Royalty Management Program

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Geothermal Payor Handbook—Product Valuation

Royalty Valuation Procedures

Release 1.0

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

Geothermal Payor Handbook—Product Valuation

Royalty Valuation Procedures

Release 1.0

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

Abbreviations

AFS	Auditing and Financial System
AL	arm's-length
BLM	Bureau of Land Management
Btu	British thermal unit
Btu/lb	Btu per pound
CFR	Code of Federal Regulations
°F	degrees Fahrenheit
f.o.b.	free on board
FR	Federal Register
ft	foot, feet
ft^3	cubic feet
ft^3/gal	cubic feet per gallon
gal	gallon
H_2S	hydrogen sulfide
kWh	kilowatthour
lb	pound
lb/ft^3	pounds per cubic foot
Mlb	thousands of pounds
MMBtu	million British thermal units
MMS	Minerals Management Service
MWh	megawatthour
NAL	non-arm's-length
O&M	operating and maintenance
PAAS	Production Accounting and Auditing System
PIF	Payor Information Form
RMP	Royalty Management Program

therm	100,000 Btu
U.S.C.	United States Code
Wh	watthour

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1. About This Handbook

The Minerals Management Service (MMS), Royalty Management Program (RMP), within the Department of the Interior, is responsible for ensuring that all revenues from Federal geothermal leases are properly collected, accounted for, and disbursed to the appropriate recipients. Geothermal revenues collected by MMS include:

- *Rentals* for leases that are not producing;
- *Minimum royalties* for producing leases that do not meet their minimum royalty obligation from actual production royalties, or for nonproducing leases that have a well capable of producing geothermal resources in commercial quantities (as determined by the Bureau of Land Management [BLM]);
- *Production royalties* for producing leases; and
- *Compensatory royalties* for geothermal resources that are avoidably lost, wasted, or drained (as determined by BLM).

This handbook describes the regulatory methods of valuing Federal geothermal resources to determine production royalties.[1] The same methods are used to determine compensatory royalties.

Royalty is due on the value of geothermal resources produced, processed, removed, sold, or utilized from the lease, or reasonably susceptible to sale or utilization by the lessee or designated operator. On November 8, 1991, MMS issued new regulations at Title 30, Code of Federal Regulations (CFR) Parts 202 and 206, to clarify its standards for valuing geothermal production. Those regulations became effective January 1, 1992.

This handbook supplements the geothermal regulations in 30 CFR Parts 202 and 206 (1992 forward) with further explanations and examples. However, it does not replace the regulations. You are responsible for the proper valuation, for royalty purposes, of Federal

[1] This handbook does not apply to valuation of Indian geothermal resources unless otherwise provided for by the Indian geothermal lease. See “Applicability of Valuation Standards” on page 2-1 and related footnote for further discussion.

geothermal production. Accordingly, you should have a working knowledge of all governing regulations. You may obtain a copy of Title 30 CFR by writing to the Superintendent of Documents, Attn: New Orders, P.O. Box 371954, Pittsburg, PA 15250-7954; ask for the volume containing Parts 200 to 699. You may telephone charge orders by calling the Government Printing Office order desk at 202-512-1800. Title 30 CFR may also be available at public information desks at your local Federal courthouse or at your local library.

You report geothermal royalties to the MMS's Auditing and Financial System (AFS) using the monthly Report of Sales and Royalty Remittance, Form MMS-2014. AFS is a revenue accounting system that accounts for royalties and related information from payors. Once a geothermal lease begins commercial production, you must submit a Form MMS-2014 to MMS for each month your lease produces. You do not submit a Form MMS-2014 for those months your lease does not produce. Be sure you have a valid Payor Information Form (PIF), Form MMS-4025, on file with MMS when you make royalty payments.

You are not required to send geothermal production reports to MMS's Production Accounting and Auditing System (PAAS). You must, however, submit production and facility reports to BLM. BLM will verify your production volumes and forward them to MMS for comparison with production reported to AFS.

1.1 Using the Geothermal Payor Handbook

This handbook is divided into the following chapters:

Chapter 2, Valuation Overview, identifies geothermal resources subject to royalty, addresses minimum royalty requirements, describes measurement standards for royalty reporting, reviews general valuation principles, defines terms crucial to valuation, and discusses housekeeping subjects that are not easily accommodated in other chapters.

Chapter 3, Valuation Standards for Electrical Generation, describes the requirements for valuing geothermal resources used to generate electricity.

Chapter 4, Netback Valuation, explains in detail the netback procedure used to value certain electrical generation resources.

Chapter 5, Valuation Standards for Direct Utilization, describes the requirements for valuing geothermal resources used in direct utilization processes.

Chapter 6, Alternative Fuel Valuation Method, explains in detail the alternative fuel method used to value certain direct utilization resources.

Chapter 7, Byproduct Valuation, describes the requirements for valuing byproducts and for determining byproduct transportation allowances.

Appendix A contains important MMS addresses.

Each chapter is designed to stand alone as much as possible, easing your need to search other topics. However, certain chapters are interdependent. For example, if you are using the netback procedure to value your production, you need to be familiar with the information in chapters 2, 3, and 4. If you are using the alternative fuel method for valuation, you need to be familiar with chapters 2, 5, and 6. If you are valuing byproducts, read chapters 2 and 7.

Pertinent regulations and authorizing statutes are cited throughout the text for legal cross-reference. For example, “30 CFR 206.352 (b)(1)(i)” refers to the regulation in Title 30 of the Code of Federal Regulations, Part 206, section 352, paragraph (b)(1)(i) that governs the valuation of electrical generation resources sold under arm’s-length contracts; “30 U.S.C. 1001 *et seq.”* refers to the codification of the Geothermal Steam Act in Title 30 of the United States Code, section 1001 and following.

1.2 Nomenclature and Terminology

The following conventions are used throughout this handbook:

You refers to the geothermal lessee, operator, or royalty payor. Although a royalty payor may not be the lessee for a particular lease, a royalty payor has the same reporting and valuation obligations as the lessee. (See definition of *lessee* at 30 CFR 206.351.) The lessee is ultimately responsible for ensuring that royalties are properly reported and paid.

We refers to the Minerals Management Service, Royalty Management Program.

Electrical generation resources refers to those fluid geothermal resources (steam, hot water, and hot brines) used to generate electricity.

Direct utilization resources refers to those fluid geothermal resources (generally hot water) used in direct utilization processes; that is, processes other than electrical generation.

Several specialized terms are used throughout this handbook; for example, *arm's-length contract, gross proceeds, geothermal netback procedure*, and *no sales*. You must be familiar with the definitions of all such terms to understand fully and use properly the valuation principles presented here. Some terms are defined in the text where appropriate or pertinent to a given discussion. Other terms are defined in 30 CFR 206.351.

1.3 Supplementary Payor Handbooks

The *Geothermal Payor Handbook—Product Valuation* is one of a series of MMS handbooks containing information on Federal and Indian mineral valuation and royalty reporting requirements. You will need the following handbooks to establish your account with MMS and report your geothermal royalties:

- The *Oil and Gas Payor Handbook—Volume I, Payor Information Form (Form MMS-4025)* contains an overview of the MMS reporting structure; describes the PIF, which all royalty payors must submit; and provides detailed instructions for completing the PIF.

- The *Oil and Gas Payor Handbook—Volume II, Report of Sales and Royalty Remittance (Form MMS-2014)* contains detailed instructions for completing your Form MMS-2014. You must submit a Form MMS-2014, together with your royalty payment, each month you have commercial geothermal production.

- The *AFS Payor Handbook—Solid Minerals* contains information for reporting royalties on byproduct production. You also report byproduct royalties on Form MMS-2014.

Also, if you claim a byproduct transportation allowance, you may need to refer to the *Oil and Gas Payor Handbook—Volume III, Product Valuation*.

1.4 Handbook Distribution

MMS is solely responsible for distributing payor handbooks. Only lessees with valid and active payor codes receive initial paper copies of handbooks and any revisions at no cost. We charge an administrative fee for additional paper copies or for copies requested by other interested parties. Companies with multiple payor codes that have the same name and address will receive only one copy free of charge.

Send requests for copies of payor handbooks to:

Minerals Management Service
Royalty Management Program
Accounting and Reports Division
P.O. Box 5760
Denver, CO 80217-5760

Or call the RMP handbook order line at 303-231-3090. Specify the handbook you are requesting.

This handbook is also available on the Internet at http://www.rmp.mms.gov/.

1.5 Handbook Maintenance

MMS periodically issues revisions to payor handbooks. You are responsible for adding or replacing pages according to the filing instructions on the transmittal sheet.

We recommend that you keep superseded releases of payor handbooks for your use in future reviews and/or audits of transactions that occurred and were reported while the release was in effect.

2. Valuation Overview

Royalty valuation of Federal geothermal resources draws its authority from the Geothermal Steam Act of 1970 (30 U.S.C. 1001 *et seq*.). The act provides for payment of royalties to the U.S. Government on the amount or value of geothermal resources derived from production under the lease and sold or utilized, or reasonably susceptible to sale or utilization. For practical reasons, and unless otherwise permitted by lease arrangements, you pay royalties on the **value** of produced geothermal resources as follows:

$$\text{royalty} = \text{royalty rate} \times \text{value of production}.$$

You determine the value of production by the regulations in 30 CFR 206.350–206.358 and the instructions in this handbook. As used in this handbook, *value of production, royalty value*, or simply *value* all have the same meaning and always refer to the value on which you pay royalties.

2.1 Applicability of Valuation Standards

The valuation standards and procedures described in this handbook apply to:

- Geothermal resources produced from Federal leases issued under the Geothermal Steam Act,[1] and

- Indian minerals agreements entered into under the Indian Mineral Development Act of 1982 (25 U.S.C. 2101–2108), by default unless otherwise addressed in the agreement. (See 25 CFR Part 225.)

Use these standards and procedures to determine the royalty value of geothermal production beginning January 1, 1992.

[1] The Geothermal Steam Act authorizes the Department of the Interior to issue geothermal leases only on certain Federal lands, namely public domain lands, acquired lands, and lands with minerals reserved to the Federal Government; the act excludes issuance of geothermal leases on Indian lands.

Geothermal resources, which the Geothermal Steam Act calls "geothermal steam and associated geothermal resources," are:

- All products of geothermal processes, including indigenous steam, hot water, and hot brines;
- Steam and other gases, hot water, and hot brines resulting from water, gas, or other fluids artificially introduced into geothermal formations;
- Heat or other associated energy found in geothermal formations; and
- Byproducts.

Byproducts are:

- Any mineral or minerals (exclusive of oil, hydrocarbon gas, and helium) that are found in solution or developed in association with geothermal fluids and have a value of less than 75 percent of the value of the geothermal energy or are not—because of quantity, quality, or technical difficulties in extraction and production—of sufficient value to warrant extraction and production by themselves; and
- Commercially demineralized water.

2.2 Geothermal Production Requiring Royalty Valuation

You must determine the value of, and pay royalties on, all geothermal resources—including byproducts—that are:

- Produced from a Federal geothermal lease and sold or utilized, or reasonably susceptible to sale or utilization; or
- Avoidably lost, wasted, or drained from a lease, as determined by the Bureau of Land Management (BLM).

You determine the royalty value of geothermal resources avoidably lost, wasted, or drained from a lease in the same manner as if they were sold or utilized, using the valuation standards in 30 CFR 206.350–206.358.

You must also pay royalty on insurance or other compensation received for geothermal resources that are unavoidably lost, unless the compensation is through self-insurance.

You don't determine value or pay royalty on geothermal resources that are:

- Unavoidably lost, as determined by BLM (unless you receive insurance or other compensation as indicated above).
- Reinjected, as approved by BLM.
- Used to generate electricity for internal operations (parasitic electricity) in your own or your affiliate's powerplant, or to generate electricity returned to the lease for lease operations. However, if a powerplant utilizes geothermal resources from more than one lease, or utilizes unitized or communitized production, you may use only that proportionate share of each lease's production—either actual or allocated—royalty free.
- Commercially demineralized water used for powerplant operations or for lease or unit operations. Again, you may use only a lease's proportionate share of commercially demineralized water—either actual or allocated—royalty free.
- Byproducts placed in stockpiles, added to inventories, or otherwise disposed of without financial benefit to you. Byproducts disposed of without financial benefit to you generally include those that are not reasonably susceptible to sale or utilization and those that are classified as hazardous waste.

NOTE

You have an implied obligation to market or use geothermal resources, including byproducts, to the mutual benefit of yourself as the lessee and the Federal Government as the lessor.

Disposal of geothermal resources without financial gain to you will incur a royalty obligation when they are reasonably susceptible to sale or utilization. Thus, if you give away geothermal resources for the convenience of disposal **and** the recipient secures financial gain or benefit from the disposed resource, you must pay royalty on the value of that disposed resource. Contact the MMS Royalty Valuation Division at the address given in appendix A for a royalty determination if you encounter this circumstance.

Regulations covering royalty-bearing production appear at 30 CFR 202.351.

2.3 Timing of Valuation and Royalty Payments

Once you place a lease into production, you must report and pay royalties on Form MMS-2014, Report of Sales and Royalty Remittance, for each month's production. Except as described in the following note, this means that you determine value for each calendar month's cumulative production attributable to each selling arrangement code reported on Form MMS-2014. You must pay royalties by the end of the month following the month of production (30 CFR 210.354); see the *Oil and Gas Payor Handbook—Volume II*, section 1.1.9, for further details. You don't have to submit a Form MMS-2014 for months you don't produce.

NOTE

If you are using the **geothermal netback procedure** (ch. 4) to value your production and the electricity purchaser's payment cutoff date is not month end, use the amounts shown on the purchase statement to report your production and royalty for the calendar month.

For example, if the purchaser's monthly accounting closes on May 17, you use the amount and value of delivered electricity shown for that closing date to report May's production; Form MMS-2014 and your royalty payment are due at the end of June. If the purchaser's next monthly accounting closes on June 21, use the amount and value of delivered electricity shown for the 21st to report June's production; Form MMS-2014 and your royalty payment are due at the end of July.

Do not extrapolate or interpolate quantities and values to the end of a reporting month when using netback valuation. (See "Netback Valuations When Electricity Payments Are Not Made on a Calendar Month" on page 4-8 for additional instruction.)

However, because BLM performs its production accounting on a calendar-month basis according to lease terms, we strongly encourage you to have your electricity purchaser's billing cycle correspond with the calendar month to avoid the possibility of MMS issuing you exception reports.

You value byproducts at the time you sell, use, or otherwise dispose of the byproduct for your or someone else's financial gain. You pay royalties on byproducts by the end of the month following the month of sale, utilization, or disposition.

2.4 Minimum Royalty

You must satisfy the minimum royalty requirement established by the geothermal lease (usually $2.00 per acre) each lease year (30 CFR 202.352). If the royalties you paid on monthly production during the lease year are less than the minimum royalty, you must pay the difference to MMS on or before the expiration date of the lease year (Geothermal Resources Lease at Sec. 3(c)(3) and BLM regulations at 43 CFR 3205.3-5(c)). MMS allows a grace period only to the last day of the month of the lease year. Report minimum royalty payments on Form MMS-2014 using transaction code 02.

If, near the end of the lease year, your projected royalties are less than the minimum royalty, you may make an estimated minimum royalty payment to MMS. You may recoup any overpayment resulting from the estimated minimum royalty payment. Contact your designated MMS representative at 1-800-525-0309 for further information regarding minimum royalties and recoupments.

2.5 Quantity Measurements for Reporting and Paying Royalties

How you use the geothermal resource (electrical generation, direct utilization, or byproduct recovery) and your method of valuing the resource (sales contract price or regulatory procedure) govern the measurement unit you report in the Sales Quantity and Royalty Quantity columns on the Form MMS-2014. Because you can use a variety of measurement units, you must identify the unit of measure reported, such as kilowatthours (kWh), million British thermal units (MMBtu), or thousands of pounds (Mlb).

Reported quantity units may differ from those actually measured. Regardless of the units reported to MMS, you must maintain records showing the actual quantities measured. Examples of measured and reported quantities by usage and valuation method follow.

2.5.1 Units of measurement for electrical generation

Arm's-length and non-arm's-length sales. For geothermal resources used to generate electricity and valued under an arm's-length or non-arm's-length contract, you report production quantities on Form MMS-2014 in the following units (30 CFR 202.353(a)):

- Kilowatthours (kWh) to the nearest whole kilowatthour if the contract specifies payment in terms of generated electricity (electrical energy). For example:

Contract-specified unit of measurement	Quantity measured	Sales quantity reported to MMS (kWh)
watthours (Wh)	38,755,256,605	38,755,257
kilowatthours (kWh)	38,755,256	38,755,256
megawatthours (MWh)	38,755	38,755,000

- Thousands of pounds (Mlb) to the nearest whole thousand pounds if the contract specifies payment in terms of mass or weight. For example:

Contract-specified unit of measurement	Quantity measured	Sales quantity reported to MMS (Mlb)
pounds (lb)	1,192,573,487	1,192,573
thousands of pounds (Mlb)	1,192,573	1,192,573
millions of pounds	1,192	1,192,000

- Millions of Btu (MMBtu) to the nearest whole million Btu if the contract specifies payment in terms of heat or thermal energy. For example:

Contract-specified unit of measurement	Quantity measured	Sales quantity reported to MMS (MMBtu)
Btu	34,197,053,755,239	34,197,054
thousands of Btu	34,197,053,755	34,197,054
millions of Btu (MMBtu)	34,197,053	34,197,053

Netback valuation. For geothermal resources valued by the geothermal netback procedure, you report production quantities on Form MMS-2014 in kilowatthours to the nearest whole kilowatthour, with Sales Quantity being the kilowatthours of **delivered electricity** allocated to lease production.

2.5.2 Units of measurement for direct utilization

For geothermal resources used in direct utilization processes, you use the following units of measurement to report production quantities on Form MMS-2014 (30 CFR 202.353(b)):

- Millions of Btu (MMBtu) to the nearest whole million Btu if valuation is in terms of thermal energy used or displaced. This includes the amount of **thermal energy displaced** for valuation under the alternative fuels method.

- Hundreds of gallons to the nearest whole hundred gallons of geothermal fluid if valuation is in terms of volume.

- Other measurement units that might be identified in sales contracts or used in alternative valuation methods. However, you must contact the MMS Royalty Valuation Division at the address given in appendix A for approval of other measurement units.

2.5.3 Units of measurement for byproducts

For byproduct minerals **except** sulfur, you use the units of measurement (such as ounces, pounds, or tons) given in MMS's *AFS Payor Handbook—Solid Minerals* (30 CFR 202.353(c)). You report sulfur on Form MMS-2014 in long tons (2,240 lb) using product code 19.

2.5.4 Units of measurement for commercially demineralized water

You report the quantity of commercially demineralized water on which royalty is due on Form MMS-2014 in hundreds of gallons to the nearest hundred gallons (30 CFR 202.353(d)). Commercially demineralized water does not have an Auditing and Financial System (AFS) product code at this time.

2.6 Quality Measurements

Quality refers to the physical and chemical properties of the resource. You do not report quality measurements to MMS for geothermal resources or byproducts (30 CFR 202.353(e)). However, you must maintain quality measurements for audit and valuation purposes, particularly if valuation is by the alternative fuels method for direct utilization resources. Quality measurements include, but are not limited to:

- Temperatures, pressures, enthalpies, and chemical analyses of geothermal fluids; and
- Chemical analyses, weight percents, or other purity measurements of byproducts.

2.7 General Valuation Principles

Royalty valuation is based on the concept that value is best determined by the gross proceeds generated under an arm's-length contract for the sale or purchase of the resource in marketable condition. Because prevailing market forces determine prices in arm's-length contracts, MMS views arm's-length prices as the best measure of market value. Thus, as a general rule, the prices established in your arm's-length sales contracts—and the gross proceeds derived therefrom—are acceptable for royalty valuation.

For those geothermal resources disposed under non-arm's-length contracts or those utilized without a sales transaction (the "no-sales" resources), you determine value by the first applicable "benchmark" in a series of prioritized methods. The first benchmark in each series considers your or your affiliate's arm's-length purchases of geothermal resources (to operate a given facility) as a measure of value. If there are no arm's-length purchases, you drop to the second benchmark, most notably the netback procedure for electrical generation resources and the alternative fuel method for direct utilization resources. If the second benchmark is unworkable, you drop to the third benchmark, any other reasonable method approved by the MMS Royalty Valuation Division.

NOTE

When you sell the resource under a non-arm's-length contract, value for royalty purposes can never be less than your gross proceeds accruing under that contract, regardless of the value you compute by one of the other benchmark methods. Thus, you determine value in non-arm's-length sales situations as the greater of your gross proceeds accruing under the sale or the value determined by the appropriate benchmark method.

2.7.1 Arm's-length contract

An *arm's-length contract* is a contract or agreement arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract (30 CFR 206.351). *Persons* are any individuals, firms, corporations, associations, partnerships, consortia, or joint ventures (when established as a separate entity), and are affiliated when one controls the other or when both are under common control. (Persons who are related either by blood or by marriage are also affiliated.) *Control* is determined by the percentage of ownership of the entity's voting securities or other forms of ownership as follows:

1. Ownership in excess of 50 percent constitutes certain control.

2. Ownership of 10 percent through 50 percent creates a presumption of control, which you may rebut.

3. Ownership of less than 10 percent creates a presumption of noncontrol, which MMS may rebut through a finding of actual or legal control, including existence of interlocking directorates.

If the sales contract fails the arm's-length criteria, then it is *non-arm's-length.*

To be considered arm's-length for any production month, the contract must meet the arm's-length criteria for that month as well as when the contract was executed. In other words, an arm's-length contract originally executed between nonaffiliated parties may become non-arm's-length if one party gains control over the other or if both parties come under common control. A non-arm's-length contract, however, remains non-arm's-length throughout its operation, regardless of the current contracting parties' affiliation.

You have the burden of demonstrating that your contract is arm's-length. MMS may require you to certify that the provisions of your arm's-length contract include all of the consideration to be paid by the buyer, either directly or indirectly, for the geothermal resource (30 CFR 206.352(b)(2)).

2.7.2 Gross proceeds

Gross proceeds is the total monies or other consideration you receive for any disposition of the geothermal resource (30 CFR 206.351). Gross proceeds includes not only the revenue received under your sales contract, but also non-cash benefits (consideration) accruing both within and outside the sales contract. Thus, gross proceeds includes, but is not limited to:

- Payments determined directly from the contract price;
- Payments for effluent injection, field operation and maintenance, drilling or workover of wells, field gathering, and other services to the extent that you are obligated to perform them at no cost to the Federal Government;
- Payments to settle past claims when those payments are attributable or allocable to past production;
- Reimbursements for severance taxes and other production taxes;
- Total revenue received for the sale of electricity generated from lease production, including payments for energy, capacity, and bonus capacity;
- Value of services, such as marketing or production services, performed for you to the extent that you are obligated to perform those services at no cost to the Federal Government, particularly when those services are performed in exchange for a reduced sales price;
- Value of non-cash benefits conferred for disposition of the resource; and
- Monies and other consideration to which you are legally or contractually entitled but did not collect or seek through reasonable efforts. (See "Contract compliance" on page 2-14 for further discussion.)

