

Chapter 4

Gross Proceeds Less Applicable Deductions or Netback Valuation for Electrical Generation (Not Arm's Length Sales of the Geothermal Resource)

This chapter explains how you calculate royalties on Federal geothermal resources used to generate electricity in your own power plant using the netback procedure.

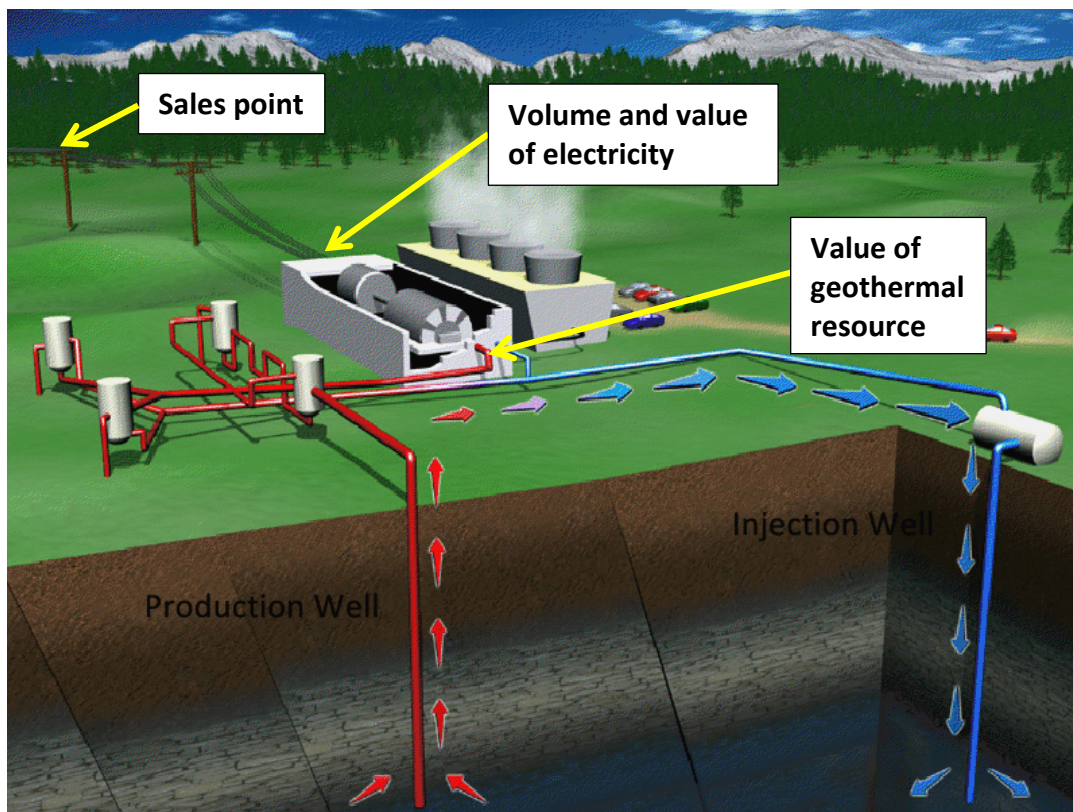
Unlike arm's length sales of geothermal resources to an unaffiliated purchaser, such as the lessee selling geothermal resources to a nearby power plant owned by someone else, ONRR refers to this situation as "not arm's length" (NARM) as opposed to an arm's length transaction. Please refer to Chapter 2, section 2.9.1 for a detailed explanation of ONRR's definition of arm's length transactions and how to distinguish arm's length versus not arm's length.

A value for the geothermal resource cannot be directly determined when you use your resource in your own power plant. Since there is no sale of the geothermal resource in such a case, that is, the lessee owns the geothermal resources as well as the power plant, the first sale of anything of value derived from the geothermal resources is electricity generated by the lessee's own (or affiliated) power plant. There is then an arm's length sale of electricity from the power plant to an unaffiliated utility. To derive a value of the geothermal resources, the gross proceeds from the arm's length sale of electricity is used as a value from which applicable generation and transmission costs may be deducted to arrive at a geothermal value back at the lease.

This chapter identifies which costs are allowed to be deducted and how to deduct them. It also identifies certain unallowable costs and explains why they are not allowed.

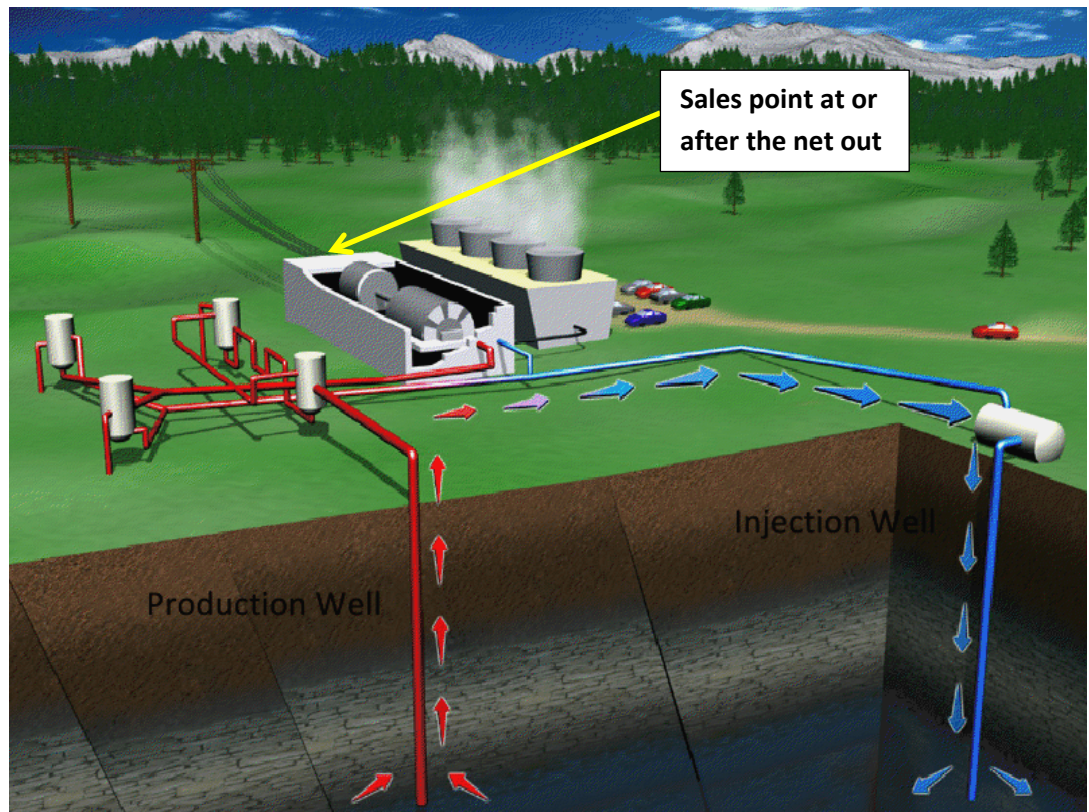
ONRR is using this procedure to arrive at a value of the resource before it enters the

plant based on the sale of electricity produced from your geothermal resources.



Under the netback procedure, you derive the value of the geothermal resource by subtracting your costs of generating and transmitting electricity from your gross proceeds from the sale of electricity , as follows:

$$\text{Netback Geothermal Value} = \text{Electricity Value} - \text{Transmission Deduction} - \text{Generating Deduction}$$



The following three conditions are necessary in order to use the netback valuation:

1. You or your power-generating affiliate uses the leased geothermal resource to generate and sell electricity.
2. There is an arm's length contractual sale of the electricity.
3. You have a volume of electricity measured at the net out meter.

