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3-3-91

SUMMARY OF GEOTHERMAL RESOURCES ASSOCIATION POSITIONS ON PROPOSED VALUATION REGULATIONS

Proposed Action

On January 5, 1989, the Minerals Management Service ("MMS") published proposed regulations to amend existing requirements regarding the valuation of geothermal resources for royalty purposes. 54 Fed. Reg. 354-371. Current regulations are found at 30 C.F.R. § 206.300.

The Geothermal Steam Act provides that royalties shall be no less than 10% and no more than 15% of "the amount or value of steam, or any other form of heat or energy derived from production under the lease and sold or utilized by the lessee or reasonably susceptible to sale or utilization by the lessee." 30 U.S.C. § 1004(a). MMS has developed informal guidelines for valuing geothermal resources. See MMS, Valuation of Federal Geothermal Resources - Electrical Generation (June 1988). The proposed regulations are intended to codify many of the provisions of the MMS Guidelines, and in doing so, to consider several alternative methods for establishing geothermal value. The comment period on the proposed regulations ends on April 17, 1989. A public hearing has been scheduled for March 28 in Lakewood, Colorado.

MMS Proposal

MMS is proposing to codify the netback valuation approach set forth in the current MMS Guidelines. This methodology is based on the netback approach that is used for oil and gas valuation. Netback would be used to value resources where there is a non-arm's-length transaction between the geothermal lessee and its power-generating affiliate. Virtually all geothermal resources are utilized through this kind of transaction, which occurs when a single company produces the geothermal resource and utilizes it to generate electricity.

The netback approach is intended to measure the resource value by subtracting the cost of electrical generation and transmission from the sales price of the electricity. This method assumes that there is inherent value in the resource and that such value will be accurately assessed after deductions from the sales price have been allowed for transmission and generation expenses. Under the method as proposed, however, a limit is placed on the deductions, regardless of the actual costs. Transmission deductions would be limited to 50% of the lessee's gross proceeds. Generating deductions would be limited to 66 2/3% of gross proceeds. Also, to compute the rate of return on capital investment, MMS proposes to use a fixed factor of 1.5 times the monthly average rate as published in the Standard and Poor's Bond Guide for the first month of the annual operating period. This is proposed in lieu of the actual rates of return or cost of capital for geothermal projects in general or any project in particular.

MMS requests comments on alternatives to the netback approach. In response to proposals submitted by geothermal lessees in recent valuation proposals, MMS seeks comment on the "proportion of profits approach." Instead of a standard rate to compute the return on invested capital, this approach would attribute to each component of a geothermal power project (e.g., resource extraction, transmission, power generation) a proportionate share of the return earned by the overall project. It relies on actual verifiable cash flows and allocates the portion of cash flow used to pay the project's debt and equity costs to power production and the steam resource based upon the actual relative investment in each project component.

The determination of the valuation methodology to be used in non-arm's-length transactions is the most important issue in the rulemaking, but MMS also has asked for responses on several other questions, including: whether capacity payments should be included in the value of electricity; how depreciation should be calculated; when the least expensive alternative fuels approach should be used; how to value geothermal byproducts; whether deductions should be allowed for abatement costs; what valuation approach should be used when the lessee also is the power generating utility; and, if the netback approach is adopted, what modifications should be made to the methodology set forth in the MMS Guidelines.

Geothermal Resources Association Positions

The Geothermal Resources Association ("GRA") is strongly opposed to the netback methodology. Netback is based on the assumption that the resource has value at the time it is extracted. When this is true, as with oil and gas, the costs of "preparing" the resource for transportation and sale are borne by the developer and paid for out of revenues received. Such costs incurred by the oil and gas developer are generally quite small as a proportion of the actual resource sale price (wellhead price), and the accuracy of the deductions allowed does not carry great significance. As a result, deductible costs for oil and gas are relatively easy to calculate and there is little risk to the developer if the allowed costs are off by a small degree. In addition, because there is relative uniformity among producers for the costs of resource preparation, the use of standard deductions and rates of return does not threaten inequitable results.

These oil and gas principles do not apply to geothermal resources, where there is virtually no value inherent in the resource, except in those few cases where it is directly utilized for heating. In all other cases, value is dependent upon the method and costs of transforming the resource into electricity, and virtually everything that is done to the resource by the developer after extraction enhances its value. For this reason, there is no market and no "wellhead price" for the geothermal resource, only a value for the electricity ultimately produced.

The lessee's costs of converting the resource into electricity always far outweigh the costs of extracting the resource itself. Thus, each cost element in the processing sequence is an integral and necessary part of adding value to the resource and must be recognized in the valuation equation if the total worth of the resource is to be determined. If these steps were not taken, the resource would have no value. Moreover, because the costs associated with the power plant are so large as a proportion of total value, it is important that they be calculated with precision; a small miscalculation in percentage of costs allowed could result in a wide disparity between the total value of the resource and the assigned royalty rate. The final important characteristic of geothermal utilization that distinguishes it from oil and gas use is that costs vary widely from project to project because of the diverse nature and quality of the resource. These project by project distinctions make it inaccurate and unfair to apply standard rates of return and uniform deductions, as required by the netback approach. The result under netback is, at best, only an approximation.

It is the GRA's position that the value of geothermal resources can be calculated accurately only if all costs are taken into account and subtracted from the price of the end product on a project specific basis. The proportion of profits approach does this by avoiding arbitrary assumptions and standard deductions and by assigning actual values to the costs and returns associated with each aspect of a particular project. The valuation methodology that the GRA will propose is:

$$STP = \frac{E + (NOI \times SI/TI)}{EO}$$

STP = Steam transfer price ($/KWH);
E = Steam field operating expenses plus royalties and other distributions;
NOI = Net operating income of the project;
SI = Investment in steam resource;
TI = Total investment in the project (before any deduction for depreciation or return);
EO = Electricity output (KWH).

The GRA hopes to convince MMS to adopt this approach. If it is not successful in doing so, the GRA will have to accept the netback approach, but only if it is substantially modified to become accurate and fair, even as an approximation of value. The requested changes in the netback method will be: 1) deleting arbitrary limits on deductible costs; 2) establishing a ceiling on how high the value of the resource can be appraised; 3) allowing a deduction for project reclamation costs; 4) allowing deductions for gathering and injection systems; 5) allowing deductions for the the cost of purchased electricity to operate well pumps and field equipment; 6) basing the processing deduction on net (rather than gross) output; and 7) promulgating a standard that would allow the lessee to use an alternative valuation approach if netback results in a value that exceeds a predetermined level. The GRA also will provide responses to many of the specific questions for which MMS has requested comments.

Conclusion

Geothermal energy has been recognized for years as a resource that can make an environmentally safe and renewable contribution to our energy supply. The expressions of public policy favoring geothermal energy have grown from the Geothermal Steam Act in 1970 to the present, when this source of electricity is one of the United States' best strategies to address global warming concerns. In the context of royalties on federal geothermal resources, these policies mandate no special treatment for geothermal, only a valuation and royalty standard that yields a fair return to the federal government and is based on the real economic and technical demands of this unique industry. The proportion of profits method endorsed by the GRA meets this test. Substantial revisions to the netback method, while less desirable, would be an improvement over the proposed approach.

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VALUATION OF FEDERAL GEOTHERMAL RESOURCES--
ELECTRICAL GENERATION

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VALUATION OF FEDERAL GEOTHERMAL RESOURCES--ELECTRICAL GENERATION

INTRODUCTION

The use of geothermal resources to generate electricity has expanded greatly during the past few years, owing both to improvements in conversion technology and to electricity sales incentives provided by the Public Utilities Regulatory Policies Act of 1978 (PURPA). The increase in geothermal power production has been paralleled by a marked increase in Federal geothermal royalty revenues. Geothermal royalties in 1985 totaled about $13.4 million with only 14 producing leases and climbed to about $17.3 million in 1986 with 18 leases in production. By comparison, the first geothermal royalties, collected in 1979, amounted to $43,316. Production from all but one of the leases is used to generate electricity. One-half (50 percent) of all royalties collected on production from Federal geothermal leases is disbursed back to the State in which the production occurred.

Federal regulations and lease terms require royalties to be based on the amount or value of geothermal resources produced, utilized, or sold. The Department of the Interior's Minerals Management Service (MMS) is charged with the responsibility of ensuring that Federal geothermal production[1] is properly valued for royalty purposes, consistent with regulatory requirements.

This report describes the policies, guidelines, and methods employed by the MMS to value Federal geothermal resources used to generate electricity. Lessees who utilize geothermal resources for purposes other than electrical generation should contact MMS for the proper valuation method. Valuation procedures are described under three types of transactions: arm's-length sales, non-arm's-length sales, and no sales. Emphasis is placed on the valuation for "no sales" transactions, because this involves a "netback" procedure whereby certain lessee-borne expenses are deducted from the value of electricity to determine the value of the resource. Statutory and regulatory valuation provisions and royalty reporting requirements are also reviewed. Although this report cannot address all of the possible scenarios for disposal of geothermal production, it is a guide to the Federal geothermal lessee or payor in computing royalties and in making economic business decisions.

The valuation procedures described here are issued pursuant to and consistent with existing regulatory requirements at 30 CFR 206.300 (1987) and will remain in effect until those regulations are modified. This procedure paper is an interpretative rule and is not subject to the advance notice and comment provisions of the Administrative Procedure Act (5 U.S.C. 553).

STATUTORY AND REGULATORY VALUATION PROVISIONS

The Geothermal Steam Act of 1970 (the Act; 84 Stat. 1566) established the statutory framework for the leasing and management of geothermal resources on public domain lands. In so doing, the Act identified "geothermal steam and associated geothermal resources" as leasable minerals subject to the rules, regulations, and orders issued by the Department of the Interior to implement the Act. Section 5(a) of the Act provides that royalties will accrue on "the amount or value of

[1]For the purpose of this report, the terms "geothermal production" and "geothermal resource" are synonymous and are used interchangeably.

steam, or any other form of heat or energy derived from production under the lease and sold or utilized by the lessee or reasonably susceptible to sale or utilization by the lessee . . . ."[2] Section 3(c)(1) of the Geothermal Resources Lease form (the Lease) elaborates on this language by adding that royalty is due on the amount or value of steam, heat, or other associated energy "produced, processed, removed, sold, or utilized" from the lease.

Under the terms of the Lease (Sec. 4), the Department of the Interior has the express authority to establish minimum value of geothermal resources to compute royalties in accordance with the applicable regulations. Regulatory criteria guiding the valuation of geothermal production for computing royalties are given in Title 30 of the Code of Federal Regulations, Section 206.300, cited as 30 CFR 206.300.[3] Section 206.300 (a) provides that the value of production shall be the reasonable value of the energy (and byproducts) attributable to the lease as determined by the "Supervisor."[4] The following criteria are taken into consideration in determining the reasonable royalty value of the resource:

(1) The highest price paid for a majority of the production of like quality in the same field or area;

(2) The total consideration accruing to the lessee from any disposition of the geothermal production;

(3) The value of the geothermal production used by the lessee;

(4) The value and cost of alternate available energy sources and byproducts;

(5) The cost of exploration and production, exclusive of taxes;[5]

(6) The economic value of the resource in terms of its ultimate utilization;

(7) Production agreements between producer and purchaser; and

(8) Any other matters that may be considered relevant.

Section 206.300(b) prescribes that under no circumstances shall the value of any geothermal production for the purposes of computing royalties be less than:

(1) The total consideration accruing to the lessee for the sale thereof in cases where geothermal resources are sold by the lessee to another party;

(2) That amount which is the value of the end product attributable to the geothermal resource produced from a particular lease where geothermal resources are not sold by the lessee before being utilized, but are instead directly used in manufacturing, power production, or other industrial activity; or

(3) When a part of the resource only is utilized by the lessee and the remainder sold, the sum of the value of the end product attributable to the geothermal resource and the sales price received for the geothermal resources.