The value of geothermal resources directly sold, under either an arm's-length contract or a non-arm's-length contract, can never be less than the gross proceeds accruing under your sales contract (for example, 30 CFR 206.352(h)). Thus, gross proceeds always defines minimum value.

Gross proceeds can have multiple meanings depending on its context. In most cases, gross proceeds is the product of contract price and quantity (that is, your revenue):

$$\text{gross proceeds} = \text{contract price} \times \text{quantity}.$$

In some cases gross proceeds may refer to a contract price, such as dollars or mills per kilowatthour. (A mill is one-thousandth of a dollar, or $0.001.) Gross proceeds can also refer to a computed, weighted average price. When you receive other consideration, gross proceeds includes the other consideration; for example,

$$\text{gross proceeds} = (\text{contract price} \times \text{quantity}) + \text{other consideration.}$$

Other consideration may be any of the items listed above, may be manifested as monetary payments or non-cash benefits, and may be identified in either the sales contract or another agreement. For example, you may agree to a reduced price in your sales contract in exchange for the purchaser's maintenance of lease facilities negotiated in a separate agreement. In this situation, your gross proceeds determined from your contract price would be adjusted upwards to reflect the services provided by the purchaser.

If you are aware of any additional consideration occurring outside the sales contract, or you have questions regarding reimbursements or other consideration received under your sales contract, please notify the MMS Royalty Valuation Division at the address given in appendix A. Explain the circumstances under which the consideration occurs and either propose a valuation procedure or request guidance.

Payments requiring special reporting. You must report some components of gross proceeds separately on Form MMS-2014; the following table gives a few examples:

Payment type	Product code	Transaction code
Effluent injection	26	01
Severance tax reimbursement	25 or 27	14
Field gathering or other field operations	25 or 27	13

Royalty is due on the amount of each of the above payments. If you have questions on reporting these or other payments, contact your designated reporter representative or the MMS Royalty Valuation Division.

2.7.3 Exceptions to acceptance of arm's-length gross proceeds

You are obligated to negotiate contracts in a prudent manner and receive the best possible price to the mutual benefit of yourself and the Federal Government. Although a contract may be arm's-length, two exceptions may negate the acceptance of gross proceeds as value:

1. The contract does not reflect the total consideration passing between the buyer and seller.

2. The gross proceeds does not reflect the reasonable value of the resource because of misconduct by or between you and your purchaser, or because you have otherwise breached your duty to market the production to the mutual benefit of yourself and the Federal Government. Misconduct or breach of duty may include, but is not limited to, collusion between you and your purchaser, negligence in negotiating contracts, or pricing practices found by a court or regulatory authority to be incorrect or fraudulently manipulated.

MMS may direct you to use other valuation methods if we encounter either of these exceptions. Regulations addressing the acceptability of arm's-length gross proceeds appear at 30 CFR 206.352(b)(1) for electrical generation resources, 30 CFR 206.355(b)(1) for direct utilization resources, and 30 CFR 206.356(b)(1) for byproducts.

2.7.4 Contract compliance

Contract compliance applies to:

- Your direct sales—either arm's-length or non-arm's-length—of geothermal resources, and

- Sales of electricity from your own or your affiliate's geothermal powerplant.

You must value your production on the highest price you can receive through legally enforceable claims under your contract. Therefore, you must make every effort to enforce compliance with contract terms. In the absence of contract revision or amendment, if you fail to take timely or proper action to receive prices or benefits to which you are entitled, you must pay royalty at a value based upon that obtainable price or benefit. Revisions or amendments to contracts must be in writing and signed by all parties to the contract.

If you make timely application for a price increase or benefit allowed under your contract but your purchaser refuses that application, and you take reasonable, timely, and documented action to force compliance, you may continue to pay royalties on the actual gross proceeds received (or other value if determined under the non-arm's-length benchmarks) until the dispute is resolved. If the dispute is resolved in your favor, you will then owe additional royalties on the monies and/or other consideration resulting from the price increase or additional benefits received. If you fail to force compliance through reasonable, timely, and documented actions or you ignore pricing or other remuneration provisions of the contract, you will owe royalty on the gross proceeds that you otherwise would have received under the contract.

Failure by a purchaser to pay in whole, in part, or timely for a quantity of production does not void your obligation to pay royalties on the produced quantity: Royalty is due on the full value and amount of monthly production regardless of whether you receive payment for that production. If the purchaser does not pay you, you must base your royalties on the gross proceeds that you otherwise would have received under the contract (or other value if determined under the non-arm's-length benchmarks).

Regulations addressing contract compliance appear at 30 CFR 206.352(j) for electrical generation resources, 30 CFR 206.355(j) for direct utilization resources, and 30 CFR 206.356(i) for byproducts.

2.7.5 Marketable condition and marketing

You must place geothermal production in marketable condition at no cost to the Federal Government. *Marketable condition* means geothermal fluids and byproducts that are sufficiently free from impurities and otherwise in a condition acceptable to a purchaser under a sales contract typical for the *field*.

Placing production in marketable condition includes, but is not limited to:

- Measuring;

- Gathering;
- Delivery to a powerplant, direct utilization facility, or purchase point;
- Liquid-vapor phase separation;
- Condensate or moisture removal;
- Purification; and
- Any other physical handling and treatment of the resource necessary to meet the delivery specifications of the contract.

You cannot deduct costs of placing production in marketable condition. For example, a sales contract may require you to deliver steam to the inlet of the purchaser's powerplant with a specified minimum moisture content. To meet the contract specifications, you construct pipelines to gather and deliver the steam and install moisture separators to purify the steam. Because you are placing the produced geothermal resource in a (marketable) condition acceptable to the purchaser, you cannot deduct the costs of these services from value.

If your purchaser or another party performs services for you and reduces your gross proceeds accordingly, either through a lower sales price or some other mechanism, you must adjust your gross proceeds upward to offset the reduction. For example, say your contract establishes the following prices and fees per Mlb:

Sales price of steam delivered to the inlet of the purchaser's powerplant		$1.500
Less fees for condensate removal		0.050
Less fees for metering and well-control services		0.005
Less fees for gathering to the powerplant		0.150
Net price per Mlb delivered	=	$1.295

Although your sales revenues are determined by the net price ($1.295), the purchaser's fees are not allowable deductions in determining your **gross proceeds**. Thus, the unit value of production for royalty purposes in this example is the full contract sales price of $1.500/Mlb. You then calculate your gross proceeds as:

$$\text{gross proceeds} = \$1.500/\text{Mlb} \times \text{Mlb delivered.}$$

You cannot deduct the costs of brokering or marketing your geothermal resources from royalty value, whether you perform these services yourself or pay someone else to do them for you.

Marketable condition rules appear at 30 CFR 206.352(i) for electrical generation resources, 30 CFR 206.355(i) for direct utilization resources, and 30 CFR 206.356(h) for byproducts.

2.8 Audits

All royalty payments and the information on which they are calculated are subject to review, audit, and adjustment. You must maintain sufficient, verifiable records and data to support your value determinations and royalty payments.

3. Valuation Standards for Electrical Generation

This chapter describes the standards in 30 CFR 206.352 for valuing geothermal resources used to generate electricity. These resources generally consist of steam, hot water, and hot brines. Valuation standards are grouped according to the resource's disposition:

- Sales under an arm's-length contract.
- Sales under a non-arm's-length contract.
- Utilization by the lessee in the lessee's own geothermal powerplant, otherwise referred to as "no sales."

Valuation standards for resources sold under an arm's-length contract focus on the contract's gross proceeds, with the conditions that the gross proceeds reflects total consideration and reasonable value. (See "Exceptions to acceptance of arm's-length gross proceeds" on page 2-14.) Valuation standards for resources sold under non-arm's-length contracts and for no-sales resources are given as a sequence of three benchmarks, or methods, where you determine value under the first applicable method in descending order of appearance. For example, if the first benchmark is not applicable or not workable, valuation falls to the second benchmark, and so on. The **netback** procedure, appearing as the second benchmark in the non-arm's-length and no-sales valuation standards, is detailed in chapter 4.

We refer to geothermal resources used to generate electricity as *electrical generation resources*.

3.1 Arm's-Length Sales

As a general rule, you determine the value of electrical generation resources sold under an arm's-length contract as the gross proceeds accruing under that contract (30 CFR 206.352(b)(1)(i)). (See "General Valuation Principles" on page 2-10 for additional discussion on arm's-length contracts and gross proceeds.)

However, you must satisfy two conditions to justify the contract gross proceeds (or contract prices) as value:

1. The sales contract must reflect the **total consideration** actually transferred, either directly or indirectly, from the buyer to the seller (30 CFR 206.352(b)(1)(ii)). Total consideration is synonymous with the full definition and intent of gross proceeds as discussed in section 2.7.2 on page 2-11. If the contract does not reflect total consideration, MMS **may** require you to value the resource under the no-sales benchmarks in section 3.3 on page 3-9. However, value can never be less than the gross proceeds, including any additional consideration you receive, regardless of the value calculated under the no-sales benchmarks. MMS may require you to certify that your arm's-length contract includes all of the consideration paid to you by the buyer, either directly or indirectly, for the geothermal resource (30 CFR 206.352(b)(2)).

2. The gross proceeds received under the contract must reflect **reasonable value** (30 CFR 206.352(b)(1)(iii)). If MMS determines that the gross proceeds does not reflect the reasonable value of the resource because of misconduct by or between the contracting parties, or because you have otherwise breached your duty to market the production to the mutual benefit of yourself and the Federal Government, MMS **will** require valuation under the no-sales benchmarks. When we determine that the value may be unreasonable, we will notify you and give you an opportunity to provide written information justifying your value.

Notification requirements. You don't need to notify MMS if valuation is under an arm's-length contract. However, if there is consideration outside the contract, you should notify the MMS Royalty Valuation Division at the address given in appendix A. Explain the circumstances under which the consideration occurs and either propose a valuation procedure or request guidance.

3.2 Non-Arm's-Length Sales

Non-arm's-length sales occur when you sell geothermal production to your power-generating affiliate. Non-arm's-length sales automatically generate gross proceeds, which, because it is non-arm's-length, you must compare with other values to determine the proper royalty value.

You determine the value of these non-arm's-length resources by the first applicable of three benchmark methods: (1) gross proceeds, (2) netback valuation, or (3) other valuation methods (30 CFR 206.352(c)(1)(i), (ii), and (iii), respectively).

3.2.1 First non-arm's-length valuation benchmark: Gross proceeds

You use the first non-arm's-length benchmark when:

1. You sell geothermal resources to your power-generating affiliate, and

2. Your power-generating affiliate purchases—under arm's-length contracts—**significant quantities** of geothermal resources to operate the **same powerplant**.

This benchmark actually incorporates two prioritized valuation standards that hinge on the comparability of your non-arm's-length gross proceeds with minimum value. *Minimum value* is the gross proceeds derived under the lowest-priced available, comparable arm's-length contract for sales of geothermal fluids to your affiliate's same powerplant.

If the gross proceeds under your non-arm's-length contract is equal to or greater than the minimum value, it is acceptable for value. If it is less than the minimum value, or if there are no available, comparable arm's-length contracts, you determine value as the weighted average of the gross proceeds established under arm's-length contracts for the sale of significant quantities of geothermal resources to the same powerplant (see example 3-1 below). *Gross proceeds* for the purpose of determining a weighted average means the contract prices. *Significant quantities* is not precisely defined but depends on the circumstances of each situation; a particular quantity of geothermal resources may be considered significant for one powerplant but not another.

Available contracts are those contracts possessed by you, your affiliate, or MMS. You determine the comparability of arm's-length contracts by their similarity to your non-arm's-length contract. In determining comparability, consider such factors as the time of execution, duration, terms, quality and volume of resource, dedication to the same powerplant, and other factors reflecting the value of the resource. An example of a comparable arm's-length contract would be one executed at the same time and for the same duration as your non-arm's-length contract and providing for the delivery of 50 percent or more of the powerplant's operating requirements. On the other hand, a noncomparable arm's-length contract would be one executed after startup of the powerplant and providing only for temporary delivery of a small quantity at a premium price.

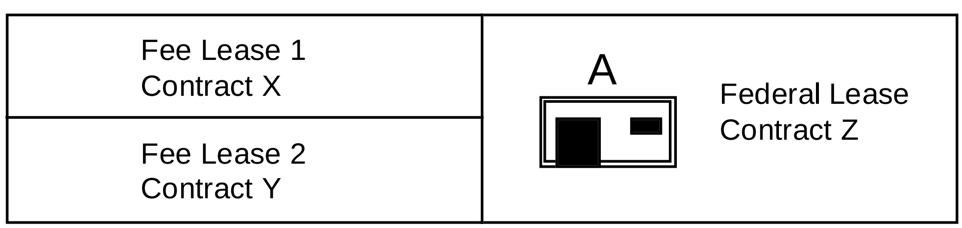
Valuation falls to the second benchmark if your power-generating affiliate:

1. Purchases only your production (that is, there are no arm's-length sales of geothermal fluids to your affiliate's powerplant), or

2. Does not make arm's-length purchases of significant quantities of geothermal fluids to operate its powerplant.

Example 3-1: Valuing electrical generation resources under the first non-arm's-length benchmark

As lessee of the Federal lease, you sell geothermal production to your affiliated powerplant operator A under non-arm's-length (NAL) contract Z. The powerplant operator also purchases geothermal production from two adjacent fee lessees under arm's-length (AL) contracts X and Y. You produce 150,000 thousands of pounds (Mlb) for the month, for which you must determine proper value and pay royalties.



SUMMARY DATA

Lease	Contract	Contract type	Production (Mlb)	Gross proceeds	
				Price ($/Mlb)	Revenue ($)
Fee 1	X	AL	145,000	2.00	290,000.00
Fee 2	Y	AL	5,000	2.15	10,750.00
Federal	Z	NAL	150,000	1.80	270,000.00

Arm's-length contract X and non-arm's-length contract Z were executed as major, long-term suppliers to the powerplant; both have the same terms and conditions, except for price. Arm's-length contract Y was executed as a makeup supplier for the first 5 years of operation.

In this example, arm's-length contract Y does not meet the comparability test—its terms and duration are limited and it does not supply a significant quantity of resources—and therefore is not applicable to valuation. Thus, contract X is the lowest-priced available, comparable arm's-length contract for sales to your power-generating affiliate, and its price ($2.00/Mlb) establishes minimum value. Because the price and resultant revenues under your non-arm's-length contract Z are less than the minimum value, they are not acceptable for royalty valuation. Therefore, the value on which you report and pay royalties is:

$$\$2.00/\text{Mlb} \times 150{,}000 \text{ Mlb} = \$300{,}000.$$

Assuming your royalty rate is 12.5 percent, you report the following information on the Form MMS-2014:

Sales Quantity	150,000 Mlb
Sales Value	$300,000.00
Royalty Quantity	18,750 Mlb
Royalty Value	$37,500.00

Now let's change the terms of contract Y so that they are comparable to those of contract X (that is, both are major, long-term suppliers to the powerplant). Say that deliveries for the month under contract Y are 130,000 Mlb.

Summary Data

Lease	Contract	Contract type	Production (Mlb)	Gross proceeds	
				Price ($/Mlb)	Revenue ($)
Fee 1	X	AL	145,000	2.00	290,000.00
Fee 2	Y	AL	130,000	2.15	279,500.00
Federal	Z	NAL	150,000	1.80	270,000.00

Because your gross proceeds under your non-arm's-length contract is still less than the minimum value but you now have two comparable arm's-length contracts supplying the powerplant, you calculate value as the weighted average of the arm's-length contract prices. Calculate to six decimal places.

$$\frac{(\$2.00/\text{Mlb} \times 145{,}000\ \text{Mlb}) + (\$2.15/\text{Mlb} \times 130{,}000\ \text{Mlb})}{145{,}000\ \text{Mlb} + 130{,}000\ \text{Mlb}} = \$2.070909/\text{Mlb}$$

You then report and pay royalties on 150,000 Mlb at a value of $2.070909/Mlb, or $310,636.36.

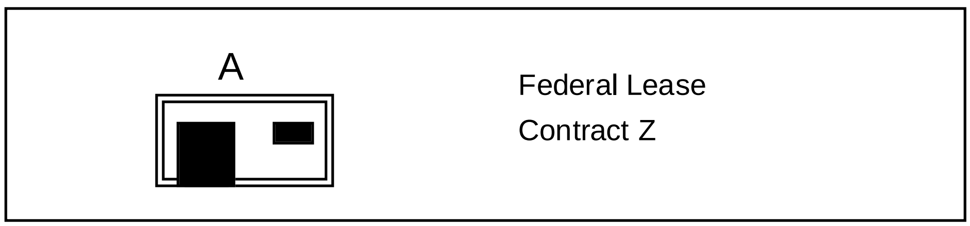
3.2.2 Second non-arm's-length valuation benchmark: Netback valuation

The second non-arm's-length valuation benchmark for electrical generation resources prescribes the geothermal netback procedure (see chapter 4). However, under no circumstances can value be less than your gross proceeds accruing for the sale of the resource (30 CFR 206.352(h)). Thus, you determine value as the **greater** of the gross proceeds under your non-arm's-length contract or the netback value (see example 3-2 below).

Netback valuation is generally contingent on a bona fide sale of electricity from your affiliate's powerplant. If the electricity is not sold or the netback procedure is otherwise unworkable or not applicable, valuation falls to the third benchmark.

Example 3-2: Valuing electrical generation resources under the second non-arm's-length benchmark

As lessee of the Federal lease, you supply geothermal production to your affiliated powerplant operator A under non-arm's-length (NAL) contract Z. The sales price under the contract is 21 mills/net kWh ($0.021/net kWh). The powerplant operator purchases only your production and generates 32,895,700 net kWh for the month.



SUMMARY DATA

Lease	Contract	Contract type	Production (kWh)	Gross proceeds	
				Price ($/kWh)	Revenue ($)
Federal	Z	NAL	32,895,700	0.021	690,809.70

Because there are no arm's-length contracts for sales to your power-generating affiliate's same powerplant, you have no arm's-length gross proceeds against which to compare your non-arm's-length gross proceeds. Therefore, valuation falls to the second benchmark: the greater of your gross proceeds under your non-arm's-length contract or the netback value.

Say that the netback value for the month is only $380,675.00. Because your non-arm's-length gross proceeds is greater than the netback value, you report and pay royalties on your gross proceeds, $690,809.70. Assuming your royalty rate is 12.5 percent, you report the following information on Form MMS-2014:

Sales Quantity	32,895,700 kWh
Sales Value	$690,809.70
Royalty Quantity	4,111,963 kWh
Royalty Value	$86,351.21

NOTE

If your netback value had been greater than your gross proceeds, you would report delivered electricity for Sales Quantity and your calculated netback value for Sales Value (see “Reporting Netback Values on Form MMS-2014” on p. 4-34).

3.2.3 Third non-arm’s-length valuation benchmark: Other valuation methods

The third non-arm’s-length valuation benchmark allows you to use any other reasonable method to determine value. To implement the third benchmark, you must demonstrate that the first two benchmarks—and particularly the second—do not apply or are unworkable. You must propose an alternative valuation method and receive MMS’s approval to use that method (see “Valuation Requests” on p. 3-14).

3.2.4 Notification requirements

You must notify MMS if valuation is under the non-arm’s-length sales benchmarks (30 CFR 206.352(e)(3)). Send notification by letter to the MMS Royalty Valuation Division at the address given in appendix A. You must identify the valuation method used and describe the procedure you plan to follow. Include sufficient narrative explanation and backup data to support your valuation method.

This notification is due no later than the end of the month following the month you first report royalties on Form MMS-2014 using the described valuation method. The notification is one-time and remains in effect during use of the method. If you change to a different valuation method, you must submit a new notification.

3.3 No Sales

No sales of electrical generation resources occur when you use the geothermal fluids in your own powerplant to generate electricity. You determine the value of these no-sales resources by the first applicable of three benchmark methods: (1) weighted average of arm's-length gross proceeds, (2) netback valuation, or (3) other valuation methods (30 CFR 206.352(d)(1)(i), (ii), and (iii), respectively).

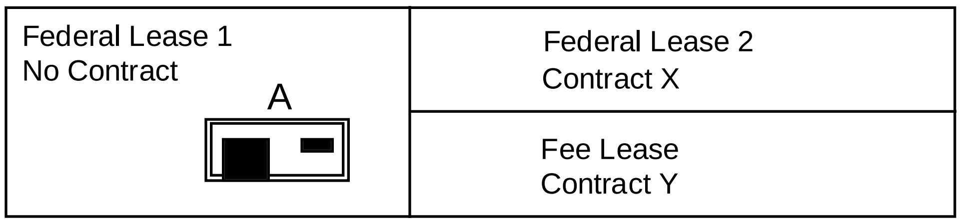
3.3.1 First no-sales valuation benchmark: Weighted average of arm's-length gross proceeds

The first no-sales valuation benchmark is applicable **only** when you purchase—under arm's-length contracts—**significant quantities** of geothermal fluids to operate the **same powerplant**. In this situation, you value the geothermal resource as the weighted average of the gross proceeds established in the arm's-length contracts (see example 3-3 below). *Gross proceeds* for the purpose of determining a weighted average means contract prices. The volumes of resource purchased must meet the *significant quantities* test. You must judge the acceptability of the arm's-length contracts by considering their time of execution, duration, terms, quality and volume of resource purchased, and other factors that may reflect the value of the resource.

Valuation falls to the second benchmark if you use only your own production to operate your powerplant; that is, you do not purchase significant quantities of geothermal resources under arm's-length contracts (see sec. 3.3.2 on p. 3-11).

Example 3-3: Valuing electrical generation resources under the first no-sales benchmark

As lessee of the Federal lease and owner of Powerplant A, you purchase geothermal production from adjacent Federal and fee leases to supplement powerplant supply. You produce 21,500 Mlb for the month, for which you must value and pay royalties.



SUMMARY DATA

Lease	Contract	Contract type	Production (Mlb)	Gross proceeds	
				Price ($/Mlb)	Revenue ($)
Federal 1	None	—	21,500	—	—
Federal 2	X	AL	19,800	1.855	36,729.00
Fee	Y	AL	18,700	1.795	33,566.50

Contracts X and Y are arm's-length (AL) and satisfy the comparability and significant quantities tests. Thus, you calculate the value of your Federal lease production as the monthly weighted average price under the two contracts:

$$\frac{(\$1.855/\text{Mlb} \times 19{,}800\ \text{Mlb} + (\$1.795/\text{Mlb} \times 18{,}700\ \text{Mlb})}{19{,}800\ \text{Mlb} + 18{,}700\ \text{Mlb}} = \$1.825857/\text{Mlb}$$

You report and pay royalties on production of 21,500 Mlb at a value of $1.825857/Mlb, or $39,255.93. Assuming your royalty rate is 12.5 percent, you report the following information on Form MMS-2014:

Sales Quantity	21,500 Mlb
Sales Value	$39,255.93
Royalty Quantity	2,688 Mlb
Royalty Value	$4,906.99

Note that if either contract X or Y did not satisfy the significant quantities test, you would not use its price in the value calculation. For example, say that contract X was executed only to supply makeup production not to exceed 5,000 Mlb/month. In this case, you would base value solely on contract Y's price, or 1.795/Mlb.