The second condition is paramount because the sales contract establishes the value of the electricity, which forms the basis for netback valuation. If you do not sell the electricity you or your affiliate generates to an unaffiliated third party, you cannot use this netback method. The netback procedure is unworkable if the above conditions are not met. If the netback method is not workable because of any of the above conditions, the regulations at 30 CFR 1206.352 (b)(1)(ii) allow "A royalty determined by any other reasonable method approved by ONRR". Please contact the ONRR royalty valuation mailbox at royaltyvaluation@onrr.gov for guidance.

4.1 General Concepts

This section refers to general concepts that help with understanding the Netback procedure.

4.1.1 *Electricity Value*

The electricity value is the total amount of revenues (gross proceeds) that 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. The principles of total consideration and reasonable value, discussed in “Arm’s-Length Sales” in Chapter 3, apply to electricity sales as they do to sales of geothermal resources.

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

We recognize 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” in section 2.3). This does not affect the calculation or application of your annual cost rates; they remain calculated on the 12-month deduction period you select.

For more detailed explanation of netback deductions and cost rates, please see Chapter 4.

For example, if you receive payment for electricity delivered on 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) in order to determine your December deductions. Likewise, if you receive payment for electricity delivered on 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. Of course, for months without production, no royalty is due.

4.1.3 **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 power plant entered into service.
- 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 ONRR approval.

If you have allowable deductible costs, they must be prorated to monthly costs in order royalties which are due on a monthly basis. Royalties are due each month that you are producing geothermal resources. This is explained more below.

You start at the last place a volume of electricity attributable to resource removed from can be determined. Following is an outline of the steps to follow to construct netback. We will cover these steps in greater detail in subsequent sections.

- Step 1** Calculate your annual cost rate for transmission deductions (if you have transmission costs).
- Step 2** Calculate your monthly transmission deduction (if you have transmission costs).
- Step 3** Calculate your annual generation cost rate.
- Step 4** Calculate your monthly generation deduction.
- Step 5** Calculate the monthly value of geothermal resources used in the power plant 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 gross proceeds less deduction value of all geothermal resources of source, at the power plant inlet.
- Step 6** Allocate the monthly value to Federal leases, as necessary.
- Step 7** Report monthly delivered electricity and values allocated to each lease on ONRR-2014.
- Step 8** At the beginning of the next deduction period, which is the annual period chosen for depreciation (see below), recalculate the previous deduction period’s estimated annual cost rates, deductions, and netback values based on your known costs for that period. Submit corrected Form ONRR-2014’s, adjusted.

royalty lines for each month using adjustment reason code 25.

4.1.4 ***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 1206.352(b)(1)(i)). Our 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.

4.1.5 ***Requisite Electricity Measurements***

Figure 4-1

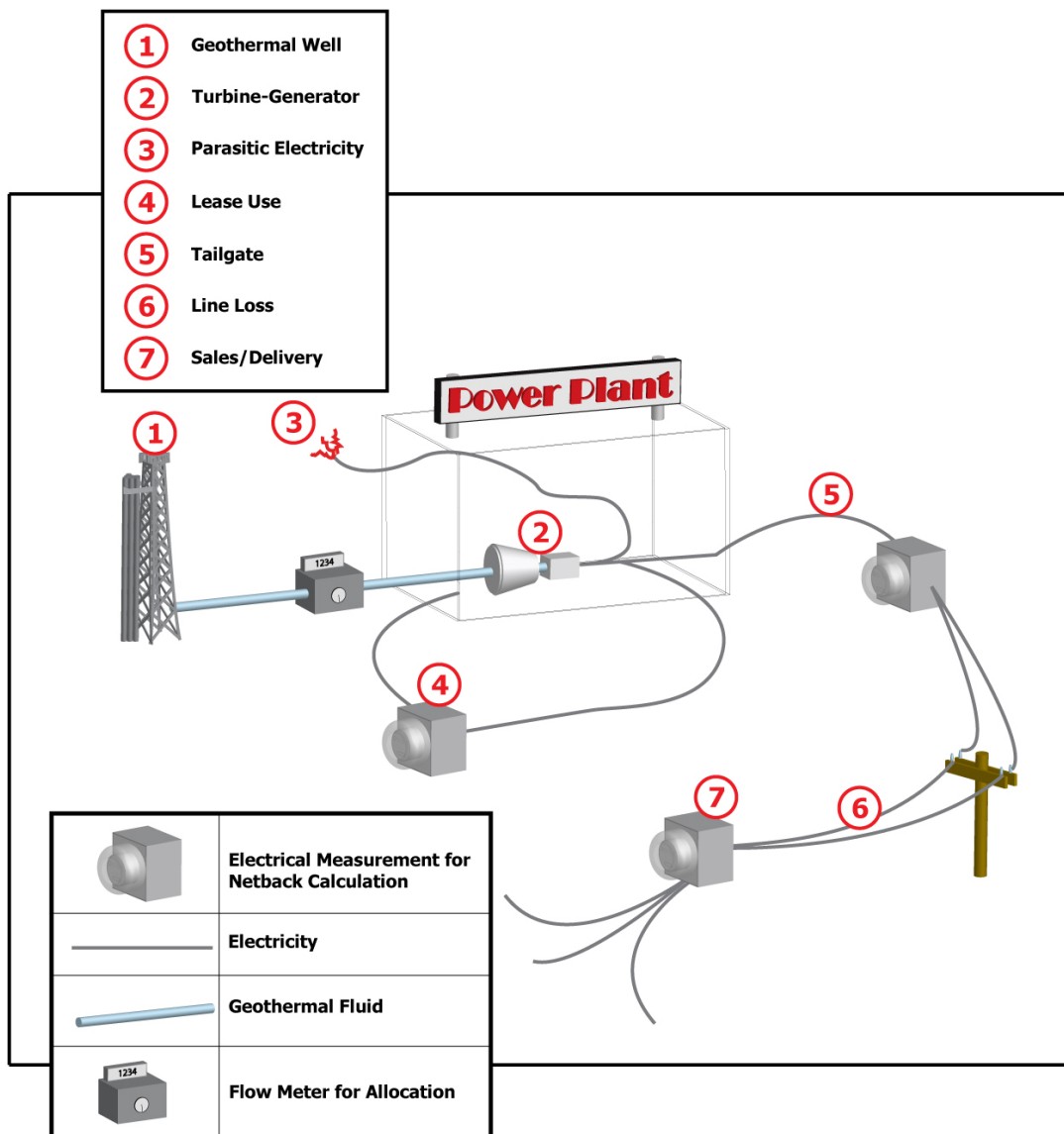


Figure 4-1 shows the electricity measurements needed to determine your deductions. For the transmission-line deduction, you must determine the amount of delivered electricity or the amount of interconnect electricity (if your transmission line interconnects with another transmission line to wheel the 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. All electricity measurements must be in kilowatt hours and must be prorated based on the Federal versus non-Federal

percent allocation. Be sure to separately measure parasitic electricity (see below Section 4.1.4.5 for definition) and electricity returned to the lease.

4.1.5.1 **Delivered Electricity**

“Delivered electricity” means the amount of electricity in kilowatt-hours delivered to the purchaser.