In fulfilling its obligation to ensure that geothermal production is properly valued for royalty purposes, MMS considers all of the relevant valuation criteria collectively as individual circumstances may dictate.

[2]Section 5(b) of the Act also provides for royalties on byproducts, including commercially demineralized water.

[3]Section 206.300 was redesignated in the Federal Register (53 FR 1185, January 15, 1988) as § 206.350 effective March 1, 1988, but has not been published in the Code of Federal Regulations as of this writing.

[4]The authority for determining proper royalty value has been delegated to MMS's Royalty Valuation and Standards Division.

[5]This criterion is inconsistent with the generally accepted oil and gas definition of royalty as being free of the expenses of production (Williams and Meyers, 1980, p. 511). Cost of exploration and production are considered relevant valuation factors by the MMS only in those instances where the lessee is reimbursed or receives other consideration for his exploration and production expenditures. Royalties are due on all production-related reimbursements pursuant to § 206.300(b)(1).

VALUATION PROCEDURES

ARM'S-LENGTH SALES

A transaction involving the direct sale of produced geothermal resources is considered arm's-length when the selling arrangement is negotiated and entered into between unaffiliated parties of adverse economic interests. Arm's-length negotiated sales prices are generally established by either definite prices or pricing formulas or by a percentage of the proceeds accruing to the powerplant operator.

Definite Prices and Pricing Formulas

Consistent with royalty valuation policy, the MMS generally regards definite prices or pricing formulas established under arm's-length sales contracts as representative of reasonable value. Thus, with the exceptions for percentage-of-proceeds sales discussed below, the proceeds accruing to the lessee under the contract generally form the value basis for royalty computations.

Any fees or expenses charged by the purchaser (or other third party) for performing field- or production-related services, whether or not specified by contract, cannot be deducted from the base value of the production before computing royalties. Such services include, but are not limited to, gathering, metering, conditioning, well monitoring or control, workovers, and any costs incidental to marketing. Under terms of the lease and operational regulations in 43 CFR Part 3200, the lessee is responsible for performing these services and all other activities necessary to produce the resource and deliver it to its point of purchase or utilization. The value of geothermal production cannot be reduced by production or gathering costs.

Percentage-of-Proceeds

"Percentage-of-proceeds" contracts are defined as those sales agreements with independent, usually non-utility powerplant operators whereby payment for delivery of the resource is based on a percentage of the revenue accruing to the plant for the sale of electricity. The MMS considers these contracts to be arm's-length if entered into between unaffiliated parties and will generally accept the lessee's revenue as value for royalty purposes. However, MMS will not accept a value that is less than one-third of the powerplant's revenue. (The one-third limit may be considered for waiver upon specific application by the lessee with convincing supporting documentation that the Federal Government should accept less.) As with the more customary sales contracts discussed above, any fees or expenses charged to the lessee by the plant owner for field- or production-related services are not allowed as deductions from the base value.

Reimbursements

Royalties are due on any reimbursements or other considerations the lessee may receive for disposition of the resource, pursuant to 30 CFR 206.300(b)(1). Reimbursements or other considerations include, but are not limited to, any monies paid to the lessee for various production taxes, other taxes, gathering, effluent injection, field operation and maintenance, and drilling and workover of wells, or any other consideration accruing to the lessee for disposition of the geothermal resource. As indicated above, MMS views these expenses as production costs that are the responsibility of the lessee. Production-related reimbursements must be accounted for and reported separately on Form MMS-2014.

NON-ARM'S-LENGTH SALES

Any transaction between affiliated parties for the sale or delivery of geothermal production is considered non-arm's-length by MMS. An example of a non-arm's-length transaction would be when the production arm of a company sells the resource to an affiliated powerplant operator.

As a general rule, MMS will accept the prices established in non-arm's-length sales arrangements as representative of reasonable value if those prices are comparable to the highest price paid for a majority of like-quality production from the same field or area [30 CFR 206.300(a)(1)]. However, the following conditions must be satisfied:

(1) There must be other arm's-length sales of comparable resources in the same field or area; and

(2) The electricity generated from the resource must have the same value as electricity generated from other comparable geothermal production in the same field or area.

The electricity value is considered a material factor in geothermal valuation in contemplation of the regulations at 30 CFR 206.300, paragraphs (a)(2), (a)(6), and (b)(2). An examination of the electricity rates charged by five California utilities to their residential customers (as reported in California Energy Commission's Energy Watch) suggests that the value of electricity varies for the different utilities. Also, the electricity generated by a powerplant qualifying under PURPA as a "small power production facility" (one restricted to sales of 80 megawatts or less) will have a different value from electricity generated by nonqualifying powerplants. Because geothermal production provides the fuel for geothermal powerplants, it follows that resource values will vary with differing values of the generated electricity.

If the above conditions are not met under a non-arm's-length sales arrangement, MMS will either establish a minimum acceptable value for the resource or consider a value proposed by the lessee.

As with arm's-length sales arrangements, royalties are also due on reimbursements or other considerations the lessee receives under the contract for disposition of the resource, unless the established minimum acceptable value is greater than the sum of the non-arm's-length sales price plus reimbursements and other payments; royalties are then due on only the minimum acceptable value. Stated another way, the lessee incurs a royalty liability on reimbursements and other contractual payments when the sum of those payments plus the non-arm's-length contract price exceeds the MMS minimum acceptable value.

If the lessee shares in the costs of operating an affiliate-owned powerplant, either under the terms of a non-arm's-length resource sales arrangement or a separate joint operating agreement, the lessee's reasonable actual expenditures, not to exceed two-thirds of the monthly revenue received for delivery of the resource (unless a greater amount is approved by MMS), may be deducted from the monthly revenue, contingent upon MMS approval. Generally, MMS will not accept a royalty value that is less than one-third of the net value of the electricity sold by the affiliate-owned powerplant; that is, the difference between the lessee's payment for delivery of the resource and his actual share of powerplant operating costs cannot be less than one-third of the electricity's net value. The "net value" here means the sales value of the electricity less any transmission (wheeling) costs to deliver the electricity to its point of sale.

NO SALES: NETBACK VALUATION

State and Federal rules implementing PURPA require electric utilities to purchase energy and capacity from non-utility, qualifying small power producers at rates equal to the purchasing utility's avoided costs. To take advantage of the incentives offered under PURPA, an increasing number of geothermal lessees are constructing and operating their own powerplants to use lease production for the generation and sale of electricity. Because no sale of the geothermal production occurs in these situations, the value of the resource must be determined as a function of the value of the electricity--the first marketed product attributable to lease production--in accordance with the requirements of 30 CFR 206.300, paragraphs (a)(6) and (b)(2).

value of the

The MMS recognizes that only a part of the generated electricity can be attributed to the geothermal resource, with the remainder credited to the powerplant and electrical transmission systems. The value of the geothermal production is thus derived by subtracting the contribution of allowable transmission and powerplant costs from the value of the electricity. This valuation method, termed the "geothermal netback procedure," is applied to all "no-sales" situations. The lessee must apply to MMS for approval of the netback valuation.

The geothermal netback procedure uses two types of deductions to derive the geothermal value from the electricity sales value. First, a transmission deduction recognizing the lessee's cost of wheeling (transmitting) the electricity to the point of sale or delivery is subtracted from the electricity sales revenue to derive a value of the electricity at the plant tailgate, usually the busbar on the high-voltage side of the transformer in the plant switchyard. This transmission-reduced value is termed the "plant tailgate value." A generating deduction recognizing the lessee's cost of converting the resource heat energy into saleable electricity is then subtracted from the plant tailgate value to derive the equivalent value of the geothermal production at the plant inlet. Royalties become due on this equivalent value. Methods of computing and applying the deductions are described below.

The deductions are based on actual costs incurred by the lessee and are generally computed from cost rates (in dollars per kilowatthour; $/kWh) that are determined on a yearly basis using annual expenditures and electricity production. Procedural policy imposes a maximum limit on each deduction. The transmission deduction is limited to a maximum of 50 percent of the electricity sales revenue unless a greater amount is approved by MMS. The generating deduction is limited to a maximum of two-thirds of the electricity's plant tailgate value unless a greater amount is approved by MMS. Although the deduction cost rates are computed annually, the actual deductions taken during any given month must be tested against the actual sales revenues and tailgate values for that month to ensure that the limits are not exceeded. That is, each deduction cannot exceed its monthly limit for any individual selling arrangement unless otherwise approved by MMS.

Three electrical energy measurements, in kilowatthours (kWh), are required to determine the deductions and execute the netback valuation: (1) The amount of electricity delivered to the purchaser, (2) the total electricity generated by the powerplant, as measured at the generator(s), and (3) the amount of tailgate electricity, as measured on the high-voltage side of the transformer in the powerplant switchyard. The delivered electricity is used to compute the transmission deduction; the generated electricity is used to compute generating costs; and the tailgate electricity is used to compute the generating deduction.

Transmission Deductions

Transmission deductions include all of the actual costs incurred by the lessee to transmit the electricity from the powerplant to a point of sale or delivery; they are subtracted from the electricity sales revenue to determine the value of the electricity at the powerplant (the "plant tailgate value"). Transmission deductions can have two components--transmission line costs and wheeling charges, one or both of which may be applicable for any given situation.

Transmission-Line Costs

Deductions for the costs of constructing and operating a transmission line (or tie line) are based on cost rates that are computed from the lessee's actual annual costs. Allowable costs include operating and maintenance expenses (including overhead) and, depending on the service date of the transmission facilities, either a depreciation and a return on undepreciated capital investment (the depreciation method), or a cost equal to the capital investment multiplied by a rate of return (the return on investment method). For transmission facilities placed in service prior to March 1, 1988, lessees must use the depreciation method to determine transmission-line costs. For transmission facilities placed in service on and after

March 1, 1988, lessees have the option of using either the depreciation method or the return on investment method; the chosen method cannot be changed after an election is made.

Operating and maintenance expenses--Allowable operating and maintenance costs include, but are not limited to:

(1) Direct wages paid to employees and supervisors while engaged in the routine operation, maintenance, and repair of the transmission line.

(2) Expenditures for supplies and miscellaneous replacement parts associated with normal operation, repair, and maintenance.

(3) Rental for transmission line rights-of-way off of the lease.

(4) Insurance, ad valorem property taxes, and payroll taxes. State and Federal income taxes, severance taxes, and royalties are not allowable expenses.

(5) General and administrative overhead costs (telephone service, office supplies, salary apportionment, etc.) that are directly allocable and attributable to the operation of the transmission line. For operations prior to March 1, 1988, the total of the allowable overhead expenses cannot exceed 10 percent of the other total operating and maintenance costs. The 10-percent limit is discontinued beginning March 1, 1988.

Capital investments -- Capital investments are those costs for the purchase, delivery, and installation of transmission-line equipment and material, including administrative and miscellaneous costs that are directly allocable and attributable to the construction of the transmission line. The costs of constructing ancillary transmission-line operating and maintenance facilities can also be included. Capital investments include only those costs for fixed, depreciable assets that are an integral part of the transmission line. The cost of purchasing transmission-line rights-of-way is not allowed as part of the capital investment because the acquisition of real estate is considered a nondepreciable expenditure. (However, costs of leasing or renting rights-of-way can be included as part of the annual operating costs.)