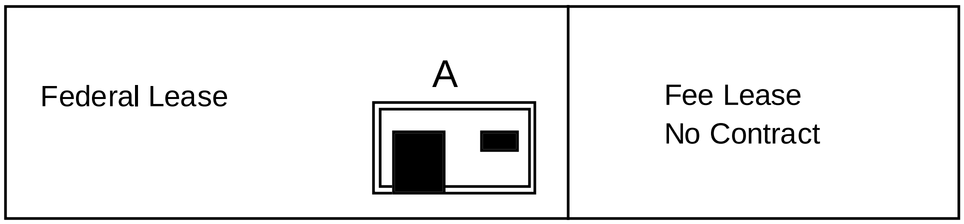
3.3.2 Second no-sales valuation benchmark: Netback valuation

The second no-sales valuation benchmark for electrical generation resources prescribes the geothermal netback procedure (see example 3-4 below). Netback valuation is described in chapter 4.

Netback valuation is generally contingent on a bona fide sale of electricity from your powerplant. If the electricity is not sold, or the netback procedure is otherwise unworkable or not applicable, valuation falls to the third benchmark (see sec. sec. 3.3.3 on p. 3-12).

Example 3-4: Valuing electrical generation resources under the second no-sales benchmark

As lessee of the Federal lease and owner of Powerplant A, you supply the powerplant with production from the Federal lease and an adjacent fee lease, which you also own.



SUMMARY DATA

Lease	Contract	Contract type	Production (Mlb)	Gross proceeds	
				Price ($/Mlb)	Revenue ($)
Federal	None	—	21,500	—	—
Fee	None	—	18,700	—	—

Because you make no arm's-length purchases of significant quantities of geothermal fluids to operate your powerplant, you determine value of the Federal lease production by the netback procedure described in chapter 4. Your valuation of and royalty payments on geothermal fluids produced from the fee lease have no bearing on your Federal royalty valuation.

3.3.3 Third no-sales valuation benchmark: Other valuation methods

The third no-sales valuation benchmark allows you to use any other reasonable method to determine value. To implement the third benchmark, you must demonstrate that the first two benchmarks—and particularly the second—do not apply or are unworkable. You must propose an alternative valuation method and receive MMS's approval to use that method (see "Valuation Requests" on p. 3-14).

3.3.4 Notification requirements

You must notify MMS if valuation is under the no-sales benchmarks (30 CFR 206.352(e)(3)). This notification must be by letter to the MMS Royalty Valuation Division at the address given in appendix A. You must identify the valuation method used and describe the procedure you plan to follow. Include sufficient narrative explanation and backup data to support your valuation method.

This notification is due no later than the end of the month following the month you first report royalties on Form MMS-2014 using the described valuation method. The notification is one-time and remains in effect during use of the method. If you change to a different valuation method, you must submit a new notification.

3.4 Improper Valuations

If MMS finds that you improperly determined value, we will direct you to correct your value or prescribe a different valuation procedure (30 CFR 206.352(f)). You will be liable for any difference between the royalties paid and the royalties due under the value determined by MMS, plus late payment interest on underpaid amounts pursuant to 30 CFR 218.302. If the corrected value or prescribed valuation procedure results in an overpayment, MMS will give you instructions for taking a credit. You are not entitled to interest on royalty overpayments.

You may appeal any of MMS's valuation decisions. For adverse decisions, MMS will issue appeals instructions concurrent with the decision. Otherwise, see 30 CFR Part 243 for appeals information.

3.5 Valuation Requests

If you are unsure of your valuation procedure, you may request a determination from MMS (30 CFR 206.352(g)). Send your valuation requests to the MMS Royalty Valuation Division at the address given in appendix A. Include a description of your operation, copies of sales contracts, and any other information pertinent to the valuation of your geothermal production. You must continue to pay royalties on production while MMS is making its valuation determination. You will be liable for any additional royalty and interest if our determination results in a higher value than the value on which you paid royalties.

If you request an alternative valuation method under the third non-arm's-length or no-sales benchmarks (other valuation methods), you must propose the valuation method you intend to use and include all information supporting your proposal. Remember, you must receive MMS's approval to use an alternative valuation method under the third benchmark and explain why the first two benchmarks are unworkable. You may use your proposed valuation method for royalty calculations until MMS issues a decision. If MMS approves your proposed valuation method, you must use that method until one of the following occurs:

- The circumstances of your production and/or utilization change, at which time you must notify MMS with a new valuation request.
- MMS instructs you to use a different valuation method.
- MMS issues new valuation regulations.

If MMS disapproves your proposed valuation method, we will prescribe a method to you. You must then adjust all of your past royalty reports to reflect the prescribed method (30 CFR 206.352(f)). If our prescribed method results in additional royalty due, you must pay the additional royalty plus interest. If our prescribed method results in royalty overpayments, MMS will give you instructions for taking a credit. You are not entitled to interest on royalty overpayments.

3.6 Recordkeeping and Availability

You must save all data and records relevant to your royalty valuation (30 CFR 206.352(e)(1)), particularly if you value production under the second or third non-arm's-length or no-sales benchmark.

Keep the following documents indefinitely:

- All contracts related to the sale or purchase of geothermal resources.
- All contracts related to the sale, purchase, generation, and transmission of electricity generated from the geothermal resource.
- Any other contracts that may bear on the valuation of the resource or are necessary to support your valuation.
- All MMS valuation decisions and other written communications relevant to your valuation.
- Records of capitalized costs and equipment to support netback calculations.

You must keep records relevant to your monthly royalty calculations for 6 years after the records are generated, unless MMS instructs otherwise. These records include, but are not limited to, quantities produced and/or sold and prices received for sale of the resource. For netback valuation, keep your value calculations and all source documents supporting your claimed costs. You must make all records, contracts, and other documents supporting your valuations available to authorized MMS personnel or MMS-designated agents upon request (30 CFR 206.352(e)(2)). See also 30 CFR 212.351.

4. Netback Valuation

This chapter explains how you calculate geothermal values under the netback procedure. You use netback to value electrical generation resources under the second non-arm's-length and no-sales valuation benchmarks discussed in "Non-Arm's-Length Sales" on page 3-2 and "No Sales" on page 3-9; that is, when you don't have suitable arm's-length contracts to establish the value of your production.

Under the netback procedure, you derive the value of the geothermal resource by subtracting your costs of generating and transmitting electricity from your electricity sales value:

netback geothermal value

= electricity value – transmission deduction – generating deduction.

Use the following steps to guide you through netback valuation:

STEP 1. Calculate your **annual** transmission and generating **cost rates** at the beginning of each deduction period.

STEP 2. Calculate your **monthly** transmission and generating **deductions**.

STEP 3. Calculate the **monthly value** of geothermal resources used in the powerplant by subtracting the transmission and generating deductions from your gross proceeds received for the month's sale of electricity (that is, the electricity value). This step derives the netback value of all geothermal resources, regardless of source, at the powerplant inlet.

STEP 4. Allocate the monthly value to Federal leases as necessary.

STEP 5. Report monthly delivered electricity and values allocated to each lease on Form MMS-2014.

STEP 6. At the beginning of the next deduction period, recalculate the previous deduction period's cost rates, deductions, and netback values based on your actual, known costs for that period. Submit corrected Forms MMS-2014, adjusting the royalty lines for each month using adjustment reason code 10.

Two conditions predicate netback valuation:

1. You or your power-generating affiliate uses the leased geothermal resource to generate and sell electricity, and

2. There is a current or prior contractual sale of the electricity.

The second condition is paramount because the sales contract establishes the value of the electricity, which forms the basis for netback valuation. If the value of the electricity is not established in a sales contract and cannot be determined by another method, the netback procedure is unworkable.

4.1 Electricity Value

The electricity value is the total amount of revenues (gross proceeds) you receive under your sales contract for the delivery of electricity during your accounting month. In most current cases, this amount includes your energy payment, capacity payment, and bonus capacity payment. Any other monies or consideration exchanged for your delivery of electricity may also affect the electricity value or the netback deductions; the principles of total consideration and reasonable value, discussed in "Arm's-Length Sales" on page 3-1, apply to electricity sales as they do to sales of geothermal fluids.

MMS generally will not recognize cost-of-service contracts to value the electricity; not only are such contracts non-arm's-length, they do not reflect reasonable market value. If you do not have a current, third-party electricity sales contract, other methods may be available to value either the electricity or the resource. In these cases you must contact the MMS Royalty Valuation Division at the address given in appendix A for guidance and/or approval.

4.2 Cost Rates and Deductions

Annual cost rates and monthly deductions form the basis of netback valuation, as these elements establish your costs of generating and transmitting electricity. You calculate annual cost rates in terms of dollars per kilowatthour ($/kWh) and then apply these cost rates to monthly electricity measurements to determine your monthly deductions:

deduction ($) = annual cost rate ($/kWh) × measured electricity (kWh).

You then subtract the deductions from your electricity revenues to derive your monthly geothermal resource value.

Cost rates have two cost components: (1) combined operating and maintenance (O&M) expenses and (2) capital-related costs. You have the option of claiming your capital-related costs as **either** depreciation and a return on undepreciated capital investment **or** a return on capital investment. How you handle the capital-related costs determines your method of computing the cost rate: the depreciation method or the return-on-investment method.

NOTE You cannot apply the return-on-investment method to transmission lines and powerplants placed into service before March 1, 1988.

Once you have chosen a calculation method, you cannot later use the other method without the MMS Royalty Valuation Division's approval. You must calculate all cost rates to six decimal places.

Detailed instructions on computing transmission-line cost rates and generating cost rates are given page 4-9 and 4-22, respectively.

You recalculate the cost rates at the beginning of each annual deduction period using the previous period's **actual**, cumulated costs. You use these new cost rates to calculate the new period's deductions and royalty values and to recalculate the past period's **actual** deductions and royalty values. For your first deduction period, you must use estimates of O&M costs to calculate your cost rates. For subsequent deduction periods, use the previous period's **actual** O&M costs, adjusted for any anticipated differences.

Regulations covering transmission and generating deductions are given in 30 CFR 206.353 and 206.354, respectively, particularly in paragraphs (b)(1) and (b)(2). Governing regulations are not rigorously cited in this chapter because of the many subparagraphs. Accordingly, you should refer to the CFR for regulatory cross-reference.

4.2.1 Transmission deductions

Transmission deductions recognize your reasonable, actual costs of transmitting electricity from the powerplant tailgate (high voltage side of the powerplant transformer) to the sales or delivery point. Transmission deductions consist of either or both:

- Arm's-length wheeling charges
- Transmission-line deductions

4.2.1.1 Arm's-length wheeling charges

Arm's-length wheeling charges are those contractual fees charged by a third party, generally a utility, to transmit your electricity to your purchaser's receipt point. If you transmit commingled electricity generated from different powerplants, you must allocate the wheeling charges in proportion to the amount of electricity transmitted by each powerplant.

4.2.1.2 Transmission-line deductions

Transmission lines include all transmission-related equipment that you install between the high voltage side of the powerplant transformer and the point of electricity sales or delivery. The transmission line must directly serve the powerplant using Federal geothermal production.

Transmission-line deductions are the product of the annual transmission-line cost rate and monthly **delivered** (or interconnect) **electricity**:

$$\text{transmission-line deduction (\$)} = \text{annual cost rate (\$/kWh)} \times \text{monthly delivered electricity (kWh)}.$$

4.2.1.3 Delivered and interconnect electricity

Delivered electricity generally means the amount of electricity delivered to your purchaser at the sales point. However, in cases where your transmission line interconnects with another, third-party transmission line over which you wheel the electricity to the final sales point, you must use the amount of *interconnect electricity* (the amount of electricity delivered at the interconnect) to calculate your transmission-line cost rates and deductions. (The remainder of your transmission costs will then be in the form of wheeling charges.) Example 4-7 on page 4-37 illustrates the use of interconnect electricity in netback calculations.

4.2.2 Generating deductions

Generating deductions recognize your reasonable, actual costs of constructing and operating your geothermal powerplant; that is, your costs of generating electricity. Generating deductions are the product of the annual generating cost rate and monthly **plant tailgate electricity**:

$$\text{generating deduction (\$)} = \text{annual cost rate (\$/kWh)} \times \text{monthly plant tailgate electricity (kWh)}.$$

Plant tailgate electricity is the amount of electricity generated by the powerplant exclusive of plant parasitic electricity but inclusive of any generated electricity returned to your lease for lease operations (30 CFR 206.351). In general, you will determine plant tailgate electricity by adding any electricity returned to the lease to the amount of electricity measured by the powerplant's *net-out* meter. (Net-out electricity is the electricity entering the transmission line.) You must either measure the powerplant's net-out electricity at, or calculate it for, the high voltage side of the transformer in the powerplant switchyard before adding electricity returned to the lease.

4.2.3 Deduction periods

Deduction periods, also called "reporting periods," are the 12 months during which your annual cost rates are effective. Deduction periods must begin with the month that:

- Your transmission line was placed into service,
- Your powerplant was placed into service, or
- Your annual corporate accounting period begins.

You may choose your deduction period based on the above criteria. However, both transmission- and generating-deduction periods must coincide; that is, the time periods for both deductions must be the same. Once you have selected a deduction period, you cannot later choose a different period without MMS approval.

4.2.4 Deduction limits

You must limit the sum of your transmission and generating deductions to 99 percent of your electricity sales gross proceeds. Although deductions have no regulatory threshold limits, they cannot reduce the value of the resource to zero (30 CFR 206.353(c) and 206.354(c)). MMS's administrative policy does not allow the combined transmission and generating deductions to exceed 99 percent of the electricity value; that is, the resource value cannot be less than 1 percent of your gross electricity sales proceeds.

4.3 Requisite Electricity Measurements

Figure 4-1 shows the electricity measurements needed to determine your deductions. For the **transmission-line deduction**, you must determine the amount of delivered electricity or the amount of interconnect electricity (if your transmission line interconnects with another transmission line to wheel the electricity to the sales point). For the **generating deduction**, you must determine the sum of electricity entering the transmission line, usually the net-out electricity, and any electricity returned to the lease for lease operations; these measurements combined are your *plant tailgate electricity* (see "Generating deductions" on p. 4-5). All electricity measurements must be in kilowatthours. Be sure to measure parasitic electricity and electricity returned to the lease separately.

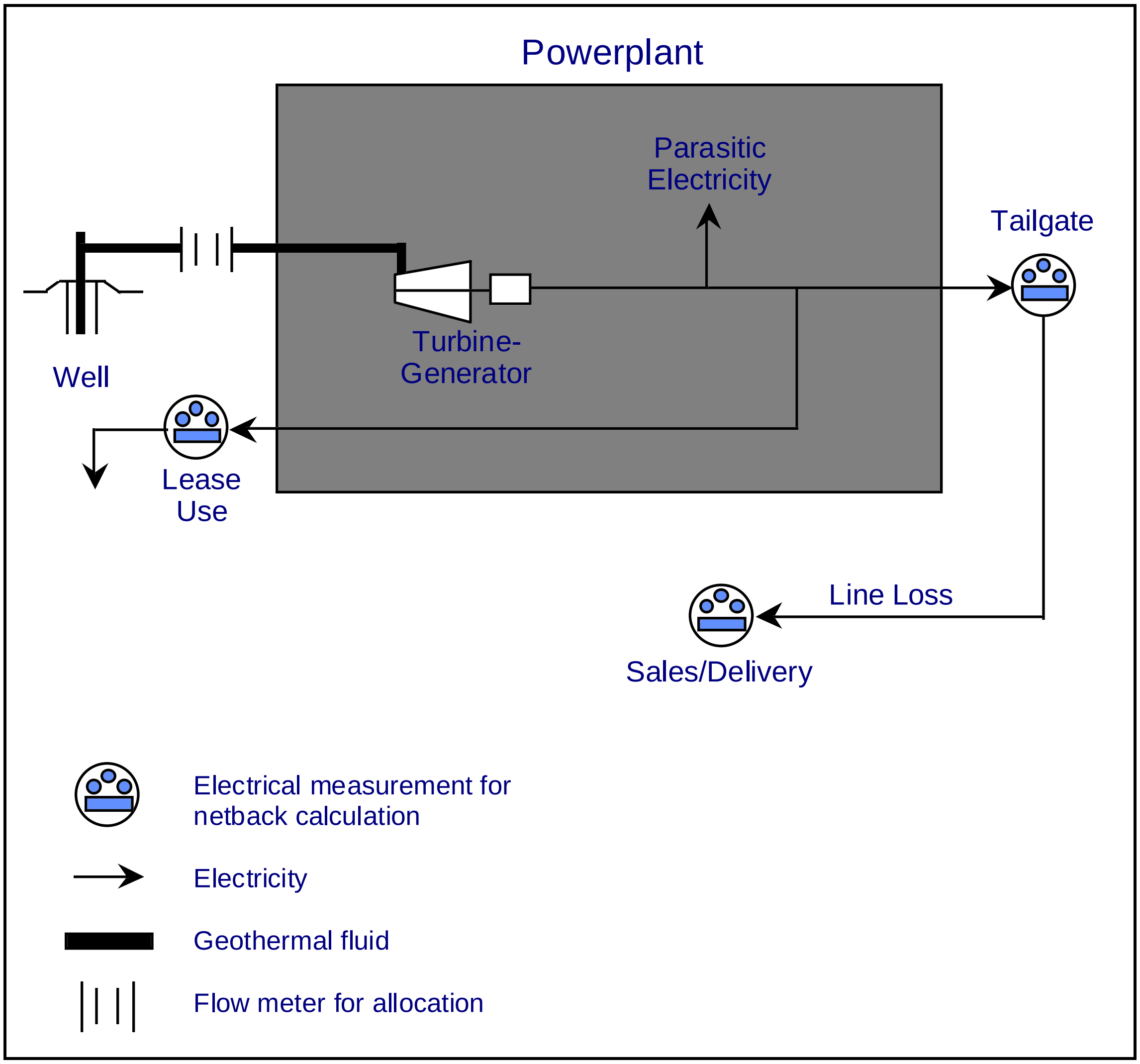


FIGURE 4-1. **Electrical measurement points for netback valuation**

4.4 Netback Valuations When Electricity Payments Are Not Made on a Calendar Month

MMS recognizes that electricity purchasers do not always close their monthly accounts on the last day of the month; that is, they do not voucher their monthly payments for a calendar month's delivery. When this happens, use the date of your purchaser's monthly statement to calculate your deductions for that month (see also "Timing of Valuation and Royalty Payments" on p. 2-4). This does not affect the calculation or application of your annual cost rates; they remain calculated on the 12-month deduction period you select under "Deduction periods" on page 4-6. For example, if you are paid for electricity delivered to December 20 and your annual deduction period ends on December 31, you would use the cost rates calculated for the full 12-month period (January through December) to determine your December deductions. Likewise, if you are paid for electricity delivered to January 20 and your annual deduction period begins January 1, you would use the cost rates calculated for the full forthcoming year to determine your January deductions.

4.5 Cost Reimbursements

Any reimbursements you receive for the construction and/or operation of the powerplant and/or transmission line offset the corresponding costs. For example, if your electricity purchaser reimburses you for operating the powerplant, that reimbursement offsets your annual O&M cost. If your purchaser or some other entity gives you a nonrecoupable grant to build the transmission line, that grant offsets your transmission-line capital investment. Cost reimbursements include manufacturer's rebates, insurance payments, and court awards (generally principal amounts exclusive of interest) where the awards relate to recovered damages for capital and O&M costs, including downtime awards.

4.6 Transmission-line Cost Rates

Transmission-line cost rates are your annualized costs associated with the construction and operation of a transmission line, divided by the annual amount of **delivered electricity**. Transmission-line costs consist of:

1. Combined O&M expenses, including direct overhead, and **either**

2. Depreciation and a return on undepreciated capital investment, **or**

3. A return on capital investment.

How you handle the capital-related costs (items 2 and 3) determines the method of calculating your cost rates: depreciation method or return-on-investment method. Once you've chosen a calculation method, you cannot later use the other method without the MMS Royalty Valuation Division's approval.

4.6.1 Calculating transmission-line cost rates by the depreciation method

If you use the depreciation method, calculate your annual transmission-line cost rates from the following equation:

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

where:

E = annual O&M expenses, estimated for the first deduction period

D = annual depreciation of **gross** capital investments (see "Depreciation" below)

I = annual return on undepreciated capital investment (see "Return on undepreciated capital investment" below)

F = annual kWh of **delivered** (or interconnect) **electricity**, estimated for the first deduction period (see "Delivered and interconnect electricity" on p. 4-5)

4.6.1.1 Depreciation

Follow these rules to determine your depreciation (D):

- Depreciate only the allowable capital investment.
- Calculate depreciation on your gross capital investments; do not deduct salvage value for any of the capital equipment.
- Use straight-line depreciation.
- Use a depreciation period equal to the term of your electricity sales contract or the normal, useful life of individual equipment if less than the term of the sales contract. Thus, you may have different depreciation schedules for different equipment, but you cannot use different depreciation periods outside those described in the previous sentence without the MMS Royalty Valuation Division's approval. You do not need approval for depreciation periods based on the term of the electricity sales contract or the lives of individual equipment.
- Adjust your depreciation schedule(s) for retired or replaced capital items using generally accepted accounting principles.
- Depreciate the transmission line and related equipment only once. A change in ownership does not alter the depreciation schedule(s) established by the original owner, except for addition or replacement of capital items.

4.6.1.2 Return on undepreciated capital investment

The return on undepreciated capital investment (I) is the product of the return rate and the undepreciated capital investment balance **at the beginning of the annual deduction period:**

$$I = \text{return rate} \times \text{undepreciated investment balance.}$$

The return rate is two times the Standard and Poor's monthly average **industrial BBB** bond rate, as published in Standard and Poor's *Bond Guide*, for the first month of the annual deduction period. This rate remains constant during the deduction period; you redetermine the return rate at the beginning of each deduction period.

Example 4-1 shows the calculation of transmission-line cost rates by the depreciation method.

Example 4-1: Calculating transmission-line cost rates by the depreciation method

The example is for the first and fifth years of operation.

Schedule of Capital Costs

- Capital investment = $3,000,000
- Depreciation period = 30 years
- Annual depreciation (D) = $100,000
- Depreciation schedule:

Year	Beginning-of-year undepreciated investment balance
1	$3,000,000
2	2,900,000
3	2,800,000
4	2,700,000
5	2,600,000

First Year of Operation (First Deduction Period)

- Estimated O&M expenses (E) = $1,000
- Undepreciated capital investment balance = $3,000,000
- Standard and Poor's monthly average industrial BBB bond rate for the month beginning the first deduction period = 8.96%
- Return on undepreciated capital investment (I):

$$(2 \times 0.0896) \times \$3{,}000{,}000 \; = \; \$537{,}600$$

- Estimated annual delivered electricity (F) = 610,500,000 kWh.