Note: Line loss should not be included in delivered electricity.

4.1.5.2 **Electricity Returned to the Lease**

Electricity returned to the lease means any electricity returned for use on the lease. If you have downhole pump costs please see the discussion in the Generation Deduction section on Operation and Maintenance Costs (O & M).

4.1.5.3 **Interconnected Electricity**

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 interconnected 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.) See the example in section 4-3 that illustrates the use of interconnected electricity in netback deductions calculation.

4.1.5.4 **Net Out Electricity**

Net Out Electricity should be measured at, or calculated for, the high voltage side of the transformer in the plant switchyard.

4.1.5.5 **Plant Parasitic Electricity**

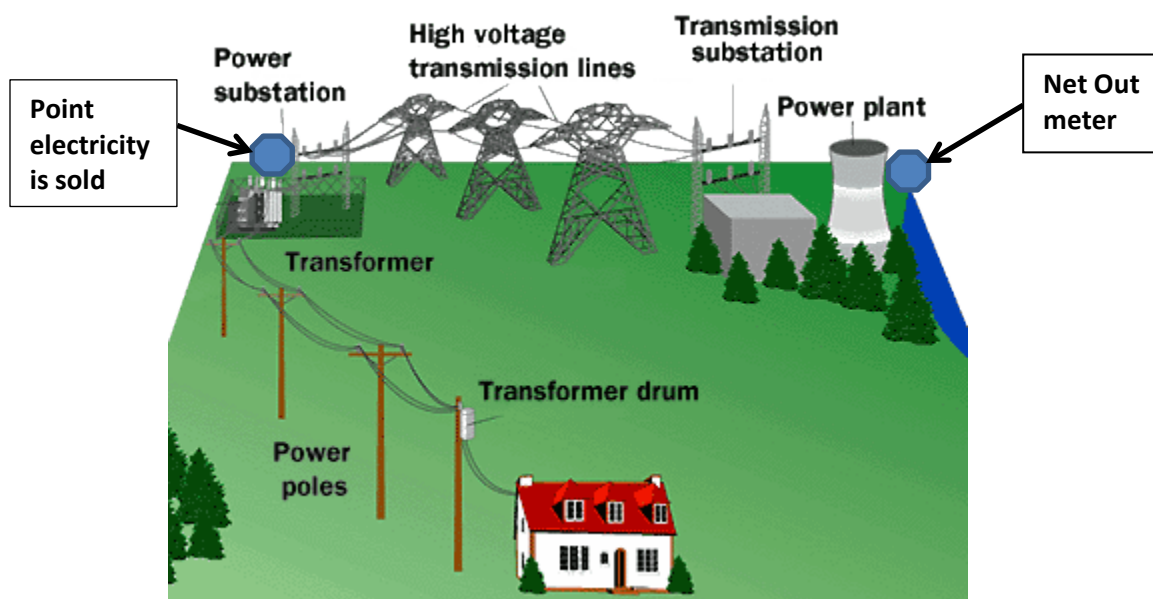
“Plant parasitic electricity” means electricity used to operate a power plant that is used for commercial production or generation of electricity.

4.1.5.6 **Plant Tailgate Electricity**

“Plant tailgate electricity” means the amount of electricity in kilowatt-hours generated by a power plant exclusive of plant parasitic electricity, but inclusive of any electricity generated by the power plant and returned to the lease for lease operations. Plant tailgate electricity should be measured at, or calculated for, the high voltage side of the transformer in the plant switchyard.

Note: Plant tailgate electricity should not include non-royalty bearing electricity measurements, (e.g. any portion of electricity generated by fee or state leases).

4.2 Step 1—Annual Cost Rate for Transmission Deduction



Cost rates for transmission deductions center around cost incurred between the net out meter and the point of sale. The last point where you can reasonably measure the volume of electricity attributable to the geothermal resource is the point where other energy producers transfer electricity to a shared electrical grid. You calculate annual cost rates in terms of dollars per kilowatt hour (\$/kWh) and then apply these cost rates to monthly electricity measurements to determine your monthly deductions.

The first step is to determine what operating and maintenance costs can be included in your cost rates (see tables of allowed and non-allowed costs in Section 4.2.1 below)

4.2.1

Step 1A—Transmission Line O&M Cost

The first step in determining your cost rate for transmission deductions is to determine your operating and maintenance cost associated with transmitting your electricity from the net out meter to the point where the electricity is sold.

The table below shows allowed and non-allowed operating and maintenance costs.

Allowed Operating and Maintenance (O&M) Costs		
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 un-depreciated 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" below)	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		

Non-Allowed Operating and Maintenance (O&M) Costs		
State and Federal income taxes	Severance taxed	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 expensed	Late payment fees for failure to make timely loan payments	Other corporate or project expenses not directly attributable and allocable to the routing operation, maintenance, and repair of the transmission line

4.2.2

Step 1B—Transmission-line Capital Investments

The second step in determining your cost rate is to determine what allowable capital investments you have to depreciate. 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). The table below shows allowed capital investments and non-allowed capital investments.

Allowable Capital Investments (in green) and Non-Allowable Capital Investments (in red)		
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 directly relate to the 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 you borrowed the money.
Lump-sum payments for transmission-line rights-of-way off Federal geothermal leases (see “Rights-of-Way costs” below)	Real estate costs, if ONRR approves them see section XXX below.	Administrative costs that directly attribute and allocate to construction of the transmission line
Other costs for the design, purchase, delivery, and installation of the transmission line and related equipment that you can document.	Socioeconomic costs (such as hospitals, schools, roads, or other civic improvements) that local government agencies impose 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 loan payments in a timely manner during the design and construction phase of the transmission line	Construction contract termination fees or penalties	Any other corporate or business costs that do not directly relate to construction of the transmission line

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

4.2.2.1

Real Estate Costs

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

- You can demonstrate the necessity for the land purchase.
- The purchased land is not on a Federal geothermal lease.
- ONRR 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 un-depreciated capital investment. If you are using the return-on-investment method, include the allowable real estate costs as part of the gross capital investment.

4.2.2.2

Transmission Lines Serving More Than One Power Plant

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

An allocation based on power plant 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 see section 4.2.4) based on the proportional amount of electricity that each power plant contributes to transmission.

4.2.3

Step 1C—Determine the Method of Handling Capital-related Cost

You have the option of choosing to handle capital related cost by one of the two methods:

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

How you handle the capital-related costs determines your method of computing

the cost rate.

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

You recalculate the previously estimated 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.

4.2.4

Step 1D—Calculate Transmission-line Cost Rates by the Depreciation Method Plus the Return on Undepreciated Capital 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:

- D = Annual depreciation of gross capital investments (see "Depreciation" below).
- E = Annual O&M expenses, estimated for the first deduction period.
- F = Annual kWh of delivered (on interconnect) electricity, estimated for the first deduction period (see "Delivered and Interconnect Electricity" above). When actual costs are known later, use them to true-up your calculations and re-report.
- I = Annual return on undepreciated capital investment (see "Return on Undepreciated Capital Investment" below).

4.2.4.1

Depreciation

Follow these rules to determine 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 of those described in the previous sentence without our 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) that the original owner established, except for addition or replacement of capital equipment.

4.2.4.2

Return on Undepreciated Capital Investments

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 15-year industrial BBB bond rate, as published in Standard and Poor's Bond Guide, for the first month of the annual deduction period. You re-determine the return rate at the beginning of each deduction period.

