20.1.2 Fractionation

Fractionation is a process in which individual NGLPs—ethane, propane, isobutane, normal butane, and natural gasoline—are separated from the raw make coming from the extraction plant through changes in temperature and pressure.

Fractionation plants may or may not be a part of the extraction plants. The owners of an extraction plant may pay a fee to have their NGLs fractionated. The fee may be either monetary or a percentage of the fractionated product.

20.2 Products Not in Marketable Condition

When calculating a processing allowance, distinction must be made between operations that are actually required to extract gas plant products and operations required to place lease products in marketable condition to meet contract specifications. To satisfy contract terms, the producer is obligated to condition the gas to meet certain pressure, purity, and water saturation specifications. Costs associated with dehydration, separation, compression, and acid gas removal do not qualify for a processing allowance.

20.3 Net Profit Share Leases

Rather than paying a fixed royalty, the net profit share lease (NPSL) operator pays a fixed percentage of the net profits based on the revenue received from the production and sale of oil and gas less the cost of production. The operator recovers expenses of exploration and development, plus a reasonable return on that investment from production revenues prior to any net profit share payment to MMS.

The operator may include, in the NPSL capital account, allowable costs associated with processing. Therefore, processing allowances should not be claimed as separate deductions on Form MMS-2014. Likewise, no forms are required to be submitted for processing allowances.

20.4 Allowable Processing Costs

A processing allowance may be claimed for the reasonable costs incurred for and directly related to the actual processing of lease production. Processing allowances are limited to 66 2/3 percent of the value of gas plant products determined at the plant. If the lessee incurs processing costs that exceed the limit of 66 2/3 percent, the lessee may request MMS approval for a processing allowance deduction in excess of the limitation.

Regulations for calculating processing allowances are as follows:

- Federal Gas, 30 CFR 206.158 through 206.160 (1996).
- Indian Gas, 30 CFR 206.178 and 206.179 (1996).

20.4.1 Arm's-length costs

For processing costs incurred by the lessee under an arm's-length contract, the processing allowance is the reasonable, actual cost incurred by the lessee for processing the gas under that contract.

20.4.2 Non-arm's-length costs

Processing allowances for non-arm's-length contracts are calculated using one of the following formulas:

Depreciation method		Return on investment method
$P = \frac{B + C + D}{A}$	or	$P = \frac{B + E}{A}$

Where:

P =	Processing allowance.
A =	Total volumes transported through the processing facility from all sources during the reporting period.
B =	Operating, maintenance, and overhead expenses for the reporting period.
C =	Depreciation for the reporting period.

D =	Return on undepreciated capital investment.
E =	Return on initial capital invested in the facility.

Processing allowances for facilities placed into service before March 1, 1988, must be computed using the depreciation method. Allowances for facilities placed into service on or after March 1, 1988, may be computed using either the depreciation method or the return on investment method. Once the lessee has elected to use either method, the lessee may not change to the other method without MMS approval.

Operating and maintenance expenses. Operating costs are the expenses required to operate and maintain the processing facility. These costs include:

- Wages paid to employees engaged in the operation and maintenance of the plant.
- Electrical or other energy expenditures.
- Chemicals and lubricants used for protection or cleaning of plant facilities.
- Repairs, contract labor, materials, and supplies directly related to plant operation.
- Insurance, ad valorem property taxes, and payroll taxes. (Federal and State income taxes, severance taxes, and royalties paid are not allowable deductions.)
- Arm's-length rental, leasing, or contract services for equipment, facilities, and onsite installation or maintenance of equipment and facilities.
- General administrative overhead costs directly attributable and allocable to the operation and maintenance of the plant. The lessee should maintain records to support all overhead costs included in a gas processing allowance.

Capital costs. Allowable capital costs are generally those expenditures for depreciable fixed assets that are an integral part of the facility used in the processing or extraction of gas products. Most capital costs are located within the confines of the plant, beginning at the inlet of the plant and ending at the tailgate of the plant. Transportation facilities owned by the lessee and used to move raw make from an extraction plant to a fractionation plant are an allowable capital plant expenditure. Examples of common allowable investment items are:

- Plant and office buildings, warehouses, shops, and laboratories.
- Sidewalks, fences, plant roads, and rights-of-way for plant roads.
- Heat, steam, power, fuel, sewage, and other general plant facilities; all related controls; and meters including plant inlet and residue gas sales meters.
- Pipe valves and fittings and equipment items whose primary function is the recovery of plant products (such as absorbers, heat exchangers, coolers, chillers, fractionating columns, and liquid sweetening facilities) and compression facilities for refrigeration or recompression of gas required during processing.

The following are **not** allowable capital costs:

- Nondepreciable property such as land and pipeline rights-of-way.
- Facilities used in bringing the raw gas from the field to the plant.
- Facilities used for delivering, storing, or disposing of the residue gas and liquids after extraction.
- Capital costs associated with placing lease production in marketable condition such as compression and dehydration processes.

Depreciation. If the lessee uses the depreciation method, depreciation is computed by either:

1. Straight line depreciation based on the reasonable life of the equipment or the reasonable life of the reserves, or
2. Unit of production method.

After the lessee has elected one method to compute depreciation, the lessee cannot change to the other method without MMS approval. In addition, a change in ownership of the processing facility does not alter the depreciation schedule established by the original lessee. Equipment may not be depreciated below a reasonable salvage value without MMS approval.

Return on investment. The rate of return used in either the depreciation method or the return on investment (ROI) method is the monthly average industrial BBB bond rate published in Standard and Poor's Bond Guide for the first month of the reporting period for which the allowance applies. The rate remains effective during the reporting period and is redetermined at the beginning of each subsequent reporting period.

Under the depreciation method, the rate of return would be used on the undepreciated capital investment at the beginning of the reporting period. The total salvage value would be included when calculating return on investment.

For lessees electing to use the nondepreciating ROI method, the rate of return is multiplied by the allowable initial capital invested in the facility. However, any changes in capitalization not as a result of depreciation (such as replacement or asset retirement) should be reflected.

20.5 Audit Steps

Gas processing allowance audit steps can be found in the RMP Intranet library.

21. Prior Period Adjustments

Payors may often make prior period adjustments to the Report of Sales and Royalty Remittance (Form MMS-2014) to correct previous payments. These adjustments are necessary, for example, to offset overpayments against underpayments, obtain refunds or recoupments for royalty overpayments, or pay additional royalties for long-term, systemic audit findings. You must decide if the adjustments were done correctly.

Offsets occur when payors net or cancel previous overpayments against previous underpayments on the same lease or across lease boundaries if all the individual leases are part of an approved unit agreement.

Recoupments occur whenever payors recover a previous overpayment through a credit against a current or future royalty or other payment or liability under a lease. A recoupment occurs whenever a payor reports a credit adjustment on a Form MMS-2014 or other royalty report form resulting in a net negative dollar value for the transaction and the credit is taken against the royalty or other payment or liability shown in the balance of the report. Payors use transaction code 50 to set up a positive recoupable balance (the difference between the incorrect overpayment and what was due). Transaction code 51 is used to record the actual recoupment in a negative amount.

Refunds occur whenever MMS directs the United States Treasury to issue a check to a payor for an overpayment. In most instances, a Form MMS-2014 is required from a payor adjusting a previous line entry. Refunds have been traditionally limited to the following situations:

- The requesting party is no longer a payor.
- The lease is no longer in the Auditing and Financial System (AFS).
- The period of time necessary to recoup the overpayment would be excessive.

The following information will help you determine the accuracy of offsets, recoupments, and refunds.

21.1 Laws, Regulations, and Other Criteria

The following laws, regulations, and other criteria apply to prior period adjustments:

- Outer Continental Shelf Lands Act (OCSLA), section 10
- (43 U.S.C. 1339 (a), (b))
- 30 CFR 230 (1996)
- 60 FR 20504, April 26, 1995
- 30 CFR 218 (1996)
- 55 FR 3232, January 31, 1990
- *Oil and Gas Payor Handbook, Volume II* (September 1992)
- Memorandum on Policies and Procedures for Modified MMS-2014 Reporting—Revised, August 28, 1995

21.2 Offshore Leases

NOTE Effective September 1, 1996, section 10 of OCSLA was repealed by the Royalty Simplification and Fairness Act (RSFA), section 8(b).

section 10 of the OCSLA (43 U.S.C. 1339) controls the recovery of overpayments for Outer Continental Shelf (OCS) leases through cash refunds or credit adjustments.

- Section 10(a) requires that a request for refund or credit of an excess payment made in connection with any OCS lease be filed within 2 years after the making the payment.

- Section 10(b) requires that:
  - All refunds or credits that the Secretary proposes to approve be reported to the Congress, and
  - The Secretary wait at least 30 days while Congress is in continuous session before making a refund payment or authorizing credit.

21.2.1 Transactions not subject to section 10

OCS transactions that meet the specific criteria below are not subject to section 10 prior-approval requirements:

- Offsets by a single payor within a lease or unit between noncurrent sales months by a single payor, if the underpayment was not created for the purpose of recouping an overpayment. Any net overpayments after offsets are subject to section 10.
- Royalty-in-kind (RIK) excess payments submitted under an RIK contract.
- Offsets resulting from approval or revision of a unit agreement. Any net overpayments after offsets are subject to section 10.
- Adjustments by a single payor between leases within a unit in the same sales month. Any net overpayments after offsets are subject to section 10.
- Payments in excess of the amounts reported on a Form MMS-2014 for OCS leases, if more than one lease is reported.
- Adjustments of estimated balances reported as transaction code 03.
- Adjustment of estimated allowances to actual allowances. Subsequent adjustments of actual allowances are subject to section 10.
- Payments of MMS bills that are the subject of a successful appeal.
- Credit adjustments of less than the de minimus amount for a report month for each lease, filed within 2 years of the overpayment. On

February 23, 1996, the de minimus amount was established at $2,500.

21.2.2 Cross-lease netting under section 10

Under section 10, an underpayment for one lease does not negate an overpayment for another lease for the purposes of submitting section 10 refund requests. Because payors report and pay on hundreds and sometimes thousands of leases, situations arise in which an otherwise correct royalty payment is attributed to the wrong lease. Under certain limited circumstances, payors may correct these reporting errors by cross-lease netting (CLN) without the Congressional reporting requirements of section 10. Only those errors resulting from misreporting of production are eligible. Rentals and minimum royalties do not qualify for CLN. Requests to CLN must meet the following criteria:

- Only one payor is involved.
- The error resulted from reporting an equal volume of production from one lease to one or more leases that should have been reported to one or more different leases. If different valuations result in a net overpayment, the payor must follow the procedures for a section 10 refund request.
- Payors must submit copies of production reports or other documentary evidence of production.
- If any of the leases involved are section 8(g), they must be located off the coast of the same State.