- Cost rate:

$$\frac{E + D + I}{F} = \frac{\$1{,}000 + \$100{,}000 + \$537{,}600}{610{,}500{,}000 \text{ kWh}} = \$0.001046/\text{kWh}$$

<u>Fifth Year of Operation (Fifth Deduction Period)</u>

- Previous deduction period's O&M expenses (E), adjusted for anticipated differences = $1,800
- Undepreciated capital investment balance = $2,600,000
- Standard and Poor's monthly average industrial BBB bond rate for the month beginning the fifth deduction period = 9.76%
- Return on undepreciated capital investment (I):

$$(2 \times 0.0976) \times \$2{,}600{,}000 = \$507{,}520$$

- Annual delivered electricity (F) = 607,945,260 kWh
- Cost rate:

$$\frac{E + D + I}{F} = \frac{\$1{,}800 + \$100{,}000 + \$507{,}520}{607{,}945{,}260 \text{ kWh}} = \$0.001002/\text{kWh}$$

4.6.2 Calculating transmission-line cost rates by the return-on-investment method

If you use the return-on-investment method, calculate your annual transmission-line cost rates from the following equation:

$$\text{cost rate } (\$/\text{kWh}) = \frac{E + R}{F}$$

where:

E = annual O&M expenses, estimated for the first deduction period

R = annual return on allowable **gross** capital investments, adjusted for retired or replaced capital items

F = annual kWh of **delivered** (or interconnect) **electricity**, estimated for the first deduction period (see "Delivered and interconnect electricity" on p. 4-5)

Calculate the cost rate to six decimal places.

NOTE

You can use the return-on-investment method only for transmission lines first placed into service on or after March 1, 1988.

The annual return (R) is the product of the return rate and the transmission-line capital investment:

$$R = \text{return rate} \times \text{capital investment.}$$

The return rate is two times the Standard and Poor's monthly average **industrial BBB** bond rate, as published in Standard and Poor's *Bond Guide*, for the first month of the annual deduction period. This rate remains constant during the deduction period; you redetermine the return rate at the beginning of each deduction period.

Use your gross capital investments in the transmission line, adjusted for retired or replaced capital items, to calculate R. If the transmission line changes ownership, you must continue to use the original owner's capital investment to calculate R; you cannot recapitalize the transmission line with a change of ownership.

Example 4-2 shows the calculation of a transmission-line cost rate by the return-on-investment method.

Example 4-2: Calculating a transmission-line cost rate by the return-on-investment method

The example is for the third year of operation (third deduction period).

- Previous deduction period's O&M expenses (E), adjusted for anticipated differences = $1,500
- Capital investment = $4,500,000
- Depreciation: Not applicable
- Standard and Poor's monthly average industrial BBB bond rate for the month beginning the third deduction period = 10.21%
- Return on capital investment (R):

$$(2 \times 0.1021) \times \$4{,}500{,}000 = \$918{,}900$$

- Annual delivered electricity (F) = 424,056,985 kWh
- Cost rate:

$$\frac{E + R}{F} = \frac{\$1{,}500 + \$918{,}900}{424{,}056{,}985 \text{ kWh}} = \$0.002170/\text{kWh}$$

4.6.3 Transmission-line O&M costs

Allowed transmission-line O&M costs include:

- Direct wages and employee benefits (such as medical and retirement) paid to employees and supervisors while engaged in the routine operation, maintenance, or repair of the transmission line, including training, recruiting, and employee moving expenses.
- Payments to consultants or service companies for routine operation, maintenance, or repair of the transmission line.
- Expenditures for tools, supplies, and miscellaneous replacement parts associated with normal operation, maintenance, and repair. As a rule of thumb, if the cost of a replacement part is 10 percent or

more of the transmission line's undepreciated capital balance **and** the part benefits future deduction periods (that is, the part is not replaced annually), you should capitalize the part's cost; otherwise, expense the part as O&M.

- Rents and leasing costs for transmission-line rights-of-way off Federal geothermal leases, if held by periodic payments (see also "Rights-of-way costs" on p. 4-17).
- Insurance, ad valorem property taxes (limited to the property occupied by the transmission line), and payroll taxes.
- General administrative and corporate overhead costs (such as telephone service, office supplies, salary apportionment, accounting and legal functions, and utilities) that you can directly attribute and allocate to the transmission-line operation.
- Other directly attributable and allocable O&M expenses you can document.

Nonallowed O&M costs include:

- State and Federal income taxes.
- Severance taxes.
- Royalty payments, including overriding royalty.
- Financial fees or costs paid **after** commission of the transmission line, such as loan and equity payments, including principal and interest, loan brokerage fees, bank costs for backup lines of credit, operational consulting services and financial analyses required by the lender, dealer costs for commercial paper programs, and rating agency expenses. These costs are accounted for by your return on capital investment and, as such, are not allowable O&M expenses.
- Late payment fees for failure to make timely loan payments.
- Other corporate or project expenses not directly attributable and allocable to the routine operation, maintenance, and repair of the transmission line.

4.6.4 Transmission-line capital investments

Allowed capital investments are your actual costs for the design, purchase, delivery, and installation of the transmission line and related equipment (that is, costs incurred prior to operation of your transmission line). Transmission-line capital investments include:

- Costs for tangible, depreciable assets (such as poles, towers, wires, and insulators).
- Engineering design, environmental studies, and legal and permitting fees to the extent they are directly related to installation of the transmission line.
- Loan service fees, loan interest paid during construction, and service payments on equity investments. These costs apply only to the actual amounts that are clearly attributable and allocable to the transmission line for which the money was borrowed. You must have incurred them during the design and construction phases of the transmission line, and you must be able to document them upon audit.
- Lump-sum payments for transmission-line rights-of-way off Federal geothermal leases (see "Rights-of-way costs" below).
- Real estate costs, if approved by MMS (see "Real estate costs" on p. 4-18).
- Administrative costs that are directly attributable and allocable to construction of the transmission line.
- Other costs for the design, purchase, delivery, and installation of the transmission line and related equipment you can document.

Remember to adjust your depreciation and investment schedules when you replace or retire capital equipment.

Nonallowed capital investments include:

- Socioeconomic costs (such as hospitals, schools, roads, or other civic improvements) imposed by local government agencies as a condition of doing business.
- Payments on borrowed principal made during the design and construction phase of the transmission line (only the interest portion of loan payments made prior to placing the transmission line in service is an allowable capital cost).
- Late payment fees for failure to make timely loan payments during the design and construction phase of the transmission line.
- Construction contract termination fees or penalties.
- Any other corporate or business costs not directly related to construction of the transmission line.

4.6.5 Rights-of-way costs

How you account for your transmission-line rights-of-way costs depends on how you pay for them. If you make periodic (monthly or annual) payments for your transmission rights-of-way, include the payments in your annual O&M costs. If you acquire the transmission rights-of-way by a lump-sum payment, the payment becomes part of your capital-related costs as follows:

- Under the depreciation method, amortize the payment over the life of the project and add the amortized amount to each year's declining capital balance as a component in computing the annual return on undepreciated capital investment (I).
- Under the return-on-investment method, include the lump-sum payment as part of the gross capital investment.

4.6.6 Real estate costs

Real estate costs, including recording fees and other costs incident to the purchase of lands, may be eligible for a return on investment **if**:

- You can demonstrate the necessity for the land purchase;
- The purchased land is not on a Federal geothermal lease; **and**
- The MMS Royalty Valuation Division approves the costs.

You can include only that portion of real estate costs necessary for the transmission corridor. If your real estate purchase includes land outside the normal transmission corridor, you must allocate the cost between the corridor and the other land.

If you are using the depreciation method to calculate your transmission-line cost rate, add the allowable real estate costs to the annual undepreciated capital balance to compute the return on undepreciated capital investment. If you are using the return-on-investment method, include the allowable real estate costs as part of the gross capital investment.

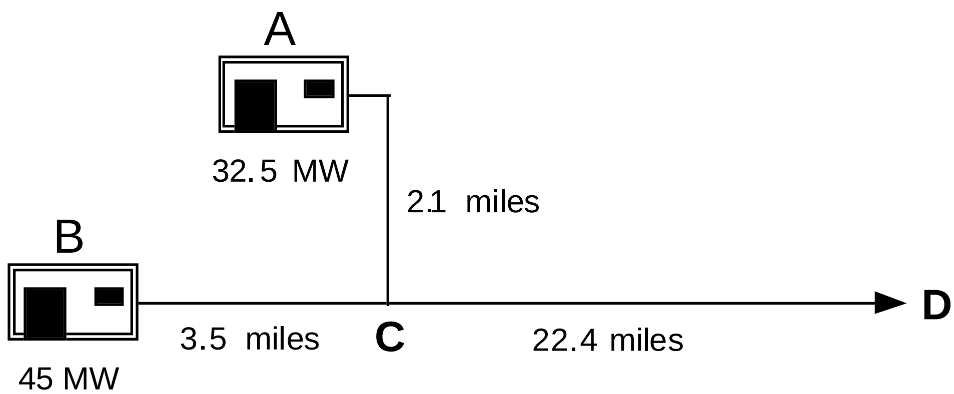
4.6.7 Transmission lines serving more than one powerplant

If your transmission line serves more than one powerplant, you must allocate the transmission costs in proportion to the amount of electricity contributed by each powerplant to determine your transmission-line cost rates. Thus, if a transmission line initially serves two powerplants and one is decommissioned, you cannot transfer the remaining transmission-line capital balance to the surviving powerplant; you must continue to allocate capital costs and, if necessary, O&M costs.

An allocation based on powerplant capacity ratios is the simplest and preferred method to allot transmission-line costs. However, you must allocate the delivered electricity (variable F in the cost rate equation) based on the proportional amount of electricity each powerplant contributes to transmission. See example 4-3 below.

Example 4-3: Calculating a transmission-line cost rate when the transmission line serves more than one powerplant

The example calculates the cost rate for electricity transmitted from Powerplant A. Calculation is by the depreciation method for the second year of operation; the depreciation period is 30 years.



<u>Capital Costs</u>

- Let's say that all transmission facilities were commissioned on the same date at a capital investment (cost) of $8,795,640.

- Calculate the average cost per mile:

$$\frac{\$8{,}795{,}640}{28 \text{ miles}} = \$314{,}130$$

- Allocate the full capital cost of tie line A–C to Powerplant A:

$$2.1 \text{ miles} \times \$314{,}130/\text{mile} = \$659{,}673$$

- Calculate the capital cost of transmission line C–D and allocate to Powerplant A using the powerplant capacity ratio.

  – Capital cost of transmission line C–D:

$$22.4 \text{ miles} \times \$314{,}130/\text{mile} = \$7{,}036{,}512$$

– Capacity ratio for Powerplant A:

$$\frac{32.5 \text{ MW}}{32.5 \text{ MW} + 45 \text{ MW}} = 0.419355$$

– Capital cost of transmission line C–D allocated to Powerplant A:

$$0.419355 \times \$7{,}036{,}512 = \$2{,}950{,}796$$

- Calculate the total transmission-line capital costs for Powerplant A:

$$\$659{,}673 + \$2{,}950{,}796 = \$3{,}610{,}469$$

- Calculate depreciation (D) for transmission lines connecting with Powerplant A:

$$D = \frac{\$3{,}610{,}469}{30 \text{ years}} = \$120{,}349$$

NOTE

If segments of the transmission facilities are placed into service at different times, you must depreciate each segment individually over its expected life.

- Calculate the return on undepreciated capital investment (I) for the second deduction period. For this example we use a Standard and Poor's monthly average industrial BBB bond rate of 9.64%. The undepreciated capital investment balance at the beginning of the second deduction period is $3,490,120:

$$I = (2 \times 0.0964) \times \$3{,}490{,}120 = \$672{,}895$$

<u>O&M Expenses</u>

- Let's say that the annual O&M expenses for tie line A–C are $100, for tie line B–C $800, and for transmission line C–D $1,000.

- Allocate O&M expenses to transmission line C–D for Powerplant A using Powerplant A capacity ratio:

$$\$1{,}000 \times 0.419355 = \$419$$

- Calculate transmission-line O&M expenses (E) for electricity transmitted from Powerplant A (tie line A–C expenses + allocated transmission line C–D expenses):

$$E = \$100 + \$419 = \$519$$

Delivered Electricity

- Calculate the delivered electricity allocable to Powerplant A from the fraction of electricity placed into transmission. Assume that the annual delivered electricity for both powerplants is 729,454,765 kWh, with Powerplant A placing 311,045,674 kWh into transmission and Powerplant B placing 429,341,913 kWh into transmission. (The difference between the amount of delivered electricity and electricity placed into transmission is due to line loss during transmission.)

  – Fraction of electricity placed into transmission by Powerplant A:

$$\frac{311{,}054{,}674 \text{ kWh}}{311{,}054{,}674 \text{ kWh} + 429{,}341{,}913 \text{ kWh}} = 0.420119$$

  – Annual delivered electricity (F) allocable to Powerplant A:

$$F = 729{,}454{,}765 \text{ kWh} \times 0.420119 = 306{,}457{,}806 \text{ kWh}$$

Cost Rate

- Calculate the transmission-line cost rate for Powerplant A:

$$\frac{E + D + I}{F} = \frac{\$519 + \$120{,}349 + \$672{,}895}{306{,}457{,}806 \text{ kWh}} = \$0.002590/\text{kWh}$$

4.7 Generating Cost Rates

Generating cost rates are your annualized costs associated with the construction and operation of a powerplant, divided by the annual amount of **plant tailgate electricity**. Generating costs consist of:

1. Combined O&M expenses, including direct overhead, and **either**
2. Depreciation and a return on undepreciated capital investment, **or**
3. A return on capital investment.

How you handle the capital-related costs (items 2 and 3) determines the method of calculating your cost rates: depreciation method or return-on-investment method. Once you've chosen a calculation method, you cannot later use the other method without the MMS Royalty Valuation Division's approval.

NOTE

Unlike transmission lines serving more than one powerplant, you do not allocate generating costs if your powerplant uses geothermal resources from more than one lease. Rather, you use total costs in determining your generating cost rate. If you believe a situation necessitates allocating (or using partial) generating costs in your cost rate calculation, contact the MMS Royalty Valuation Division for approval.

4.7.1 Calculating generating cost rates by the depreciation method

If you use the depreciation method, calculate your annual generating cost rates from the following equation:

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

where:

E = annual O&M expenses, estimated for the first deduction period

D = annual depreciation of **gross** capital investments (see "Depreciation" below)

I = annual return on undepreciated capital investment (see "Return on undepreciated capital investment" below)

F = annual kWh of **plant tailgate electricity**, estimated for the first deduction period

Calculate the cost rate to six decimal places.

4.7.1.1 Depreciation

Follow these rules to determine your depreciation:

- Depreciate only the allowable capital investment.
- Calculate your depreciation on your gross capital investments; do not deduct salvage value for any of the capital equipment.
- Use straight-line depreciation.
- Use a depreciation period equal to the term of the electricity sales contract (for major items such as plant structure, cooling tower, turbine-generator, and condenser) or the normal, useful life of individual equipment if less than the term of the sales contract. Thus, you may have different depreciation schedules for different equipment, but you cannot use different depreciation periods outside those described in the previous sentence without the MMS Royalty Valuation Division's approval. You do not need approval for depreciation periods based on the term of the electricity sales contract or lives of individual equipment.
- Adjust your depreciation schedule(s) for retired or replaced capital items using generally accepted accounting principles.
- Depreciate the powerplant and associated power-conversion equipment only once. A change in ownership does not alter the

depreciation schedule established by the original owner, except for addition or replacement of capital items.

4.7.1.2 Return on undepreciated capital investment

The return on undepreciated capital investment (I) is the product of the return rate and the undepreciated capital investment balance **at the beginning of the annual deduction period**:

$$I = \text{return rate} \times \text{undepreciated investment balance.}$$

The return rate is two times the Standard and Poor's monthly average **industrial BBB** bond rate, as published in Standard and Poor's *Bond Guide*, for the first month of the annual deduction period. This rate remains constant during the deduction period; you redetermine the return rate at the beginning of each deduction period.

Example 4-4 shows the calculation of a generating cost rate by the depreciation method.

Example 4-4: Calculating a generating cost rate by the depreciation method

Cost rates are for the first and fifth years of operation.

<u>Schedule of Capital Costs</u>

- Capital investment = $126,930,000
- Depreciation period = 30 years
- Annual depreciation (D) = $4,231,000

- Depreciation schedule:

Year	Beginning-of-year undepreciated investment balance
1	$126,930,000
2	122,699,000
3	118,468,000
4	114,237,000
5	110,006,000

First Year of Operation (First Deduction Period)

- Estimated O&M expenses (E) = $6,500,000
- Undepreciated capital investment balance = $126,930,000
- Standard and Poor's monthly average industrial BBB bond rate for the month beginning the first deduction period = 8.96%
- Return on undepreciated capital investment (I):

$$(2 \times 0.0896) \times \$126{,}930{,}000 = \$22{,}745{,}856$$

- Estimated annual plant tailgate electricity (F) = 619,710,438 kWh
- Cost rate:

$$\frac{E + D + I}{F} = \frac{\$6{,}500{,}000 + \$4{,}231{,}000 + \$22{,}745{,}856}{619{,}710{,}438 \text{ kWh}} = \$0.054020/\text{kWh}$$

Fifth Year of Operation (Fifth Deduction Period)

- Previous deduction period's O&M expenses (E), adjusted for anticipated differences = $7,255,315
- Undepreciated capital investment = $110,006,000
- Standard and Poor's monthly average industrial BBB bond rate for the month beginning the fifth deduction period = 9.76%

- Return on undepreciated capital investment (I):

$$(2 \times 0.0976) \times \$110{,}006{,}000 \;=\; \$21{,}473{,}171$$

- Annual plant tailgate electricity (F) = 620,104,165 kWh

- Cost rate:

$$\frac{E + D + I}{F} = \frac{\$7{,}255{,}315 + \$4{,}231{,}000 + \$21{,}473{,}171}{620{,}104{,}165 \text{ kWh}} = \$0.053152/\text{kWh}$$

4.7.2 Calculating generating cost rates by the return-on-investment method

If you use the return-on-investment method, calculate your annual generating cost rates from the following equation:

$$\text{cost rate } (\$/\text{kWh}) \;=\; \frac{E + R}{F}$$

where:

E = annual O&M expenses, estimated for the first deduction period

R = annual return on allowable **gross** capital investments, adjusted for retired or replaced capital items

F = annual kWh of **plant tailgate electricity**, estimated for the first deduction period

NOTE

You can use the return-on-investment method only for powerplants first placed into service on or after March 1, 1988.

The annual return (R) is the product of the return rate and the powerplant capital investment:

$$R = \text{return rate} \times \text{capital investment.}$$

The return rate is two times the Standard and Poor's monthly average **industrial BBB** bond rate, as published in Standard and Poor's *Bond Guide*, for the first month of the annual deduction period. This rate remains constant during the deduction period; you redetermine the return rate at the beginning of each deduction period.

Use your gross capital investments in the powerplant, adjusted for retired or replaced capital items, to calculate R. If the powerplant changes ownership, you must continue to use the original owner's capital investment to calculate R; you cannot recapitalize the powerplant with a change of ownership.

Example 4-5 shows the calculation of a generating cost rate by the return-on-investment method.

Example 4-5: Calculating a generating cost rate by the return-on-investment method

The example is for the third year of operation (third deduction period).

- Previous deduction period's O&M expenses (E), adjusted for anticipated differences = $6,027,500
- Capital investment = $105,935,000
- Depreciation: Not applicable
- Standard and Poor's monthly average industrial BBB bond rate for the month beginning the third deduction period = 10.21%
- Return on capital investment (R):

$$(2 \times 0.1021) \times \$105{,}935{,}000 = \$21{,}631{,}927$$

- Annual plant tailgate electricity (F) = 434,537,512 kWh
- Cost rate:

$$\frac{E + R}{F} = \frac{\$6{,}027{,}500 + \$21{,}631{,}927}{434{,}537{,}512 \text{ kWh}} = \$0.063653/\text{kWh}$$

4.7.3 Powerplant O&M costs

Allowed powerplant O&M costs include:

- Direct wages and employee benefits (such as medical and retirement) paid to employees and supervisors while engaged in the routine operation, maintenance, or repair of the powerplant, including training, recruiting, and employee moving expenses.

- Payments to consultants or service companies for routine operation, maintenance, or repair of the powerplant.

- Expenditures for supplies and miscellaneous replacement parts associated with normal operation, maintenance, and repair. As a rule of thumb, if the cost of a replacement part is 10 percent or more of the powerplant's undepreciated capital balance **and** the part benefits future deduction periods (that is, the part is not replaced annually), you should capitalize the part's cost; otherwise, expense the part as O&M. Expense minor spare parts (such as valves, meters, and fittings) in the year they are purchased if they are uniquely designed for the particular powerplant and held in reserve; otherwise, expense them in the year installed if they are common-variety, off-the-shelf parts.

- Shop tools necessary for the repair and maintenance of power conversion equipment.

- Expenditures for lubricants used in powerplant equipment, such as the turbine-generator and cooling-water pumps, but not effluent/condensate reinjection pumps.

- Expenditures for chemicals used in the power-generation process, including chemicals used in abating hydrogen sulfide and chemicals used for preventing or treating scale or corrosion upstream of the turbine or heat exchanger.

- That portion of O&M expenditures for downhole well pumps, including costs of purchased electricity to run downhole pumps, **necessary for** the specific design requirements of the power conversion process.[1] You must accurately allocate only that part of downhole pump costs that contribute to power conversion; you cannot claim downhole pump costs necessary for extraction or lift of geothermal fluids.[2]

- Costs of purchased electricity to operate the powerplant.

- Fuel and other expenses for auxiliary generators.

- Rents and leasing costs for powerplant sites off Federal geothermal leases.

- Insurance, ad valorem property taxes (limited to the property occupied by the powerplant), and payroll taxes.

- Automotive equipment (cars, trucks, etc., and permanent equipment mounted thereon) incident and allocable to powerplant operation, including maintenance and repair.

- Office furniture and equipment (such as desks, chairs, file cabinets, telephones, typewriters, and computers).

- General administrative and corporate overhead costs (such as telephone service, office supplies, salary apportionment, accounting and legal functions, and utilities) that you can directly attribute and allocate to the powerplant operation.

- Other directly attributable and allocable O&M expenses you can document.

For high-cost items such as automotive equipment, you can either fully expense them in the year of acquisition or depreciate them over their

[1] Downhole pump costs are mostly applicable to binary-type conversion processes where increased operating pressures are required to keep the geothermal fluid in the liquid phase. Some flash plants may also require pressurization of the geothermal fluid to maintain a liquid phase into the first separator.

[2] MMS does not require a specific method to allocate downhole pump costs. Whatever method you use must be technically reasonable and verifiable. One method is to calculate the ratio of the horsepower needed to maintain a certain inlet pressure versus the total pump horsepower. Other methods may also apply.

ordinary depreciable life (include the annual depreciation in your O&M expenses).