Example 4-1 Calculating Transmission-Line Cost Rates by Depreciation Method

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

Given :

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 15-year industrial BBB bond rate for the month beginning the first deduction period = 8.96 percent
- 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:

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

Fifth Year of Operation (Fifth Deduction Period)

- 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 15-year industrial BBB bond rate for the month beginning the fifth deduction period = 9.76 percent
- 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:

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

4.2.5

Step 1E—Calculate 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:

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

where:

- E = Annual O&M expenses, estimated for the first deduction period.
- F = Annual kWh of delivered (on interconnect) electricity, estimated for the first

deduction period (see “Delivered and Interconnect Electricity” above).

R = Annual return on allowable gross capital investments, adjusted for retired or replaced capital items.

Calculate the cost rate to six decimal places.

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 15-year 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 re-determine the return rate at the beginning of each deduction period.

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 15-year industrial BBB bond rate for the month beginning the third deduction period = 10.21 percent
- Return on capital investment (R):

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

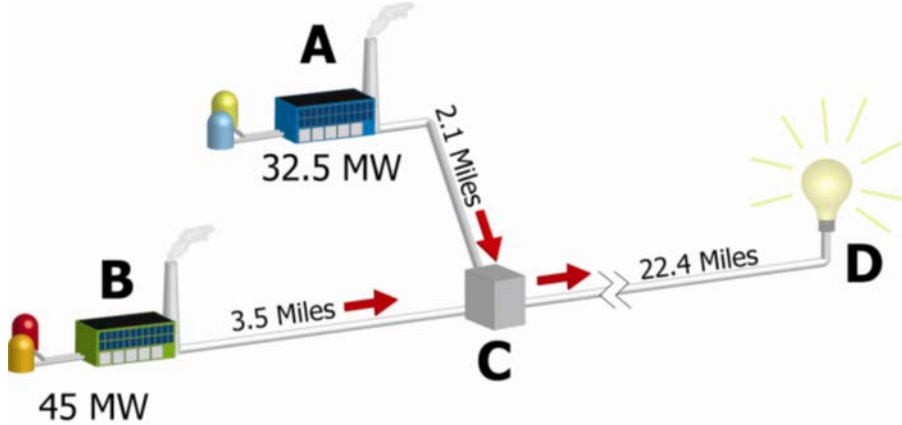
- Annual delivered electricity (F) = 424,056,985 kWh

Cost rate:

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

Example 4-3 Calculating a Transmission-Line Cost Rate When the Transmission Line Serves More Than One Power Plant

This example starts by calculating the cost rate for electricity transmitted from Power Plant A. Power plant A generates electricity from a federal lease. Power plant B generates electricity from a fee lease. Calculation is by the depreciation method for the second year of operation; the depreciation period is 30 years.



• **Capital Costs**

— Let’s say that all transmission facilities 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 Power Plant A:

$$1.1 \text{ miles} \times \$314,130/\text{mile} = \$659,673$$

— Calculate the capital cost of transmission C–D and allocate to Power Plant A using the power plant capacity ratio.

I. Capital cost of transmission line C–D:

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

II. Capacity ratio for Power Plant A:

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

III. Capital cost of transmission line C–D allocated to Power Plant A:

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

— Calculate the total transmission-line capital costs for Power Plant A:

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

— Calculate depreciation (D) for transmission lines connecting with Power Plant A:

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

Note : *If segments of the transmission facilities enter 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 15-year industrial BBB bond rate of 9.64%. The undepreciated capital investment balance at the beginning of the second deduction period is \$3,490,120:

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

- **O&M Expenses**

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

— Allocate O&M expenses to transmission line C–D for Power Plant A using Power Plant A capacity ratio:

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

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

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

- **Delivered Electricity**

Calculate the delivered electricity allocable to Power Plant A from the fraction of electricity placed into transmission. Assume that the annual delivered electricity for both power plants is 729,454,765 kWh, with Power Plant A placing 311,054,674 kWh into transmission and Power Plant 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 (10,941,822 kWh).)

I. Fraction of electricity placed into transmission by Power Plant A:

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

II. Annual delivered electricity (F) allocable to Power Plant A:

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

- **Cost Rate**

— Calculate the transmission-line cost rate for Power Plant A:

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

4.3 Step 2—Calculate Your Transmission Deduction

Transmission deductions recognize your reasonable, actual costs of transmitting electricity from the power plant tailgate (high voltage side of the power plant transformer) to the sales or delivery point. Transmission deductions consist of either or both of the following: arm’s-length wheeling charges and/or transmission-line deductions.

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

Apply the cost rate calculated to monthly delivered electricity measurements to determine your monthly transmission deductions as follows:

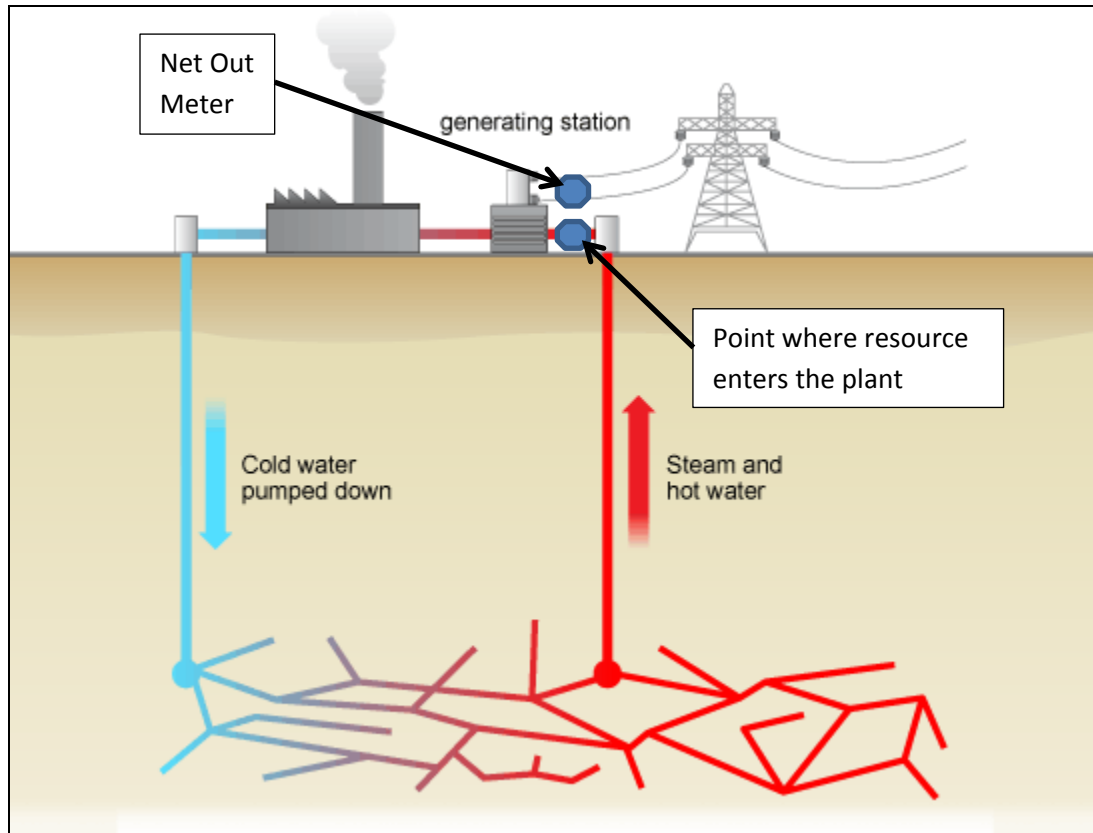
$$\text{Deduction (\$)} = \text{Annual Cost Rate (\$/kWh)} \times \text{Delivered Electricity (kWh)}$$

Annual cost rates are based on estimated costs projected for the coming year. When these costs are known, you must use actual costs to recalculate deductions, which ONRR calls the annual) true-up.