21.2.3 Offsets among different payors for same lease

Payors who report and pay royalty on reallocated production (other than for amendments to unit agreements) may reconcile any resulting differences in royalty payment obligations between themselves. These payors are not required to submit revised royalty reports or requests for refund or credit except when:

- Any payor who paid any amount that remains as a net overpayment after such reconciliation must file a request for refund or credit to recover the excess payment.
- Any payor whose royalty obligation remains underpaid after such reconciliation must report the additional royalties due for the prior sales month on a Form MMS-2014 and pay interest. Interest is due on the underpayment from the last day of the month following the sales month until the date the additional royalties are paid.

All payors involved in such reconciliation must retain all documents. These documents include the reallocation of production, calculation of royalties due, the subsequent reconciliation among the payors involved, and other records on the leases. These documents must be available for review and audit in the same manner as other records on the leases.

A request for refund or credit is required if payors, who report and pay royalties, do not reconcile any differences between themselves to recover the excess payment. Payors must pay additional royalties due plus interest on the unreconciled differences. Interest is due on the underpayment from the last day of the month following the sales month until the date the additional royalties are paid.

21.2.4 Unauthorized credit adjustments

A payor has taken an unauthorized credit adjustment if the adjustment is subject to MMS approval and creates a credit before MMS approves the recoupment.

- The payor must repay the amount recouped plus late payment interest from the date the unauthorized recoupment was taken until the date it is repaid.

- If the payor does not file a request for refund or credit within 2 years of making the excess payment for which the unauthorized credit adjustment was reported, the excess payment cannot be refunded or recouped.

- If the payor files a request for refund or credit within 2 years of making the excess payment for which the unauthorized credit adjustment was reported, MMS may approve the unauthorized credit. Reporting the unauthorized credit adjustment on the Form MMS-2014 alone does not toll the 2-year requirement in section 10(a) of the OCSLA.

- A payor who reports an unauthorized credit adjustment on a Form MMS-2014 will be assessed $500 for each unauthorized credit adjustment.

21.2.5 Tolling the 2-year requirement

The 2-year refund period begins when MMS receives the payment. That period is tolled, or stopped, when:

- MMS receives the payor’s substantially complete request for a refund or credit.

- The payor submits a tolling notice that:

  - Identifies a specific contingency, such as a pending administrative or judicial ruling or any other contingency that may cause payments to become excessive.

  - Provides a list of affected leases and sales months, and estimates of the amounts involved.

- MMS issues a general notice in the Federal Register tolling the 2-year period for a specific class of payments.

- The payor submits an application for unitization. In this case, the 2-year period is stopped only for those payments that may become excessive from the reallocation of production among the leases after the unit or revision is approved.

21.2.6 Subsequent audit of authorized credit

An approved request for refund or credit may be subject to later review or audit. If MMS determines that the refund or recoupment should not have been granted or authorized, the person who requested the refund or credit must repay the amount refunded or recouped plus interest. Interest is due from the date the refund was made or the recoupment taken until the date it is repaid.

21.3 Onshore Leases

Refund and recoupment rules on Federal and Indian onshore leases are different from rules governing offshore leases.

21.3.1 Federal

Prior permission is not required to recoup overpayments on Federal onshore leases. However, the Statute of Limitations for Refunds bars claims against the United States unless asserted within 6 years after the right accrues.

21.3.2 Indian

MMS policy prevents a payor from getting a refund on any Indian lease because a refund could create an undue financial burden on recipients with limited resources.

A payor can, however, recover overpayments through recoupments—subject to specific limits. Credits must be taken against the same lease (except for Tribal leases when the payor has obtained prior written approval from the Tribe). Recoupments cannot exceed:

- 100 percent of the current month’s revenue from an overpaid Tribal lease, and

- 50 percent of the current month's revenue from an overpaid allotted lease.

Recouping overpayments on one allotted lease from royalties paid to another allotted lease is specifically prohibited.

21.4 Rolled-Up or Net Entry Reporting

Payors may need to adjust several years of reported data representing hundreds, sometimes thousands, of Form MMS-2014 lines as a result of audits, Federal Energy Regulatory Commision (FERC) orders, or valuation determinations. In these cases, payors frequently ask to report some type of rolled-up or net entry.

The *MMS Oil and Gas Payor Handbook, Volume II* and the *Solid Minerals Payor Handbook* contain specific instructions on how adjusting entries are to be reported. The handbook instructions require the payor to reverse MMS-2014 data that was originally reported and reenter the corrected data. Net adjustments are usually not allowed because of the possible impact on various downstream exception processing routines such as interest billing, Auditing and Financial System (AFS)/Production Accounting and Auditing System (PAAS) comparison, and majority price comparisons.

On August 28, 1995, the Reports and Payments Division issued an instruction memorandum entitled "Policy and Procedures for Modified Form MMS-2014 Reporting—Revised" that provides general criteria for approving modified reporting and specific instructions for:

- Coordinating approval for rolled-up reporting among all affected divisions.
- Instructing payors on reporting requirements if rolled-up reporting is approved.
- Calculating interest.

The memorandum also included a check list of actions necessary to obtain approval for each rolled-up reporting situation. You must comply with the requirements of this memorandum before telling payors they may use rolled-up reporting on the Form MMS-2014.

22. Contract Settlements

This chapter is about contract settlement laws, regulations, important terms, and audit steps.

22.1 Laws, Regulations, and Other Criteria

Contract settlement proceeds are royalty bearing to the extent that they are attributable to production.

Before Diamond Shamrock Exploration Co. v. Hodel, 853 F.2d 1159 (5th Cir. 1988), royalties were due on all types of advanced payments whether or not the payments were associated with production. After Diamond Shamrock, MMS published a final rule in the Federal Register (53 FR 45082) on November 8, 1988, that changed the definition of gross proceeds by deleting all references to advanced payments; for example, take-or-pay payments. The change was necessary to make the oil and gas valuation regulations at 30 CFR 206 (1996) consistent with the Fifth Circuit Diamond Shamrock ruling.

MMS also issued a Dear Payor letter dated November 8, 1988, to explain the policy on advanced payments, that is:

1. No royalties are assessed on advanced payments.

2. Royalties are due on take-or-pay payments when the gas is produced and taken.

As stated in a Department of the Interior (DOI), Office of Inspector General (OIG) report dated March 31, 1992, (C-IN-MMS-02-91B), MMS had no final policy on the collection of royalties on proceeds received from gas contract settlements. To define contract settlement policy for payors and lessees, MMS sent a Dear Payor letter dated May 3, 1993. This letter explained MMS's experience regarding contract settlement issues and the regulations that authorized the audit and collection of royalties from those proceeds.

22.2 Important Terms

To audit contract settlements successfully, you must understand the following terms.

Element of a settlement (element). Elements of a settlement are those disputed contractual issues or claims that create the need for a contract settlement between a producer and purchaser. Current guidance for audit of contract settlements found in the Dear Payor letter dated May 3, 1993, lists the following elements that you may encounter:

- **Past-pricing dispute**. The purchaser failed to pay the price specified by the original contract at the time production occurred—including reimbursements such as Federal Energy Regulatory Commision (FERC) Order 94 payments that were not remitted to the producer.

- **Take-or-pay dispute**. The purchaser failed to take or to pay for the minimum takes of gas agreed to in the contract.

- **Buydown**. Under an amended or successor contract, the contracting parties agree to reduce the price for future production.

- **Buyout**. The contracting parties agree to reduce or terminate the purchaser's obligation under the original contract to take volumes in the future.

Full economic value (FEV). The FEV of an element is the value of the issue or claim given up by the lessee as a result of a contract settlement. The FEV computations for the elements found in contract settlements are:

- **Past-pricing**

$$(\text{Contract price} - \text{Actual sales price}) \times \text{Sales volume}$$

- **Take-or-pay**

$$(\text{Old contract minimum take volume} - \text{Actual sales volume}) \times \text{Old contract price}$$

- **Buydowns**

  (Old contract price - New contract price) × (Minimum takes under amended contract) × (Number of days left under original contract)

- **Buyouts**

  (Old daily minimum takes - New daily minimum takes) × (Number of days left under original contract) × (Old contract price - market price)

22.3 Audit Steps

Contract settlements audit steps can be found in the RMP Intranet library. Also, the *MMS Contract Settlement Training Manual*, dated August 18, 1994, includes guidelines and examples of contract settlement audits.

23. Late-Payment Charges

MMS must charge interest on underpayments or late payments collected as a result of audit. Interest is also included with royalties due in cases where the auditee requests permission to post a bond or letter of credit pending the outcome of an appeal. Interest compensates lessors for the use of funds lost during the period for which payments were due but not paid.

NOTE Royalty Simplification and Fairness Act (RSFA), section 6, requires MMS to pay interest on overpayments beginning in February 1997.

23.1 Laws, Regulations, and Other Criteria

Legal requirements to charge late-payment interest are defined by various case laws, regulations, and more recently by statute. The Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) required MMS to change the interest rate used for all oil and gas leases from the U.S. Treasury funds rate to the rate established by the Internal Revenue Code. Section 111(a) of the act (30 U.S.C. 1721(a)), states:

> In the case of oil and gas leases where royalty payments are not received by the Secretary on the date that such payments are due, or are less than the amount due, the Secretary shall charge interest on such late payments or under payments at the rate applicable under section 6621 of the Internal Revenue Code of 1954.

Effective January 12, 1983, MMS began using the underpayment rate established by the Internal Revenue Code, 26 U.S.C. 6621(a)(2) (Supp. 1987). See also MMS Directors Decision MMS-84-0028-O&G dated October 4, 1985.

Late-payment charges for solid minerals and geothermal leases are calculated on the basis of a percentage assessment rate. Beginning April 1, 1994, the rate applied is in accordance with the Internal Revenue Code, 26 U.S.C. 6621(a)(2) (compound interest). On all payments due before March 31, 1994, interest is calculated at the Treasury Current Value of Funds Rate through March 31, 1994 (simple interest), plus the IRS rate from April 1, 1994, through the date royalties are paid.

Current regulations for late payments are found at 30 CFR 218, sections 42, 54, 55, 102, 150, 202, and 302 (1996).

23.2 Automated Billing Process

The Compliance Verification Division (CVD) issues automated bills for interest on underpayments.

- For pre-RSFA audit periods, interest is calculated from the date the payment was due until the date a corrected royalty report is received. Interest is billed on FBILs (audit exceptions) as the individual lines on the Form MMS-2014 are cleared in Auditing and Financial System (AFS). For pre-RSFA audit periods, CVD issues an order for payment.
- For post-RSFA audit periods (begining with the January 1997 sales month), interest is calculated from the date the payment was due until the date the payment is received. Interest is billed on GBILs (Federal late payment) after the entire Form MMS-2014 clears in AFS. For post-RSFA audit periods, CVD issues a statement of amount due rather than an order for payment. Auditees must use adjustment reason code (ARC) 40, 41, 42 or 43 for payments of audit findings. Interest on these payments is attributed to audit in a separate section of the GBIL. Auditors should never generate separate interest bills for post-RSFA audit periods because the bills will duplicate interest amounts billed on GBILs.