Nonallowed O&M costs include:

- State and Federal income taxes.
- Severance taxes.
- Royalty payments, including overriding royalty.
- O&M expenses associated with effluent/condensate reinjection.
- O&M expenses associated with geothermal production (see discussion of downhole pumps on page 4-29).
- Financial fees or costs paid **after** commission of the powerplant, such as loan and equity payments, including principal and interest, loan brokerage fees, bank costs for backup lines of credit, consulting services and financial analyses required by the lender, dealer costs for commercial paper programs, and rating agency expenses. These costs are accounted for by your return on capital investment and, as such, are not allowable O&M expenses.
- Late payment fees for failure to make timely loan payments.
- Penalties for environmental violations.
- Other corporate or project expenses not directly attributable and allocable to the routine operation, maintenance, and repair of the powerplant, including, but not limited to, costs of preparing and filing production reports, royalty payments, and tax statements; audit costs; and costs of litigation against the Federal Government or other parties.

4.7.4 Powerplant capital investments

Allowed powerplant capital investments are your actual costs for the design, purchase, delivery, and installation of the powerplant and related power-generating equipment. Powerplant capital investments include costs for:

- Earth work and foundation preparation.
- Tangible, depreciable assets, such as:
  - Plant structure.
  - Flash tanks and separators, including wellhead and field separators.
  - Turbines, generators, condensers, cooling towers, noncondensable gas ejectors, demisters, and associated pipes, fittings, valves, pumps (including condensate pumps between the condensers and cooling towers to the extent the condensate is used in cooling, but exclusive of condensate pumps used for reinjection), and electrical controls.
  - Hydrogen sulfide abatement facilities.
  - Fresh water supply wells and systems used for cooling, fire protection, and domestic purposes.
  - Transformers, switchyard equipment, and electricity dispatching and control systems.
  - Auxiliary generators.
  - Sidewalks, fences, and pavement within the confines of the plant site, and plant roads, provided the roads serve only the powerplant.
  - Onsite control, shop, and administrative buildings.
  - Fire protection equipment.
  - Downhole well pumps to the extent the downhole pumps serve a design requirement of the power conversion process. You must

accurately allocate only that part of downhole pump investments that contribute to the power conversion process; you cannot claim downhole pump investments related to extraction or lift of geothermal fluids (see footnotes 1 and 2 on p. 4-29).

  – Major spare parts unique to the powerplant and maintained for immediate use, such as turbine rotors and diaphragms.

- Engineering design, environmental studies, and legal and permitting fees to the extent they are directly related to installation of the powerplant.

- Loan service fees, loan interest paid during construction, and service payments on equity investments. These costs apply only to the actual amounts that are clearly attributable and allocable to the powerplant for which the money was borrowed. You must have incurred them during the design and construction phases of the powerplant, and you must be able to document them upon audit.

- Real estate costs, if approved by MMS (see "Real estate costs" below).

- Administrative costs that are directly attributable and allocable to construction of the powerplant.

- Other costs for the design, purchase, delivery, and installation of the powerplant and related power-generating equipment you can document.

Don't forget to adjust your depreciation and investment schedules when you replace or retire capital equipment.

Nonallowed capital investments include:

- Production wells, well control systems, and any other production-related equipment.

- Pipelines (including drip pots) between the wellhead and powerplant, including pipelines both upstream and downstream of wellhead or field separators.

- Effluent/condensate reinjection pumps, boxes, pipelines, wells, and controls.

- Lease acquisition costs.
- Lease restoration costs.
- Costs of acquiring, negotiating, or administering electricity sales contracts.
- Socioeconomic costs, such as hospitals, schools, roads, or other civic improvements, imposed by local government agencies as a condition of doing business.
- Payments on borrowed principal made during the design and construction phase of the powerplant (only the interest portion of loan payments made prior to placing the powerplant in service is an allowable capital cost).
- Late payment fees for failure to make timely loan payments during the design and construction phase of the powerplant.
- Construction contract termination fees or penalties.
- Any other corporate or business costs not directly related to construction of the powerplant and installation of power-generating equipment.

4.7.5 Real estate costs

Real estate costs, including recording fees and other costs incident to the purchase of lands, may be eligible for a return on investment **if**:

- You can demonstrate the necessity for the land purchase;
- The purchased land is not on a Federal geothermal lease; **and**
- The MMS Royalty Valuation Division approves the costs.

You can include only that portion of real estate costs necessary for the powerplant site. If your real estate purchase includes land outside the powerplant site, you must allocate the cost between the plant site and the other land.

If you are using the depreciation method to calculate your generating cost rate, add the allowable real estate costs to the annual undepreciated capital balance to compute the return on undepreciated capital investment. If you are using the return-on-investment method, include the allowable real estate costs as part of the gross capital investment.

4.8 Allocating Value to Leases

The netback procedure derives the dollar value, at the plant inlet, of all geothermal resources used by a powerplant regardless of resource origin. If you use geothermal resources from more than one lease, you must allocate the value to each lease based on one of the following:

- The proportion of measured wellhead or lease production, as approved by the Bureau of Land Management (BLM).
- The allocation schedule in your unitization or communitization agreement, as approved by BLM.
- Any other measurement or allocation method approved by BLM.

4.9 Reporting Netback Values on Form MMS-2014

Report netback quantities and values on Form MMS-2014 as follows:

Sales Quantity	Amount of **delivered** electricity allocated to the lease.
Sales Value	**Netback value** of geothermal production allocated to the lease.
Royalty Quantity	Product of Sales Quantity and lease royalty rate.
Royalty Value	Product of Sales Value and lease royalty rate.

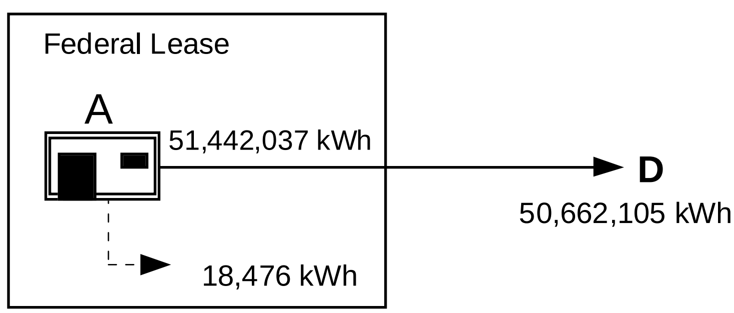
4.10 Example Netback Calculations

To review, you calculate monthly netback values by subtracting your transmission and generating deductions from your gross electricity sales proceeds. You then allocate the values to leases as necessary. You must calculate deductions monthly. Transmission deductions consist of arm's-length wheeling charges, transmission-line deductions, or both. Generating deductions are your full costs of generating electricity. Transmission-line and generating deductions are the products of annual cost rates and monthly electricity quantities.

Examples 4-6 through 4-10 below illustrate netback valuation. These examples by no means represent all the possible situations that may exist in the real world, but are intended to give you a general understanding of calculating netback values. Remember, the more complicated your company's operations, the more complex the valuation may become.

Example 4-6: Calculating a netback value when production is from a single lease

Powerplant A uses geothermal production from only the Federal lease. The lessee transmits electricity across its own transmission line to the purchaser at point D. Some electricity is used on-lease to operate well valves and run effluent reinjection pumps. Lease royalty rate is 12.5 percent.



Annual Cost Rates

- Transmission-line cost rate = $0.001002/kWh

- Generating cost rate = $0.053152/kWh

Electricity Measurements for Reporting Month

- Delivered electricity **50,662,105 kWh**
- Tailgate electricity:
  - Electricity delivered into transmission 51,422,037 kWh
  - Electricity used on-lease + 18,476 kWh
  - Total **51,440,513 kWh**

Electricity Sales Revenue (Gross Proceeds) **$4,078,299.45**

Transmission Deduction

- Transmission line:

$0.001002/kWh × 50,662,105 kWh = **– $50,763.43**

Generating Deduction

$0.053152/kWh × 51,440,513 kWh = **– $2,734,166.15**

Value of Geothermal Production **$1,293,369.87**

Value as percentage of revenue = 31.71%

Report on Form MMS-2014 (royalty rate = 12.5%)

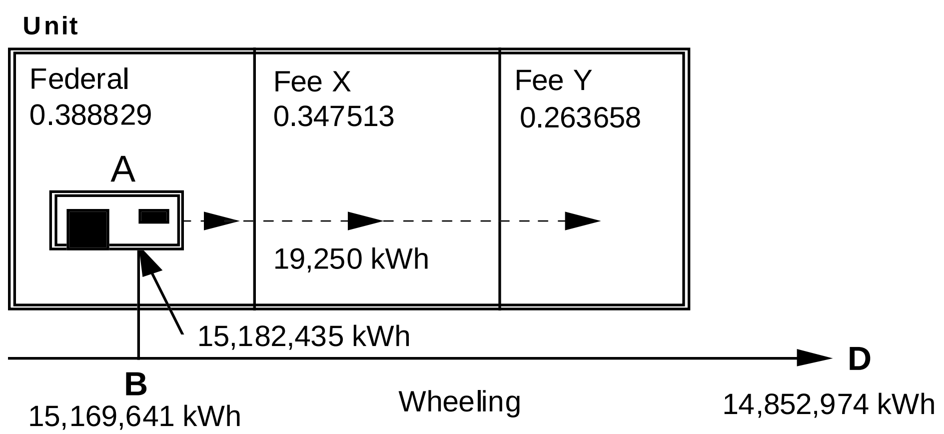
Sales Quantity	50,662,105 kWh
Sales Value	$1,293,369.87
Royalty Quantity	6,332,763 kWh
Royalty Value	$161,671.23

Example 4-7: Calculating a netback value when production is from multiple leases

Powerplant A uses geothermal production from three unitized leases with the following allocation schedule:

Lease	Allocation factor
Federal	0.388829
Fee X	0.347513
Fee Y	0.263658

The lessee transmits electricity across its own transmission line to an interconnect with a third-party transmission line at point B, then wheels the electricity to the purchaser at point D. Some electricity is used on the unit to regulate well production and run effluent reinjection pumps. The royalty rate for the Federal lease is 10 percent.



Annual Cost Rates

- Transmission-line cost rate = $0.002167/kWh
- Generating cost rate = $0.063653/kWh

Electricity Measurements for Reporting Month

- Delivered electricity, point D **14,852,974 kWh**
- Interconnect electricity at point B **15,169,641 kWh**
- Tailgate electricity:
  - Electricity delivered into transmission 15,182,435 kWh
  - Electricity used on-unit + 19,250 kWh
  - Total **15,201,685 kWh**

Electricity Sales Revenue (Gross Proceeds) **$1,448,164.97**

Transmission Deduction

- Transmission line:

$0.002167/kWh × 15,169,641 kWh = $32,872.61

- Wheeling charges $29,736.00
- Total transmission deduction **– $62,608.61**

Generating Deduction

$0.063653/kWh × 15,201,685 kWh = **– $967,632.86**

Value of Geothermal Production **$417,923.50**

Value as percentage of revenue = 28.86%

- Value allocated to Federal lease

0.388829 × $417,923.50 = **$162,500.78**

Report on Form MMS-2014 (royalty rate = 10%)

Sales Quantity, allocated to lease:

$0.388829 \times 14{,}852{,}974$ kWh = 5,775,267 kWh

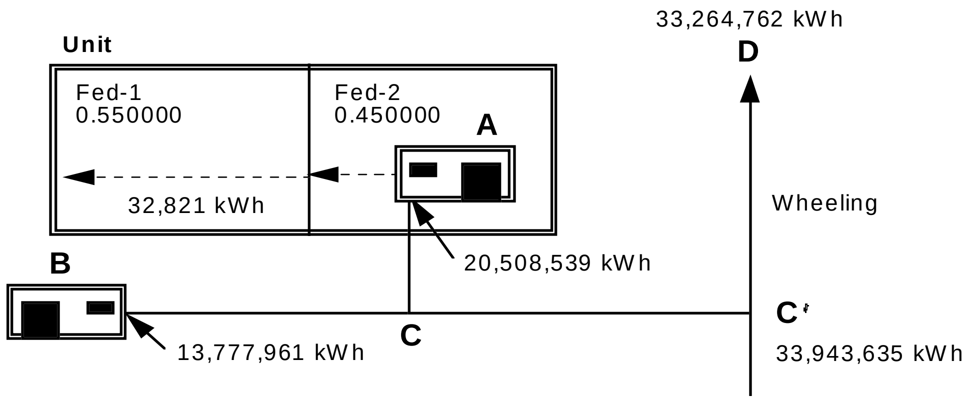
Sales Value	$162,500.78
Royalty Quantity	577,527 kWh
Royalty Value	$16,250.08

Example 4-8: Calculating a netback value when a transmission line serves two powerplants

Powerplant A uses geothermal production from two unitized Federal leases with the following allocation schedule:

Lease	Allocation factor
Fed-1	0.550000
Fed-2	0.450000

Powerplant B uses geothermal production from non-Federal leases. Both powerplants are under common ownership. The operator transmits commingled electricity across its own transmission line to an interconnect with a third-party transmission line at point C′, then wheels the electricity to the purchaser at point D; wheeling charge on line C′–D is $0.000250/kWh. The royalty rate for each Federal lease is 10 percent. Netback values are calculated for Leases Fed-1 and Fed-2.



Annual Cost Rates

- Transmission-line A–C–C′ cost rate[3] = $0.002167/kWh
- Powerplant A generating cost rate = $0.043683/kWh

Electricity Measurements for Reporting Month

- Powerplant A tailgate electricity:

–	Metered to tie line	20,508,539 kWh
–	Lease operations	<u>+ 32,821 kWh</u>
–	Total	**20,541,360 kWh**

[3] See example 4-3 (p. 4-19) for calculating a transmission-line cost rate for transmission lines serving more than one powerplant.

- Electricity delivered for transmission (metered to tie lines):
  - Powerplant A + B:

    20,508,539 kWh + 13,777,961 kWh = 34,286,500 kWh

  - Fraction allocated to Powerplant A:

$$\frac{20{,}508{,}539\ \text{kWh}}{34{,}286{,}500\ \text{kWh}} = 0.598152$$

- Electricity delivered to wheeling interconnect (point C′): 33,943,635 kWh
  - Allocated to Powerplant A:

$$0.598152 \times 33{,}943{,}635\ \text{kWh} = \mathbf{20{,}303{,}453\ kWh}$$

- Delivered electricity (point D) **33,264,762 kWh**

Electricity Sales Revenue (Gross Proceeds)

- Total revenue Powerplant A + B $3,659,123.82
- Revenue allocated to Powerplant A:

$$0.598152 \times 3{,}659{,}123.82 = \mathbf{\$2{,}188{,}712.23}$$

Transmission Deduction

- Transmission-line A–C–C′ costs:

$$\$0.002167/\text{kWh} \times 20{,}303{,}453\ \text{kWh}^{4} = \$43{,}997.58$$

[4] Allocated interconnect electricity.

- Wheeling charges allocated to Powerplant A:

$0.000250/kWh × 20,303,453 kWh = $5,075.86

- Total transmission deduction **– $49,073.44**

Generating Deduction

$0.043683/kWh × 20,541,360 kWh = **– $897,308.23**

Value of Geothermal Production at Powerplant A **$1,242,330.56**

Value as percentage of revenue = 56.76%

- Value allocated to Lease Fed-1:

0.550000 × $1,242,330.56 = **$683,281.81**

- Value allocated to Lease Fed-2:

0.450000 × $1,242,330.56 = **$559,048.75**

Report on Form MMS-2014

- Lease Fed-1 (royalty rate = 10%)

Sales Quantity, allocated to lease:

33,264,762 kWh × 0.598152 × 0.550000 = 10,943,561 kWh

Sales Value	$683,281.81
Royalty Quantity	1,094,356 kWh
Royalty Value	$68,328.18

- Lease Fed-2 (royalty rate = 10%)

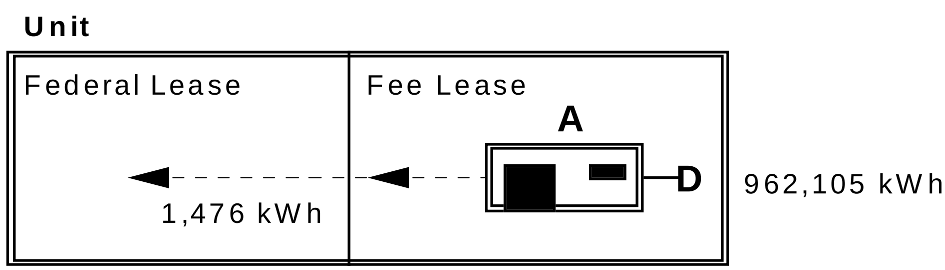
  Sales Quantity, allocated to lease:

  33,264,762 kWh × 0.598152 × 0.450000 = 8,953,823 kWh

Sales Value	$559,048.75
Royalty Quantity	895,382 kWh
Royalty Value	$55,904.88

Example 4-9: Calculating a netback value when deductions exceed 99 percent of electricity sales value

Powerplant A uses geothermal production from unitized Federal and fee leases; allocation is based on lease production. Assume a Federal lease allocation factor of 0.834721 for the month. The electricity purchaser takes delivery at the powerplant tailgate (point D). Lease royalty rate is 12.5 percent.



Annual Cost Rates

- Transmission = Not applicable
- Generating cost rate = $0.055483/kWh

Electricity Measurements for Reporting Month

• Delivered electricity	**962,105 kWh**
• Electricity used on-lease	+ 1,476 kWh
• Tailgate electricity	**963,581 kWh**

Electricity Sales Revenue (Gross Proceeds)	**$53,877.88**
Transmission Deduction	0
Generating Deduction	
$0.055483/kWh × 963,581 kWh =	**– $53,462.36**
Netted Back Value of Geothermal Production	$415.52

Value as percentage of revenue = 0.77%

Minimum Value of Geothermal Production (1.00% of sales value)

0.01 × $53,877.88 = **$538.78**

- Value allocated to Federal lease:

0.834721 × $538.78 = **$449.73**

Report on Form MMS-2014 (royalty rate = 12.5%)

Sales Quantity, allocated to lease:

962,105 kWh × 0.834721 = 803,089 kWh

Sales Value	$449.73
Royalty Quantity	100,386 kWh
Royalty Value	$56.22

4.11 Recalculated Netback Values: Underpayments and Overpayments

As indicated in “Cost Rates and Deductions” on page 4-3, you recalculate your cost rates at the beginning of each annual deduction period, using your actual costs from the prior period, to redetermine the prior period’s actual deductions and royalty values. (You also use the new cost rates, adjusted for anticipated cost differences, for the new deduction period.) You must then submit corrected Forms MMS-2014 to show each month's adjusted royalty values, using adjustment reason code 10. You have 90 days from the end of the deduction period to file the corrected Forms MMS-2014.

If your adjusted royalty values are greater than those originally reported for any month (meaning you underpaid royalties for that month), you must pay the additional royalties plus interest from the date the additional royalty was due (30 CFR 218.302). You cannot offset an underpayment for one month against an overpayment for another month.

If your adjusted royalty values are less than those originally reported (meaning you overpaid royalties), you may recoup the overpayment by taking a credit against future royalties until the overpayment is exhausted (see example 4-10 below). However, you cannot offset an overpayment for one month against an underpayment for another month.

Remember that, independent of your deduction period, you must satisfy the lease's annual minimum royalty requirement on or before the expiration date of the lease year (see "Minimum Royalty" on p. 2-6).

Example 4-10: Recouping royalty payments when you adjust netback values

For a given month, you reported a netback Sales Value of $32,000 and a Royalty Value of $3,200. The Sales Value equaled 1.6 percent of that month's gross electrical sales proceeds of $2,000,000. Upon recalculating your annual cost rates, monthly deductions, and netback values for the deduction period, you find that the corrected netback Sales Value for that month is $10,000, which equaled only 0.05 percent of the month's gross electrical sales proceeds. Because the resource value cannot be less than 1 percent of the month's gross proceeds, you report an adjusted Sales Value of $20,000 and an adjusted Royalty Value of $2,000. You may recoup the difference between the reported and adjusted Royalty Values ($1,200) by crediting against future royalties.

4.12 Dismantlement Cost Refunds

At the end of your project's life **and** upon completion of dismantlement and salvage operations, you may take a one-time refund of royalties equal to the royalty amount of actual dismantlement costs that exceed your salvage income (30 CFR 206.353(f) and 206.354(f)). Calculate the refund as follows:

$$\text{dismantlement cost refund} = \text{royalty rate} \times (\text{dismantlement costs} - \text{salvage income}).$$

Contact your MMS payor representative for instructions on taking the refund.

4.13 Recordkeeping and Availability

You must keep all records necessary to support your transmission and generating cost rates and deductions, together with records showing your netback calculations (30 CFR 206.353(e)(2) and 206.354(e)(2)). Itemize your capital equipment and save indefinitely the source documents and receipts supporting their purchase and installation costs. You will need this information to support your annual depreciation and return on investment.

Itemize your annual O&M expenses and retain receipts, vouchers, and other documents supporting each cost for at least 6 years from the month they are applicable, unless MMS instructs you to keep them for a longer period. Likewise, keep electricity sales statements and electricity measurements needed to support your netback calculations for at least 6 years. Maintain indefinitely all contracts related to electricity sales, transmission, operation and maintenance, and other functions that may bear on valuation.

MMS will deny any cost you cannot support with source documents and require you to adjust royalty values accordingly (30 CFR 206.353(e)(1) and 206.354(e)(1)). See 30 CFR 212.351 for additional recordkeeping requirements.

5. Valuation Standards for Direct Utilization

This chapter describes the standards in 30 CFR 206.355 for valuing geothermal resources used in direct utilization processes. Direct utilization includes commercial and residential space heating, greenhouse heating, industrial and agricultural operations requiring process heat, and other operations where thermal water can be used as a heat source. These resources usually involve warm to hot water and the heat derived therefrom. Valuation standards are grouped according to the resource's disposition:

- Sales under an arm's-length contract.
- Sales under a non-arm's-length contract.
- Utilization by the lessee in the lessee's own direct utilization facility, otherwise referred to as "no sales."

Valuation standards for resources sold under an arm's-length contract focus on the contract's gross proceeds, with the conditions that the gross proceeds reflects total consideration and reasonable value. (See "Exceptions to acceptance of arm's-length gross proceeds" on page 2-14.) Valuation standards for resources sold under non-arm's-length contracts and for no-sales resources are given as a sequence of three benchmarks, or methods, where you determine value under the first applicable method in descending order of appearance. For example, if the first benchmark is not applicable or not workable, valuation falls to the second benchmark, and so on. The **alternative fuel** method, appearing as the second benchmark in the non-arm's-length and no-sales valuation standards, is detailed in chapter 6.

We refer to geothermal resources used in direct utilization processes as *direct utilization resources*.

5.1 Arm's-Length Sales

You generally determine the value of direct utilization resources sold under an **arm's-length contract** as the **gross proceeds** accruing under that contract (30 CFR 206.355(b)). (See "General Valuation Principles" on page 2-10 for additional discussion on arm's-length contracts and gross proceeds.)