The lessee is advised to maintain an itemized breakdown of costs to support his claim for capital investment. Under the depreciation method, subsequent expenditures for the addition or replacement of major capital items can be added to the undepreciated capital balance and depreciated over the life of the item. The costs of subsequent improvements or replacement of major capital items under the return-on-investment method are added to the original investment.

Rates of return -- For operations prior to March 1, 1988, the rate of return used to compute the annual return on undepreciated capital investment (the depreciation method) must be the prime rate as published in the "Money Rate" section of the Wall Street Journal and in effect on the first day of the first annual deduction period. When established, the rate of return shall remain constant until March 1, 1988.

Beginning March 1, 1988, the rate of return used in both the depreciation and the return-on-investment methods shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the annual reporting period for which the deduction is applicable. The rates are effective for 1 year and are to be redetermined at the beginning of each subsequent reporting year.

The intent of the return on investment is to allow the lessee a reasonable return on the cost of funds necessary to finance the project. The return on investment granted by MMS is not intended to reflect a discounted cash-flow or other rate-of-return analysis used by a particular lessee to evaluate a proposed investment. Nor is it intended to reflect a particular project's opportunity costs. The MMS is not in a position to make a determination of risk or to evaluate a given company's cash-flow situation.

Computation of annual transmission-line cost rates by the depreciation method-- Examples of computing annual cost rates by the depreciation method are shown in table 1. The cost rates are calculated from the following equation:

$$\text{Cost rate } (\$/\text{kWh}) = \frac{E + D + I}{F} \qquad (1)$$

where:

E = Annual operating and maintenance expenses (estimated for the first year of operation).

D = Annual depreciation (in dollars) of the lessee's allowable depreciable capital investment (capital investment less salvage value). Depreciation is by the "straight-line" method for the length of the electricity sales contract, unless the lessee can demonstrate to MMS that a different depreciation life is justified. The transmission line can be depreciated only once; a change in ownership does not alter the depreciation schedule established by the original lessee, except for addition or replacement of major capital items.

I = Annual return on undepreciated investment. The return on investment is determined by multiplying the allowable rate of return (prime rate for operations before March 1, 1988; Standard and Poor's BBB industrial bond rate for operations on and after March 1, 1988) by the beginning-of-the-year depreciated investment balance.

F = Annual kWh of delivered electricity (estimated for the first year of operation.)

Each annual cost rate must be calculated to six decimal places.

The allowable depreciable capital investment is the total permitted capital investment less the transmission line's estimated reasonable salvage value. The lessee may determine the salvage value, providing the estimate is supported by documentation. Otherwise, the salvage value will be determined as 10 percent of the total permitted capital investment.

The first-year's cost rate is calculated using estimates of operating and maintenance expenses and delivered electricity. At the end of the first year of operation, the cost rate is recalculated using the first-year's actual costs and delivered electricity, with the resultant value constituting the estimated cost rate for the second year of operation. Cost rates for succeeding years are calculated and applied in the same manner.

Computation of annual transmission-line cost rates by the return-on-investment method — For transmission lines placed into service on or after March 1, 1988, the lessee may elect to determine transportation-line cost rates by the return-on-investment method. The cost rates are calculated from the following equation:

$$\text{Cost rate } (\$/\text{kWh}) = \frac{E + R}{F} \qquad (2)$$

where: E = Annual operating and maintenance expenses (estimated for the first year of operation; previous year's actual costs used for subsequent years of operation).

R = Annual return (in dollars) on the capital investment. The return is computed by multiplying the permitted capital investment by the allowable rate of return (Standard and Poor's BBB industrial bond rate) for each year of the primary term of the electricity sales contract.

F = Annual kWh of delivered electricity (estimated for the first year of operation).

Example calculations are shown in table 2. Each annual cost rate must be calculated to six decimal places.

The capital investment includes all costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) that are an integral part of the transmission line; a salvage value is not deducted from the investment.

Computation of deductions for transmission-line costs -- Deductions for transmission-line costs are computed monthly by multiplying the applicable annual cost rate by the quantity of electricity delivered to the purchaser:

Monthly transmission-line cost (\$) = annual cost rate (\$/kWh) x monthly delivered electricity (kWh).

The use of delivered electricity as the basis for transmission-line deductions, as well as the basis for computing the cost rates, compensates for line losses that are inherent in electrical transmission.

Wheeling Charges

Wheeling charges are those costs to the lessee, as established in a negotiated wheeling agreement, to transmit electricity across third-party's power lines. Because wheeling charges are generally paid monthly, the actual charges can be deducted directly from the monthly electricity sales revenue to determine the plant tailgate value. If the lessee also operates a transmission line, the wheeling charges are added to the monthly transmission line costs to determine the total transmission deduction for any given month.

Allowable Transmission Deductions

The total transmission deduction--transmission-line costs and (or) wheeling charges--cannot exceed 50 percent of the monthly electricity sales revenues, unless approved by MMS. If the monthly transmission costs are less than the 50-percent limit, then those actual costs become the

Table 1.--Example calculations of transmission-line cost rates by the depreciation method

Transmission-line investment depreciated over a 30-year[1] straight-line schedule. Depreciable investment (capital investment of \$4,000,000 less salvage value of \$250,000) = \$3,750,000; rate of return = 8.5 percent[2]

Year	Investment balance (beginning of year)	Annual depreciation	Depreciated investment (end of year)	Return on investment balance at beginning of year
1	\$3,750,000	\$125,000	\$3,625,000	\$318,750
2	3,625,000	125,000	3,500,000	308,125
.	.	.	.	.
.	.	.	.	.
.	.	.	.	.
30	125,000	125,000	-0-	10,625
31	-0-	-0-	-0-	-0-

Transmission-line cost rate calculations: Cost rate = $\frac{E + D + I}{F}$

First year of operation

E = \$210,000 (estimated)
D = \$125,000
I = \$318,750
F = 765,400,000 kWh (estimated first-year's delivery)

First-year's transmission-line cost rate = \$0.000854/kWh.

Second year of operation

E = \$222,000 (first-year's actual)
D = \$125,000
I = \$308,125
F = 785,940,000 kWh (first-year's actual delivery)

Second-year's transmission-line cost rate = \$0.000834/kWh.

[1]Term of sales contract.

[2]Prime rate for operations prior to March 1, 1988; Standard and Poor's BBB industrial bond rate beginning March 1, 1988.

allowable transmission deduction. If the monthly transmission costs are greater than the 50-percent limit, then the transmission deduction will be determined as 50 percent of the electricity sales revenue.

Generating Deductions

Generating deductions account for the lessee's actual costs of generating saleable electricity and is subtracted from the plant tailgate value of the electricity to determine the equivalent value of the geothermal resource. As with deductions for transmission-line costs, generating deductions are based on cost rates that are computed from the lessee's annual costs associated with the construction and operation of the powerplant. Allowable costs include operating and maintenance expenses (including overhead) and, depending on the service date of the powerplant, either a depreciation and return on undepreciated capital investment (the depreciation method) or a cost equal to the capital investment multiplied by a rate of return (the return on investment method). For powerplants in operation prior to March 1, 1988, generating cost rates must be computed by the depreciation method. For powerplants placed in service on and after March 1, 1988, the lessee may elect to compute generating cost rates by either the depreciation method or the return on investment method; methods cannot be changed after an election is made. Generating cost rates are computed, with minor exceptions, from the same basic equations 1 and 2 used to compute transmission-line cost rates; the equations and computational methods are reviewed below.

Two electrical energy measurements are required to determine a generating deduction: Gross generator output and plant tailgate electricity. Gross generator output includes all electricity--saleable electricity, plant parasitic electricity, and electricity returned to the geothermal

Table 2.--Example calculations of generic cost rates by the return-on-investment method

Investment = $76,500,000; life of investment = 25 years

Year	Investment	Rate of return[1] (percent)	Return on investment
1	$76,500,000	9.5	$7,267,500
.	.	.	.
5	76,500,000	10.5	8,032,500
.	.	.	.
.	.	.	.
25	76,500,000	8.0	6,120,000

$$\text{Cost rate} = \frac{E + R}{F}$$

Year 1	Year 5	Year 25
E = $625,000 (estimated)	E = $ 610,000	E = $780,000
R = $7,267,500	R = $8,032,500	R = $6,120,000
F = 430,600,000 kWh (estimated)	F = 510,900,000 kWh	F = 325,400,000 kWh
Cost rate = $0.016878/kWh	Cost rate = $0.015722/kWh	Cost rate = $0.018808/kWh

[1]Standard and Poor's BBB industrial bond rate.

lease for lease operations--generated by the powerplant and attributable to the geothermal resource. Plant tailgate electricity is equivalent to saleable electricity (that is, electricity exclusive of plant parasitic electricity, lease-use electricity, and transmission-line losses); tailgate electricity should be measured on the high voltage side of the transformer in the plant switchyard because electricity consumed by the transformer and other switchyard equipment is considered plant parasitic electricity.

Generating cost rates are determined annually and are based on annual gross generator output. Actual generating deductions (or costs) are determined monthly and are based on plant tailgate electricity. The effect of this procedure is to allow that portion of the geothermal resource used to generate plant parasitic and lease-use electricity to be consumed royalty free, but obviates the government's participation in the cost of generating such electricity because deductions cannot be applied against non-royalty-bearing production.

Operating and maintenance expenses -- Allowable operating and maintenance costs are those nondepreciable expenditures directly related to the routine operation of the powerplant during generation of saleable electricity. Operating and maintenance expenditures include, but are not limited to:

(1) Direct wages paid to employees and supervisors while engaged in operating and maintaining the power plant.

(2) Expenditures for miscellaneous replacement parts associated with normal repair and maintenance.

(3) Contract labor, materials, and supplies required for routine repair and maintenance of the plant.

(4) Arm's-length rental or leasing expenditures for the plant site when the plant is located on private surface.

(5) Chemicals and lubricants used in powerplant equipment, except those chemicals used in hydrogen sulfide abatement processes.

(6) Insurance and taxes, except State and Federal income taxes.

(7) General and administrative overhead costs directly allocable and attributable to the operation of the powerplant during generation of saleable electricity. For operations prior to March 1, 1988, the total of the allowable overhead expenses cannot exceed 10 percent of the other total operating and maintenance costs. The 10 percent limitation is discontinued beginning March 1, 1988.

Capital investments -- Capital investments are those costs for fixed depreciable assets that are an integral part of the powerplant, including costs for the purchase, delivery, and installation of powerplant equipment and material. Investment items are generally located within the confines of the powerplant site. Allowable capital costs include, but are not limited to:

Earth and foundation work; plant structure; plant systems (including flash tanks, separators, turbines, generators, condensers, cooling towers, and all associated pipes, fittings, valves, and electrical control systems); transformers and other switchyard equipment; support buildings (office, warehouse, shops); freshwater wells and supply systems used for cooling and (or) domestic purposes; sidewalks, fences, and plant roads; general plant facilities; and administrative and miscellaneous costs that are directly allocable and attributable to the powerplant's construction.

The following items are specifically disallowed as plant investments: Land and rights-of-way purchased by the lessee, field gathering systems, effluent injection/disposal systems, and hydrogen sulfide (H_2S) abatement facilities. The acquisition of land is considered a nondepreciable investment and thus is not allowed in determining deductions. More important, the lessee has the specific right under Section 1(b) of the Geothermal Resources Lease to use as much of the lease land as necessary for the construction and operation of any facilities that produce, transport, or utilize the resource, subject to environmental restrictions. The lessee also is generally entitled to surface easements for the production and utilization of the leased resource when the surface estate is private but the mineral rights are reserved to the United States, such as lands disposed of under the Stock-Raising Homestead Act of 1916. The courts have found the minerals estate to be dominant in these situations (for example, Occidental Geothermal, Inc. v. Charles T. Simmons and Robert M. Curtis, 1982). Thus, the lessee has no obligation to purchase land for siting a powerplant on a Federal geothermal lease, and MMS does not recognize the lessee's costs of acquiring land to site a powerplant off lease.