4.3.1 Arm’s-Length Wheeling Charges

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

4.4 Step 3A—Generation Cost Rates and Deductions



Generation cost rates and generation deductions focus on the cost between the point where the resource is delivered to the plant and where electricity leaves the plant.

You calculate annual cost rates in terms of dollars per kilowatt hour (\$/kWh) and then apply these cost rates to monthly electricity measurements to determine your monthly deductions.

The first step is to determine the O&M Cost for the generating plant.

Allowed Operating and Maintenance (O&M) Costs for Power Plants		
Direct wages and employee benefits (such as medical and retirement) that you pay to employees and supervisors while engaged in the routine operation, maintenance, or repair of the power plant, including training, recruiting, and employee moving expenses	Payments to consultants or service companies for routine operation, maintenance, or repair of the power plant	Expenditures for supplies and miscellaneous replacement parts associated with normal operation, maintenance, and repair(see further detail below)
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 (see further detail below)	Expenditures for lubricants used in power plant 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
Shop tools necessary for the repair and maintenance of power conversion equipment	Costs of purchased electricity to operate the power plant	Fuel and other expenses for auxiliary generators
Rents and leasing costs for power plant sites off Federal geothermal leases	Insurance, ad valorem property taxes (limited to the property that the power plant occupies), and payroll taxes	Automotive equipment (cars, trucks, etc., and permanent equipment mounted thereon) incident and allocable to power plant 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 functions, legal functions, and utilities) that you can directly attribute and allocate to the power plant 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 ordinary depreciable life (include the annual depreciation in your O&M expenses).

Downhole pump costs are mostly applicable to binary-type conversion processes that require increased operating pressures 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.

ONRR 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.

Certain costs are not allowed because they are not directly applicable and allocable to the generation of electricity.

NON-allowable Operating and Maintenance (O&M) Costs for Power Plants		
State and Federal income taxes	Severance taxes	Royalty payments, including overriding royalty
O&M expenses associated with effluent/condensate reinjection	Other corporate or project expenses not directly attributable and allocable to the routine operation, maintenance, and repair of the power plant, 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	Financial fees or costs paid after commission of the power plant, 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 that the lender requires; dealer costs for commercial paper programs; and rating agency expenses (see below)
Late payment fees for failure to make timely loan payments	Penalties for environmental violations	O&M expenses associated with geothermal production (see discussion of downhole pumps in this chapter)

Your return on capital investment accounts for these costs. As such, they are not allowable O&M expenses. See the table below that outlines these costs.

4.5 **Step 3B—Determine Power Plant Costs**

4.5.1 ***Power Plant Capital Investments***

Allowed power plant capital investments are your actual costs for the design, purchase, delivery, and installation of the power plant and related power-

generating equipment. Power plant capital investments include costs for the following items.

Allowable Power Plant Capital Investments		
Earth work and foundation preparation	Tangible, depreciable assets (see details below)	Engineering design, environmental studies, and legal and permitting fees to the extent they directly relate to installation of the power plant
Loan service fees, loan interest paid during construction, and service payments on equity investments(see note below)	Real estate costs, if ONRR-approved (see “Real Estate Costs” below)	Administrative costs that directly attribute and allocate to construction of the power plant
Other costs for the design, purchase, delivery, and installation of the power plant and related power-generating equipment you can document		

Tangible, depreciable assets may include the following:

- Plant structure
- Flash tanks and separators, including wellhead and field separators
- Turbines, generators, condensers, cooling towers, non-condensable 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 power plant
- 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 ¹; you cannot claim downhole pump investments related to extraction or lift of geothermal fluids. ²

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 ONRR 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

- Major spare parts unique to the power plant and maintained for immediate use, such as turbine rotors and diaphragms.

Costs associated with loan service fees apply only to the actual amounts that clearly attribute and allocate to the power plant for which you borrowed the money; you must have incurred the costs during the design and construction phases of the power plant, and you must be able to document them upon audit.

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

The following are non-allowed capital costs because they are not directly related to the construction of the power plant and installation of power-generating equipment. It should be noted that no costs related to the well-field are allowed, including reinjection of geothermal fluids, except for a portion of the downhole pump costs mentioned in the above two footnotes.

NON-Allowable Capital Costs		
Production wells, well control systems, and any other production-related equipment	Pipelines (including drip pots) between the wellhead and power plant, 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, that local government agencies impose as a condition of doing business	Payments on borrowed principal made during the design and construction phase of the power plant (only the interest portion of loan payments made prior to placing the power plant 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 power plant

Construction contract termination fees or penalties	Any other corporate or business costs not directly related to construction of the power plant and installation of power-generating equipment	
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4.5.2

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 all of the following apply:

- You can demonstrate the necessity for the land purchase.
- The purchased land is not on a Federal geothermal lease.
- ONRR approves the costs.

You can include only that portion of real estate costs necessary for the power plant site. If your real estate purchase includes land outside the power plant 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.

4.6

Step 3C—Determine Your Method of Handling Capital Cost

You may choose between using:

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

NOTE

Unlike transmission lines serving more than one power plant, you do not allocate generating costs if your power plant 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 ONRR for approval.

4.7

Step 3C(1)—Calculate 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:

D = Annual depreciation of gross capital investments (see “Depreciation” below)

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

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

I = Annual return on undepreciated capital investment (see “Return on Undepreciated Capital Investment” below)

Calculate the cost rate to six decimal places.

4.7.1

Depreciation

Follow these rules to determine 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 it is 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 ONRR’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 power plant and associated power-conversion equipment only once. A change in ownership does not alter the depreciation schedule that the original owner established, except for addition or replacement of capital items.

4.7.2

Return on Undepreciated Capital Investment

The return on un-depreciated capital Investment (I) is the product of the return rate and the un-depreciated 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 15-year 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 re-determine the return rate at the beginning of each deduction period.

Example 4-4 Calculating a Generating Cost Rate by the Depreciation Method

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

- **Schedule of Capital Costs**
 - 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 15-year 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 15-year industrial BBB bond rate for the month beginning the fifth deduction period = 9.76%

- Return on undepreciated capital Investment (I):

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

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

- Cost rate:

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

4.8

Step 3 C (2) Calculating Generating Cost Rates by the Return-on-Investment Method

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

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

where:

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

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

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

Note : You can use the return-on-investment method only for power plants that you first placed into service on or after March 1, 1988.

The annual Return (R) is the product of the return rate and the power plant capital investment:

$$R = \text{Return Rate} \times \text{Capital Investment}$$

The return rate is two times the Standard and Poor’s monthly average 15-year 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 re-determine the return rate at the beginning of each deduction period.