However, you must satisfy two conditions to justify the contract gross proceeds (or contract prices) as value:

1. The sales contract must reflect the **total consideration** actually transferred, either directly or indirectly, from the buyer to the seller (30 CFR 206.355(b)(1)(ii)). Total consideration is synonymous with the full definition and intent of gross proceeds as discussed on page 2-11. If the contract does not reflect total consideration, MMS **may** require you to value the resource under the no-sales benchmarks in section 5.3 on page 5-8. However, value can never be less than the gross proceeds, including any additional consideration you receive, regardless of the value calculated under the no-sales benchmarks. MMS may require you to certify that your arm's-length contract includes all of the consideration paid to you by the buyer, either directly or indirectly, for the geothermal resource (30 CFR 206.355(b)(2)).

2. The gross proceeds received under the contract must reflect **reasonable value** (30 CFR 206.355(b)(1)(iii)). If MMS determines that the gross proceeds does not reflect the reasonable value of the resource because of misconduct by or between the contracting parties, or because you have otherwise breached your duty to market the production to the mutual benefit of yourself and the Federal Government, we **will** require valuation under the no-sales benchmarks. When we determine that the value may be unreasonable, we will notify you and give you an opportunity to provide written information justifying your value.

Notification requirements. You don't need to notify MMS if valuation is under an arm's-length contract. However, if there is consideration outside the contract, you should notify the MMS Royalty Valuation Division at the address given in appendix A. Explain the circumstances under which the consideration occurs and either propose a valuation procedure or request guidance.

5.2 Non-Arm's-Length Sales

Non-arm's-length sales occur when you sell geothermal production to your direct use affiliate. Non-arm's-length sales automatically generate gross proceeds, which, because it is non-arm's-length, you must compare with other values to determine the proper royalty value. You determine the value of these non-arm's-length resources by the first applicable of three benchmark methods: (1) gross proceeds, (2) alternative fuel value, or (3) other valuation methods (30 CFR 206.355(c)(1)(i), (ii), and (iii), respectively).

5.2.1 First non-arm's-length valuation benchmark: Gross proceeds

You use the first non-arm's-length benchmark when:

1. You sell geothermal resources to your affiliated direct use operator, and

2. Your affiliated operator purchases—under arm's-length contracts—significant quantities of geothermal resources to operate the same direct utilization facility.

This benchmark actually incorporates two prioritized valuation standards that hinge on the comparability of your non-arm's-length gross proceeds with minimum value. *Minimum value* is the gross proceeds derived under the lowest-priced available, comparable arm's-length contract for sales of geothermal resources to your affiliate's same direct utilization facility.

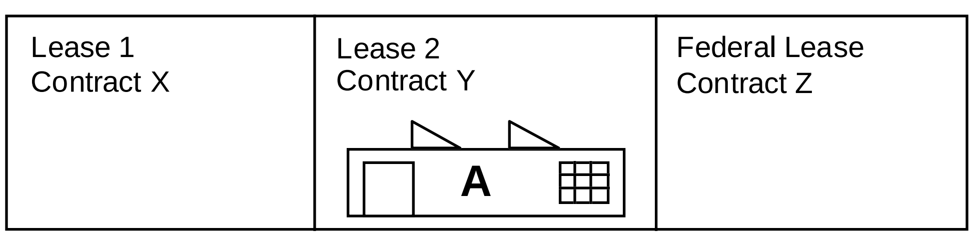
If the gross proceeds under your non-arm's-length contract is equal to or greater than the minimum value, it is acceptable for value. If it is less than the minimum value, or if there are no available, comparable arm's-length contracts, you determine value as the weighted average of the gross proceeds established under arm's-length contracts for the sale of significant quantities of geothermal resources to the same direct utilization facility (see example 5-1 below). *Gross proceeds* for the purpose of determining a weighted average means the contract prices. *Significant quantities* is not precisely defined but depends on the circumstances of each situation. A particular quantity of geothermal resources may be considered significant for one facility but not another.

Available contracts are those contracts possessed by you, your affiliate, or MMS. You determine the comparability of arm's-length contracts by their similarity to your non-arm's-length contract. In determining comparability, consider such factors as the time of execution, duration, terms, quality and volume of resource, dedication to the same direct utilization facility, and other factors reflecting the value of the resource. An example of a comparable arm's-length contract would be one executed at the same time and for the same duration as your non-arm's-length contract and providing for the delivery of 50 percent or more of the facility's operating requirements. On the other hand, a noncomparable arm's-length contract would be one executed after startup of the facility and providing only for temporary delivery of a small quantity at a premium price.

If your direct use affiliate (1) purchases only your production (that is, there are no arm's-length sales of geothermal resources to your affiliate's facility), or (2) does not make arm's-length purchases of significant quantities of geothermal resources to operate its facility, then valuation falls to the second benchmark (see sec. 5.2.2 on p. 5-6).

Example 5-1: Valuing direct utilization resources under the first non-arm's-length benchmark

As lessee of the Federal lease, you sell geothermal production to your affiliated direct utilization operator (A) under non-arm's-length contract Z. The direct utilization operator also purchases geothermal production from two adjacent lessees under arm's-length contracts X and Y. You have determined that contracts X, Y, and Z satisfy the comparability test.



SUMMARY DATA

Lease	Contract	Contract type	Production (hundred gal)	Gross proceeds: Price ($/hundred gal)	Gross proceeds: Revenue ($)
Lease 1	X	AL	56,000	0.60	33,600.00
Lease 2	Y	AL	58,000	0.65	37,700.00
Federal	Z	NAL	57,000	0.60	34,200.00

Contract X is the lowest-priced available, comparable arm's-length contract for sales to your direct utilization affiliate. Thus, the minimum value is $0.60/hundred gal, which is equal to your non-arm's-length contract Z price. In this example, the price and resultant revenues (collectively your gross proceeds) under your non-arm's-length contract ($34,200.00) are acceptable for royalty value.

Let's change the price under your non-arm's-length contract Z to $0.55/hundred gal:

SUMMARY DATA

Lease	Contract	Contract type	Production (hundred gal)	Gross proceeds: Price ($/hundred gal)	Gross proceeds: Revenue ($)
Lease 1	X	AL	56,000	0.60	33,600.00
Lease 2	Y	AL	58,000	0.65	37,700.00
Federal	Z	NAL	57,000	0.55	31,350.00

Now your gross proceeds is less than minimum value and is not acceptable for royalty purposes. In this case you determine value by calculating the weighted average price under contracts X and Y:

$$\frac{(\$0.60 \times 56{,}000) + (\$0.65 \times 58{,}000)}{56{,}000 + 58{,}000} = \$0.625439\text{/hundred gal}$$

You then report and pay royalties on 57,000 hundred gal at a value of $0.625439/hundred gal, or $35,650.00.

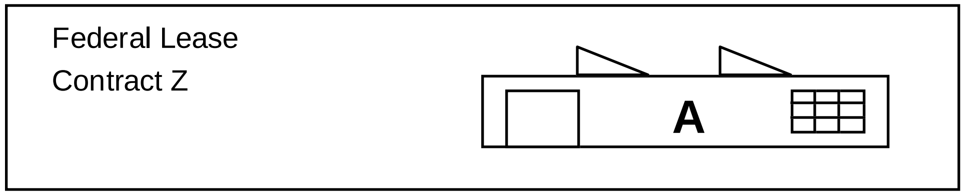
5.2.2 Second non-arm's-length valuation benchmark: Alternative fuel valuation

Under the second non-arm's-length valuation benchmark for direct utilization resources, you must determine the equivalent value of the least expensive, reasonable alternative energy source (fuel) that your affiliate otherwise would use for heating in its direct use operation. This procedure is called the "alternative fuel valuation method" and is detailed in chapter 6. However, under no circumstances can value be less than your gross proceeds accruing for the sale of the resource (30 CFR 206.355(h)). Thus, you determine value as the greater of the gross proceeds under your non-arm's-length contract or the alternative fuel value (see example 5-2 below).

If, for some unlikely reason, the alternative fuel method is unworkable, valuation falls to the third non-arm's-length benchmark (see sec. 5.2.3 on p. 5-8).

Example 5-2: Valuing direct utilization resources under the second non-arm's-length benchmark

As lessee of the Federal lease, you supply geothermal production to your affiliated direct utilization operator A under non-arm's-length contract Z; operator A purchases only your production.



SUMMARY DATA

Lease	Contract	Contract type	Production (hundred gal)	Gross proceeds	
				Price ($/hundred gal)	Revenue ($)
Federal	Z	NAL	57,000	0.60	34,200.00

Because there are no arm's-length contracts for sales to your affiliate's same direct utilization facility, you have no arm's-length gross proceeds against which to compare your non-arm's-length gross proceeds. Therefore, valuation falls to the second benchmark: the greater of your gross proceeds under your non-arm's-length contract or the alternative fuel value.

Your gross proceeds in this example is $34,200.00. Say that your alternative fuel calculation for the month derives a value of $37,455.80. You then report and pay royalties on $37,455.80.

NOTE

In this example you report the Sales Quantity on Form MMS-2014 as the amount of thermal energy displaced, in millions of British thermal units (MMBtu), that you calculated under the alternative fuel method. If your gross proceeds had been greater than the alternative fuel value, you would report 57,000 (hundred gal) for Sales Quantity.

5.2.3 Third non-arm's-length valuation benchmark: Other valuation methods

The third non-arm's-length valuation benchmark allows you to use any other reasonable method to determine value. To implement the third benchmark, you must demonstrate that the first two benchmarks—and particularly the second—do not apply or are unworkable. You must propose an alternative valuation method and receive MMS's approval to use that method (see "Valuation Requests" on p. 5-13).

5.2.4 Notification requirements

You must notify MMS if valuation is under the non-arm's-length sales benchmarks (30 CFR 206.355(e)(3)). Send notification by letter to the MMS Royalty Valuation Division at the address given in appendix A. You must identify the valuation method used and describe the procedure you plan to follow. Include sufficient narrative explanation and backup data to support your valuation method.

This notification is due no later than the end of the month following the month you first report royalties on Form MMS-2014 using the described valuation method. The notification is one-time and remains in effect during use of the method. If you change to a different valuation method, you must submit a new notification.

5.3 No Sales

No sales of direct utilization resources occur when you use the geothermal production in your own direct utilization facility. You determine the value of these no-sales resources by the first applicable of three benchmark methods: (1) weighted average of arm's-length gross proceeds, (2) alternative fuel value, or (3) other valuation methods (30 CFR 206.355(d)(1)(i), (ii), and (iii), respectively).

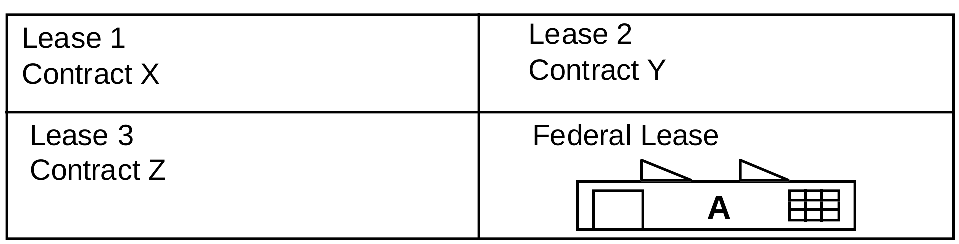
5.3.1 First no-sales valuation benchmark: Weighted average of arm's-length gross proceeds

The first no-sales valuation benchmark is applicable **only** when you purchase—under arm's-length contracts—**significant quantities** of geothermal resources to operate the **same direct utilization facility**. In this situation, you value the geothermal resource as the weighted average of the gross proceeds established in the arm's-length contracts (see example 5-3 below). *Gross proceeds* for the purpose of determining a weighted average means contract prices. The volumes of resource purchased must meet the *significant quantities* test. You must judge the acceptability of the arm's-length contracts by considering their time of execution, duration, terms, quality and volume of resource purchased, and other factors that may reflect the value of the resource.

If you use only your own production to operate your direct utilization facility (that is, you don't purchase significant quantities of geothermal resources under arm's-length contracts), valuation falls to the second benchmark (see sec. 5.3.2 on p. 5-10).

Example 5-3: Valuing direct utilization resources under the first no-sales benchmark

As lessee of the Federal lease and owner of direct utilization facility A, you purchase most of your geothermal fluids from adjacent leases 1, 2, and 3 under contracts X, Y, and Z, respectively. Contracts X and Y are arm's-length and both meet the comparability and significant quantities tests; contract Z, with your affiliate, is non-arm's-length.



SUMMARY DATA

Lease	Contract	Contract type	Production (MMBtu)	Gross proceeds	
				Price ($/MMBtu)	Revenue ($)
Federal	—	—	8,000	—	—
Lease 1	X	AL	35,000	2.05	71,750.00
Lease 2	Y	AL	30,000	2.12	63,600.00
Lease 3	Z	NAL	12,000	1.85	22,200.00

In this example you calculate the value of your Federal lease production as the monthly weighted average of prices under your two arm's-length contracts:

$$\frac{(\$2.05 \times 35{,}000) + (\$2.12 \times \$30{,}000)}{35{,}000 + \$30{,}000} = \$2.082308/\text{MMBtu}$$

You report and pay royalty on production of 8,000 MMBtu at a value of $2.082308/MMBtu, or $16,658.46.

NOTE

If contract Z were arm's-length instead of non-arm's-length, you still would not use it in your value calculation because it does not supply a significant quantity of geothermal resources to your direct utilization facility.

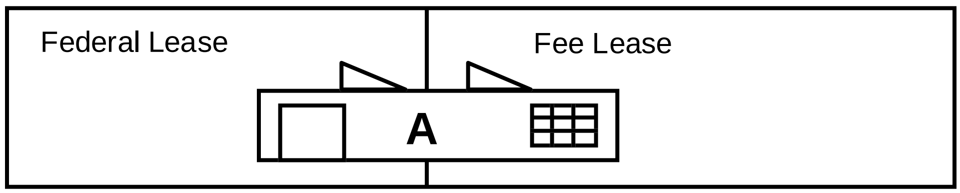
5.3.2 Second no-sales valuation benchmark: Alternative fuel valuation

Under the second no-sales valuation benchmark for direct utilization resources, you must determine the equivalent value of the least expensive, reasonable alternative energy source (fuel) that you otherwise would use for heating in your direct use operation. This procedure is called the "alternative fuel valuation method" and is detailed in chapter 6.

If, for some unlikely reason, the alternative fuel method is unworkable, valuation falls to the third benchmark (see sec. 5.3.3 below).

Example 5-4: Valuing direct utilization resources under the second no-sales benchmark

As lessee of the Federal lease and owner of direct utilization facility A, you supply all the facility's geothermal requirements with production from the Federal lease and an adjacent fee lease, which you also own.



SUMMARY DATA

Lease	Contract	Contract type	Production (hundred gal)	Gross proceeds: Price ($/hundred gal)	Gross proceeds: Revenue ($)
Federal	None	—	52,975	0	0
Fee	None	—	24,630	0	0

Because you make no arm's-length purchases of geothermal fluids to operate your facility, you determine value for the Federal lease production by the alternative fuel method described in chapter 6.

5.3.3 Third no-sales valuation benchmark: Other valuation methods

The third no-sales valuation benchmark allows you to use any other reasonable method to determine value. To implement the third benchmark, you must demonstrate that the first two benchmarks—and particularly the second—do not apply or are unworkable. You must propose an alternative valuation method and receive MMS's approval to use that method (see "Valuation Requests" on page 5-13).

5.3.4 Notification requirements

You must notify MMS if valuation is under the no-sales benchmarks (30 CFR 206.355(e)(3)). Send notification by letter to the MMS Royalty Valuation Division at the address given in appendix A. You must identify the valuation method used and describe the procedure you plan to follow. Include sufficient narrative explanation and backup data to support your valuation method.

This notification is due no later than the end of the month following the month you first report royalties on Form MMS-2014 using the described valuation method. The notification is one-time and remains in effect during use of the method. If you change to a different valuation method, you must submit a new notification.

5.4 Improper Valuations

If MMS finds that you improperly determined value, we will direct you to correct your value or prescribe a different valuation procedure (30 CFR 206.355(f)). You will be liable for any difference between the royalties paid and the royalties due under the value determined by MMS, plus late payment interest on underpaid amounts pursuant to 30 CFR 218.302. If the corrected value or prescribed valuation procedure results in an overpayment, MMS will give you instructions for taking a credit. You are not entitled to interest on royalty overpayments.

You may appeal any of MMS's valuation decisions. For adverse decisions, MMS will issue appeals instructions concurrent with the decision. Otherwise, see 30 CFR Part 243 for appeals information.

5.5 Valuation Requests

If you are unsure of your valuation procedure, you may request a determination from MMS (30 CFR 206.355(g)). Send your valuation requests to the MMS Royalty Valuation Division at the address given in appendix A. Include a description of your operation, copies of sales contracts, and any other information pertinent to the valuation of your geothermal production. You must continue to pay royalties on production while MMS is making its determination. You will be liable for any additional royalty and interest if our determination results in a higher value than the value on which you paid royalties.

If you request an alternative valuation method under the third non-arm's-length or no-sales benchmarks (other valuation methods), you must propose the valuation method you intend to use and include all information supporting your proposal. Remember, you must receive MMS's approval to use an alternative valuation method under the third benchmark and explain why the first two benchmarks are unworkable. You may use your proposed valuation method for royalty calculations until MMS issues a decision. If MMS approves your proposed valuation method, you must use that method until one of the following occurs:

- The circumstances of your production and/or utilization change, at which time you must notify MMS with a new valuation request.
- MMS instructs you to use a different valuation method.
- MMS issues new valuation regulations.

If MMS disapproves your proposed valuation method, we will prescribe a method to you. You must then adjust all of your past royalty reports to reflect the prescribed method (30 CFR 206.355(f)). If our prescribed method results in additional royalty due, you must pay the additional royalty plus interest. If our prescribed method results in royalty overpayments, MMS will give you instructions for taking a credit. You are not entitled to interest on royalty overpayments.

5.6 Recordkeeping and Availability

You must save all data and records relevant to your royalty valuation (30 CFR 206.355(e)(1)), particularly if you value production under the second or third non-arm's-length or no-sales benchmark.

Keep the following documents indefinitely:

- All contracts related to the sale or purchase of geothermal resources.
- Any other contracts that may bear on the valuation of the resource or are necessary to support your valuation.
- All MMS valuation decisions.
- Other written communications relevant to your valuation.

You must keep records relevant to your monthly royalty calculations for 6 years after the records are generated, unless MMS instructs otherwise. Such records include, but are not limited to, quantities produced and/or sold; prices received for sale of the resource; and calculations of alternative fuel values, thermal energy displaced, and geothermal values under the alternative fuel method, including related documents. You must make all records, contracts, or other documents supporting your valuations available to authorized MMS personnel or MMS-designated agents upon request (30 CFR 206.355(e)(2)). See also 30 CFR 212.351.

6. Alternative Fuel Valuation Method

This chapter explains the alternative fuel method of valuing direct utilization resources. You use this method when your valuation falls to the second non-arm's-length or no-sales valuation benchmark discussed in "Non-Arm's-Length Sales" on page 5-3 and "No Sales" on page 5-8; that is, when you don't have suitable arm's-length contracts to establish the value of your direct utilization production.

Under the alternative fuel method, you calculate the value of your geothermal production as the product of (1) the value of the least expensive, reasonable alternative fuel replaced by the geothermal resource and (2) the amount of thermal energy displaced by the geothermal resource:

$$\text{geothermal value} = \text{alternative fuel value} \times \text{thermal energy displaced.}$$

The value of the alternative fuel is its retail price in the local market, converted to dollars per million British thermal units ($/MMBtu). Thermal energy displaced is the amount of the alternative fuel, in MMBtu, you would otherwise use in your direct utilization process in place of the geothermal resource. You calculate the amount of thermal energy displaced from the equation on page 6-4.

You must determine the price of the alternative fuel, the amount of thermal energy displaced, and the geothermal value for each month you have production. The following steps will guide you through the valuation process:

STEP 1. Select the least expensive, reasonable alternative fuel that you would otherwise use in place of the geothermal resource.

STEP 2. Obtain the price (value) of your alternative fuel from your local supplier and convert it to $/MMBtu (see "Valuing Your Alternative Fuel" on p. 6-3).

STEP 3. Calculate the amount of thermal energy displaced (see "Calculating Thermal Energy Displaced" on p. 6-4).

STEP 4. Calculate the geothermal value and allocate to leases as necessary (see example 6-4 on page 6-10).

STEP 5. Report on Form MMS-2014 (for each Federal lease) the allocated thermal energy displaced (in MMBtu) and allocated value (in dollars), and pay royalties accordingly.

6.1 Selecting Your Alternative Fuel

The alternative fuel is the one you would reasonably use at your location and in your facility in place of the geothermal resource. Answer the following questions to make your selection:

1. Did you previously use this fuel before converting to geothermal?

2. Is the alternative fuel compatible with and commonly used in processes like yours?

3. Is the alternative fuel available in the local market?

If you answer "yes" to question 1, don't go any further; your selected fuel is the one you are actually replacing and thus is the reasonable alternative. If you answer "no" to question 1, then you must also consider questions 2 and 3 together. For example, natural gas may be the most commonly used fuel in processes like yours, but it might not be available at your location. In this case another fuel, such as diesel or heating oil, might be your reasonable alternative. If you have access to more than one type of fuel in your area, choose the least expensive one that would be compatible with your facility or process.

Once you have selected your alternative fuel, notify the MMS Royalty Valuation Division of your selection (30 CFR 206.355(e)(3)). Send your letter to us at the address given in appendix A. Include a brief explanation supporting your choice. The notification is due no later than the end of the month following the month you first report royalties using your selected alternative fuel. If you later select a different alternative fuel, you must again notify us. We will confirm the acceptability of your alternative fuel if you request; otherwise, we do not require approval of your selected alternative fuel. We do reserve the right to review your choice and determine a different alternative fuel if we find your choice does not meet the reasonableness test.

6.2 Valuing Your Alternative Fuel

The value of your selected alternative fuel is the unit price normally paid in the local retail market. Thus, when natural gas is the alternative, value will be the commercial rates—including cost-of-gas, cost-of-service, and other rates normally charged—available from your local distribution company or utility. When diesel, heating oil, propane, coal, or another fuel is the alternative, value will be that fuel's retail price normally available from distributors or other sources in the local market. You are responsible for obtaining and documenting the value of your alternative fuel for each month you report production.

You must state the value of the alternative fuel in terms of $/MMBtu. If the price of the alternative fuel is in another unit of measurement, such as cents per gallon or dollars per therm (100,000 Btu), you must convert to equivalent $/MMBtu based on the fuel's **gross** heating value (heat of combustion or heat content) (see examples 6-1 and 6-2 below). Your local distributor should be able to give you the fuel's heating value.

NOTE

Calculate prices to six decimal places when converting to $/MMBtu.