Expenses for operations such as gathering, effluent injection, and H_2S abatement are considered the responsibility of the lessee under the terms of the lease and operating regulations. Regulations at 43 CFR 3262.1(c) require the lessee to prevent unnecessary waste of the resource and to operate the lease and manage the resource in an environmentally sound manner. Under the definition of "waste" at 43 CFR 3260.5(c)(4), the lessee is responsible for constructing and operating an efficient field gathering system to transport the resource from the wellhead to the point of utilization. The MMS considers all pipelines connecting wellheads and powerplant as a field gathering system, and all costs of gathering are regarded as production-related costs, which are the sole responsibility of the lessee. In addition, all costs of effluent injection, whether to prevent excessive dissipation of reservoir energy under the definition of "waste" at 43 CFR 3260.5(c)(2) or to mitigate environmental hazards, are considered field-operation expenses to be borne solely by the lessee. Again, the lessee is required to perform these functions under regulations. Likewise, the installation of H_2S abatement facilities to meet air quality standards is a responsibility of the lessee to manage the resource in an environmentally sound manner. Accordingly, plant H_2S abatement facilities are not allowable investment items.

The lessee is advised to maintain an itemized breakdown of asset expenditures to support his claim for capital investment. Under the depreciation method, any subsequent expenditures for the addition or replacement of major capital items, or for other powerplant improvements, can be added to the undepreciated capital balance and depreciated over the life of the item. The costs of subsequent improvements or replacement of major capital items under the return on investment method are added to the original capital investment.

Rates of return -- For operations prior to March 1, 1988, the rate of return used to compute the annual return on undepreciated capital investment (the depreciation method) must be the prime rate as published in the "Money Rate" section of the Wall Street Journal and in effect on the first day of the first annual deduction period. When established, the rate of return shall remain constant until March 1, 1988.

Beginning March 1, 1988, the rate of return used in both the depreciation method and the return-on-investment method shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the annual reporting period for which the deduction is applicable. The rates are effective for 1 year and are to be redetermined at the beginning of each subsequent reporting year.

Computation of generating cost rates by the depreciation method -- Annual generating cost rates using the depreciation method are calculated by equation 1:

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

where: E = Annual operating and maintenance expenses (estimated for the first year of operation).

D = Annual depreciation (in dollars) of the lessee's allowable depreciable capital investment (capital investment less salvage value). Depreciation is by the "straight-line" method for the primary term of the electricity sales contract, ~~the life of the powerplant, or 20 years, whichever is less~~, unless the lessee

See Errata sheet

can demonstrate to MMS that a different depreciation life is justified. The powerplant can be depreciated only once; a change in ownership does not alter the depreciation schedule established by the original lessee, except for addition or replacement of major capital items.

I = Annual return on undepreciated capital investment. The return on investment is determined by multiplying the appropriate rate of return (prime rate for operations before March 1, 1988; Standard and Poor's BBB industrial bond rate for operation on and after March 1, 1988) by the beginning-of-the-year depreciated investment balance.

F = Annual gross generator output, in kWh (estimated for the first year of operation).

Each annual cost rate must be calculated to six decimal places. Examples of computing generating cost rates by the depreciation method are shown in table 3.

The allowable depreciable capital investment is the total permitted capital investment less the powerplant's estimated reasonable salvage value. The lessee may determine the salvage value, providing the estimate is supported by documentation. Otherwise, MMS will determine the salvage value as 10 percent of the total permitted capital investment.

The first-year's generating cost rate is calculated from estimates of annual operating costs and generated electricity. At the end of the first year of operation, the cost rate is recalculated using the first-year's actual operating costs and generated electricity; the resultant figure then becomes the estimated cost rate for the second year of operation. Cost rates for succeeding years are calculated and applied in the same manner.

Table 3.—Example calculations of generating cost rates by the depreciation method

Power plant investment depreciated over a 20-year straight-line schedule. Depreciable investment (capital investment of $165,000,000 less salvage value of $12,000,000) = $153,000,000; rate of return = 8.5 percent[1]

Year	Investment balance (beginning of year)	Annual depreciation	Depreciated investment (end of year)	Return on investment balance at beginning of year
1	$153,000,000	$7,650,000	$145,350,000	$13,005,000
2	145,350,000	7,650,000	137,700,000	12,354,750
.	.	.	.	.
.	.	.	.	.
.	.	.	.	.
20	7,650,000	7,650,000	-0-	650,250
21	-0-	-0-	-0-	-0-

Generating cost rate calculations: $\text{Cost rate} = \frac{E + D + I}{F}$

First year of operation

E = $11,500,000 (estimated)
D = $7,650,000
I = $13,005,000
F = 803,670,000 kWh (estimated generator output)

First-year's generating cost rate = $0.040010/kWh

Second year of operation

E = $8,000,000 (first-year's actual operating costs)
D = $7,650,000
I = $12,354,750
F = 803,500,000 kWh (first-year's actual generator output)

Second-year's generating cost rate = $0.034853/kWh

[1]Prime rate for operations prior to March 1, 1988; Standard and Poor's BBB industrial bond rate used beginning March 1, 1988.

Computation of generating cost rates by the return-on-investment method -- For powerplants placed in service on or after March 1, 1988, the lessee may elect to determine generating cost rates by the return-on-investment method. Cost rates under this method are calculated by equation 2:

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

where: E = Annual operating and maintenance expenses (estimated for the first year of operation; previous year's actual costs used for subsequent years of operation).

R = Annual return (in dollars) on the capital investment. The return is computed by multiplying the permitted capital investment by the allowable rate of return (Standard and Poor's BBB industrial bond rate) for each year of the ~~total deduction~~ period -- the primary term of the electricity sales contract, ~~the life of the powerplant, or 20 years, whichever is less~~, unless the lessee can demonstrate otherwise.

See Errata sheet

F = Annual gross generator output, in kWh (estimated for the first year of operation; previous year's actual outputs used for subsequent years of operation).

Each annual cost rate must be calculated to six decimal places. (See table 2 for examples of cost rates calculated by the return-on-investment method.)

The capital investment includes all costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) that are integral to the powerplant; a salvage value is not deducted from the initial investment.

Allowable Generating Deductions

Generating deductions cannot exceed two-thirds of the electricity's plant tailgate value for any given production month, unless otherwise approved by MMS. Accordingly, generating deductions must be determined by comparing the monthly generating costs against the two-thirds limitation. Monthly generating costs are computed by multiplying the annual generating cost rate by the monthly tailgate electricity:

Monthly generating cost (\$) = annual generating cost rate (\$/kWh) x monthly tailgate electricity (kWh).

If the monthly generating costs are equal to or less than two-thirds of the electricity's plant tailgate value, then those actual costs become the allowable generating deduction. If the monthly generating costs are greater than two-thirds of the electricity's plant tailgate value, then the generating deduction will be determined as two-thirds of the electricity's plant tailgate value.

Electricity Values

The value of the delivered electricity is the total of the revenue received by the lessee for the sale of the electricity, pursuant to the intent of regulations at 30 CFR 206.300(a)(2) and (b)(2). Because purchases from PURPA-qualified small power producers include both an energy payment and a capacity payment, in accordance with FERC regulations, the sum of both payments is considered as the value of delivered electricity.

The plant tailgate value of electricity is the delivered value less the transmission deduction.

Reimbursements

Any reimbursements the lessee may receive for wheeling the electricity to the point of sale or delivery are subtracted from the monthly transmission costs to compute the actual transmission deduction. Any reimbursements the lessee may receive for electrical generation or powerplant operations are subtracted from the monthly generating costs to compute the actual generating deduction.

As with arm's-length sales arrangements, any reimbursements the lessee receives for production of the resource or any other field-related operations are royalty-bearing. Production or field reimbursements and their royalties are reported (on Form MMS-2014) separately from the netted-back geothermal value.

Computation of Netback Values

Examples of computing monthly geothermal values using the netback procedure and computations of royalties due are given in tables 4 and 5. Example 1 (table 4) is the simpler of the two computational models and will likely apply to most netback valuations. Example 2 (table 5) illustrates the method of handling reimbursements if the lessee receives any. As shown in both examples, the monthly transmission costs do not exceed the 50-percent limit of the value of delivered electricity. Thus, the computed transmission costs become the allowable transmission deductions. The computed generating costs in example 1 (table 4), however, exceed two-thirds (66.67 percent) of the plant tailgate value of electricity. Accordingly, the allowable generating deduction for example 1 is limited to two-thirds of the electricity's plant tailgate value. The computed generating costs in example 2 (table 5) are less than two-thirds of the electricity's plant tailgate value and thus are an acceptable generating deduction as computed.

For audit purposes, the lessee must prepare records detailing the monthly computations of the netback values and associated royalties, as exemplified in tables 4 and 5. These records must be maintained for 6 years and be made available to MMS upon request.

Because deductions during an operational year are based on the previous year's cost rates, year-end adjustments to the monthly geothermal values may be necessary when the operational year's actual costs are known. If the recalculated cost rates result in higher geothermal values for the year, the additional royalties due are paid as a lump sum when the lessee submits corrected monthly reports. If the recalculated cost rates result in lower geothermal values, the resultant overpayment of royalties is recouped by subtracting the overpaid amount from the monthly royalty payments in the following year of operation. Alternatively, the lessee may request a lump-sum settlement, but the granting of a lump sum will be at the discretion of MMS.

APPROVALS AND SUBMITTALS

All royalty payments, and the valuations on which they are based, are subject to audit. The lessee is not required to receive MMS approval for valuing geothermal production sold under an arm's-length contract; the MMS generally accepts arm's-length sales values for royalty purposes. For geothermal production sold under a non-arm's-length transaction, the lessee should submit a valuation proposal for MMS review and approval. For "no sales" transactions, the lessee should submit a proposed valuation based on the netback procedure. Proposed netback valuations should be submitted when the investments are known and the operating expenses can be reasonably estimated, but at least 90 days prior to commercial production so that ample time is allowed for MMS approval of deductions. Sufficient backup documentation, including sales contracts, wheeling arrangements, and any pertinent approvals by other jurisdictional agencies, must accompany the valuation proposal for MMS to determine its acceptability. Invoices for capital expenditures should be maintained by the lessee in case they are requested during any subsequent audit.

All inquiries or submittals regarding the valuation of geothermal production should be sent to:

Royalty Valuation and Standards Division
Minerals Management Service
P.O. Box 25165, Mail Stop 653
Denver, Colorado 80225

Table 4.--Computation of monthly geothermal netback value, example 1

Delivered electricity...............60,000,000 kWh	
Tailgate electricity................63,000,000 kWh	
Value of delivered electricity[1]................................	$3,500,000.00
Transportation deduction:	
Transmission line costs (cost rate x delivered electricity):	
$0.000854/kWh(2) x 60,000,000 kWh = $51,240.00	
Transmission costs as percentage of delivered value: 1.46 percent	
Allowable transmission deduction..............................	$51,240.00
Tailgate value of electricity.................................	$3,448,760.00
Generating deduction:	
Generating costs (cost rate x tailgate electricity):	
$0.040010/kWh(3) x 63,000,000 kWh = $2,520,630.00	
Generating costs as percentage of tailgate value: 73.09 percent	
Allowable generating deduction (2/3 of tailgate value).....	$2,299,173.33-8.5%
Value of geothermal production................................	$1,149,586.67+23%
Royalty due (based on a royalty rate of 12.5 percent)...........	$143,698.33

[1]Total revenue received for sale of electricity, including energy payment and capacity payment.
[2]Second year's cost rate from table 1.
[3]Second year's cost rate from table 3.