NOTE Interest on late payments of Indian royalties is not affected by RSFA and will continue to be billed entirely on FBILs.

The automated process includes recording audit findings and collections in the Royalty Audit Tracking System (RATS) and the replacement system, Case Tracking System (CTS). A RATS finding control number

(FCN) is assigned to an issue letter, an order to perform, or an order to pay additional royalties. The FCN is a unique identifier used to track enforcement actions. The issue letter or order states that the auditee must use the FCN on the adjusting green Form MMS-2014. The FCN is used to facilitate the download of results in RATS and CTS.

23.3 Surety Calculations

When an auditee appeals a bill for royalty and posts surety, you must calculate interest due, including a projection for an additional 1-year interest. The amount of the bond or letter of credit is equal to the royalty due plus any accrued interest owed and the projected interest for the 1-year period. Thereafter, the RMP Debt Collection Section monitors and ensures that the bond is increased as necessary to protect the Federal or Indian interest.

Surety is not required for bills under $1,000, nor for contract settlement bills. Projected surety calculation amounts over $1,000,000 are rounded to the nearest $1,000, and amounts under $1,000,000 are rounded to the nearest $100. Sureties are also not required for orders to perform.

Each audit office has a computer program that calculates the amount of interest due and prints out an interest calculation worksheet. When executing the interest program, you must choose between onshore, offshore, or solid mineral lease types. This allows the program to select the correct rates to use for the specific lease type and time period involved. Input the lease number, the production month, and under/over payment information. You must also enter the last month, with the number of days in the last month, instructing the program how far to run the calculation. The program allows edits and will print an optional data sheet for input verification.

The letter sent to the auditee with an interest bill includes instructions for appealing the bill and calculating the amount of the surety. This amount is calculated by multiplying the appealed amount by a factor (for example, 1.0833) and rounding up to the nearest $100.

23.4 Cross-Lease Netting Exception

Under certain conditions, an overpayment on a Federal or Tribal lease may be offset against an underpayment on a different lease to determine a net underpayment on which interest is due. However, cross-lease netting is not allowed on any Indian allotted leases. For specific guidelines on cross-lease netting, refer to 30 CFR 218.42 (1996). Also refer to chapter 21 for more information on offsetting.

24. Document Preparation Guidelines

In the course of an audit, you will issue various documents to the auditee and others. This chapter contains brief descriptions and examples of these documents along with guidelines for content. In many instances, you will use standardized language for consistency between audit offices.

24.1 Issue Letter

An issue letter is one method of ensuring that preliminary audit findings are accurate, objective, and complete. You send an issue letter to the auditee to communicate preliminary audit findings and obtain advance comments about the findings. An issue letter assists in obtaining the auditee's agreement on findings and in acquiring additional data that might affect the initial findings.

NOTE In some cases, informal discussions with the auditee can eliminate the need for an issue letter if the auditee agrees to voluntarily pay the potential findings.

You should present an issue letter to the auditee as soon as possible after the field work is completed and the potential findings are developed. The issue letter includes:

- A statement of audit purpose and scope,
- A discussion of the condition, criteria, cause, and effect for each finding, and
- A statement that the audit was conducted using generally accepted Government auditing standards (GAGAS).

The auditee is allowed 30 days to respond in writing with information and data supporting his/her position.

You must take all reasonable steps to ensure that your preliminary findings are sound and consistent with appropriate laws, regulations, and policies. Full discussion, when possible, with the auditee during and at the completion of the field work aids in clarifying findings.

24.2 Enforcement Documents

When an auditee's response to an issue letter does not resolve a discrepancy, you may issue an order to pay or perform. An order to pay or perform contains all the elements of an issue letter, including a discussion of condition, criteria, cause, and effect as well as a statement that the audit was conducted in accordance with GAGAS. An order also contains notice of the right to appeal, notice of possible civil penalties, and advice that late payment charges will be assessed if additional royalties are paid as a result of the audit. Failure to comply with an order to pay or perform subjects the auditee to civil penalties.

24.2.1 Order to pay

An order to pay directs payment of a certain sum based on your audit findings. You prepare an order for payment to the auditee with a bill for collection form for processing by the RMP Billing Section. Both the order and the bill are mailed by the RMP Billing Section.

24.2.2 Order to perform

An order to perform directs the auditee to perform a restructured accounting for a specified period for a lease or group of leases. After completing the restructured accounting, the auditee computes and pays additional royalties. You send an order to perform when the auditee continues an erroneous practice over a substantial period of time or when the erroneous practice involves a large number of leases. To achieve desired results, the order should clearly state the method of restructured accounting and a reasonable deadline for completion of the required tasks.

Restructured accounting is provided for by the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) section 107(a), 30 U.S.C. 1317 (a). This section provides, in part, that in connection with an audit, the Secretary may require in writing such answers to questions as the Secretary may reasonably prescribe. A memorandum dated May 20, 1993, from the Associate Director for Royalty Management contains the revised policy regarding orders to perform restructured accounting. A memorandum dated December 22, 1993, from the Deputy Associate director for Audit includes a quality control checklist for orders to perform restructured accounting.

When MMS orders a lessee to perform restructured or revised accounting, the MMS audit has already demonstrated noncompliance with the lease terms, related laws, and regulations that resulted in the lessee paying less royalty than required. Because the order directs actions to correct royalties for demonstrated deficiencies, it is a requirement for the lessee to comply with its obligations to properly determine and pay royalty. Specific corrections required by such orders are a part of the remedy. See Phillips Petroleum Co. v. Lujan, 957 F. 2d 257 (10th Cir. 1991); Phillips Petroleum Co. v. Lujan, 963 F. 2d 1380, 1386 (10th Cir. 1992); Amoco Production Co. 123 IBLA 278, 285 (1992).

NOTE

Effective for the production month beginning September 1, 1996, Royalty Simplification and Fairness Act (RSFA), section 4(d), requires MMS to demonstrate that reporting errors are repeated and systemic for a significant number of leases or for a single lease for a significant number of reporting months, constituting a pattern of violations that are likely to result in either significant underpayments or overpayments, before issuing an order to perform a restructured accounting. Orders to perform must be issued by the Associate Director for Royalty Management, and the responsibility cannot be delegated to a lower level.

After the auditee complies with the order to perform, you must test sample computations to determine the accuracy of any additional royalty payments. If performance is inadequate, you may issue additional issue letters, orders, or notices of noncompliance.

24.3 Other Documents

A variety of other documents may be required during the course of an audit. Examples include audit summary letters and conclusion of field work letters. These documents may be prepared depending on the circumstances encountered during the audit and at the discretion of the division chief. The following guidance relates to all correspondence, including audit reports, issue letters, orders, and papers supporting MMS positions in appeals and litigation. The objective of all reports is to communicate to appropriate parties sufficient information to summarize the audit.

Mission accomplishment and the audit office's image is measured by the quality of enforcement documents. Prepare professional enforcement documents by anticipating content, organization, and appearance. The following guidance relates to all documents, including issue letters, orders to pay or perform, and appeal field reports. The objective of the enforcement documents and the appeal field reports is to communicate sufficient information on the findings issue.

24.3.1 Writing guidelines

Quality documents include use of:

- Simple, clear, and concise language;
- Active voice, "Plain English" conversational style;
- Correct format, content, spelling, grammar, typing, and reproduction;
- *Gregg Reference Manual (Seventh Edition)* style; and
- Correctly spelled words and legible copy.

Simplicity. Use short paragraphs, sentences, and words. Use brief headings and captions that convey a message. Avoid qualifying words such as “although,” “while,” “since,” “based on,” and “in addition” at the beginning of a sentence.

Clarity. Documents should be clear and easily understandable. Present facts in a logical sequence.

- Use specific words. Avoid nonspecific words such as “many,” “some,” “several,” “few,” and “most.”
- Place modifiers close to the words they modify.
- Use parallelism, the use of like form to express like ideas.
- The sentence predicate must agree with the sentence subject in number.
- Verb tenses should be consistent throughout the document.

Conciseness. Make every word count by eliminating repetitive or unnecessary verbiage. Limit documents to the minimum information necessary.

Indirect references. Avoid words such as “this,” “it,” “they,” and other indirect references. These words refer to people, items, or ideas in a previous sentence. Weak sentences are introduced with phrases like “it is” or “there are.”

Transitions and fragments. Transitions such as “because,” “even though,” and “since” establish causality between events and help prevent fragmented sentences. The word “and” should not be used as a transition. Don’t assume the reader will discover the causality in simple sentences.

24.3.2 Organizing documents

Some useful suggestions for organizing documents follow:

- Form the basic outline of enforcement documents by writing the findings as soon as they are developed.

- Identify elements or parts of the enforcement document, such as each finding, criteria, cause, effect, heading, subheading, conclusion, recommendation, example of weakness or condition, etc.

- Make draft notes, in outline form, of phrases, sentences, references, and all information pertinent to each finding. These notes will help sort out and identify the elements, major points, and subpoints of the document. Using an outline helps you prepare a more logical, effective presentation.

- After identifying and drafting each heading, subheading, etc., determine the main point of the findings. You cannot write a clearly focused document without conclusions in mind. More information, re-evaluation, and analysis may be necessary if the opening paragraph cannot be easily summarized from existing material.

- Review the completed draft twice. The purpose of the first review is to become familiar with the document. The second should be a delayed review to permit an objective analysis of the complete document.

- Edit, change, simplify, or rewrite the document as necessary. Rewrite any document or section that does not comply with standards or isn't sound and convincing.

24.3.3 Contents

Enforcement documents contain some or all of the following parts, which should be in the order shown here.

Introduction. The introduction provides the reader with important facts about the auditee and the nature of the review. This part of the enforcement document provides information that is essential for understanding the auditee and judging the significance of the audit results. Introductory material should be relatively short and avoid unnecessary detail that is more appropriately discussed in other parts of the document.

Objective and scope. The objective and scope provide the reader with details concerning what was audited, why the audit was done, audit standards, the period of the audit, prior audit coverage, and where the audit work was done, including comments on any multi-location audit relationships.

The time to consider the purpose and approach of an enforcement document is when planning the audit. An initial statement of the intended scope of work should be prepared during the planning stages of an assignment. This section of the document should also explain why the audit was conducted; for example, major payor, random audit, Bureau of Indian Affairs (BIA) or Bureau of Land Management (BLM) referral, etc.