Example 6-1: Converting an alternative fuel price from $/gal to $/MMBtu

Alternative fuel = No. 1 heating oil

Heating value = 138,800 Btu/gal

Price = $0.795/gal

Unit value of alternative fuel:

$$\frac{\$0.795}{\text{gal}} \times \frac{1\ \text{gal}}{138{,}800\ \text{Btu}} \times \frac{1{,}000{,}000\ \text{Btu}}{1\ \text{MMBtu}} = \$5.727666/\text{MMBtu}$$

Example 6-2: Converting an alternative fuel price from $/therm to $/MMBtu, with monthly service charges

Alternative fuel: Natural gas

Price rates:

Cost of gas = $0.2639/therm ($2.639/MMBtu)

Basic cost of service = $0.0844/therm ($0.844/MMBtu)

Service charge = $500/month

Thermal energy displaced = 12,000 MMBtu

In this example, use the amount of thermal energy displaced to calculate the component value of the service charge:

$$\text{unit value of service charge} = \frac{\$500}{12{,}000\ \text{MMBtu}} = \$0.041667/\text{MMBtu}$$

The unit value of the alternative fuel is the sum of the price rates:

$$\$2.639 + \$0.844 + \$0.041667 = \$3.524667/\text{MMBtu}$$

6.3 Calculating Thermal Energy Displaced

Use the following equation to calculate thermal energy displaced (30 CFR 206.355(c)(1)(ii) and (d)(1)(ii)):

$$\text{thermal energy displaced} = \frac{(h_{\text{in}} - h_{\text{out}}) \times \text{density} \times 0.133681 \times \text{volume}}{\text{efficiency factor}},$$

where:

h_{in}	=	enthalpy in Btu per pound (Btu/lb) of the geothermal fluid entering the direct utilization facility, based on inlet temperature
h_{out}	=	enthalpy in Btu/lb of the spent geothermal fluid leaving the direct utilization facility, based on outlet temperature
density	=	density in pounds per cubic foot (lb/ft^3) of the geothermal fluid entering the direct utilization facility, based on inlet temperature and generally calculated as the reciprocal of the specific volume
0.133681	=	constant factor in cubic feet per gallon (ft^3/gal) to convert gallons to cubic feet
volume	=	gallons of geothermal fluids produced
efficiency factor	=	0.7 for coal and 0.8 for natural gas, diesel, heating oil, and other refined petroleum products

Example calculations of thermal energy displaced are given in example 6-3 on page 6-9 and example 6-4 on page 6-10.

Enthalpies (h_{in} and h_{out}) are for **saturated liquid** (water) at the corresponding inlet and outlet temperatures. Determine them from standard steam tables found in engineering and thermodynamic handbooks, such as:

- *Steam Tables: Thermodynamic Properties of Water Including Vapor, Liquid, and Solid Phases (English Units)*, published by John Wiley and Sons;
- *CRC Handbook of Chemistry and Physics*, published by CRC Press, Inc.; and
- *ASME Steam Tables*, published by the American Society of Mechanical Engineers.

Calculate **density** as the reciprocal of the **specific volume** of saturated liquid (water) that corresponds to the inlet temperature:

$$\text{density} = \frac{1}{\text{specific volume}}.$$

Specific volumes are given in the steam tables.

Select the **efficiency factor** that corresponds to your alternative fuel. (The efficiency factor accounts for stack and boiler heat losses that would occur with combustion of the alternative fuel.) You may propose a different efficiency factor, but you must receive MMS approval to use it.

Calculate the **thermal energy displaced** to the nearest whole Btu. For valuation and reporting purposes, convert the Btu to MMBtu by dividing by one million (1,000,000). Maintain six decimal places to calculate your geothermal value, rounding to the nearest whole cent to report Sales Value on your Form MMS-2014. Then round the thermal energy displaced to the nearest whole MMBtu to report Sales Quantity on your Form MMS-2014.

6.4 Resource Measurements

You need the following three resource measurements to calculate thermal energy displaced:

1. Volume in gallons of geothermal fluid entering your direct utilization facility.

2. Temperature in degrees Fahrenheit (°F) of the geothermal fluid at the inlet to your direct utilization facility.

3. Temperature in °F of the spent geothermal fluid at the outlet of your direct utilization facility.

Figure 6-1 shows the general location of measurement points. You may need other measurements if your production is from more than one lease. The Bureau of Land Management (BLM) must approve your metering system and measurement points prior to operation.

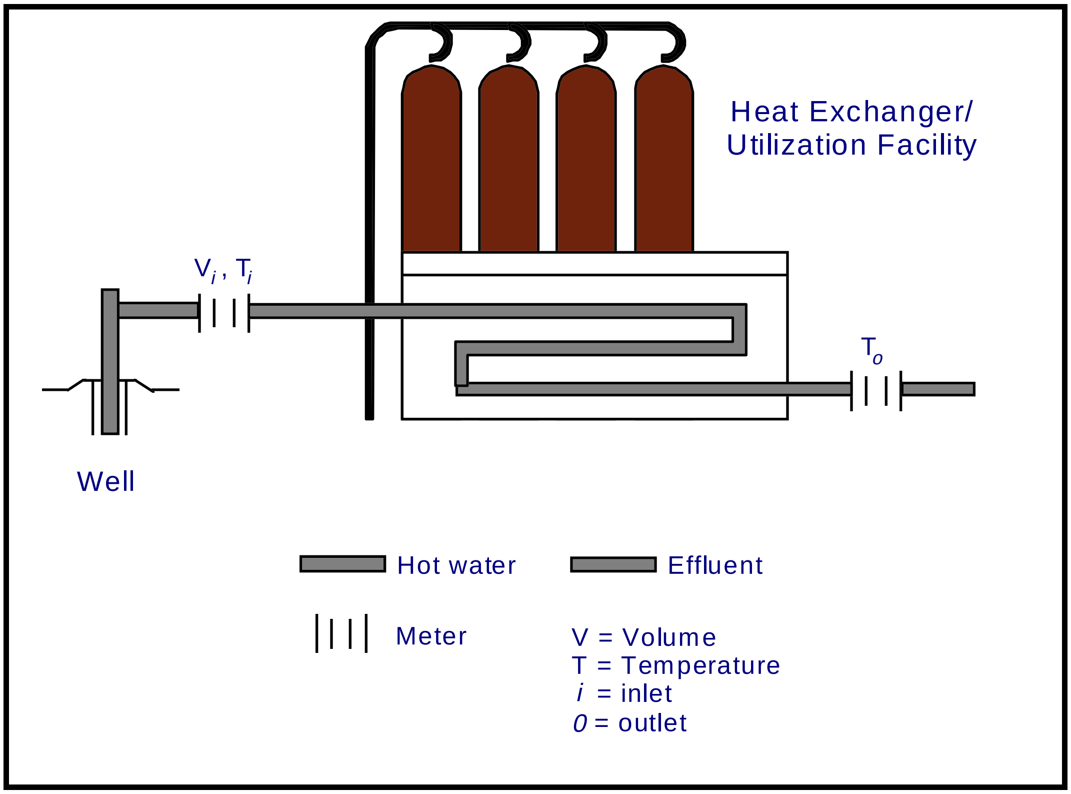


FIGURE 6-1. Resource measurements for alternative fuel valuation method

6.5 Allocation to Leases

You must allocate your calculated thermal energy displaced and geothermal value to individual leases when you use geothermal resources from more than one lease in your direct utilization facility and you commingle the production.

Allocation may be based on:

- The proportion of measured wellhead or lease production,
- The allocation schedule in your unitization or communitization agreement, or
- Any other approved measurement or allocation method.

BLM must approve your allocation method before you use it. BLM must also approve any commingling and measurement of non-Federal geothermal fluids used in your direct utilization facility.

6.6 Reporting on Form MMS-2014

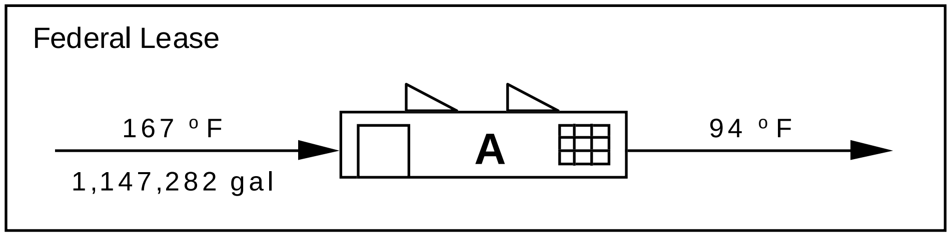
Report quantities and values calculated under the alternative fuel method on Form MMS-2014 as follows:

Sales Quantity	Amount of **thermal energy displaced** in MMBtu allocated to the lease
Sales Value	The dollar value of geothermal production allocated to the lease as calculated by the alternative fuel method
Royalty Quantity	Product of Sales Quantity and lease royalty rate
Royalty Value	Product of Sales Value and lease royalty rate

6.7 Example Valuations Using the Alternative Fuel Method

The following examples 6-3 and 6-4 illustrate valuation of geothermal resources using the alternative fuel method. These examples assume hand calculation of thermal energies displaced, with inlet and outlet temperatures given as weighted averages of periodic recordings. If your metering system automatically calculates and totals thermal energy displaced, then you need only download this amount and multiply it by the alternative fuel value (price) to calculate and report your geothermal value.

Example 6-3: Calculating value under the alternative fuel method when production is from a single lease



In this example, you use only your own Federal lease production in your direct utilization facility A. The selected alternative fuel is heating oil (efficiency factor = 0.8) with an equivalent value of $5.727666/MMBtu. The lease royalty rate is 10 percent.

<u>Month's Resource Measurements</u>

- Production = 1,147,282 gal
- Inlet temperature = 167 °F
- Outlet temperature = 94 °F

<u>From Steam Tables</u>

- Enthalpy of inlet fluid (h_{in}) = 134.97 Btu/lb
- Specific volume of inlet fluid = 0.016434 (ft^3/lb)
- Calculated density of inlet fluid:

$$\frac{1}{0.016434\ \text{ft}^3/\text{lb}} = 60.849458\ \text{lb/ft}^3$$

- Enthalpy of outlet fluid (h_{out}) = 62.06 Btu/lb

Thermal Energy Displaced

$$\frac{(134.97 - 62.06)\ \text{Btu/lb} \times 60.849458\ \text{lb/ft}^3 \times 0.133681\ \text{ft}^3\text{/gal} \times 1{,}147{,}282\ \text{gal}}{0.8}$$

= 850,537,940 Btu

= 850.537940 MMBtu

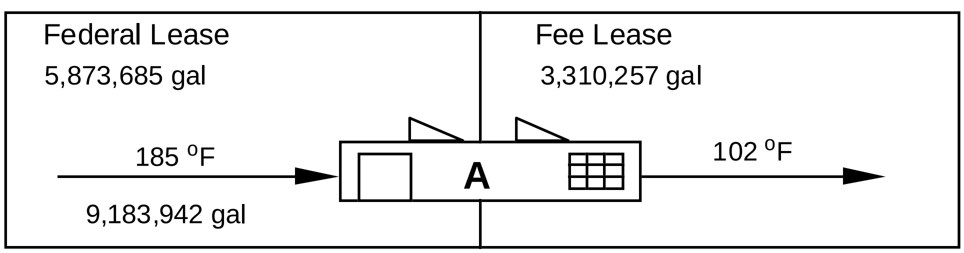
Value of Geothermal Resource

$5.727666/MMBtu × 850.537940 MMBtu = **$4,871.60**

Report on Form MMS-2014 (royalty rate = 10%)

Sales Quantity	851 MMBtu
Sales Value	$4,871.60
Royalty Quantity	85 MMBtu
Royalty Value	$487.16

Example 6-4: Calculating value under the alternative fuel method when production is from more than one lease



In this example, you use both your own Federal lease production and production from an adjacent private lease, which you also own, to operate direct utilization facility A. BLM has approved commingling and established allocation on the basis of proportionate well production.

The alternative fuel is natural gas (efficiency factor = 0.8) with the following rates:

- Cost of gas = \$0.1795/therm (\$1.795/MMBtu)
- Basic cost of service = \$0.0764/therm (\$0.764/MMBtu)
- Service charge = \$750/month

The Federal lease royalty rate is 10 percent.

Month's Resource Measurements

- Federal lease production = 5,873,685 gal
- Private lease production = 3,310,257 gal
- Total production = 9,183,942 gal
- Federal lease allocation factor:

$$\frac{5{,}873{,}685 \text{ gal}}{9{,}183{,}942 \text{ gal}} = 0.639560$$

- Inlet temperature = 185 °F
- Outlet temperature = 102 °F

From Steam Tables

- Enthalpy of inlet fluid (h_{in}) = 153.01 Btu/lb
- Specific volume of inlet fluid = 0.016539 ft^3/lb
- Calculated density of inlet fluid:

$$\frac{1}{0.016539 \text{ ft}^3/\text{lb}} = 60.463148 \text{ lb/ft}^3$$

- Enthalpy of outlet fluid (h_{out}) = 70.04 Btu/lb

Thermal energy displaced

$$\frac{(153.01 - 70.04)\ \text{Btu/lb} \times 60.463148\ \text{lb/ft}^3 \times 0.133681\ \text{ft}^3\text{/gal} \times 9{,}183{,}942\ \text{gal}}{0.8}$$

= 7,698,758,134 Btu

= 7,698.758134 MMBtu

Value of Alternative Fuel

- Unit value of service charge:

$$\frac{\$750}{7{,}698.758134\ \text{MMBtu}} = \$0.097418\text{/MMBtu}$$

- Unit value of alternative fuel:

$$\$1.795 + \$0.764 + \$0.097418 = \$2.656418\text{/MMBtu}$$

Value of Geothermal Resource

$$\$2.656418\text{/MMBtu} \times 7{,}698.758134\ \text{MMBtu} = \mathbf{\$20{,}451.12}$$

- Value allocated to Federal lease:

$$\$20{,}451.12 \times 0.639560 = \mathbf{\$13{,}079.72}$$

Report on Form MMS-2014 (royalty rate = 10%)

Sales Quantity, allocated to lease:

$$0.639560 \times 7{,}698.758134\ \text{MMBtu} = 4{,}924\ \text{MMBtu}$$

Sales Value	$13,079.72
Royalty Quantity	492 MMBtu
Royalty Value	$1,307.97

6.8 Recordkeeping and Availability

You must maintain sufficient records to support your value calculations, including all records to support your calculation of thermal energy displaced and your determination of the alternative fuel value (30 CFR 206.355(e)(1)). Retain these records for at least 6 years from the month they are applicable, unless MMS instructs you to keep them for a longer period. See 30 CFR 212.351 for additional recordkeeping requirements.

7. Byproduct Valuation

This chapter describes the standards for valuing geothermal byproducts. Byproducts are generally those recovered minerals occurring in solution or developed in association with geothermal fluid production, excluding oil, hydrocarbon gas, and helium, but including commercially demineralized water. (Also see "Applicability of Valuation Standards" on p. 2-1.) At the time of this writing, the most commonly recovered byproduct in the United States is sulfur, and much of that is treated as a hazardous waste. Standard byproduct royalty rates are 5 percent of value.

Royalties are due on byproducts when they are sold or utilized, or reasonably susceptible to sale or utilization. If you dispose of byproducts without a sale, then you must determine whether they could have been reasonably sold or utilized to determine if royalty is due. (See "Geothermal Production Requiring Royalty Valuation" on p. 2-2 for additional discussion.) If you are unsure whether royalties might be due on recovered byproducts, contact the MMS Royalty Valuation Division at the address given in appendix A.

Byproduct valuation standards are grouped according to the byproduct's disposition:

- Sales under an arm's-length contract.
- Sales under non-arm's-length contracts and no sales, the latter of which includes utilization and other dispositions without a sales transaction.

Valuation standards for byproducts sold under an arm's-length contract focus on the contract's gross proceeds, with the conditions that the gross proceeds reflects total consideration and reasonable value as discussed in "Exceptions to acceptance of arm's-length gross proceeds" on page 2-14. Valuation standards for byproducts sold under non-arm's-length contracts and for no-sales byproducts are given as a sequence of three benchmarks, or methods, where you determine value under the first applicable method in descending order of appearance. For example, if the first benchmark is not applicable or not workable, valuation falls to the second benchmark, and so on.

If the byproduct value is determined at a point off the geothermal lease, unit, or participating area, you may deduct a transportation allowance to determine your net royalties due. You report transportation allowances as a separate line item on Form MMS-2014 using transaction code 11. Byproduct transportation allowances are discussed in “Transportation Allowances” on page 7-7.

You cannot reduce the value of the byproduct for your costs of treating, beneficiating, manufacturing, or otherwise processing the byproduct into a marketable commodity. In other words, you cannot take processing allowances for geothermal byproducts.

7.1 Arm’s-length Sales

You generally determine the value of byproducts sold under an **arm’s-length contract** as the **gross proceeds** accruing under that contract (30 CFR 206.356(b)(1)(i)). (See “General Valuation Principles” on page 2-10 for additional discussion on arm’s-length contracts and gross proceeds.)

However, you must satisfy two conditions to justify the contract gross proceeds (or contract prices) as value:

1. The sales contract must reflect the **total consideration** actually transferred, either directly or indirectly, from the buyer to the seller (30 CFR 206.356(b)(1)(ii)). Total consideration is synonymous with the full definition and intent of gross proceeds as discussed on page 2-11. If the contract does not reflect total consideration, MMS **may** require you to value the resource under the non-arm’s-length and no-sales benchmarks in section 7.2 below. However, value can never be less than the gross proceeds, including any additional consideration you receive, regardless of the value calculated under the benchmarks. MMS may require you to certify that your arm’s-length contract includes all of the consideration paid to you by the buyer, either directly or indirectly, for the byproduct (30 CFR 206.356(b)(2)).

2. The gross proceeds received under the contract must reflect **reasonable value** (30 CFR 206.356(b)(1)(iii)). If MMS determines that the gross proceeds does not reflect the reasonable value of the byproduct because of misconduct by or between the contracting

parties, or because you have otherwise breached your duty to market the byproduct to the mutual benefit of yourself and the Federal Government, MMS **will** require you to value the byproduct under the non-arm's-length and no-sales benchmarks. When we determine that the value may be unreasonable, we will notify you and give you an opportunity to provide written information justifying your value.

Example 7-1 on page 7-18 illustrates valuation under an arm's-length sales contract.

Notification requirements. You don't need to notify MMS if valuation is under an arm's-length contract. However, if there is consideration outside the contract, you should notify the MMS Royalty Valuation Division at the address given in appendix A. Explain the circumstances under which the consideration occurs and either propose a valuation procedure or request guidance.

7.2 Non-Arm's-Length and No Sales

This category of valuation standards covers byproducts that you:

- Sell to your affiliate under a non-arm's-length contract,
- Use for economic benefit, or
- Dispose of without a sales transaction when the byproduct was reasonably susceptible to sales or utilization.

You determine the value of these non-arm's-length and no-sales byproducts by the first applicable of three benchmark methods: (1) gross proceeds, (2) other relevant matters, or (3) netback or other reasonable method (30 CFR 206.356(c)(1), (c)(2), and (c)(3), respectively).

7.2.1 First non-arm's-length and no-sales valuation benchmark: Gross proceeds

You use the first benchmark when (1) you have a non-arm's-length sale to your affiliated byproduct purchaser and (2) there are arm's-length sales of like-quality byproducts in the same field or area. This benchmark actually incorporates two valuation standards, which hinge on the comparability of your non-arm's-length gross proceeds with minimum value. **Minimum value** is the gross proceeds derived under the **lowest-priced available**, **comparable arm's-length contract** for the sale, purchase, or other disposition of **like-quality** byproducts in the **same** field or—if necessary to obtain a representative sample—from the same area. *Like quality* generally means byproducts with similar chemical and physical characteristics. *Area* generally means a nearby field or group of fields; it has no specific definition and must be determined case by case.

If the gross proceeds under your non-arm's-length contract is equal to or greater than the minimum value, it is acceptable for value. If it is less than the minimum value, you determine value as the weighted average of the gross proceeds derived under arm's-length contracts for the sale of like-quality byproducts in the same field or from the same area.

Available contracts are those arm's-length contracts possessed by you, your affiliate, or MMS. You determine the comparability of arm's-length contracts by their similarity to your non-arm's-length contract, considering such factors as the field or area, price, time of execution, duration, terms, quality and volume of byproduct, market or markets served, and other factors that reflect the value of the byproduct.

Example 7-2 on page 7-19 illustrates valuation under the first benchmark. If there are no comparable arm's-length contracts in the field or area, non-arm's-length valuation falls to the second benchmark.

7.2.2 Second non-arm's-length and no-sales valuation benchmark: Other relevant matters

You use the second benchmark when:

- Your affiliate purchases only your byproducts and there are no comparable arm's-length sales of like-quality byproducts in the same field or area,
- You use the byproduct(s) for economic benefit, or
- You otherwise dispose of them without a sale.

This benchmark permits a wide range of criteria to value the byproduct, including published, offered, or averaged prices; the markets for and salability of the byproduct; and circumstances peculiar to a given lease operation. You must investigate all criteria relevant to the valuation of the byproduct and select the one that best establishes value. The selected criterion should either:

1. Reflect most closely the circumstances surrounding your disposition of the byproduct, or
2. Be the most relevant factor in valuing the byproduct.

Remember that if you sell the byproduct under a non-arm's-length sales contract, value can never be less than the gross proceeds accruing under your contract, regardless of which criterion you select under the second benchmark (30 CFR 206.356(g)).

Examples 7-3 (p. 7-19) and 7-4 (p. 7-21) illustrate valuation under the second benchmark. If you are unable to determine value under this benchmark, use the third benchmark.

7.2.3 Third non-arm's-length and no-sales valuation benchmark: Netback or other reasonable method

This benchmark allows the use of unforeseen valuation methods when there are no other criteria relevant for valuing byproducts. The types of valuation methods conceivable and the circumstances surrounding their use are impossible to predict. Accordingly, MMS will determine the acceptability of proposed alternative valuation methods based on each method's merits (see "Notification requirements" and "Improper Valuations" below). For any proposed alternative valuation, keep in mind that MMS does not allow processing costs as deductions from value and that you must bear the costs of placing byproducts in marketable condition (30 CFR 206.356(h)).

7.2.4 Notification requirements

You must notify MMS if you value byproducts under any of the non-arm's-length and no-sales benchmarks (30 CFR 206.356(d)(3)). This notification must be by letter to the MMS Royalty Valuation Division at the address given in appendix A. Identify the valuation method used and describe the procedure you plan to follow. Include sufficient narrative explanation and backup data to support your valuation method.

This notification is due no later than the end of the month following the month you first report royalties on Form MMS-2014 using the described valuation method. The notification is one-time and remains in effect during use of the method. If you change to a different valuation method, you must submit a new notification.

7.3 Improper Valuations

If MMS finds that you improperly determined value, we will direct you to correct your value or prescribe a different valuation procedure (30 CFR 206.356(e)). You will be liable for any difference between the royalties paid and the royalties due under the value determined by MMS, plus late payment interest on underpaid amounts pursuant to 30 CFR 218.302. If the corrected value or prescribed valuation procedure results in an overpayment, MMS will give you instructions for taking a credit. You are not entitled to interest on royalty overpayments.

You may appeal any of MMS's valuation decisions. For adverse decisions, MMS will issue appeals instructions concurrent with the decision. Otherwise, see 30 CFR Part 243 for appeals information.