Table 5.--Computation of monthly geothermal netback value, example 2

Delivered electricity................ 61,500,000 kWh
Tailgate electricity................ 64,575,000 kWh
Gross Elect [illegible]
Value of delivered electricity[1]................................ $3,688,770.00

Transportation deduction:

Wheeling charges: $2,500.00

Transmission line costs (cost rate x delivered electricity):

$0.0000834/kWh(2) x 61,500,000 kWh = $51,291.00

Transmission line costs and wheeling charges as percentage of delivered value: 1.46 percent

Allowable transmission deduction................................ $53,791.00

Tailgate value of electricity.................................. $3,634,979.00

Generating deduction:

Generating costs (cost rate x tailgate electricity)
.046471 = 3,000,843.30
$0.034853/kWh(3) x 64,575,000 kWh = $2,250,632.48

Generating cost reimbursement = -$10,000.00
2,990,843.30
Actual generating costs = $2,240,632.48

Generating costs as percentage of gross tailgate value: 61.64 percent

Allowable generating deduction............................ $2,240,632.48 -33%

Value of geothermal production............................ $1,394,346.52 +116.5%

Royalty due on value of production (based on a royalty rate of 12.5 percent).. $174,293.32

Production reimbursement: $20,000.00

Royalty due on reimbursement.................................... $2,500.00

Total royalty due.. $176,793.32 + 113%

[1]Total revenue received for sale of electricity, including energy payment and capacity payment.
[2]Second year's cost rate from table 1.
[3]Second year's cost rate from table 3.

REPORTING REQUIREMENTS

The geothermal lease provides that royalties on production are due and payable monthly on the last day of the next month following the month in which production occurred. Monthly royalties must be reported to MMS's Auditing and Financial System (AFS) for proper accounting and crediting. To accomplish this, the lessee, operator, or royalty payor must submit two forms: (1) A generally one-time Payor Information Form (PIF) MMS-4025 and (2) a monthly Report of Sales and Royalty Remittance Form MMS-2014.

The PIF must be submitted no later than 30 days following the beginning of commercial production. The PIF is used to establish and maintain lease and payor accounts that are required for the monthly reporting of sales and royalty remittance.

Monthly production and sales, by transaction codes, are reported on Form MMS-2014. For lessees with arm's-length and acceptable non-arm's-length selling arrangements, each sales transaction and any production-related reimbursements are reported as separate line items on Form MMS-2014. For lessees using the netback procedure to value geothermal production, only the netted value ("Value of geothermal production" in tables 4 and 5) is reported as a single line item; production-related reimbursements are reported as separate line items. Royalty payments must accompany Form MMS-2014 unless accomplished by electronic funds transfer (EFT) or otherwise instructed by MMS.

Specific units of measurement for reporting geothermal production are not required by MMS at this time. The royalty payor should report production in the units prescribed in his sales contract. For most payors, including those valuing the resource under the netback method, the unit of measurement will be kilowatthours. Any other commonly used, standard units of measurement for mass, volume, or energy prescribed by sales contracts are acceptable. The production measurements required by the MMS should not be confused with those reported to the Bureau of Land Management, which may require different measurements used for different purposes.

UNECONOMICAL OPERATIONS

If the lessee finds that a Federal geothermal lease cannot be successfully operated as a result of an issued royalty valuation decision or order, particularly those lessees valuing resources under the netback procedure, an appeal can be made to the Director, MMS, for relief from the decision or order in accordance with the provisions of 30 CFR Part 290. (This report does not constitute an issued valuation decision or order, and cannot be appealed in and of itself.) Specific appeals procedures will be given at the time MMS issues a decision or order.

If the lessee fails to obtain economic relief from MMS, he can petition the appropriate Bureau of Land Management office for a temporary royalty rate reduction pursuant to the provisions of 43 CFR 3205.3-7. The lessee must demonstrate an operating loss before a royalty rate reduction will be considered. Royalty rate reductions are not intended to subsidize a lessee for higher than normal start-up-costs; to support poor or inadequate engineering designs, bad business decisions, or poor operating practices; or to compensate the lessee for losses incurred as a result of market fluctuations. Likewise, a royalty rate reduction cannot be considered if the apparent purpose is to maintain a profit margin or to mitigate the intent of lease terms and regulations.

REFERENCES CITED

Occidental Geothermal, Inc. v. Charles T. Simmons and Robert M. Curtis, 1982: U.S. District Court, Northern District of California, No. C-81-0510 MHP.

Williams, H.R., and Meyers, C.J., 1980, Oil and gas law, index volume, oil and gas terms: New York, Matthew Bender, 657 p.

VALUATION OF FEDERAL GEOTHERMAL RESOURCES--ELECTRICAL GENERATION

ERRATA SHEET

Page 11 - Column 2 - Computation of generating cost rates by the depreciation method

Factor D - Delete ...the life of the powerplant, or 20 years, whichever is less,...

Page 13 - Column 1 - Computation of generating cost rates by the return-on-investment method

Factor R - Delete ...total deduction--the... and ...the life of the powerplant, or 20 years, whichever is less,...

Bill Leedy
3-3-91

MEMORANDUM

April 14, 1989

TO: Geothermal Resources Association
Federal Geothermal Valuation Steering Committee

FROM: Guy Martin

RE: GRA Comments on Proposed Rulemaking

Attached are the GRA comments submitted by this office on your behalf today. I want to thank all of you for a terrific job in formulating the GRA position and assisting in the preparation and review of these regulations. Special thanks also go to Don Baur and Tom Starrs of this office who did the heavy lifting on research and drafting.

I hope all of you will be pleased to learn that the final draft of these comments was reviewed by the Edison Electric Institute, and specifically by PG&E, Southern California Edison and San Diego Gas & Electric, with the result that they will be submitting an unequivocal endorsement of the GRA comments, including specific endorsement of the proportion of profits methodology as the preferred approach to valuation. In addition, they will be submitting comments along the lines of those presented at the Denver hearings. For this, we are grateful to Chuck Linderman, and I hope those of you who have regular contacts with these utilities will thank them for their support at your next opportunity.

With the comments submitted, we should now turn our attention to the strategy for reaching an acceptable result in this rulemaking. I will be discussing these issues with Ken Nemzer and Don Liddell next week and forwarding some recommendations to you shortly thereafter. In essence, we need to sustain interest and knowledge in this rulemaking in the relevant offices of the Department of the Interior and to generate ongoing Congressional, state and industry support for the GRA approach. Anyone who has ideas or contacts which can help in this endeavor should let me or Don Baur know at your earliest opportunity.

Thanks again for your help and support. We will be talking soon.

Attachments
2194R

K-192-82-2-SB

GEOTHERMAL
RESOURCES
ASSOCIATION
P.O. Box 598 • Davis, California 95617-1350 • (916) 758-2360 Telex 882410
Chairman's Address: 664 Hilary Drive, Tiburon, CA 94920
(415) 435-4576

April 14, 1989

Mr. Dennis C. Whitcomb
Chief, Rules and Procedures Branch
Royalty Management Program
Minerals Management Service
Denver Federal Center, Building 85
P.O. Box 25165
Mail Stop 662
Denver, Colorado 80225

Re: Proposed Rulemaking -- Revision of Geothermal Resources Valuation Regulations and Related Topics

Dear Mr. Whitcomb:

On January 5, 1989, the Minerals Management Service ("MMS") published proposed rules to amend and clarify existing regulations defining the value, for royalty purposes, of geothermal resources produced from federal lands. This letter transmits the comments of the Geothermal Resources Association ("GRA"). The GRA is a trade association composed of individual member companies, all of whom are involved in the extraction and utilization of geothermal resources. Virtually every major U.S. developer of geothermal resources is a member of the GRA. One of the principal purposes of the GRA, as distinct from other professional or business geothermal organizations, is governmental relations, including issues related to geothermal development on federal lands.

The proposed regulations address issues that are of considerable importance to the GRA and its member companies. The royalty structure adopted by MMS, especially for non-arm's length transactions in which electricity is generated on-site and marketed to utilities, will play a significant role in determining the long-term viability of geothermal as an environmentally sound alternative power source to meet domestic energy needs. The GRA greatly appreciates the Department of the Interior's willingness to undertake this review and looks forward to strengthening its working relationship with MMS on geothermal royalty matters.

The comments set forth in the enclosed document represent the common views of the GRA members. These comments are responsive to the central thrust and most elements of the proposed regulations, however, individual members of the GRA may submit their own comments on specific issues.

If you require further assistance or have any questions concerning our comments, please contact GRA's counsel, Guy Martin of Perkins Coie, (202) 887-9030. Thank you for considering our views on this important matter.

Sincerely,

Kenneth Press Nemzer
Chairman

1545R

COMMENTS OF THE

GEOTHERMAL RESOURCES ASSOCIATION

ON

PROPOSED REVISIONS OF GEOTHERMAL RESOURCES VALUATION REGULATIONS AND RELATED TOPICS

54 FED. REG. 354 (JANUARY 5, 1989)

SUBMITTED
TO THE
MINERALS MANAGEMENT SERVICE

APRIL 14, 1989

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INTRODUCTION

These comments are set forth in five sections. In the first section, we discuss the legal framework for geothermal royalty valuations. This discussion demonstrates that the Minerals Management Service ("MMS") has considerable flexibility, under applicable legal requirements, to set geothermal royalty valuation requirements and address national energy policy objectives. The second section discusses policy issues that should be considered during this rulemaking, including the congressional directive that royalty rates should encourage the utilization of geothermal resources and the need to invest in innovative energy generation technologies. The third section focuses on what the Geothermal Resources Association ("GRA") considers to be the most important issue presented in this rulemaking: the valuation approach used for non-arm's length transactions. In this section, we explain why the netback approach must be rejected in favor of the proportion of profits approach. The fourth section sets forth GRA's comments on specific questions raised by MMS in the proposed regulations. The final section discusses additional issues that require consideration.

LEGAL FRAMEWORK

Enacted in 1970, the Geothermal Steam Act ("GSA"), 30 U.S.C. §§ 1001-1025, grants authority to the Secretary of the Interior to issue leases for geothermal development on specified public lands. _Id_. § 1002. Competitive bidding is required for lands included within a "known geothermal resource area." _Id_. § 1003. Other lands may be leased to the first qualified applicant. _Id_. The GSA is concerned with all aspects of the leasing, production, and utilization of geothermal resources, including indigenous steam, hot water, hot brines, and byproducts. It serves as the principal statement of law and policy governing the federal government's approach to the use of geothermal resources.

The stated purpose of the GSA is to "open to exploration and development, through private enterprise, the geothermal steam and associated geothermal resources underlying certain of the public domain lands of the United States." S. Rep. No. 1160, 91st Cong., 2d Sess. 1 (1970). As stated in 1970 by the Senate Committee on Interior and Insular Affairs, "[t]he Nation's geothermal resources promise to be a relatively pollution-free source of energy, and their development should be encouraged." _Id_. at 3.

Although geothermal resources, like other resources extracted from federally owned public lands, must produce a fair economic return to the United States, the royalty requirements of the GSA are tied closely to the policy goal of encouraging private development of geothermal resources on public lands. The royalty rate must be at least 10% (and no more than 15%) of the value of the geothermal heat or energy derived from production under the lease. 30 U.S.C. § 1004(a).