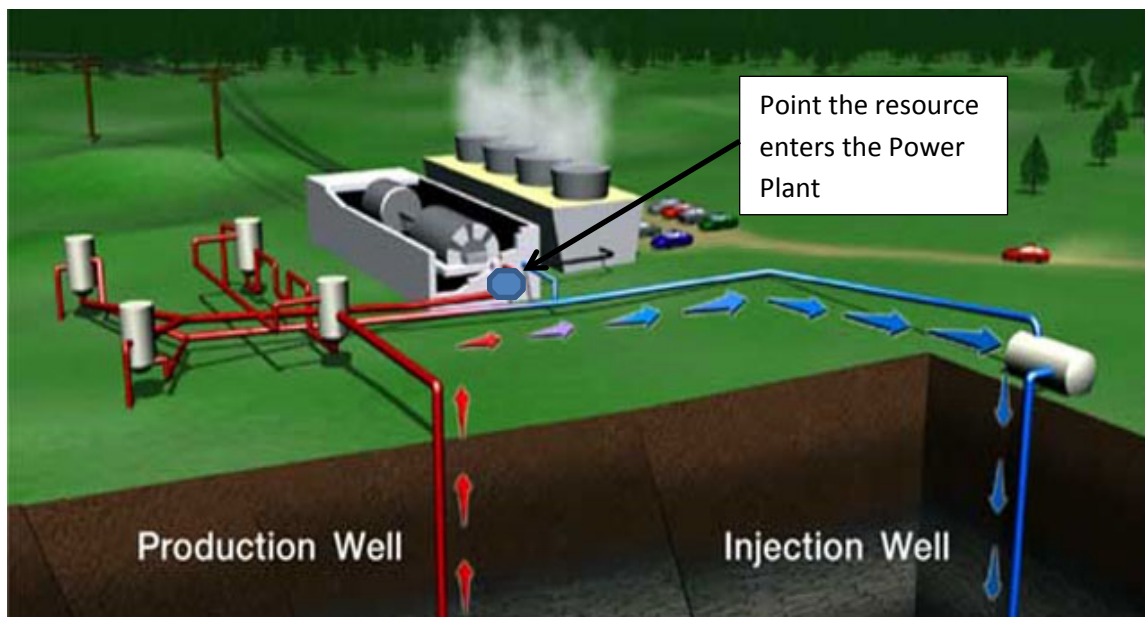
4.9 **Step 4 Calculating your Monthly Generation Deduction**

Generating deductions recognize your reasonable, actual costs of constructing and operating your geothermal power plant; that is, your costs of generating electricity. Generating deductions are the product of the annual generating cost rate and monthly plant tailgate electricity (adjusted for non-royalty bearing portions of electricity) as follows:

$$\text{Generating Deduction (\$)} = \text{Annual Cost Rate (\$/kWh)} \times \text{Monthly Plant Tailgate Electricity (kWh)}$$

Plant tailgate electricity is the amount of electricity that the power plant generates exclusive of plant parasitic electricity but inclusive of any generated electricity returned to your lease for lease operations (30 CFR 1206.351). In general, you will determine plant tailgate electricity by adding any electricity returned to the lease to the amount of electricity that the power plant’s net-out meter measures (net-out electricity is the electricity entering the transmission line). You must either measure the power plant’s net-out electricity at, or calculate it for, the high-voltage side of the transformer in the power plant switchyard before adding electricity returned to the lease.

Step 5 Calculating the Monthly Value of the Geothermal Resource



This step nets the deductions from the value of the electricity sold to arrive at the value of the geothermal resource. You apply the previously calculated values, as follows:

$$\text{Netback Geothermal Value} = \text{Electricity Value} - \text{Transmission Deduction} - \text{Generating Deduction}$$

4.10 Step 6 Allocating Value to Leases

The netback procedure derives the dollar value, at the plant inlet, of all geothermal resources that a power plant uses 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 the Bureau of Land Management (BLM) approves.
- The allocation schedule in your unitization or communitization agreement, as BLM approves.

Any other measurement or allocation method that BLM approves.

4.11 Step 7 Reporting Netback Values on Form ONRR-2014

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

Sales Volume	Amount of delivered electricity allocated to the lease
Sales Value	Netback value of geothermal production allocated to the lease
Royalty Value	Product of sales value and lease royalty rate

4.12 **Step 8 Recalculated Netback Values: Underpayments and Overpayments**

As indicated in throughout this chapter, you recalculate your cost rates at the beginning of each annual deduction period, using your actual costs from the prior period, to re-determine 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 Form ONRR-2014s 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 Form ONRR-2014. ONRR refers to this annual as-needed recalculation as the "true-up".

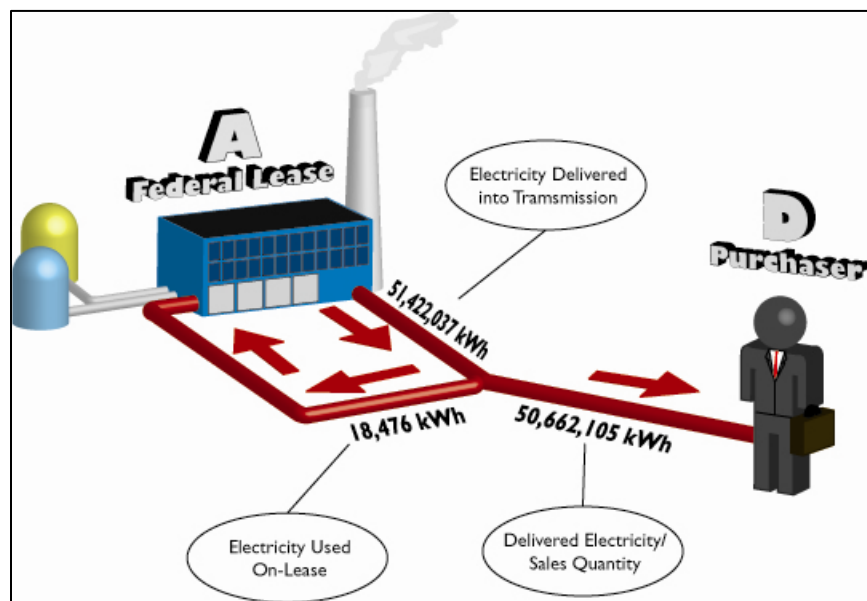
If your adjusted royalty values are greater than those originally reported for any month (meaning you underpaid royalties for that month), you must pay the additional royalties plus interest from the date the additional royalty was due (30 CFR 1218.302). You cannot offset an underpayment for one month 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" in [Chapter 2](#)) (usually \$2.00 per acre) each lease year (30 CFR 1202.352). If the royalties paid on monthly production during the lease year are less than the minimum royalty, you must pay the difference to ONRR on or before the expiration date of the lease year.

4.13 Netback Calculation Examples

Example 4-6 Calculating a Netback Value When Production Is from a Single Lease



Power Plant A uses geothermal production from only the Federal lease. The lessee transmits electricity across its own transmission line to the purchaser at point D. You use some electricity on-lease to operate well valves and run effluent reinjection pumps. The lease royalty rate is 12.5%. Value of geothermal production.