- **Objective**. State the audit objective in clear and concise terms that emphasize the overall purpose of the audit. Include any special circumstances that precipitated the audit. Most audits encompass determination of compliance with laws and regulations. For example, pertinent laws, regulations, procedures, or other such criteria are identified in each finding. However, when a major objective of the audit is to determine compliance, it should be identified as one of the purposes of the audit.

- **Scope**. The audit scope should include the following:

  – **Reporting/revenue entity**. The reporting entity, typically the company/subsidiary name, is generally responsible for both the preparation of the items under examination and royalty payments. The entity information should establish reporting and payment responsibility for findings, identify affiliated entities, and help identify the scope of the examination.

  – **Segments examined**. The specific segments examined—for example, the ten largest leases, the ABC unitized field, or the XYZ gas plant—define the royalty-generating activities subject to audit. There are several methods for summarizing these segments. Describe the sample selection method, such as all leases with production greater than 100 barrels per day. In some instances, you may simply state that the examination covered all Federal and Indian leases for which the entity reports and pays.

  – **Period covered**. The period covered further explains the scope of examination. Typically, a statement of time period is sufficient, such as all production for calendar year 19XX. If different time periods were examined for different segments, a table may best satisfy this requirement.

- **Specific elements of royalty obligation**. The specific elements of royalty obligation provide the final level of detail necessary to focus on the examination coverage. These elements include gross production volumes, volume reduction, product values, allowances, royalty rates, and computational accuracy.

  In stating that the examination covers all elements of royalty determination, you must address the elements in the audit.

- **Participation by other auditors**. Participation by auditors from outside organizations, such as State or Tribal auditors, must be identified to help establish responsibility for results. Those auditors should be identified and the nature of their participation carefully described. If no comment is made with respect to participation, it is presumed that either none occurred or that your office is taking full responsibility for the enforcement document.

- **Auditing standards**. A statement of compliance with relevant auditing standards indicates the quality of the examination. Not all standards are relevant to each audit. Suggested language for a statement of compliance with the auditing standards follows:

  > The audit work was performed as applicable, in accordance with the "Standards for Audit of Governmental Organizations, Program, Activities, and Functions" (1994 Revision), issued by the Comptroller General of the United States. Accordingly, we included such tests of records and other auditing procedures that were considered necessary under the circumstances. These results are incorporated in the audit findings and conclusions section of this letter.

- **Scope limitations**. Scope limitations may be imposed by either the auditee or external circumstances. Auditee-imposed limitations must be vigorously pursued through all legal channels; consequently, those that survive and require reporting considerations should be rare. Any scope limitation should be described as to nature, reason, and potential impact in a separate paragraph. lf no scope limitation has occurred, the enforcement document should make no comment. If the issue is not addressed, it is presumed not to exist.

Summary of findings and conclusions. The findings and conclusions section summarizes each finding, including situation, causative factors, and adverse effects. A well-developed finding, regardless of subject matter, has certain characteristics and parts. The attributes of the findings include:

- **Condition**. Conditions identify the nature and extent of the finding. Results of the audit should be incorporated to support the existence of a significant problem.

- **Criteria**. Criteria are the standards, rules, or tests measuring the questionable condition or performance. Some criteria examples are:

  - Written requirements such as laws, regulations, lease terms, instructions, manuals, and directives.

  - Independent opinions of experts within or outside the Department.

- **Cause**. Cause is the underlying action, lack of action, weakness, deficiency, or inadequacy that resulted in the problem.

- **Effect**. The effect is what resulted from the condition being questioned, in dollars or other terms.

Open issues. The open issues section covers unresolved topics. Generally, these items are longstanding, controversial issues or complex issues needing further analysis. Examples of these include but are not limited to the following: contract settlements, major portion, dual accounting, and comparable pricing.

Clearly identify open issue items and the dates related to these items. Advise the auditee to retain all records related to these items. Closure statements are not required because RSFA dictates a 7-year closure to further collections if not initiated timely.

Exhibits. Schedules, tables, charts, graphs, etc., that explain or supplement other parts of the enforcement document should be presented as exhibits. Assign each exhibit a number and an identifying title.

25. Referencing

Referencing is the final review of a draft document to verify the accuracy of reported facts and to ensure that findings, conclusions, and recommendations are properly supported. Referencing must be conducted on audit products to maintain professional auditing and reporting standards.

All orders to pay, orders to perform, and field reports are referenced. Orders for late-payment charges and issue letters are referenced at the discretion of the division chief or designee. Referencing is performed by an experienced auditor who did not directly participate in the audit or prepare the document.

Referencing is accomplished by checking the document content—including all attachments such as the Request for Billing Action, schedules, and other information:

- Working paper files,
- Laws and decisions, and
- Cross-referenced documents and similar sources.

Referencing also includes verifying data by comparison and professional judgement.

The document to be referenced will include a list of attachments cross-referenced to an appropriate source. At the discretion of the division chief, an attachment prepared by other organizations—such as laws, regulations, letters, and memoranda—will not require referencing.

25.1 Referencing Principles

Referencing requires an understanding of audit objectives, the use of sound judgment, and the diligent application of proper procedures. Referencing is not governed by rigid rules and regulations; however, some basic referencing principles are outlined below.

1. Each document subject to referencing should be referenced before release, including any substantive changes made after the original referencing.

2. Before submitting a document for referencing, the team supervisor should ensure that the work papers are in order. The draft document should be accurate, complete, and properly cross-referenced to the work papers. A document submitted for referencing should be typed in double-spaced format with “DRAFT” stamped on the first page.

3. Until supervisory review of the work papers is complete, the referencer has no basis for accepting the contents of the work papers.

4. The referencer must be provided all cross-referenced work papers. The team supervisor should be accessible for explanations and provide assistance in locating any additional materials.

5. Oral explanations are useful, but the referencer cannot accept them as a substitute for adequate documentation in the work papers.

6. The referencer should not accept secondary sources of support when primary sources are available. For example, when a law is quoted or paraphrased in a report, the primary source for referencing is the law itself. Lease, audit, or file summaries are not acceptable sources; the underlying work papers should be cited as the source.

7. Figures or factual statements from prior referenced documents are considered adequate primary support and need not be referenced again. However, the referencer should compare the statement or figures with the citation.

8. The referencer should record all issues (points) found during referencing on a Reference Sheet and record the corresponding point numbers on the copy of the document being referenced.

9. Only the division chief is authorized to direct the referencer to drop a point.

10. The acceptance, modification, or rejection of the referencer’s points should be indicated on the Reference Sheet. If the work papers are changed as a result of the referencer’s points, the team supervisor must verify the changes.

11. The team supervisor, auditor, and referencer have an obligation to work together to resolve all differences. The division chief will act on any unresolved points at the conclusion of the referencing process.

12. The Reference Sheet and referenced copy of the document become part of the permanent audit file. The referencer's work should be selectively reviewed by the supervisor and used to evaluate the referencer's performance.

25.2 Selecting the Referencer

Because of the legal importance of the documents being referenced and their impact on the reputation of RMP, referencing should be performed by experienced auditors.

Rotating referencing assignments among qualified auditors broadens knowledge and sharpens abilities to write and analyze audit products.

25.3 Referencer Responsibilities

The referencer represents and is directly responsible to the division chief. Specifically, the referencer is responsible for determining that:

1. The document is well-written and conveys the intended message.

2. Every figure, statement of fact, and proper noun is correctly reported.

3. Findings, conclusions, and recommendations are adequately supported by work papers or other valid sources.

The referencing process is not a substitute for supervisory review, and the referencer will not be asked to make such a review.

25.4 Referencing Procedures

These referencing procedures are guidelines and should not be construed as all-inclusive. These guidelines should be modified to meet each changing situation. The procedures are:

1. Read the document thoroughly to become familiar with its content and ensure that it is understandable.

2. Verify that all facts reported are supported in the work papers cited.

   a. Verify that citations to laws (including State, Tribal, and U.S. Codes), regulations, manuals, bulletins, and other authorizing documents and instructions are correct and appropriately related to the matters described.

   b. Determine whether the accuracy of all calculations, percentages, totals, cross-footings, and other mathematical computations in schedules, tabulations, and exhibits, as well as those in the work papers that affect the figures, were independently verified.

      (1) Independent verification may be waived for all computer-generated calculations and resulting data. However, logic or mathematical formulas used in computer calculations should be reasonably verified.

      (2) Lead schedules of work papers may be accepted as a reference source if they have been cross-indexed to the source documents.

      The referencer should not have to make calculations to verify figures in the document. For example, if two figures are added together and the total entered in the document, the addition should be shown in the work papers.

   c. Verify that dates are correct and that amounts and other items referred to more than once in the document are consistent.

   d. Verify that all other reported statements of fact are adequately supported in the cited work papers.

   e. Review all insertions on the typed draft to assure that these changes have been referenced.

3. Make a note in the “comments” column on the Reference Sheet if a reported fact is not found in the cited working paper and proceed with the next item. Do not spend time searching through the work papers.

4. Determine whether opinions and conclusions stated in the body and summary of the document are reasonable and consistent with the facts.

5. Determine whether recommendations logically follow from the facts and conclusions. Use professional judgement to determine whether the recommendations:

   a. Are feasible and reasonably attainable,

   b. Will correct the deficiencies if properly carried out, and

   c. Are addressed to the appropriate level for corrective action and implementation.

   Although the referencer may lack first-hand knowledge of the audited operations, any opinion, conclusion, or recommendation believed to be unreasonable or inconsistent with the facts should be questioned.

6. The referencer will not make any changes or corrections to the document. If for any reason a second referencer is assigned, he/she should use a different colored pencil.

   Place tick-marks on the document with a colored pencil to indicate verification and satisfaction with the supporting material. For example, place a tick-mark over each figure, date, citation to legal or other reference material, and proper name. For the remaining narrative material, place a tick- mark in the left margin opposite each line or statement. Place tick-marks only on the document.

7. Compare all figures, titles, abbreviations, etc., within the document for consistency of presentation.

8. Watch for instances where:

   a. Reporting policies have not been followed,

   b. The document is not grammatically correct, or

c. RMP style and usage have not been followed.

The referencer should be concerned with grammar and choice of words to prevent any grammatical misunderstandings with the customer.

After the referencer has completed these steps, the team supervisor or auditor indicates resolution of the referenced points by commenting and initialing in the “disposition” column of the Reference Sheet. The referencer indicates acceptance of the resolution by writing “OK” and initialing and dating in red. When all referencing notes are cleared, the referencer should write after the last note, “All referencing notes cleared,” then sign and date the sheet below the statement.

Every effort should be made by the team or area supervisor to clear all reference points with the referencer. If agreement cannot be reached, submit the unresolved points to the division chief for final disposition.

25.5 Retention of Referencer Comments

Place referenced documents and Reference Sheets in the audit file as permanent work papers upon completion of the referencing process.