In adopting the 10% minimum royalty, Congress recognized the need to grant greater incentives to private geothermal developers, who must use capital-intensive, innovative technology in remote regions of the country, than are granted to the developers of conventional energy resources such as oil and gas.1/ H.R. Rep. No. 1544, 91st Cong., 2d Sess. 7 (1970). Consistent with this statement of congressional intent, MMS applies the 10% minimum royalty to liquid dominated geothermal leases.

The important issue addressed in this rulemaking is how to determine the "value" of the resource against which the 10% royalty shall be charged. It is the GRA's view that the same energy policy objectives that apply to the establishment of the 10% minimum rate also apply, within the constraints of applicable law, to the calculation of the value against which that rate is applied.

In 1973, the Department of the Interior promulgated geothermal resource valuation regulations. 38 Fed. Reg. 35,068 (1973). These are the standards that will be revised as a result of this rulemaking.

1/Indeed, there was strong feeling at the time the GSA was enacted that 10% was too high. For example, Congressman Hosmer stated that, "I am fairly certain that at some later time we will have to amend this legislation to permit a lower minimum royalty than that specified in the legislation as amended. . . . There are probably a lot of areas where the economics of geothermal steam production with very dirty steam are submarginal at a 10 percent royalty rate. Yet, marginal at 5 percent. . . ." 116 Cong. Rec. H41,757 (daily ed. Dec. 9, 1970).

Like the GSA, the 1973 regulations establish broad standards that grant considerable flexibility to MMS. In 30 C.F.R. § 206.300(a), for example, it is stated that "[t]he value of geothermal production from the leased premises for the purpose of computing royalties shall be the reasonable value of the energy and the byproducts attributable to the lease as determined by the Supervisor." A number of general factors are to be taken into account in establishing this value, but no precise formula is articulated. As the 1973 regulations make clear, MMS' only "bottom line" in defining value is that the United States must receive a fair return for the resources extracted from federal lands.[2/]

No specific guidance is provided in the GSA as to how a fair return is defined. The legislative history of the Act, however, establishes several objectives which are specific to the geothermal resource. These objectives are to be satisfied in the course of ensuring that the United States defines a fair return on geothermal resources. These objectives are:

[2/]With respect to non-arm's length transactions, the regulations specify only that the value of production shall be no less than "[t]hat amount which is the value of the end product attributable to the geothermal resource produced from a particular lease where geothermal resources are not sold by the lessee before being utilized, but are instead directly used in manufacturing, power production, or other industrial activity." Id. § 206.300(b)(2).

1) Geothermal producers and investors should be given a clear indication of how royalties will be calculated so that private industry understands the economic factors and risks involved in geothermal utilization. S. Rep. No. 1160, at 7, 9.

2) The valuation standards should reflect that a "fundamental purpose" of the GSA is to provide "investment incentives." Id. at 7.

3) "[P]rompt and vigorous development" of geothermal resources is in the public interest, and "royalties are a major consideration in planning and obtaining financial commitments for the development of such [geothermal] facilities." Id. at 9.

4) In the long-run, benefits to the United States will be maximized if greater use is made of geothermal resources. Id. at 9, 10.

5) Costs to developers will be high, and the GSA is intended "to give as much encouragement as possible to potential developers." Id. at 10. MMS (and each agency administering the GSA) is directed to "keep this basic purpose in mind."

6) There is an important distinction between geothermal development and oil and gas development. H.R. Rep. No. 1544, at 9.

As recognized by these references to the legislative history of the GSA, there is a clear relationship between the royalty valuation approach adopted by MMS and the fulfillment of other federal environmental and energy security objectives. See, e.g., S. Rep. No. 1160, at 9. If honored, the GRA's recommendations on royalty valuation will result in regulations which: (a) advance the goal of the GSA to promote the development of geothermal resources; (b) promote alternative energy supplies that do not produce environmentally harmful emissions; and (c) ensure a fair, adequate and legally acceptable return to the United States.

POLICY ISSUES

The Advantage of Geothermal Energy

In deliberations leading up to enactment of the GSA, Congress made it clear that there are strong policy justifications for encouraging the development and utilization of geothermal resources. Although presented only in summary here, the policy imperatives for geothermal are significant and numerous.

Beneficial Energy Supply

As Congress has observed, even though geothermal is not likely to become a major contributor to the total energy requirements of the United States in the immediate future, "the local energy impact of the geothermal resources can be substantial and beneficial." H.R. Rep. No. 1544, at 19. An added benefit is that geothermal byproducts, such as superheated waters that contain recoverable minerals, can be put to productive use. *Id*. at 3.

Reduce Demand on Nonrenewable Energy Sources

Congress also has recognized that failure to develop geothermal power places additional demands on nonrenewable resources that already are in short supply. S. Rep. No. 1160, at 27. As then Congressman Lujan noted in 1974, "if geothermal energy is implemented in the areas where it is presently known to be in abundance, the savings of fossil fuels will be more than enough to satisfy the needs of those areas without geothermal for many many years to come." 120 Cong. Rec. H22,642 (daily ed. July 10, 1974). For these reasons, the House Committee on Interior and Insular Affairs concluded that "geothermal power stands out as a potentially invaluable untapped natural resource." H.R. Rep. No. 1544, at 4. It is a "new source of energy [that] is needed and it is needed now." *Id*. at 9.

Environmentally Acceptable Energy Supply

In addition to recognizing its energy production and byproduct benefits, Congress has focused on the fact that geothermal energy causes virtually no adverse environmental impacts. "Environmentally the beneficial results will be from energy production without significant atmospheric pollution such as [is] produced from hydrocarbon conversion forming noxious gases or radiation hazards from atomic conversion." S. Rep. No. 1160, at 27. "There are," the Senate Report continues, "no major problems related in this regard to this resource which should deter its development." Id. In summary, Congress recognized in 1970 that failure to develop sources of geothermal energy "will create an increased drain on other resources, higher pollution, adverse environmental effects and higher costs." H.R. Rep. No. 1544, at 20.

State Support and Recognition

State governments also have recognized the advantages of geothermal energy. California's State Legislature, for example, has declared:

> it is also the policy of the state to encourage the use of . . . geothermal resources . . . wherever feasible, recognizing that such use has the potential of providing direct economic benefit to the public, while helping to conserve limited fossil fuel resources and promoting air cleanliness.

Cal. Pub. Res. Code § 800.

Energy Security Considerations

Energy security considerations call attention to the importance of developing geothermal technologies. National security concerns stem from the strategic and economic importance of ensuring a ready supply of energy at a reasonable cost. In recent years, Congress has recognized that attempts to increase domestic production of oil must be accompanied by attempts to increase development of alternative energy resources. For example, then Congressman Lujan stated in 1985 that, with respect to geothermal and other alternative energy resources, "[o]ur overall national energy security requirements demand a well-balanced domestic program, emphasizing development of promising energy reserves such as renewable energy resources," and that "the need for . . . alternative energy is just as real today as it was in 1974. . . ." Renewable Energy Incentives: Hearing Before the Subcomm. on Energy Conservation and Power of the House Comm. on Energy and Commerce, 99th Cong., 1st Sess. 8 (1985).[3/]

Response to Global Warning Concerns

Global warming concerns provide yet another compelling reason for placing increased emphasis on geothermal development. Because the so-called "greenhouse effect" is caused by the combustion of all carbon-based fossil fuels, whether domestic or imported, and increasing domestic fossil fuel production to offset fuel imports is no solution,

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[3/]This testimony was offered in support of proposed legislation that would have provided a tax credit for the production of electricity from renewable energy sources. Congressman Lujan's proposed credit for geothermal was one of the highest proposed.

attention is being turned to environmentally "clean" technologies such as geothermal.[4/]

Recently, several bills addressing global warming have been introduced in Congress. Once such bill, S.324, sets a goal of a 20% reduction from 1988 CO_2 emission levels by the year 2000 and lays out an energy strategy for realizing that goal which includes "an accelerated examination of alternative sources of energy," including geothermal, that "have the potential to meet the energy demand of the future in a more environmentally benign manner." 135 Cong. Rec. S1035 (daily ed. Feb. 2, 1989)(statement of Sen. Wirth).

Summary

Both energy security and global climate concerns can be addressed by strengthening federal policies that encourage the development of geothermal technologies. Recognizing that we have long provided incentives to conventional energy industries, the Blueprint for the Environment, prepared for the new administration by a broad coalition of environmental organizations, states that a shift to alternative energy must be one of the cornerstones of a sustainable energy policy.

[4/]Fossil fuel combustion is responsible for approximately 80% of the global warming problem. One group of experts recently determined that a 20% cut in fossil fuel use by 2025 would be necessary to avoid dramatic global climate impacts. Yet, without policy changes, recent trends indicate an 80% increase in carbon emissions over the same period. See Flavin, The Heat Is On, WorldWatch, Nov.-Dec. 1988, at 16.

Because the costs of such technologies are high, the Blueprint states, "[w]e must begin to implement a policy that allows . . . renewable energy resources to compete with conventional resources on an equal basis--a 'level playing field.'" Blueprint for the Environment at 15. Geothermal energy is prominently featured in this proposed program. Id. at 16.

Geothermal energy technologies have the potential to provide a cost-effective, clean, and strategically secure source of energy. These technologies have a variety of advantages over more traditional energy sources: they rely on domestically available sources of energy; they can be developed in relatively short lead times; they release none of the fossil fuel pollutants; they do not contribute to the build-up of carbon dioxide in the atmosphere; and they generate electricity by using turbine technology that is compatible with the conventional electrical supply transmission system.

The Relationship Between Resource Valuation and Advancing Policy Goals

As the preceding discussion demonstrates, for approximately 20 years federal laws and policies have emphasized the importance of encouraging the growth of the geothermal industry. This goal assumes even greater importance today in light of new concerns over environment and energy security.

If geothermal development is to reach its full potential, MMS and other agencies responsible for implementing the GSA must recognize the unique characteristics of this industry. Unlike oil and gas, geothermal steam cannot be pumped into a tank truck and transported to the nearest market. Instead, it must be utilized at the site of production. This requirement introduces numerous special considerations into the development of geothermal resources. In the remote locations where virtually all geothermal facilities are located, there is usually no power plant to which the lessee can sell the resource. Consequently, to market the resource, the lessee must undertake the risk and expense of constructing a generating plant and installing a transmission line. The costs of doing so are substantial. Because of the risks involved, financing for geothermal projects is both more expensive and more difficult to obtain than financing for conventional energy projects. In addition, because geothermal extraction and the associated energy production require state-of-the-art technology, capital costs are very high.

Unfortunately, as a result of the proposed valuation regulations, the geothermal industry now faces a situation quite the opposite of what Congress intended when it passed the GSA and of what is needed to meet current policy objectives.[5] Rather than proposing a royalty valuation approach that reflects the true costs of the geothermal industry and thereby encourages the proper level of investment, MMS proposes to use a valuation approach that lumps geothermal production with conventional technologies by basing geothermal royalty valuation rates on the same netback approach that is used for oil and gas. Rather than encouraging development, this approach creates disincentives for the geothermal industry by failing to account for financial considerations that are unique to the construction and operation of geothermal projects. These costs vary widely from project to project, but they invariably are higher than those for conventional energy technologies.