- 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:
 - I. Electricity delivered into transmission; 51,422,037 kWh
 - II. Electricity used on-lease: 18,476 kWh
 - III. Total: 51,440,513 kWh
- Electricity sales revenue (gross proceeds): \$4,078,299.45
- Transmission deduction

— Transmission line:

$$\$0.001002/\text{kWh} \times 50,662,105 \text{ kWh} = -\$50,763.43$$

- Generating deduction

$$\$0.053152/\text{kWh} \times 51,440,513 \text{ kWh} = -\$2,734,160.15$$

- Value of geothermal production: \$1,293,375.87

— Value as percentage of revenue: 31.71%

- Report on Form ONRR-2014 (Royalty rate = 12.5%)

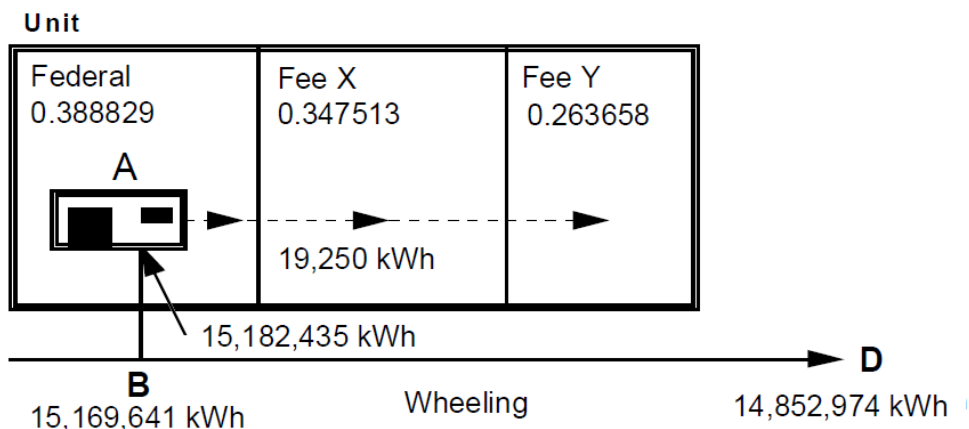
Sales Volume	50,662,105 kWh
Sales Value	\$1,293,375.87
Royalty Value	\$161,671.98

Example 4-7 Calculating a Netback Value When Production Is from Multiple Leases

Power Plant 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. They use some electricity on the unit to regulate well production and run effluent reinjection pumps. The royalty rate for the Federal lease is 10%.



- 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:
 - I. Electricity delivered into transmission: 15,182,435 kWh
 - II. Electricity used on-unit: 19,250 kWh
 - III. Total: 15,201,685 kWh
- Electricity Sales Revenue (Gross Proceeds): \$1,448,164.97
- Transmission Deduction
 - Transmission line:

$$\$0.002167/\text{kWh} \times 15,169,641 \text{ kWh} = \$32,872.61$$
 - Wheeling charges: \$29,736.00
 - Total transmission deduction: -\$62,608.61
- Generating Deduction

$$\$0.063653/\text{kWh} \times 15,201,685 \text{ kWh} = -\$967,632.86$$
- Value of Geothermal Production \$417,923.50
 - Value as a percentage of revenue = 28.86%

— Value allocated to Federal lease:

$$0.388829 \times \$417,923.50 = \$162,500.78$$

- Report on Form ONRR-2014 (Royalty Rate = 10%):

— Sales volume, allocated to lease: $0.3888239 \times 14,852,974 \text{ kWh} = 5,577,267$

— Sales value: \$162,500.78

— Royalty value: \$16,250.08

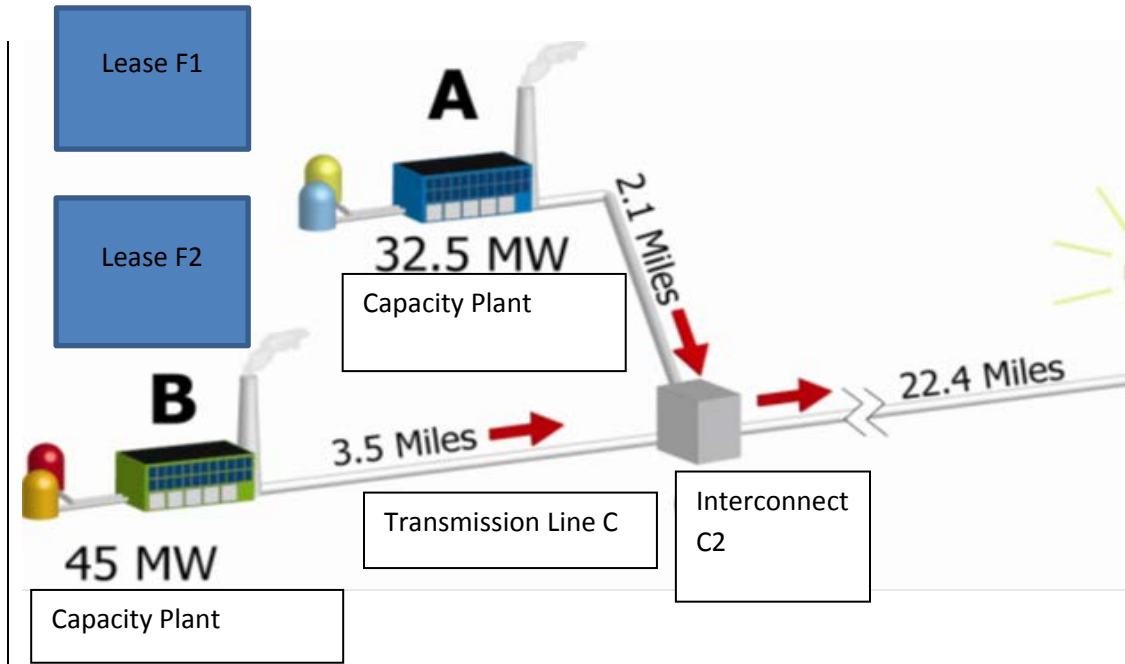
Example 4-8 Calculating a Netback Value When Production Is from Multiple Leases

Given:

1. Power plant A uses geothermal production from unitized Federal leases with the following allocation schedule:

Lease	Allocation Factor
F1	0.550000
F2	0.450000

2. Power plant B uses geothermal production from non-Federal leases
3. Power plant A & B are under common ownership
4. Operator transmits comingled electricity across its own transmission lines(c) to an interconnect with a third party transmission line at (C₂)
5. Electricity is wheeled on the third party line from (C₂) to a purchaser at a delivery point (D)
6. Wheeling charge = \$.00250/ kWh
7. Royalty rate for F1 & F2 is 10%
8. Line loss from C to C₂ =342,865 kWh and the line loss from C₂ to D = 678,873 kWh
9. Electrical Value = 11 ¢/ kWh
10. Total revenue for reporting month \$3,659,123.82
11. Transmission cost from C to C₂ + \$.002167/ kWh and Wheeling charge from C₂ to D = \$.000250/ kWh
12. Generating Cost (power plant A): \$.043683 kWh



Electrical measurements for reporting month

Power plant A:

Power plant B:

Metered to tie line: 20,508,539 kWh
 + lease operations 32,821 kWh
 Total 20,541,360 kWh

Metered to tie line: 13,777,961 kWh

Electricity delivered for transmission (metered to tie line)
 20,508,539 kWh + 13,777,961 kWh = 34,286,500 kWh

Line Loss is 342,865 kWh

Delivered electricity to Wheeling Pt = 34,286,500 - 342,865 = 33,943,635 kWh

Fraction of delivered electricity allocated to power plant A:
 $\frac{20,508,539 \text{ kWh}}{34,286,500 \text{ kWh}} = 0.598152$

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

Revenue Allocated to Power plant A
 $\$3,659,123.82 * 0.598152 = \$2,188,712.23$

Transmission Deductions:
 C-C₂: $20,303,453 * \$0.002167/\text{kWh} = \$43,997.58$