7.4 Valuation Requests

If you are unsure of your valuation procedure, you may request a determination from MMS (30 CFR 206.356(f)). Send your valuation requests to the MMS Royalty Valuation Division at the address given in appendix A. Include a description of your operation, copies of sales contracts, and any other information pertinent to the valuation of your byproduct. You must continue to pay royalties on byproducts removed or sold from the lease while MMS is making its determination. You will be liable for any additional royalty and interest if our determination results in a higher value than the value on which you paid royalties.

If you propose an alternative valuation method under the third non-arm's-length and no-sales benchmark (other valuation methods), you must include all information supporting your proposal. Remember, you must explain why the first two benchmarks are unworkable. You may use your proposed valuation method for royalty calculations until MMS issues a decision. If MMS approves your proposed valuation method, you must use that method until one of the following occurs:

- The circumstances of your production and/or utilization change, at which time you must notify MMS with a new valuation request.
- MMS instructs you to use a different valuation method.
- MMS issues new valuation regulations.

If MMS disapproves your proposed valuation method, we will prescribe a method to you. You must then adjust all of your past royalty reports to reflect the prescribed method (30 CFR 206.356(e)). If our prescribed method results in additional royalty due, you must pay the additional royalty plus interest. If our prescribed method results in royalty overpayments, MMS will give you instructions for taking a credit. You are not entitled to interest on royalty overpayments.

7.5 Transportation Allowances

You may claim a transportation allowance to recover your actual costs of transporting the royalty portion of your byproduct production. Rules governing byproduct transportation allowances appear at 30 CFR 206.357 and 206.358.

7.5.1 When you can claim a transportation allowance

You can claim a transportation allowance when (1) the value of the byproduct is determined at a point—generally the sales point—off the geothermal lease, unit, or participating area, **and** (2) you have incurred actual costs to transport the byproduct to that point.

Byproduct transportation may occur in segments from the lease to a byproduct recovery facility and from the byproduct recovery facility to the point of sale or delivery. Thus, you can claim a transportation allowance for your costs incurred to transport the byproduct:

1. From the lease, unit, or participating area to a sales or delivery point off the lease, unit, or participating area;

2. From the lease, unit, or participating area, or from a geothermal utilization facility (powerplant or direct utilization facility) to a byproduct recovery facility off the lease, unit, or participating area; and/or

3. From a byproduct recovery facility that is off the lease, unit, or participating area to a sales or delivery point also **off** the lease, unit, or participating area.

NOTE

The key to claiming a byproduct transportation allowance is that the transportation must occur **off** the lease, unit, or participating area.

Transportation allowances are not permitted for transporting byproducts within the lease, unit, or participating area. In addition, you cannot claim or include costs of transporting geothermal fluids from the lease, unit, or participating area to a geothermal utilization facility, whether or not the facility is on or off the lease, unit, or participating area (30 CFR 206.357(a)(2)).

You can take a transportation allowance only when you sell, deliver, or otherwise utilize the transported byproduct and you report and pay royalties; that is, you cannot take a transportation allowance when you store or add byproducts to stockpiles.

You must take a separate transportation allowance for each byproduct sold, delivered, or utilized; you cannot transfer the costs of transporting one byproduct to another or from one selling arrangement to another. If you commingle Federal and non-Federal byproducts for transport, you cannot disproportionately attribute transportation costs to Federal byproducts. (You essentially allocate transportation costs by computing the cost per unit of total byproduct transported and multiplying by the allocated quantity, or portion, of Federal byproduct transported. This procedure will become more apparent as you calculate and report your transportation allowance.)

7.5.2 Determining transportation allowances

You determine your transportation allowance(s) from your actual, reasonable costs of transporting the byproduct. Your determination will depend on whether an unaffiliated third party transports the byproduct (arm's-length contract) or your affiliate or you transport the byproduct (non-arm's-length or no contract).

A transportation allowance covers only the cost of transporting the royalty portion of byproducts. As a general rule, you will determine your transportation costs on a dollar-per-unit, or cost rate, basis. Your transportation allowance then becomes the product of your cost rate and the royalty quantity:

$$\text{transportation allowance} = \text{cost rate} \times \text{royalty quantity.}$$

To help you determine your transportation allowances and maintain supporting records, we recommend you use MMS's oil, gas, or coal transportation allowance reports (Forms MMS-4110, -4295, and -4293, respectively) and their related schedules as a guide, particularly if transportation is under the non-arm's-length or no-contract category. See the *Oil and Gas Payor Handbook—Volume III, Product Valuation* or the *AFS Payor Handbook—Solid Minerals* for examples of these forms. All reported transportation allowances are subject to monitoring, review, audit, and adjustment. Following is a general discussion on determining byproduct transportation allowances.

7.5.2.1 Arm's-length contracts

As a general rule, you may take your actual costs incurred under an arm's-length transportation contract as your transportation allowance (30 CFR 206.358(a)(1)). This rule, however, is subject to the following conditions:

1. The costs under your arm's-length transportation contract must reflect the total consideration passing either directly or indirectly between you and your transporter. If MMS determines there are other considerations that affect either the transportation costs or the value of the byproduct, we may require you to determine your transportation allowance under the non-arm's-length and no-contract regulations.

2. The costs under your arm's-length transportation contract must reflect the reasonable value of the transportation. If MMS determines that the costs do not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because you have otherwise breached your duty to market the byproduct to the mutual benefit of yourself and the Federal Government, we **will** require you to determine the byproduct transportation allowance under the non-arm's-length and no-contract regulations. When MMS determines that the transportation costs may be unreasonable, we will notify you and give you an opportunity to justify your costs.

You report your arm's-length transportation allowance on the Form MMS-2014 in dollars. However, you must calculate the allowance in terms of dollars-per-unit of the byproduct transported, using the units of measure required by MMS (see "Units of measurement for byproducts" on p. 2-9). If your payments are not on a dollar-per-unit basis, you must convert whatever consideration you pay to a dollar-value equivalent for your recordkeeping and to justify your claimed transportation allowance.

7.5.2.2 Non-arm's-length and no contract

Transportation allowances for non-arm's-length and no-contract transportation (30 CFR 206.358(b)) are based on your reasonable, actual costs (if you provide your own transportation or you otherwise have no transportation contract) or on your affiliated transporter's reasonable, actual costs (if you have a non-arm's-length contract). Your reasonable, actual costs consist of:

1. Your combined operating and maintenance (O&M) expenses, including overhead, and **either**

2. Depreciation and a return on undepreciated capital investment, **or**

3. A return on capital investment.

You state your transportation costs in terms of cost rates, which you calculate annually.

Cost rates. You have the option of calculating your cost rates by either the depreciation method or return-on-investment method. Once you've chosen a calculation method, you cannot later use the other method without the MMS Royalty Valuation Division's approval.

You calculate a new cost rate at the beginning of each annual reporting period during which you take allowances; that cost rate remains in effect during the reporting period. (A *reporting period* is the 12 months beginning with the commencement or anniversary date of your transportation system.) Use estimated O&M expenses and quantities transported for the first reporting period. For subsequent reporting periods, use the previous period's actual O&M expenses and quantities transported, adjusted for any anticipated differences.

Within 90 days following the end of each reporting period, recalculate that period's exact cost rates and transportation allowances—based on your actual costs incurred and quantities transported for that period—and submit corrected Forms MMS-2014, together with any additional royalty due.

Calculating transportation cost rates by the depreciation method. If you elect the depreciation method, calculate annual transportation cost rates from the following equation:

$$\text{cost rate (\$/unit)} = \frac{E + D + I}{F}$$

where:

E = annual O&M expenses, estimated for the first year

D = annual depreciation of capital investments

I = annual return on beginning-of-year undepreciated capital investment

F = annual quantity of byproduct transported, estimated for the first year, in the units of measure required by MMS for the byproduct

Calculate the cost rate to six decimal places.

Compute your depreciation (D) by the straight-line method, using as the depreciation period either the life of the equipment or the life of the geothermal project that the transportation system serves. Once you've chosen a basis for your deduction period, you cannot change to the other. You can depreciate a transportation system only once; a change in ownership does not alter the depreciation schedule established by the original owner, except for addition or replacement of capital items. Do not depreciate equipment below a reasonable salvage value.

Compute your return on undepreciated capital investment (I) as the product of the return rate and the undepreciated capital investment balance at the beginning of the annual reporting period:

$$I = \text{return rate} \times \text{undepreciated investment balance.}$$

The return rate is Standard and Poor's monthly average **industrial BBB** bond rate, as published in Standard and Poor's *Bond Guide*, for the first month of the annual reporting period. This rate remains constant during the reporting period; you redetermine the return rate at the beginning of each new reporting period.

Calculating transportation cost rates by the return-on-investment method. If you elect the return-on-investment method, calculate your annual transportation cost rates from the following equation:

$$\text{cost rate (\$/unit)} = \frac{E + R}{F}$$

where:

E = annual O&M expenses, estimated for the first year

R = annual return on **gross** capital investments

F = annual quantity of byproduct transported, estimated for the first year, in the units of measure required by MMS for the byproduct

Calculate the cost rate to six decimal places.

Compute the annual return (R) as the product of the return rate and your gross capital investment in the transportation system:

$$R = \text{return rate} \times \text{capital investment.}$$

The return rate is Standard and Poor's monthly average **industrial BBB** bond rate, as published in Standard and Poor's *Bond Guide*, for the first month of the annual reporting period. This rate remains constant during the reporting period; you redetermine the return rate at the beginning of each new reporting period.

Use your gross capital investments in the transportation equipment, adjusted for retired or replaced items, to calculate R. Do not reduce your capital expenditure for salvage value. However, if you trade in a capital item, reduce the capital cost of the new item by the amount of your trade-in allowance. If you acquire an existing transportation system, you must continue to use the original owner's capital investment to calculate R; you cannot recapitalize a transportation system with a change in ownership. There is no term limit, such as a depreciation period, for the return-on-investment method.

O&M costs. **Allowed** O&M costs are those expenses that are directly attributable and allocable to the routine operation, maintenance, and repair of the transportation system. Examples of allowed O&M costs include labor, supervision, materials and supplies, fuel, rent and/or lease payments, insurance, property taxes, payroll taxes, and general administrative and corporate overhead costs that you can directly attribute and allocate to the operation of the transportation system.

Nonallowed O&M costs include State and Federal income taxes; severance taxes; royalty payments, including overriding royalty;

financial fees or costs paid after commission of the transportation system, such as loan and equity payments, including principal and interest; and other corporate or project expenses not directly attributable and allocable to the routine operation, maintenance, and repair of the transportation system.

Capital investments. **Allowed** capital investments are your actual costs for the design, purchase, delivery, and/or installation of capital equipment integral to the transportation system. Examples of allowed capital investments include the costs of tangible, depreciable assets, such as trucks, conveyors, and other haulage equipment; roads; engineering design and permitting fees; loan interest paid during construction; and other transportation-related capital costs you can document.

Nonallowed capital investments include socioeconomic costs and civic improvements imposed by local governments as a condition of doing business, payments on borrowed principal made during the construction phase of the transportation system, and other corporate or business costs not directly related to construction or procurement of the transportation system.

Rights-of-way. You may include rights-of-way costs in your allowances. How you account for them depends on how you pay for them. If you make periodic (monthly or annual) payments for your transportation rights-of-way, include the payments in your annual O&M costs. If you acquire your transportation rights-of-way by a lump-sum payment, the payment becomes part of your capital-related costs as follows:

- Under the depreciation method, amortize the payment over the life of the transportation system and add the amortized amount to each year's declining capital balance as a component in computing the annual return on undepreciated capital investment.

- Under the return-on-investment method, include the lump-sum payment as part of the gross capital investment.

Real estate costs. Real estate costs, including recording fees and other costs incident to the purchase of lands, may be eligible for a return on investment **if**:

- You can demonstrate the necessity for the land purchase;

- The purchased land is not on a Federal geothermal lease; **and**
- The MMS Royalty Valuation Division approves the costs.

You can include only that portion of real estate costs necessary for the transportation corridor. If your real estate purchase includes land outside the normal transportation corridor, you must allocate the cost between the corridor and the other land.

If you are using the depreciation method to calculate your transportation cost rate, add the allowable real estate costs to the annual undepreciated capital balance to compute the return on undepreciated capital investment. If you are using the return-on-investment method, include the allowable real estate costs as part of the gross capital investment.

7.5.3 Segmented transportation systems

If you have a segmented transportation system, you must compute separate cost rates and allowances for each segment. An example of a segmented transportation system is one where you transport, say by conveyor, a byproduct mix from the lease, unit, or participating area to a byproduct recovery facility off the lease, unit, or participating area. You then truck the marketable byproduct from the byproduct recovery facility to the delivery or sales point. If you transport a byproduct mix, you do not allocate transportation costs between the quantities of marketable byproduct and rejected waste material; rather, you use the entire quantity of material transported in your computations. After you've determined the monthly transportation allowances for all segments, add them to report your total allowance on Form MMS-2014.

7.5.4 Reporting transportation allowances

You report each byproduct transportation allowance as a separate line item on the Form MMS-2014 (30 CFR 206.357(g)), using transaction code 11 with the product and selling arrangement codes of the byproduct. Report your byproduct allowance only in the Royalty Quantity and Royalty Value columns by placing a minus sign (–) in front of the numbers; leave the Sales Quantity and Sales Value columns blank. (See example 7-1 on page 7-18.)

You don't file byproduct transportation allowance forms or reports with MMS, and you don't need prior approval before taking an allowance. You must maintain sufficient records to support your claimed allowance(s) upon audit or review.

7.5.5 Limit on transportation allowances

Transportation allowances cannot reduce the value of byproducts to zero (30 CFR 206.357(b)). As an administrative policy, MMS limits transportation allowances to a maximum of 99 percent of the value of the byproduct.

7.5.6 Transportation factors

Transportation factors are reductions in sales prices specified in sales contracts for transportation services performed by the purchaser. They are generally found in the pricing clause of the sales contract and essentially represent the purchaser's fee for taking delivery of a byproduct at the seller's location, particularly where the sales price is a free-on-board (f.o.b.) destination price. For example, a sales contract with a transportation factor might read, "The Seller's price of the byproduct shall be the posted price for the Western Region less $4.00/ton for the Purchaser's pickup at the Seller's location."

MMS recognizes transportation factors as part of the pricing formula only in arm's-length sales contracts. Thus, if you have an arm's-length sales contract with a transportation factor, the net price and resultant gross proceeds under the contract are acceptable for value. You report a one-line entry, using transaction code 01, on your Form MMS-2014; you do not report a separate transportation allowance.

MMS views transportation factors in non-arm's-length sales contracts as non-arm's-length transportation arrangements, **unless** you satisfy the condition of gross proceeds comparability under the first non-arm's-length valuation benchmark (see example 7-2 on page 7-19). Otherwise, you must calculate and report the value of the byproduct on the full, or base, contract price (see example 7-3 on page 7-19). You may then claim a separate transportation allowance, but you must calculate your allowance from your affiliated purchaser's actual, reasonable transportation costs. Bear in mind that the gross proceeds under your non-arm's-length sales contract establishes minimum value. Therefore, do not claim a transportation allowance greater than the transportation factor.

7.6 Recordkeeping and Availability

You must keep all data and records supporting your royalty valuation, particularly if you value byproducts under the non-arm's-length and no-sales benchmarks (30 CFR 206.356(d)(1)). Also keep all data and records supporting your transportation allowances.

Keep the following documents indefinitely:

- All contracts related to the sale or purchase of byproducts.
- Any other contracts that may bear on the valuation or are necessary to support your valuation, including transportation contracts, agreements, or arrangements.
- All MMS valuation decisions and other written communications relevant to your valuation.

You must save records supporting your monthly royalty calculations for 6 years unless MMS instructs otherwise. These records include, but are not limited to, quality of the byproduct; quantities produced, added to inventories, and/or sold; prices received; and transportation costs. You must make all records, contracts, and other documents supporting your valuations available to authorized MMS personnel or MMS-designated agents upon request (30 CFR 206.356(d)(2)). See also 30 CFR 212.351.

7.7 Byproduct Valuation Examples

It is impossible to give valuation examples that cover all the possible byproduct dispositions. The following examples 7-1 through 7-4 give a few of the simpler situations that are reasonably foreseeable and also illustrate valuation principles. Examples 7-2 and 7-3 (p. 7-19) particularly show how values and royalty payments can differ under the non-arm's-length and no-sales valuation benchmarks.

Example 7-1: Valuing a byproduct sold under an arm's-length contract

Say you recover sulfur at your on-lease hydrogen sulfide (H_2S) abatement facility and you haul it by truck to the sales point off the lease. You've determined that your transportation cost rate for the current reporting year is $2.764953/long ton. The sales price of the sulfur is $70/long ton. For the month you deliver 50 long tons. The byproduct royalty rate is 5 percent.

The value of the byproduct is:

$$\$70/\text{long ton} \times 50 \text{ long tons} = \$3{,}500.00$$

Your transportation allowance for the month is:

$$\$2.764953/\text{long ton} \times 50 \text{ long tons} \times 0.05 = \$6.91$$

You would report the following information on Form MMS-2014:

<u>Line 1 (Byproduct Value)</u>

Product code	19
Transaction code	01
Sales Quantity (long tons)	50
Sales Value	$3,500.00
Royalty Quantity (long tons)	2.5
Royalty Value	$175.00

<u>Line 2 (Transportation Allowance)</u>

Product code	19
Transaction code	11
Royalty Quantity (long tons)	– 2.5
Royalty Value	– $6.91

Your net royalty due on the byproduct for the month is:

$175.00 – $6.91 = $168.09.

Example 7-2: Valuing a byproduct sold under a non-arm's-length contract using the first benchmark: Comparability of gross proceeds

Say you recover sulfur at your powerplant's H_2S abatement facility and sell it to your affiliated chemical manufacturer. Your affiliate takes delivery at the powerplant and pays you an f.o.b. destination price of $70/long ton less a transportation differential of $8/long ton, so your gross proceeds is $62/long ton. The transportation differential is a term of the sales contract, so it is a transportation factor. Your affiliated purchaser also buys like-quality sulfur from other producers in the field under arm's-length contracts identical to yours. You sell 50 long tons during the month.

In this example, the gross proceeds under your non-arm's-length contract ($62/long ton) is the same as that under the arm's-length contracts for the field. Accordingly, your gross proceeds is acceptable for value. The transportation differential (transportation factor) under your non-arm's-length contract is not a valuation factor in this case, nor is it eligible for a transportation allowance, because the arm's-length sales contracts essentially establish a field value for the byproduct. You report and pay royalties on 50 long tons of sulfur at $62/long ton, or $3,100.

Note that if your gross proceeds was less than those under the arm's-length contracts (say they were $60/long ton), you would value your sulfur as the weighted average of the gross proceeds under the arm's-length contracts, or $62/long ton. You still would not be eligible for a transportation allowance because the arm's-length gross proceeds incorporates transportation.

Example 7-3: Valuing a byproduct sold under a non-arm's-length contract using the second benchmark: Other relevant matters

Again, say you recover sulfur at your powerplant's H_2S abatement facility and sell it to your affiliated chemical manufacturer. But in this example your affiliated purchaser does not buy any other sulfur from the field. Accordingly, you have no arm's-length contracts against which to compare your gross proceeds. Let's use the same contract terms as for example 7-2. Your affiliate takes delivery at the powerplant and pays you an f.o.b. destination price of $70/long ton less a transportation differential of $8/long ton, so your gross proceeds is $62/long ton. You sell 50 long tons during the month. Your byproduct royalty rate is 5 percent.

Because there are no arm's-length sales contracts in the field or area on which to establish value, the base price in your sales contract ($70/long ton) would likely establish value, particularly if it was an acknowledged market price. You would treat the transportation differential as a non-arm's-length transportation arrangement that would be eligible for a transportation allowance, but you must determine the transportation allowance from your affiliated purchaser's actual costs. Say your calculated transportation costs are $3.500000/long ton, so your allowance is:

$$\$3.500000 \times 50 \text{ long tons} \times 0.05 = \$8.75$$

You would report the following information on your Form MMS-2014:

Line 1 (Byproduct Value)

Product code	19
Transaction code	01
Sales Quantity (long tons)	50
Sales Value, at $70/long ton	$3,500.00
Royalty Quantity (long tons)	2.5
Royalty Value	$175.00

Line 2 (Transportation Allowance)

Product code	19
Transaction code	11
Royalty Quantity	– 2.5
Royalty Value	– $8.75

Your net royalty due on the byproduct for the month is:

$175.00 – $8.75 = $166.25.

Let's change your calculated transportation costs to $9.245000/long ton. In this case the transportation costs are greater than the transportation differential. Because the gross proceeds under your transportation-factored, non-arm's-length contract establishes minimum value, your transportation allowance is limited to $8/long ton. Your net royalty due on the byproduct for the month is then:

$175.00 – (2.5 long tons × $8/long ton) = $155.00.

This amount is equivalent to the royalty you would pay under your gross proceeds of $62/long ton, but you must report two lines in the Form MMS-2014 to arrive at it.

Example 7-4: Valuing marketable byproducts disposed of without a sales transaction

When you dispose of a byproduct without a sales transaction, you first must determine whether the byproduct is marketable or has a market in your area to determine if royalty is due. If you use the byproduct in some process or make other products, you benefit financially from it and automatically create a market for it. If you give the byproduct to someone who benefits financially from it, they create the market. You then must use the second or third non-arm's-length and no-sales valuation benchmarks to determine the value of the byproduct. The most obvious choice for value would be local market prices. You may wish to undertake an economic study to determine and support your value. In any case, you must report your valuation method to MMS (see "Notification requirements" on p. 7-6).

A. Important Addresses

Royalty valuation. Send all correspondence regarding the valuation of geothermal resources production to:

Minerals Management Service
Royalty Management Program
Royalty Valuation Division, MS 3150
P.O. Box 25165
Denver, CO 80225-0165

Payor Information Forms (PIF) (Form MMS-4025). Send initial PIFs, revised PIFs, and correspondence regarding PIFs to:

Minerals Management Service
Royalty Management Program
P.O. Box 5760
Denver, CO 80217-5760

If you have questions concerning PIFs, call one of the following telephone numbers:

Toll-free: 1-800-525-9167
Commercial: 303-231-3112

See the *Oil and Gas Payor Handbook—Volume I* for additional PIF information.

Report of Sales and Royalty Remittance (Form MMS-2014). Send royalty payments and Forms MMS-2014 to:

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

Send all other correspondence regarding Forms MMS-2014 to:

Minerals Management Service
Royalty Management Program
P.O. Box 5760
Denver, CO 80217-5760

If you have questions regarding Forms MMS-2014, call your assigned MMS company representative at 1-800-525-0309.

See the *Oil and Gas Payor Handbook—Volume II* for additional Form MMS-2014 information.

Release History

Release number	Release date	Revised chapters/sections	RMP originator	Preparer
1.0	12/27/96		Royalty Valuation Division	AMS/OC[a]

a. American Management Systems/Operations Corporation, Inc.

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.