A far better approach would be to establish royalty standards that, while providing a fair and legally sufficient return to the United States, would recognize the true risks and costs inherent in geothermal resource extraction and energy production and, by doing so, guide and encourage the future

[5] Instead of receiving the kind of encouragement Congress envisioned when it passed the GSA in 1970, the geothermal industry has found itself competing with traditional generating technologies that have long benefited from favorable tax treatment and other incentives. For example, a recent study indicated that of approximately $30 billion in energy tax subsidies in 1984, the nuclear power industry received $15 billion, while other conventional technologies received $13 billion. All of the alternative energy technologies combined, including geothermal, received only $1.7 billion. See Morgan, The Hidden Costs of Energy (1985).

development of federally owned geothermal resources. In other words, the value of the resource, and a fair return on it, must be accomplished in the context of the business of developing geothermal energy. The legislative history of the GSA calls for such an approach:

> [T]he committee seriously questions the wisdom of placing undue emphasis at this time on rentals and royalties from geothermal leases as a source of Federal revenue. The emphasis now must be to establish a climate favorable to the development of the resource. Looking to the future, the tax revenue . . . from a vigorous, prosperous geothermal power industry producing low-cost, pollution-free energy will far exceed any present return from lease rentals and royalties.

S. Rep. No. 1160, at 9 (1970). In short, royalties should be set "to encourage the development of geothermal resources." Id. at 7 (emphasis in original).

In submitting these comments, the GRA does not request special consideration or extra incentives, even though Congress has made it clear that such treatment is justified. Instead, this unified industry group requests only that disincentives not be built into MMS' geothermal royalty valuation approach. By definition, the "value" of geothermal resources should reflect their true worth relative to the costs of their development. For the reasons that will be discussed in the following section, MMS' proposed netback approach does not accurately account for this worth; the GRA's recommended alternative does.

VALUATION OF GEOTHERMAL RESOURCES IN NON-ARM'S LENGTH TRANSACTIONS

This section discusses the valuation methodologies under consideration by MMS. It begins by explaining in detail why the proposed netback approach cannot be used to value geothermal resources accurately. The GRA's preferred alternative, the proportion of profits approach, is discussed in detail. Consideration also is given to the changes that must be made to the netback approach if it is adopted. Finally, the weighted average of gross proceeds and alternative fuels methodologies are discussed.

The Netback Approach

In the proposed regulations, MMS indicates that the value of geothermal resources used to generate electricity that is not sold under an arm's length contract shall be based upon the "first applicable" of two concepts:

> 1) The weighted average of the gross proceeds paid or received by the lessee under its own arm's length contracts for the purchase or sale of similar quantities on like-quality resources; or
>
> 2) The value determined by the netback method, taking into account the lessee's costs of generating and transmitting electricity.

54 Fed. Reg. 355 (Jan. 5, 1989). MMS indicates that the weighted average approach seldom will be applicable because there are few instances in which the lessee will purchase additional geothermal resources.

MMS also proposes that other "reasonable" valuation methods may be used if approved by MMS. Id. at 355. Possible alternatives to netback identified by MMS include the proportion of profits method and the alternative fuels method. Id. at 356-357. In fact, however, the MMS Royalty Valuation and Standards Division ("RVSD") has uniformly rejected other reasonable methods without providing useful explanations of its reasons for doing so. It has done so without making any showing that these alternatives fail to provide a fair return to the United States. In this context, the important policy issues related to geothermal have gone unaddressed.

In at least five royalty valuation proceedings pending before MMS, lessees have proposed alternatives to the netback approach. Consequently, MMS is well aware of the objections that geothermal producers have to the netback approach. See Coso Energy Developers (Lease CA-11402); Ormat/Ormesa I (Lease CA-966); Ormat/Ormesa II (Lease CA-6218); Oxbow Geothermal Corporation (Leases N-8317, N-12393, N-12862, N-12863); and Santa Fe Geothermal, Inc. (Lease CA-5636).

The GRA strongly opposes the use of the netback approach and supports the adoption of the proportion of profits method. The arguments against the use of netback set forth in the above-referenced valuation proposals are compelling, and the GRA regards this rulemaking as MMS' best opportunity to move away from that approach and establish a lawful alternative that is accurate and acceptable to the industry.

Under the netback procedure, the value of electricity forms the basis for deriving the value of the geothermal resource. MMS correctly recognizes that only a portion of the value of generated electricity can be attributed to the geothermal resource, with the remainder credited to the power plant and electrical transmission system. Unfortunately, the MMS' proposed netback methodology fails to respond to the economic realities of the geothermal industry, vastly overstates the value attributable to the resources, and acts as a disincentive to investment in geothermal development.

Borrowing from oil and gas royalty valuation procedures, MMS' geothermal netback approach subtracts from the value of electricity sold the contribution made by allowable transmission and power plant costs. See MMS, Valuation of Federal Geothermal Resources - Electrical Generation, 4-14 (1988) ("Valuation Guidelines"). This approach assumes that whatever is left after the allowable transmission and generation expenses have been deducted is the value of the resource for royalty purposes. However well they may work for oil and gas, when applied to geothermal the assumptions used in the netback approach do not reflect accurately the value of the resource.

As discussed below, there are numerous problems inherent in attempting to apply the proposed netback formula to geothermal energy production. Any one of these reasons is sufficient to justify rejecting the netback approach. Together, they demonstrate that MMS has no reasonable option but to adopt a different methodology.

The Netback Approach is Conceptually Inappropriate for Geothermal Resources.

As a general practice, MMS has determined resource royalties on the basis of a price that is determined by "free market" forces dealing in a commodity that is easily transportable and has purchasers ready to receive it in its natural condition. Oil royalties, for example, are based on the posted price for the resource at the wellhead. This is possible because oil has inherent value the moment it is produced. In addition, it is readily transportable to any location for sale and processing. Thus, the costs of "preparing" oil for transportation are borne by the developer and paid for out of revenues received. The magnitude of the costs incurred by the developer in putting the oil in a condition suitable for transportation generally are quite small. Consequently, the accuracy of the deductions allowed in an oil royalty valuation does not carry much significance. In this respect, netback royalty computation for oil and gas is straightforward and presents little risk to the developer. For all of these reasons, it is difficult to fault netback as applied to oil and gas.

The characteristics of geothermal resources are very different.[6] Geothermal heat does not sell on an open market, and there is no posted price for the resource at the wellhead. Instead, its value is dependent upon the cost of transforming the resource into electricity. Thus, the resource must be utilized (i.e., converted into electricity) at the point of extraction. Invariably, the lessee's investment in converting the resource into electricity far outweighs the investment in producing the resource itself. If the geothermal lessee is unsuccessful in obtaining a power sales contract at a price that makes its project economically viable by covering the costs associated with drilling for the resource, producing the fluid, generating the electricity, transporting the power to the market place, and injecting the remaining fluid, operations will cease (or never be initiated) and the resource literally will be without value.

In recent years, many power purchasers and geothermal producers have determined the price for electricity generated from geothermal resources based upon an arm's length

[6] The IBLA has recognized that it is inappropriate to make economic comparisons between oil and gas development and geothermal development. In California Energy Co., 92 I.D. 125, 133 (1985), the IBLA held that MMS should not estimate drilling costs for a geothermal well based on oil and well drilling data. As the IBLA concluded, "oil and gas drilling is sufficiently unlike geothermal resource exploration that meaningful cost comparisons cannot be made." Id.

negotiation or through bidding. Under this approach, the power purchaser and the producer negotiate the price on the basis of the economic factors involved in developing the resource and the power generation facilities. In these negotiations, the purchaser is seeking to pay the lowest price while the producer is attempting to cover costs and realize a gain. Each cost element in the processing sequence is an integral and necessary part of adding value to the resource and therefore should be allowed as a deduction. Furthermore, because the costs associated with the power plant are so large, it is essential that these deductions be calculated with precision. Even a small miscalculation of the allowable deductions for the power plant will cause a disproportionately large amount of the gross proceeds to be attributed to the resource, thereby greatly distorting its value for royalty purposes.

The effort and expense involved in converting geothermal resources into electricity varies considerably from project to project, but the electrical conversion process typically accounts for approximately 80-85% of the total investment in the project. As MMS acknowledges, "[t]he physical and chemical characteristics of geothermal resources vary widely from field to field" and "[g]eothermal fluid characteristics dictate the type of conversion technology and design of the power plant for utilization of a particular geothermal resource." 54 Fed. Reg. 356 (Jan. 5, 1989). MMS states that this difference makes it difficult to apply an "area concept" to valuation. *Id.* The GRA agrees and notes that the same logic applies to the uniform application of the netback method and argues against the use of an approach that relies on fixed rates of return and standard deductions.

If MMS is to adopt a valuation methodology that accurately reflects the value of the resource, as required by the GSA, it must abandon its reliance on the principle that geothermal resources have a posted value at the wellhead or that one can be calculated under the proposed netback approach. Whatever value geothermal resources hold only can be determined under the netback approach on a case-by-case basis, taking all transmission and generation costs into account and subtracting them from the price of the end product.

Simply stated, anything done by the geothermal producer to the resource after it has been brought to the wellhead enhances its value. All of the costs for resource enhancement should be deductible, including the cost of funds needed for the investment in that enhancement. Although it may be possible to significantly amend the netback method so that it approximates value in this way, such a course is a difficult path to a second-best result. As will be explained below, the proportion of profits approach proposed by the GRA is the best currently available methodology for arriving at this result.

Netback Undercompensates for the Cost of Capital.

The proposed netback procedure purports to "compensate . . . for [the] enhancement of value by subtracting the costs of electrical generation and transmission . . . from the sales price of the electricity." *Id.* In fact, among its other deficiencies, the netback method grossly undercompensates for the cost of capital invested in electrical generation and transmission.

Substantial capital investment in the form of debt and equity is required to convert geothermal fluid into electricity and to deliver that electricity to market. It is essential, therefore, that the cost of capital be reflected accurately in any valuation formula.

The proposed netback formula allows a developer two choices regarding deductions for capital-related costs, either:

Option 1

- undepreciated capital investment times 1.5 times S&P's BBB bond rate, plus depreciation (30-year straight-line);

or

Option 2

- historical capital investment times 1.5 times S&P's BBB bond rate, with no deduction for depreciation.[7]

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[7] The cost of capital adjustment adopted by MMS in the June 1988 revised valuation standards is a welcome improvement over the pre-existing approach, inasmuch as it comes closer to accurately reflecting project costs. However, it still represents only an artificial and unduly low approximation of the cost of capital.

Although the proposal offers some improvement over past MMS guidance, it is still lacking in terms of defining value in an accurate manner based on real world considerations. A developer's actual costs of capital do not match the general structure of the netback allowances. Real world costs of capital fall into three categories:

- interest and fees on project debt;
- repayment of borrowed principal; and
- return on equity investment (as measured by discounted cash flows).

Debt financing for geothermal projects typically is available for a term of 10-20 years at rates that reflect a premium to compensate for the risks inherent in this emerging energy technology. Similarly, equity can be attracted to geothermal investments only by offering a return that is competitive with other investment opportunities of comparable risk. Typically, these rates are substantially higher than the prime rate and other common investment rates.

The "cost" of the debt should include all closing fees, construction interest, term interest on outstanding principal, and repayment of principal over the debt term. After payment of debt costs, equity investors expect to earn a return on their full initial investment as measured by discounted cash flows. As with the construction interest allowance, equity investors should be allowed to begin earning a return on each dollar invested from the day on which it is invested. Return on equity invested prior to commercial operations should be treated as a capital cost consistent with the treatment of construction interest on project debt.

These costs are encountered by all geothermal projects, although their magnitude varies. When the netback allowances under either option are compared to these actual costs of capital over time, the netback allowances always fall short of compensating for the full cost actually incurred by the project. In most cases, Option 1 will result in larger net present value deductions than Option 2. Both options, however, are inaccurate measures of cost and, hence, of resource value. For example, under Option 1, the use of a declining basis upon which return is calculated and the 30-year depreciation schedule result in deductions significantly less than actual costs of capital. Under Option 2, interest allowed on the constant investment basis may recover interest on debt and equity investment (although the timing is mismatched), but it makes no allowance for the repayment of borrowed principal. The proposed 1.5 multiplier on the S&P's BBB bond rate would increase the allowed deduction over the previously allowed prime rate factor. However, the effect of this change is still not sufficient to cover to the actual costs described above.