C₂-D: 20,303,453 kWh *\$0.000250 /kWh=\$5,075.86

Total Transmission Deductions \$43,997.58+\$5,075.86 = \$49,073.44

Generating Deductions

20,541,360 kWh * \$.043683/ kWh = 897,308.23

Revenue for power plant A: 22,188712.23

Subtract Transmission deduction: 49,073.44

Subtract Generation deduction: 897,308.23

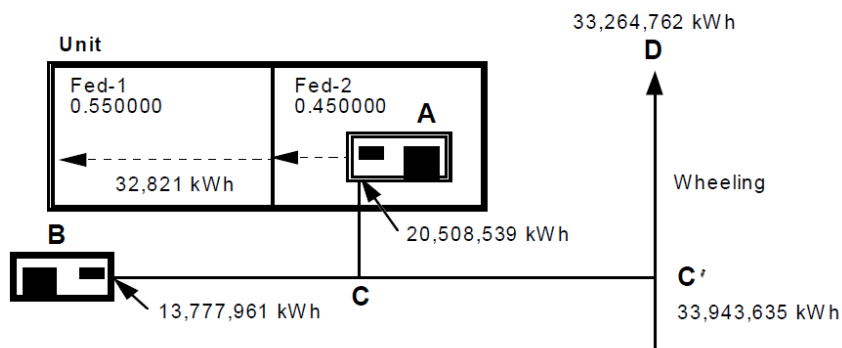
Net Value to power plant A: \$1,242,330.56

Example 4-9 Calculating a Netback Value When a Transmission Line Serves Two Power Plants

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

Lease Allocation Factor	
Federal 1	0.550000
Federal 2	0.450000

Power Plant B uses geothermal production from non-Federal leases. Both power plants 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 C1 then wheels the electricity to the purchaser at point D; the wheeling charge on line C1–D is \$0.000250/kWh. The royalty rate for each Federal lease is 10 percent. Calculate netback values for Leases Fed-1 and Fed-2.



- Annual cost rates
 - Transmission line A–C–C1 cost rate 3 = \$0.002167/kWh
 - Power Plant A generating cost rate = \$0.043683/kWh
- Electricity measurements for reporting month
 - Power Plant A tailgate electricity:
 - I. Metered to tie line: 20,508,539 kWh
 - II. Lease operations: +32,821 kWh
 - III. Total: 20,541,360 kWh
 - Electricity delivered for transmission (metered to tie lines):
 - I. Power Plant A + B:
 - $20,508,539 \text{ kWh} + 13,777,961 \text{ kWh} = 34,286,500 \text{ kWh}$
 - II. Fraction allocated to Power Plant A:
 - $$\frac{20,508,539 \text{ kWh}}{34,286,500 \text{ kWh}} = 0.598152$$
 - Electricity delivered to wheeling interconnect (point C1):
 - 33,943,635 kWh
 - I. Allocated to Power Plant A:
 - $0.598152 \times 33,943,635 \text{ kWh} = 20,303,453 \text{ kWh}$
 - Delivered electricity (point D): 33,264,762 kWh
- Electricity sales revenue (gross proceeds):
 - Total revenue Power Plant A + B \$3,659,123.82
 - Revenue allocated to Power Plant A:
 - $0.598152 \times 3,69,123.82 = \$2,188,712.23$
- Transmission deduction
 - Transmission-line A–C–C1 costs:
 - $\$0.002167 \times 20,303,453 \text{ kWh}^3 = \$43,997.58$
 - Wheeling charges allocated to Power Plant A:
 - $\$0.000250/\text{kWh} \times 20,303,453 \text{ kWh} = \$5,075.86$
 - Total transmission deduction: = -\$49,073.44
- Generating deduction
 - $0.043683/\text{kWh} \times 20,541,360 \text{ kWh} = -\$897,308.23$

- Value of geothermal production at Power Plant A: \$1,242,330.56
 - Value as percentage of revenue = 56.76%
 - Value allocated to Lease Fed-1:

$$0.550000 \times \$1,242,330.56 = \$683,281.81$$
 - Value allocated to Lease Fed-2:

$$0.450000 \times \$1,242,330.56 = 559,048.75$$

³ Allocated interconnect electricity

- Report on Form ONRR-2014:
 - Lease Fed-1 (royalty rate = 10%)
 - Sales volume allocated to lease:

$$33,264,762 \text{ kWh} \times 0.598152 \times 0.550000 = 10,943,561 \text{ kWh}$$
 - Sales Value: \$693,281.81
 - Royalty Value: \$68,328.18
 - Lease Fed-2 (royalty rate = 10%)
 - Sales volume allocated to lease:

$$33,264,762 \text{ kWh} \times 0.598152 \times 0.450000 = 8,953,823 \text{ kWh}$$
 - Sales Value: \$559,048.75
 - Royalty Value: \$55,904.88

Example 4-10 Calculating a Netback Value When Deductions Exceed 99 Percent of Electricity Sales Value

Power Plant A uses geothermal production from unitized Federal and fee leases; lease production is the basis for allocation. Assume a Federal lease allocation factor of 0.834721 for the month. The electricity purchaser takes delivery at the power plant tailgate (point D). The 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: +1,475 kWh
 - Tailgate electricity: 963,580 kWh

- Electricity sales revenue (gross proceeds): \$53,877.88
- Transmission deduction: 0
- Generating deduction:
$$\$0.055483/\text{kWh} \times 963,580 \text{ kWh} = -\$53,462.31$$
- Netted back value of geothermal production: \$415.57
 - Value as percentage of revenue= 0.77%
- Minimum value of geothermal production (1.00% of sales value):
$$0.01 \times \$53,877.88 = \$538.78$$
 - Value allocated to Federal lease:
$$0.834721 \times \$538.78 = \$449.73$$
- Report on Form ONRR-2014 (royalty rate = 12.5%):
 - Sales volume allocated to lease:
$$962,105 \text{ kWh} \times 0.834721 = 803,089 \text{ kWh}$$
 - Sales Value: \$449.73
 - Royalty Quantity: 100,386 kWh
 - Royalty Value: \$56.22

Example 4-11 Recouping Royalty Payments When You Adjust Netback Values

For a given month, with your lease royalty rate of 10%, you reported a Sales Value of \$200,000 and a Royalty Value less Allowances (deductions) of \$320. Your calculated sales value less deductions of \$3,200 (which is not reported on the Form 2014) equaled 1.6 percent of that month's gross electrical sales proceeds of \$200,000. Upon recalculating your annual cost rates, monthly deductions, and netback values for the deduction period, you find that the corrected Sales Value for that month is \$100,000, which equaled only 0.05 percent of the month's gross electrical sales less deductions. Because the resource value (gross proceeds less deductions) 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 to result in 1 percent of gross proceeds using Adjustment Reason Code 15. You may recoup the difference between the reported and adjusted Royalty Values (\$320-\$200 = \$120) by crediting against future royalties.

- Sales value: \$200,000
Royalty value: (not reported on Form-2014) = Sales value less deductions: \$3200.00
- Sales value less deductions percentage of revenue= $\$3200 / \$200,000 = 1.6\%$
- Minimum value of geothermal production (1.00% of sales value):
 $\text{— } \times \$200,000 = \$2,000$
- Recalculated, corrected sales value less deductions: \$1,000
 $\text{— Value as percentage of revenue} = 0.5\%$
- Adjusted royalty value less deductions: \$200

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

- Sales Value: \$20,000
- Royalty Value less Allowances: \$200