26. Enforcement Procedures

MMS has several enforcement tools to ensure prompt and proper collection of revenues due from Federal, Indian, and Outer Continental Shelf (OCS) leases. These tools include notices, penalties, settlement negotiations, and lease cancellations.

26.1 Laws, Regulations, and Other Criteria

The Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) requires MMS to enforce reporting and payment practices to ensure proper mineral revenue collection. The following authorities are the basis of MMS enforcement practices and procedures.

- FOGRMA, Section 109 (30 U.S.C. 1701) provides the general framework for MMS civil penalties.
- 30 CFR 241 (1996) implemented the civil penalty provisions of FOGRMA.
- Administrative Dispute Resolution (ADR) Act of 1990 (5 U.S.C. 572) established requirements for Federal agencies to practice ADR.
- Federal Register Notice 59 F.R. 30368 (June 13, 1994) implemented provisions of the ADR Act in the Department of the Interior (DOI).
- A “Dear Payor” letter, dated February 9, 1995, entitled Notice of Opportunity to Use Alternative Dispute Resolution, established MMS policies and procedures on ADR.

26.2 Notice of Noncompliance

MMS must issue a Notice of Noncompliance concurrent with penalty notices for intentional violations but before assessing civil penalties for nonintentional violations.

26.2.1 Nonintentional violations

Issuance of Notice of Noncompliance. Except for those divisions delegated authority to issue routine, nonintentional Notices of Noncompliance, all RMP units must submit a request to issue a notice to the Office of Enforcement (OE). The requesting office must provide a draft notice and complete documentation supporting the violation.

OE reviews the request and issues the notice signed by the Chief, OE within 15 days of receipt of the request. The notice allows the addressee 20 days from the date of receipt to correct the violation without a civil penalty liability. The notice alerts the addressee of the potential for a penalty up to $500 per violation per day for the first 40 days the violation continues, beginning on the day the notice is received. If the violation is not corrected within 40 days, the penalty increases to $5,000 per violation per day.

If the payor or operator is not the lessee of record, a copy of the notice is usually provided to the lessee depending on the administrative burden required to identify all lessees in a timely manner. The notice advises the lessee that the potential civil penalty applies only to the party to whom the original of the notice is addressed and not to other parties to whom copies are sent for informational purposes. Also, the notice informs the lessee that he/she is responsible for all obligations under the lease including payment obligations that, if not paid, are subject to collection under the lease surety or directly from the lessee through collection action.

If the addressee corrects the violation within 20 days of the date of receipt, no penalties are assessed, and the addressee is not entitled to a hearing on the record. It is the responsibility of the office issuing the original order letter to advise OE if the violation is corrected.

Examples of nonintentional violations. Examples of nonintentional violations for which a notice is appropriate are described below.

- **Failure to provide records**. Failure to provide records required by law, rule, regulation, or lease terms.

NOTE

A subpoena is usually served for records needed in an audit before issuing a notice. Subpoenas are enforced by Federal District Court.

- **Failure to pay**. Failure to timely submit payment of an amount specified in a report or on a Bill for Collection issued by MMS if the payment has not been suspended by MMS, Interior Board of Land Appeals (IBLA), or judicial administrative actions. The timely payment requirement applies to payments made to RMP, Tribal lockboxes, or others in accordance with demands, instructions, or invoice designations. A notice for nonintentional failure to pay may be limited to amounts of $5,000 or more. Delinquent amounts under $5,000 on either a Federal or Indian lease may also be collected directly against the lease surety.

- **Failure to post a surety**. Failure to submit or update an acceptable surety, for amounts over $1,000, in lieu of payment of an appealed bill for collection or an order for payment issued by RMP.

- **Failure to perform**. Failure to comply with an RMP order including orders to submit information collection forms; to provide information necessary to verify prompt and proper payment of oil and gas revenues and to timely disburse such payments; to perform restructured accounting or other actions required by audit offices; and to report and pay underpayment exceptions identified in Auditing and Financial System (AFS)/Production Accounting and Auditing System (PAAS) comparison routines.

- **Failure to comply with regulations or lease terms**. Failure to comply with clear directives in statutes, regulations, and lease terms.

Hearing on the record/appeals. If the violation is not corrected, the payor or operator served with the notice has 20 days from the date of receipt of the notice to file a written request for a hearing with the Hearings Division of the Office of Hearings and Appeals. A hearing does not suspend the requirement to comply with the notice or stop the daily accumulation of penalties. If the violation is corrected, the payor or operator is entitled to file an administrative appeal within 30 days of the date of receipt of the notice.

26.2.2 Intentional violations

Issuance of Notice of Noncompliance. A Notice of Noncompliance for intentional violation may be issued to a party who demonstrates knowing or willful disregard of reporting and paying requirements. Any person served with a notice for intentional violation is liable for a penalty up to $10,000 per violation for each day the violation continues, beginning with the day the violation occurred. A notice for intentional violation imposes civil penalties without giving an opportunity to correct the violation and avoid penalties.

Examples of intentional violations. Intentional violations include:

- Knowing or willful failure to make royalty payments by the date specified in statutes, regulations, final orders, or lease terms;
- Knowing or willful failure to permit lawful entry, inspection, or audit;
- Knowing or willful preparation, maintenance, or submission of false, inaccurate, or misleading reports, notices, affidavits, records, data, or other written information;
- Knowing or willful taking, transporting, use, or diversion of oil or gas from a lease site without valid, legal authority to do so; and
- Purchasing, accepting, selling, transporting, or conveying any oil or gas to another party, knowing or having reason to know that such oil or gas was stolen or unlawfully removed or diverted.

A knowing or willful act may be proved by procuring admissions by the party or by other facts, such as repetitive conduct and tending to show knowledge or willfulness.

Hearings on record/appeals. Regulations do not provide for an appeal of a notice for an intentional violation. However, the payor or operator served a notice for intentional violation has 20 days from the date served to file a written request for a hearing with the Hearings Division of the Office of Hearings and Appeals. Adverse decisions by the Office of Hearings and Appeals may be appealed to the IBLA.

26.2.3 Delegation of routine cases to division

Operating divisions have been delegated authority to issue Notices of Noncompliance when the violation is considered routine and nonintentional. Cases involving intentional violations have not been delegated to divisions.

The following violations are considered routine, and the authority for issuing a notice is delegated as shown below.

Type	Responsible organization
Failure to pay	Reports and Financial Division (RFD) and Compliance Verification Division (CVD) (for AFS/PAAS exception resolution orders to perform)
Failure to post or update a surety pending appeal of amount due	RFD
Failure to perform	CVD
Failure to report	RFD, CVD, and Data Management Division (DMD)

26.3 Civil Penalties

A civil penalty is the last administrative phase of the RMP enforcement process to ensure compliance with applicable laws, rules, regulations, and lease terms other than implementing a lease shut-in or cancellation. The Secretary of the Interior is authorized to issue civil penalty assessments for oil and gas leases in two broad circumstances:

- Those nonintentional situations in which any person is provided notice of a violation, given an opportunity to correct the violation, and fails to correct the violation within the time allowed by the notice.

- Those intentional situations in which any person knowingly or willfully commits certain violations.

Actions that may lead to the assessment of a civil penalty must be taken by the designated RMP office at the appropriate time. No office should allow a lessee, operator, or payor to fail to properly respond to an order or directive without taking proper actions. Possible exceptions are responses to Bills for Collection where the responsible person may wait until a follow-up letter has also been ignored before beginning the civil penalty process.

If a party who has been issued an order or demand timely files an administrative appeal, compliance with that order or demand is stayed pending the conclusion of the administrative appeal. However, if a party fails to post surety after receiving written authorization from MMS to suspend payment because of an appeal, further enforcement actions may be taken for the failure to post surety. In addition, judicial review of the order is often, but not always, accompanied by a stay. Further enforcement actions may not be taken without concurrence of the RMP Bankruptcy Coordinator when the person to whom the order or demand was issued files for bankruptcy.

26.3.1 Penalty notice

OE issues Notices of Civil Penalty to parties who do not correct violations within the 20-day time period allowed in the Notice of Noncompliance. OE prepares the penalty notice after verifying that a hearing was not requested by the payor, operator, lessee, or other party within 20 days after receipt of the notice. The penalty notice advises that the civil penalty liability applies only to the party to whom the original penalty notice was issued and not to other parties to whom copies are sent for informational purposes.

26.3.2 Order assessing civil penalty

The Chief, OE issues an Order Assessing Civil Penalty, based on the Notice of Civil Penalty, against the payor, operator, lessee, or other party subject to penalties, who does not request a hearing on the record within the 20-day time period allowed in the notice. Because no hearing on the record was requested, the order is not subject to further administrative appeal.

The order advises the lessee that the civil penalty liability applies only to the party to whom the original of the order is addressed and not to other parties to whom copies are sent for informational purposes.

- **Processing of the order**. OE prepares the order after the Notice of Civil Penalty has been issued, the violation has been corrected, and the total amount of civil penalties can be established.

- **Payment of civil penalty**. The penalty assessment must be paid within 30 days of issuance and is a final order subject to collection. If a payor, operator, lessee, or other party fails to pay a civil penalty assessment, MMS may, as appropriate, make a demand for payment of the accrued civil penalties against the lease surety or submit a petition to the Department of Justice for collection of the outstanding balance in accordance with 30 U.S.C. 1719(k) and 30 CFR 241.51(j).

26.3.3 Demand against lease surety

Notices for routine failure to pay or failure to post a surety violations are delegated to the RMP Debt Collection Section (DCS). In addition to issuing the notice, DCS makes demands against the lease surety for the amount owed on a Bill for Collection up to the amount of the surety. For onshore Federal or Indian leases, DCS issues a demand memorandum for payment of the balance due on a Bill for Collection from the lease surety posted by the lessee of record at the Bureau of Land Management (BLM), Bureau of Indian Affairs (BIA), or Offshore Minerals Management (OMM).

26.3.4 Compromise of civil penalty

The Associate Director for Royalty Management (AD/RM), as the Secretary's authorized representative, may compromise or reduce civil penalties on a case-by-case basis. The amount of any final civil penalty may be deducted from sums owed by the United States to the payor, operator, lessee, or other party subject to the penalty.

26.3.5 Failure to pay civil penalty

If a payor, operator, lessee, or other party fails to pay a civil penalty assessment based on a final order issued by the Chief, OE or the AD/RM, MMS may make a demand to BLM or BIA for payment of the accrued civil penalties against the lease surety—provided the party to whom the penalty was assessed has a surety posted—and request that the Department of Justice file an appropriate judicial claim for collection of the outstanding balance.

26.4 Settlement Negotiation Procedures

Auditees may express interest in settling disputed bills and orders issued by audit and other RMP units. Procedures for entering into settlement negotiations and involving affected States and Tribes in the settlement negotiation process follow.

26.4.1 Contacts and procedures

If you are contacted about the possibility of settling any disputed issues, you should advise the company representative to put the company's proposal in writing and send it to:

Chief, Office of Enforcement
Minerals Management Service
P.O. Box 25165, MS 3030
Denver, CO 80225-0165

The Chief, OE informs the AD/RM, the Associate Director for Policy Management Improvement (AD/PMI) and the Director, when appropriate. The AD/RM, the AD/PMI, and the Director determine whether a negotiation team should be formed. The Director, in consultation with the ADs, names the lead negotiator and other DOI members of the negotiating team—including representatives from the Office of the Solicitor—and arrange for pre-planning and strategy meetings.

The Chief, OE provides States and Tribes copies of settlement proposals received by MMS that affect the leases within their areas before any substantive meetings or discussions take place and before MMS exchanges any information with the lessee. For proposals that affect States or Tribes, MMS requests State and/or Tribal representation for the team.

26.4.2 Federal onshore and offshore leases

Upon notification of a proposed settlement, State representatives from any affected State have the option to attend scheduled meetings with MMS to discuss the settlement. A State's decision to decline to attend the meetings does not mean that the State will not be informed of the progress of the negotiations.

- OE informs each State representative in advance of the purpose and scope of each meeting.
- Those choosing to attend the meetings must come prepared with information necessary to participate in pre-settlement planning meetings when strategy and process are discussed. Each representative may select technical or professional assistants to accompany him/her to the meeting.
- A State may designate an agent as its representative, subject to confidentiality and other requirements of FOGRMA. The agent must inform all States who designated that agent about the results of the meeting.
- OE keeps affected States informed about the progress of the settlement process as it affects that State's revenues, and solicits the State's views on the settlement.

For settlements involving only one State, the State should name a representative who has authority to represent its interest in negotiations. That representative may be assisted by technical or professional staff.

For negotiations involving leases in more than one State, the affected States usually agree on one individual to represent all of their interests. More delegates may be appropriate if issues are complex and numerous.

The Federal lead negotiator is the lead negotiator for the team. Participation of all other members of the team, including the State representative, is through the lead negotiator. The specific role of each member of the team is discussed and decided in the pre-settlement planning meetings.

- State representatives make their views known in strategy meetings, hear what the MMS strategy will be, and seek to achieve agreements on disputed common concerns.
- When negotiations begin, State representatives—like all team members—listen to arguments and offers, participate in discussions, and seek resolution.
- Negotiations involve privileged information that may not be shared with persons not directly within the scope of the privilege. See 30 U.S.C. 1733 and 18 U.S.C. 1905.

Before the lead negotiator gets necessary approvals from the Director for the tentative agreement, State representatives are given adequate opportunity to brief affected State officials. OE works diligently to keep any affected State that does not have State representation informed about the progress of the settlement to ensure timely information to the negotiating team.

26.4.3 Tribal leases

For negotiations involving Tribal leases in which the Tribe is the lessor, each Tribe has the responsibility and authority to participate in or organize settlement negotiations. Because the DOI is the trustee for Tribes and allottees, it also has the responsibility and authority to participate in settlement negotiations.

- The Assistant Secretary for Indian Affairs is delegated responsibility to concur with all settlements affecting Tribal or allotted leases.
- MMS is delegated responsibility to oversee the royalty collection, valuation, and verification process; and in that role, MMS officers and employees participate in negotiations involving Indian leases.

Each Tribe may have its own negotiator or may choose to designate an agent.

Before any negotiation is conducted involving Tribal leases, MMS contacts the affected Tribes to ascertain their preferences regarding inclusion or noninclusion. Often negotiations involving Indian leases are conducted separately from those involving Federal leases, due to the multiplicity of parties. However, upon consent by all parties, joint negotiations involving Indian and Federal issues may be conducted.

Tribal negotiators use similar practices in settlements involving Tribal leases as State representatives follow in Federal negotiations. These include:

- Having a single lead negotiator to strengthen the ability of the team to come to an agreement with the greatest net return;
- Agreeing to the negotiation process, developing a negotiation strategy, and reviewing the facts in advance of discussions with the lessee; and
- Receiving expeditious agreement from Tribal leadership.

Each Tribe must sign the settlement agreement, through an authorized officer, for the agreement to be binding on that Tribe's claim. If a Tribe's constitution requires a Tribal resolution for an agreement to be binding, that resolution must be attached when the Tribal official signs the agreement on behalf of the Tribe.

For allotted leases, MMS negotiates on behalf of the allottees as their trustee. However, in the event an allottee group exists and can demonstrate legal or representative standing, then it may name a representative, including legal counsel, to participate in negotiations. BIA may also participate in negotiations.

26.4.4 Negotiation process

Before the negotiation session begins, the parties exchange lists of issues—such as leases affected, value estimates, or procedures—and arguments for compromising the value of issues, such as legal and statistical.

The lead negotiator, either directly or by appointment of a representative, polls each RMP unit with potential responsibility for billing, assessing, or otherwise giving orders to the lessee, either as payor, operator, or lessee.

The lead negotiator assigns other members of the negotiating team their roles during the actual session. Notes prepared on agreed-upon points are provided to State and Tribal representatives to use in briefing other States or Tribes. These notes are confidential documents for negotiation purposes only. OE briefs any parties not represented.

In the event that negotiations reach an impasse, the Director may attempt to resolve the conflict using MMS's ADR program. Any proposal reached through this program is nonbinding; that is, it requires approval in the same manner as a negotiated settlement.

26.4.5 Settlement agreement

When the draft settlement agreement is complete, it is given to the lead negotiator, who may request other members of the team to draft memoranda to the Director recommending approval of the agreement. Affected States and Tribes are provided a copy of the draft agreement.

- When the draft agreement is approved by the lead negotiator, it is prepared in final form and presented to the other parties for formal approval.
- The lead negotiator assigns one Federal member of the team the responsibility for drafting a memorandum explaining the terms of the settlement and the reasons it should be approved.
- The lead negotiator signs both memoranda and includes them in the settlement package prepared for the signature of the Director.
- After the settlement is signed, the Director returns the executed copy to OE, and OE sends copies to all parties.

26.4.6 Settlement information distribution

Every settlement, by its terms, closes certain issues for certain periods to further examination. Various RMP units and the Appeals Division need to know which issues are closed to further examination.

OE examines the settlement agreement and prepares a memorandum for the operating divisions that describes the settlement, the issues that are settled, and those still open to further examination or future enforcement actions.

OE forwards a copy of the settlement agreement and the memoranda to all affected States and Tribes.

26.5 Lease Cancellation

In nonpayment situations, MMS can recommend lease cancellation to surface management agencies. Generally, if a lessee fails to pay a bill, the RMP Debt Collection Section issues two followup notices, a demand for payment to the lessee, and then a demand against the lease surety. The demand against lease surety is addressed to the surface management agency that issued the lease. The surface management agency has the option of cancelling a lease if the lessee and/or bondholder fails to pay the bill in full.

RMP has other debt collection options such as:

- Referring the debt for internal MMS administrative offset.
- Reporting the delinquency to a credit bureau.
- Referring the debt to the Department of Justice for litigation.
- Reporting the debt to the Internal Revenue Service for a tax refund offset.

27. Appeals And Sureties

Administrative appeals procedures are an important part of the audit process. Audit offices issue orders to pay, perform, or provide records during audits; however, an auditee can submit a written response appealing the order and postpone the process if he/she disagrees with the content. If an appellant challenges your audit work, you must be able to persuasively rebut the appellant's arguments. Evidence must be available in audit work papers to defend the audit position through all levels of the administrative and judicial appeals process.

27.1 Laws, Regulations, and Other Criteria

The following is a list of criteria on which RMP administrative appeals policies and practices are based:

- 30 CFR Part 243 (1996)—RMP Appeals Procedures;
- 30 CFR Part 290 (1996)—Appeal Rights;
- 43 CFR Part 4 (1996)—Department of the Interior (DOI) Hearings and Appeals Procedures; and
- MMS delegation of Authority to Render Decisions on Appeals effective February 1, 1994.

27.2 Levels of Appeals

NOTE

The Royalty Simplification and Fairness Act (RSFA), section 4(h), requires MMS to process all appeals through the DOI within 33 months from the date the proceeding was begun, or 33 months from August 13, 1996, whichever is later. RSFA allows the 33-month period to be extended by any period of time if mutually agreed to in writing by the Secretary and the appellant.

The administrative appeal process usually begins with an administrative appeal to the Director of MMS or the Commissioner of Indian Affairs and may be continued through the Interior Board of Land Appeals (IBLA) and ultimately through the Federal Courts.

The first level of administrative appeal is to the Director of MMS for Federal leases and to the Commissioner of Indian Affairs for Indian leases. The following actions are subject to administrative appeal:

- Orders for payment of interest.
- Orders for payment of royalty or rentals.
- Orders to perform.
- Orders to provide records.
- Denial of refund requests.

The second level of administrative appeal is to IBLA. Administrative appeals of the following issues can be made to IBLA:

- Penalty assessments under the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA).
- Final decisions made by the Director, MMS.
- Final decisions made by the Commissioner of Indian Affairs.

The next level is judicial appeal to the U.S. District Court or the U.S. Claims Court. Decisions made by IBLA and decisions by Assistant Secretaries of DOI are final decisions of the Secretary and are appealable to the U.S. District Court or the U.S. Claims Court, depending upon the relief sought.

Decisions made by the U.S. District Court or the U.S. Claims Court are appealable to the U.S. Court of Appeals. If necessary, the U.S. Supreme Court is the final level of appeal.

27.3 Administrative Appeals Process

A notice of administrative appeal to the Director of MMS or the Commissioner of Indian Affairs must be filed in writing with the issuing audit office within 30 days from receipt of the order or decision. There is a 10-day grace period if the notice of administrative appeal was transmitted but not received at MMS within the required time frame. Extension of the filing period is not permitted unless requested in writing by the appellant, with justification showing good cause. The notice of administrative appeal must justify reversal or modification of the order or decision.

Compliance with any order or decision is suspended by reason of an administrative appeal unless the Director of MMS notifies the appellant in writing that the decision or order is not suspended. If the amount under administrative appeal is greater than $1,000, suspension of the order or decision is contingent upon the appellant’s posting of adequate surety.

When a notice of administrative appeal is received, the case is assigned a docket number by the MMS Appeals Tracking System (MATS). Basic tracking information must be entered into the MATS system as follows: appellant name, appellant location, appealed amount, organization number, date received, and Federal or Indian indicator. MATS automatically provides the next sequential docket number.

The administrative appeal is tracked through the system by using uniform three-digit milestone codes. When MATS assigns a docket number, milestone code 101 is automatically assigned to indicate that the administrative appeal has been received by a field office.

The office originating the order or decision sends a letter to the appellant indicating that the notice of administrative appeal has been received and that any further correspondence relating to the case should reference the MMS docket number. Any further correspondence prepared by MMS should also reference the docket number. MATS is updated to reflect milestone code 102—acknowledgment letter and docket number have been forwarded to the appellant.

Upon receipt of the appellant's statement of reasons and arguments, milestone code 105 is entered in MATS. The office originating the order or decision prepares a field report with recommendations on the administrative appeal and submits it to the Appeals Division and the appellant. The appellant is given an opportunity to comment on the field report directly to the Appeals Division. After forwarding the field report to the Appeals Division and the appellant, milestone code 131 is entered into MATS.

Draft agency decisions are then prepared by the Appeals Division and are generally sent to the audit office for review and comment before issue. Decisions for Federal leases are signed by the Director of MMS, while decisions on Indian leases are signed by the Commissioner of Indian Affairs. Decisions may also be signed by the appropriate Assistant Secretary. The Appeals Division mails copies of the signed decision to the appellant with copies to the appropriate MMS office. The appropriate milestone code should be entered to record the proposed decision.

If the appeal is not filed timely, enter milestone code 109 into MATS along with the receipt date. Prepare a draft decision using appropriate guidelines and send it to the appellant. The appellant has 21 days to respond to the draft decision, after which the originating division issues a final decision. The final decision is appealable to IBLA.

27.4 Field Reports

The number of administrative appeals have increased significantly in recent years. To manage the heavy workload, it is crucial that the Appeals Division be furnished thorough and convincing field reports on MMS positions.

A memorandum dated July 15, 1993, from the Associate Director for Royalty Management (AD/RM) established time frames for processing all RMP routine and complex appeals. A memorandum dated August 27, 1993, from the Deputy Associate Director for Audit contained further guidance for audit appeals. Please read these documents carefully. The following are general guidelines for the preparation of field reports that will improve communications with the Appeals Division and strengthen MMS positions.

1. Indicate whether the notice of administrative appeal was timely filed.

   The field report must indicate if the notice was timely filed, preferably in an early paragraph. Even if the filing was not within the 30-day limit, a field report must be prepared that includes a statement that the notice of administrative appeal was not filed on time. Original documents showing the critical dates should be attached.

NOTE

Under RSFA, only 60 days are allowed to file both the appeal and statement of reasons (SOR) for Federal leases.

2. Select a clear and effective format.

   Present the audit case and rebut the appellant's arguments clearly. Begin with a paragraph introducing the issue, followed by a section on background information leading up to the administrative appeal. Following the background, the method of presentation may vary, depending upon the complexity of the issue, the appellant's arguments, and the extent of reference data. The method selected should be easy to understand and persuasive. If several issues are covered, list them in outline form. Tables, quotes, subcaptions, and exhibits help the reader understand complex issues and information.

3. Present appellant's position briefly.

   Many independent and interdependent arguments may be presented to bolster an appellant's position. Each argument should be acknowledged and presented. It is not necessary to elaborate on the appellant's arguments because the administrative appeal and the statements of reasons are attached to the field report. However, each argument should be sufficiently paraphrased to clearly describe the point.

4. Discuss or rebut each argument raised by the appellant.

   Each argument should receive a response either individually or as a group; however, the response need not be a rebuttal. State if you are unable to rebut a legal argument and it is referred to the Appeals Division for review. If an appellant's argument appears irrelevant or pointless, make this view known. If you agree with the appellant on a point, indicate that adjustments will be made.

5. Cite supporting regulations and decisions.

   The MMS position should be based on appropriate laws, regulations, Secretarial decisions, IBLA decisions, solicitor's opinions, Director's decisions, DOI practices, and courts of law. Although it may seem redundant, the field report should cite all known legal documents that bolster the MMS position.

6. Elaborate on pertinent, factual conditions and circumstances.

   Perhaps the most important contribution you can make to a sound position is the development and presentation of facts. Presenting facts beyond those included with the demand for payment may effectively rebut an argument founded on legal grounds, or additional facts may render much of the appellant's legal rhetoric ineffective. If not clearly elaborated in the field report, factual conditions may not be given due consideration in the final decision.

7. Furnish supporting documentation.

   Attach copies of supporting documentation to assist the Appeals Division in its review of the appellant's arguments and the audit position. Such documentation may include the lease agreement, sales contract, correspondence, and engineering reports. Original documents should be provided if available (IBLA requires original documents).

8. Offer conclusions and clear, relevant opinions.

   Facts alone often do not convey the message intended. When presenting the audit position, state the conclusions you want drawn from the facts. Elaborate to make each point and conclusion clear. Relevant opinions, if clearly presented, may contribute greatly to the audit position. Opinions not factually supported but logically reached may also be important considerations for the Appeals Division.

9. Include a conclusion and recommendations section.

   Always end the field report with a conclusion and recommendation. This may be a brief paragraph or a more lengthy statement. If the issue is complicated or the argument lengthy, the concluding statements become an important means of reducing the disputed issues and positions to their simplest form. The recommendation, if appropriate, must state that the appeal in total or in part should be upheld or denied.

10. Include a list of attachments.

    Include a list of all the documents submitted immediately following the field report. This is extremely important because attachments may be misplaced or lost in the transmittal process.

11. Use a neutral, factual tone.

    When preparing the field report, keep in mind that the appellant is furnished a copy. Comments in the report should be considered carefully and presented in a neutral, factual tone. The field report may bring an additional response from the appellant. The Appeals Division considers the response if it is received within 21 days of the date of the letter transmitting the field report to the appellant. After the operating division forwards the field report to the Appeals Division and the appellant, the responsibility for updating MATS transfers to the Appeals Division.

27.5 Surety in Lieu of Compliance

Compliance with an order or decision is suspended if appealed timely. However, if the amount under administrative appeal is greater than $1,000, suspension is contingent upon the appellant's posting of adequate surety. Acceptable surety instruments include an appeal bond, an irrevocable letter of credit (LOC), a certificate of deposit (CD), or a U.S. Treasury Security (TS). The surety amount and expiration date should be entered into MATS.

NOTE

Effective with production after August 31, 1996, RSFA, section 4(l) eliminated the requirement to post a bond or any other surety instrument in order to receive a stay of payment until appeal proceedings are completed unless there are indications that the appellant is financially solvent.

27.5.1 Administrative appeal bond

An administrative appeal bond must be completed in accordance with Form MMS-4326 with no modifications. The bond must also be issued by a qualified surety company that is approved by the Department of the Treasury, as indicated in the Department of the Treasury Circular 570, which is revised periodically in the Federal Register. Approval of an acceptable surety type is the responsibility of the Office of Enforcement (OE).

27.5.2 Letter of credit

MMS will accept as surety an irrevocable LOC with a minimum coverage period of 1 year. The LOC must be automatically renewable and from a bank with a minimum Thompson BankWatch rating of: “C” for an LOC less than $1 million; “B/C” for an LOC between $1 million and $10 million; or “B” for an LOC over $10 million. When an LOC is renewed or extended, the LOC amount must be increased to cover an additional year’s interest based on the principal, or an amount as otherwise specified by MMS.

27.5.3 Certificate of deposit

The appellant must request in writing to use a CD as surety. RMP accepts a Financial Institution book-entry CD that explicitly assigns the CD to the MMS AD/RM.

27.5.4 U.S. Treasury Security

The appellant must request in writing to use a TS as surety. The TS is restricted to U.S. Treasury notes or bonds with maturity equal to or greater than 1 year. The TS must equal 120 percent of the appealed amount in order to protect the MMS against interest rate fluctuations.

28. Bankrupt Entities

Special rules apply to auditees who file for bankruptcy protection. You must be aware of the bankruptcy process as it affects the MMS audit function.

28.1 Laws, Regulations, and Other Criteria

The following is a list of criteria upon which MMS's bankruptcy policies and practices are based:

- Bankruptcy Reform Act of 1978 (11 U.S.C. 101 et seq; 98 STAT 333).
- Bankruptcy Amendments and Federal Judgeship Act of 1984, Chapters 1, 3, 5, 7 and 11 (28 U.S.C. 151 et seq; 92 STAT 2549). Chapters 7 and 11 are the bankruptcy filings you will encounter.
- MMS Bankruptcy Procedures, dated July 1, 1994.

28.2 Forms of Bankruptcy Protection

Two types of protection—liquidation and reorganization—are generally available under U.S. bankruptcy laws for companies in the minerals industry.

28.2.1 Chapter 7 bankruptcy (liquidation)

Filing a bankruptcy petition under Chapter 7 indicates the desire to liquidate all assets and discontinue business. The proceeds from the asset sales are used to either partially or fully pay debts. Under a Chapter 7 petition, the debtor ceases to exist as a going concern upon conclusion of the bankruptcy.

28.2.2 Chapter 11 bankruptcy (reorganization)

Filing a bankruptcy petition under Chapter 11 indicates a desire to reorganize and, in most cases, remain in business. In a Chapter 11 case, either the debtor or creditor submits a reorganization plan subject to approval by the bankruptcy court. After it is approved, the reorganization plan replaces the debts of the company and provides for payments to individual creditors. Payments are based on the amount of previous indebtedness and the class under which each creditor's claim falls. The company remains as a going concern after the conclusion of most Chapter 11 cases. However, liquidations are also allowed under Chapter 11 and may result in termination of the business similar to a Chapter 7 case.

28.3 Automatic Stay Provision and Prohibited Actions

Under the U.S. Bankruptcy Code (11 U.S.C. 362), a petition for bankruptcy operates as a stay of the commencement or continuation of a judicial, administrative, or other proceeding against the debtor that was or could have been commenced before the bankruptcy case. This includes proceedings to recover a claim against the debtor that arose before the commencement of the bankruptcy case. Section 362 also operates as a stay or prohibition of any act to collect, assess, or recover a claim against the debtor that arose before the commencement of the bankruptcy case.

NOTE The courts have held that the provisions of the automatic stay apply to the Federal Government.

The courts take a liberal view of the types of pre-petition actions against a debtor that are prohibited. The types of pre-petition actions barred by the automatic stay provision include all MMS orders, any form of verbal order or demand from an auditor, Notices of Noncompliance, or any other actions that threaten or imply possible sanctions against the debtor for situations that occurred or could have occurred before filing of bankruptcy petition. The automatic stay does not necessarily prohibit an audit; however, a debtor may attempt to withhold records or be uncooperative during the course of an audit by hiding behind the provisions of the automatic stay. If the debtor attempts this type of action when you make a reasonable request for records or information, you should ask for assistance from the Office of the Solicitor. The Solicitor will request the Department of Justice to file a motion for relief from the stay if necessary to allow an audit to be initiated or continued. Refer questions regarding a party's bankruptcy status to the Office of Enforcement (OE).

NOTE

Because the automatic stay is an order of the bankruptcy court, any action taken that is prohibited under the stay is considered contempt of court. Seek appropriate guidance if there is any doubt as to the propriety of any course of action being considered against a bankrupt entity.

28.4 Pre-Petition Versus Post-Petition

Bankruptcy laws allow a debtor to seek relief for any debts that arose or could have arisen before filing the bankruptcy petition. The date the bankruptcy petition was filed controls what actions may or may not be taken against a bankrupt entity.

- Actions of a pre-petition nature are prohibited by the filing of a bankruptcy petition.
- Debtors may be pursued for matters that did not exist until after the petition was filed.

The Regional Office of the Solicitor (Denver) has provided guidance for determining whether an item is pre- or post-petition:

1. **Royalties** are based on the day the mineral was sold, not the due date of the royalty report or payment. For example, if the debtor files for bankruptcy on July 15, 1984, all sales months before July 1984 are pre-petition and subject to the automatic stay. All sales months after July 1984 are post-petition and not subject to the stay. The month of July 1984 is more troublesome. Sales that took place in the first 14 days of July 1984 are pre-petition, while sales that took place on or after July 15, 1984, are post-petition. You must verify

individual transaction dates to determine whether royalty is pre- or post-petition. Any demands should be made in accordance with this determination.

2. **Interest** is based on each day for which interest accrues, not on the original, underlying obligation that was paid late. For example, assume the petition date was July 15, 1984; the royalty payment for the sales month of March 1984 is due April 30, 1984, and the royalty payment was actually received by MMS on September 30, 1984. The interest that accrued from May 1, 1984, through July 14, 1984, is pre-petition and subject to the stay; interest that accrued from July 15, 1984, through September 30, 1984, is post-petition and not subject to the stay. However, the accrued pre-petition interest is added to the late royalty amount as the beginning basis for post-petition interest computation purposes (for compound interest periods only). Interest assessments spanning both the pre- and post-petition periods should have separate bills.

3. **Assessments** are based on the day for which each assessment could have been made, under law, regulation, or rule, whether or not actually made. For example, assume the petition date was July 15, 1988, and the Form MMS-2014 for the sales month of March (due by April 30, 1988) was not received until September 30, 1988. The assessment for late reporting under 30 CFR 218.40(a) is pre-petition even if not assessed until October 15, 1988, because the assessment could have been made on May 1, 1988, the first late day.

You will frequently demand records or payments for past periods. To distinguish between pre-petition and post-petition periods, refer to the RMP periodic update of bankrupt entities to determine correct petition dates.

28.5 Proof-of-Claim and the Bar Date

A proof-of-claim is a document filed by a creditor with the bankruptcy court that states the amount of money the creditor is owed by the debtor. It is not always necessary for a creditor to file a proof-of-claim. When a bankruptcy petition is filed, the debtor must file a schedule listing each creditor and the amount of indebtedness at the time of filing. If an individual creditor is already listed on the schedule and for the correct amount, the creditor need not file a claim. However, because the debtor reports the royalty owed each month to MMS on an unaudited basis, MMS policy is to file a proof-of-claim in each case. The proof-of-claim must be filed with the bankruptcy court by the bar date, the last day the bankruptcy court will accept claims for consideration. As long as a claim is filed by the bar date, the amount of the claim may be amended before confirmation of a reorganization plan.

The RMP Bankruptcy Coordinator will request an audit status report for purposes of filing the MMS proof-of-claim. The audit status report form is found in RMP Bankruptcy Procedures. The form must be submitted by the date requested in the transmittal memorandum in order to file the claim by the bar date. The audit office having jurisdiction over the debtor is responsible for timely submission of the prescribed audit status report form.

28.6 Right-of-Offset

A creditor's right-of-offset exists when the creditor owes the debtor an amount of money before the filing of the debtor's petition. The creditor may offset the pre-petition amount owed by the debtor. Right-of-offset places an otherwise unsecured creditor in a secured position to the extent of the setoff amount. MMS audits frequently generate an offset situation. Post-petition amounts may not be offset against pre-petition amounts.

28.7 Assumption and Rejection of Unexpired Leases

The U.S. Bankruptcy Code (11 U.S.C. 365) allows a debtor to assume or reject executory contracts or unexpired leases. Assumption of the lease indicates that the debtor wishes to hold its interest in the lease; otherwise, the lease interest is rejected and reverts to MMS, Bureau of Land Management (BLM), or Bureau of Indian Affairs (BIA). In both Chapter 7 and Chapter 11 cases, the debtor must assume the lease within 60 days of filing the petition, or the lease is deemed rejected. The court may grant an extension of time within the 60-day period to assume the lease. The election to assume or reject the lease is done on a lease-by-lease basis and is not an all-or-none proposition. The debtor may assume the better leases and reject the others.

The importance of section 365 to MMS is that, if assumed, the debtor must cure any past defaults under the lease and provide reasonable assurance of future performance. You should report any lack of financial performance for either the pre- or post-petition periods as soon as discovered in the audit of a bankrupt company. Notify the RMP Bankruptcy Coordinator who will work with the Regional Office of the Solicitor to determine appropriate action.

28.8 Other RMP Collection Techniques

Filing a bankruptcy petition by a payor does not preclude MMS from collecting the amount due from other sources. RMP bankruptcy procedures provide that when it is determined that a bankrupt payor owes pre-petition royalties, interest, or other assessments, MMS will coordinate collections against the appropriate lease, state-wide, or nation-wide bonds with the BLM or OMM office. The automatic stay does not prohibit a creditor from pursuing collection against a debtor's bond. In addition, MMS will pursue the lessee-of-record, if different from the debtor payor, for payment of any lease obligations. Any collections from the lessees-of-record or the bond reduce the proof-of-claim against the payor.

29. Illegal Acts and Referrals

Requirements for recognizing and reporting possible illegal acts are contained in Government Auditing Standards issued by the Comptroller General. Some important standards are as follows:

- Design the audit to provide reasonable assurance of detecting material misstatements resulting from direct and material illegal acts.

- Be aware that indirect illegal acts may have occurred. Specific information may provide evidence concerning the existence of possible illegal acts that could have a material indirect effect on reporting royalties. Apply specific audit procedures to ascertain whether an illegal act has occurred.

- Be aware of the characteristics and types of potentially material irregularities that could be associated with the area audited. This awareness is necessary to plan the audit and reasonably ensure detecting material irregularities.

- Understand the laws and regulations that have a direct and material effect on reporting and determining royalties on the Form MMS-2014. You may need to work with legal counsel in the following situations:

  – Determining which laws and regulations might have a direct and material effect on reporting royalties.

  – Designing tests of compliance with laws and regulations, and evaluating the results of those tests.

  – Conducting tests required by the provisions of contracts.

- Exercise due professional care in pursuing possible irregularities and illegal acts so as not to interfere with potential investigations, legal proceedings, or both.

  – Under some circumstances, you may be required by laws, regulations, or policies to report indications of certain types of irregularities or illegal acts to law enforcement or investigatory authorities.

- Report certain types of irregularities or illegal acts before extending your audit steps.
- You may have to withdraw from or defer further work on the audit or a portion of the audit in order to not interfere with an investigation.

29.1 Types of Criminal Acts

In general, criminal acts likely to be encountered when conducting royalty audits involve fraudulent reporting to RMP. Such acts include intentional:

- Under reporting of sales values or volumes on the Form MMS-2014 to reduce royalty obligations.
- Excessive allowances claimed on the Form MMS-2014.
- Negative adjustments to nonexistent prior reports.
- Claims of minimal production and royalties on nonproducing wells to avoid the costs of plugging and abandonment.

The intentional nature of such acts may be indicated by (1) employee statements or allegations, (2) documentary evidence, (3) repeated misreporting despite prior warnings from RMP operating divisions, and (4) finding the same type of reporting "irregularities" after the auditee is cited for them in prior audits.

29.2 Investigations

The Office of Inspector General (OIG) manages, supervises, coordinates, and conducts investigations relating to Departmental programs and operations, except for specific areas assigned to other Departmental agencies by statute.

Every employee has a duty to report known, suspected, or alleged fraud, waste, or abuse affecting Departmental programs or operations to the Assistant Inspector General for Investigations immediately.

29.3 Fraud Awareness

The OIG, with assistance from other law-enforcement agencies and RMP, periodically conducts fraud awareness training sessions for RMP personnel and State and Tribal clients. These training sessions emphasize identifying potential fraud cases, making referrals, conduct after the referral, and providing assistance to law enforcement authorities.

29.4 Referrals of Suspected Fraudulent Reporting

You should refer all instances of suspected criminal activity for investigation promptly using the procedures outlined below:

- Avoid delaying the referral process by attempting to prove that a crime exists. Consult your supervisor to ensure that the issue falls into the realm of potential fraud or if a referral/investigation already exists. The supervisory chain will not filter such referrals.
- Refer cases of suspected fraud involving Federal or Indian mineral production or royalties.
- Use the one-page referral form to make your referral. Mail the referral form in a restricted (blue) envelope to the RMP Program Review Officer, Mail Stop 3030.
- Attachments are optional and should be limited to clarify the issue.
- The referral will be logged and quickly forwarded to OIG Central Region Investigations. OIG may in turn refer the issue to Bureau of Land Management (BLM) law-enforcement personnel or other law-enforcement agencies.

- Referrals will not normally interrupt the course of an ongoing audit.

- Avoid discussing the referred issue with auditee personnel, and do not attempt to proceed with an investigation.

- The agency performing the investigation will notify you if any limits on the audit are necessary. The investigating agency may contact you directly for clarification and additional information.

The Program Review Officer periodically advises RMP division chiefs of the status of ongoing mineral investigations. The Program Review Officer will inform the referring employee of the case outcome.

29.5 Referrals of Other Matters

Suspected or known cases of other criminal activity or misconduct involving MMS employees or contractors should be referred to OIG directly. Such matters include travel fraud, falsification of time and attendance reports, and compromise of proprietary data. You may use the OIG "Hotline," 800-424-5081. You should advise supervisory personnel of such referrals unless you are specifically instructed not to by the OIG investigator.

Release History

Release number	Release date	Revised chapters/sections	RMP originator	Preparer
1.0	12/01/89		TIM[a]	AMS/OC[b]
1.1	04/08/92	3.3 7.3 to 7.8 8.2 9.4 and fig. 9-1 figs. 10-4 to 10-6 12.3.5 to 12.4 15.1.1 fig. 15-2 fig. 16-11 17.4 18.4 fig. 20-21 23.6 fig. 23-2 fig. 23-5 fig. 25-2 D.31 and D.32	TIM	AMS/OC
2.0	01/16/98		RPS[c]	AMS/OC

a. Technical Information Management

b. American Management Systems/Operations Corporation, Inc.

c. Rules and Publications Staff

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil, and other mineral resources. The MMS **Royalty Management Program** meets its responsibilities by ensuring the efficient, timely, and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States, and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.