The fundamental problem with the netback treatment of return, therefore, is not that the interest rate used in the formula is too low, but rather that there is an inherent mismatch between the structure of the allowed deductions and the actual costs of capital on a project by project basis. This kind of mismatch generally will be inconsequential for an oil or gas valuation because the investment and associated deductions for processing are small relative to the overall project costs. For geothermal utilization, on the other hand, this discrepancy cannot be tolerated because there is such a substantial investment in conversion before any value is created.

The Netback Calculation Results in Subtractive Error

The netback procedure adjusts the gross proceeds of the project by the value added through the work and investment of the lessee to arrive at the value of the resource. The adjustment involves calculating the capital cost, operating expenses, and return on investment related to the electrical portion of the plant and then subtracting these from the electrical revenues.

For high grade mineral resources, the value added by the lessee is less than for low grade resources. In oil and gas production, where the value added by the lessee is a small percentage of the final value, errors in estimating the value added by the lessee do not affect the royalty significantly. For instance, if the value added by the lessee is only 20% of the final value, an error of 10% in determining the value added by the lessee creates a 2.5% error in valuing the resource and hence in calculating the royalty payment.

In geothermal projects, on the other hand, the value added by the lessee is a much larger portion of the final value, and the corresponding error is also much larger. It is frequently possible in geothermal electrical projects for the value added by the lessee to be 80% or more of the final value because of the large electrical plant investment necessary to convert the low grade energy of the resource to the high grade and saleable energy form of electrical power. The mathematical problem called subtractive error, which expands small errors into large errors, arises in these cases. For instance, if 80% of the value of the electricity for a project was added by the lessee, a 10% error in the estimate of value added by the lessee would cause a 40% error in calculating the value of the resource and royalty. This amount of error is unacceptably high.

The subtractive error problem is inherent in the use of the netback method on projects that provide large added values to the resource. This inherent defect makes the netback method unsuitable for evaluating most geothermal electrical projects.

Netback Does Not Give an Appropriate Treatment to the Rate of Return

As described above, the selection of a rate of return "appropriate" for geothermal power projects is not the central issue. The issue is the appropriate treatment of return in the formula. The deductions for return in the netback formula do not match the actual costs of capital for reasons of both timing and magnitude.

In addition, the return allowance, as currently proposed, will change arbitrarily each year based upon the bond rate that happens to be in effect during the month of a project's annual anniversary. This return ratio bears no resemblance to the project's economics over time. However, it could have a significant impact on royalty payments for no reason other than the random movement of the selected index.

Unless return and depreciation allowances are matched to actual costs on a project specific basis, the netback method always will be arbitrary and inaccurate. In fact, because of the uniqueness of each developer's and each project's financial structure, it would be virtually impossible to reflect accurately true costs of capital through return and depreciation deductions under the netback approach.

To reflect more accurately the costs of power production and transmission, the netback approach should be abandoned. If not, then the accuracy of the approximation of value must be improved and confirmed on a case-by-case basis for each project. The 1.5 multiplier generally improves the level of allowance for capital-related costs, and it comes closer than the previous valuation guidelines to matching the actual capital-related costs. Nonetheless, it still does not reflect fully or accurately the costs incurred.

An inherent problem with netback is that it allows the internal rate of return on the investment in the resource to greatly exceed the internal rate of return on the investment in power production. This problem was demonstrated by GRA witnesses at the March 28 hearing on the proposed regulations. It also has been addressed in individual valuation proposals. As geothermal lessees have pointed out, this deficiency in netback can only lead to the conclusion that the full cost of investment in the power plant is not being deducted from the gross proceeds of the entire project, and, as a consequence, the residual value of the steam resource is being overstated.

MMS' royalty methodology should be able to break down conceptually the integrated resource enhancement process into its resource production and electricity conversion elements and assign the value that would be arrived at in an arm's length transaction between a hypothetical resource producer and a hypothetical resource purchaser/electric power producer. For the reasons detailed above, netback cannot do this.

Because netback fails to reflect accurately the cost of investment in the power plant and overcompensates for the investment in the steam field, a value is given to the resource that does not come close to approximating the price that would be arrived at for that product in a hypothetical arm's length sale between the resource producer and the resource user. An illustration of how the value produced under netback differs from that achieved under an actual negotiated sale is set forth in the Appendix to these comments.

The Netback Approach Uses Arbitrary Values

In addition to the arbitrary rate of return, the proposed methodology inappropriately sets the following arbitrary limits: (1) for processing, a deduction of 66 2/3% of the plant tailgate value of the electricity; and (2) for transmission, a deduction of 50% of gross proceeds. These arbitrary limits do not reflect real costs, and they give the resource an artificially high value. While these limits are included in the Valuation Guidelines as threshold levels that can receive additional scrutiny, they are, in every practical sense, limits to which no exceptions are known.

Deductions are limited to reasonable actual costs, and there is no reason to establish an artificial cap. If necessary, reported costs can be audited to verify their reliability. As noted previously, unless legitimate costs are allowed, the value of the resource will be overstated.

While it is theoretically possible that MMS will select arbitrary values that are approximately correct for a given geothermal project, the odds of this occurring are remote. In fact, the resource values MMS has assigned to date, which vastly overstate resource value, confirm that it is unlikely MMS will be able to appraise resource value accurately under the proposed methodology.

Netback Geothermal Royalties are Disproportionately High When Compared to Other Fuels

The resource transfer values calculated for geothermal projects will, as a general matter, be two to three times greater than the market value of other fuels used for the generation of a comparable amount of electricity (after an adjustment for BTU content and conversion efficiency). For example, at a natural gas price of $3 per million BTU and a station heat rate of 8,500 BTU/KWH, electricity is produced at a fuel cost of 2.55 cents/KWH. A similar example is provided by coal-fired generation. Coal purchased at $1.50 per million BTU and converted to electricity at 12,000 BTU/KWH results in a fuel cost of 1.8 cents/KWH. Electricity produced from geothermal steam, on the other hand, is valued under the proposed netback approach anywhere from 4 cents to 6 cents/KWH.

Furthermore, the geothermal netback value will escalate over time at a rate much greater than that projected for any alternative fuel. Most geothermal projects will have an escalation of the steam value calculated by netback of about 9-10% per year. Most projects' expected revenues, on the other hand, increase only 5-7% per year. Over time, through the netback calculation, the steam value reflects an increasingly larger portion of the total revenue. Under the proposed netback approach, steam values typically begin at levels that represent approximately 35 to 45% of the electricity value, but climb to 60 to 70% by year 10. Penalizing the geothermal industry in this manner is inconsistent with the purposes of the GSA and contrary to environmental and energy security policy goals. This undesirable result can be avoided if MMS simply agrees to treat the geothermal industry fairly and adopt an equitable and accurate valuation methodology. Fortunately, as discussed below, a methodology that meets the tests of fair return, sound energy and environmental policy, and accurate valuation exists.

The Proportion of Profits Approach

The GRA believes that the proportion of profits approach is vastly superior to any other proposed valuation method, and MMS is commended for proposing it as an option. This approach avoids the problems that arise under the netback methodology. It does so by assigning real and verifiable values, not arbitrary assumptions, to the costs and returns associated with each component of an integrated geothermal project. If the proportion of profits approach results in lower royalty payments to the United States, it will be the consequence of applying greater accuracy to the valuation of resources in the setting of particular projects. In accordance with statutory mandates, the United States will still receive a fair return under the proportion of profits approach. However, unlike under the netback approach, producers will receive a realistic return on their investments; the purposes of the GSA will be advanced; and the policy objective of encouraging an environmentally preferred source of energy will be satisfied.

The GRA recommends that the following proportion of profit methodology be used:

$$STP = \frac{E + (NOI \times SI/TI)}{EO}$$

Where:

STP = Steam transfer price ($/KWH);
E = Steam field operating expenses plus royalties and other distributions;
NOI = Net Operating Income of the project, not less than zero (before any deduction for depreciation or return);
SI = Investment in steam resource;
TI = Total investment in the project; and
EO = Electricity output (KWH)(net power produced).

The major advantage of the proportion of profits approach is that it does not try to estimate the cost of debt and equity investment in the project. It is based on actual, verifiable cash flows and project returns, thereby eliminating the need to determine an appropriate proxy rate of return and depreciation schedule. It allocates the portion of actual cash flow used to pay the project's debt and equity costs to power production and to the steam resource based upon the relative investment in each project component. The specific rate of return that is earned by the project is whatever the actual cash flows produce.

The treatment of operating expenses is essentially the same as in the netback calculation. The only difference is that instead of "netting out" costs of power production and transmission expenses from gross proceeds, steamfield expenses are part of what "adds up" to a steam transfer value. In other words, the proportion of profits calculation could be restated as a formula that nets back from gross proceeds, as does the approach MMS sets forth in its Valuation Guidelines formula, but does so in a much more accurate way.

In the past, MMS has been reluctant to use any resource-related costs in the calculation of steam transfer value. One of the reasons stated for this position (once again borrowed from oil and gas valuations) is MMS' belief that production costs from any individual resource do not affect the market value of the resource involved. This should not be a legitimate concern with respect to geothermal production, however, because there is virtually no "market" for geothermal steam at the wellhead, as there is for oil and gas. In the preamble to the proposed regulations, MMS itself notes that even steam from the same reservoir may be valued differently. 53 Fed. Reg. 356.

The intent of a geothermal valuation calculation should not be to mirror a nonexistent market for geothermal steam, but rather to establish as accurately as possible what would have been the negotiated price had there been an arm's length transaction at the wellhead. In an arm's length negotiation, steamfield investment costs and operating expenses would be the central considerations of a would-be steam supplier. The proportion of profits approach takes this into consideration; the netback approach does not.

The proportion of profits calculation arrives at a steam value that would be a fair and reasonable arm's length price for the transfer of steam at the wellhead. It calculates a price at which a steam supplier could sell steam to a power producer and each would cover their operating cost and earn the same rate of return on their dollars invested. On the other hand, because of its artificial treatment of return and other capital-related costs, the netback approach often arrives at a steam value that could never have been the result of an arm's length transaction. Under the netback approach, the power producer would often receive an internal rate of return less than that earned on a passbook savings account.

Other concerns raised by the MMS regarding the proportion of profits approach focus on the risks and incentives resulting from the valuation methodology. MMS has expressed a fear that increased, inefficient spending on the resource somehow would be encouraged by the proportion of profits approach, and that the federal government would run the risk that increased resource costs would reduce royalty payments. This concern reflects a misunderstanding of the results produced by the proportion of profits approach.

In fact, the reverse is true. If the costs of developing, operating or maintaining the resource are higher than anticipated, the proportion of profits calculation will result

in a higher steam value and additional federal royalty.[8]
The approach provides a direct incentive to the lessee, encouraging efficient use of the resource.

On the power production side, risk to the federal government is reduced from that faced under the netback calculation. Under the netback approach, increased power production costs reduce the calculated steam value on a dollar-for-dollar basis. Under the proportion of profits method, increased power production costs will reduce net operating income, but only a share of that reduction (steam investment divided by total investment) will impact the steam value.

At the MMS hearing on March 28, a question was raised concerning the possibility that the steam transfer value could be negative under the proportion of profits approach. Theoretically, this would be possible if the project's net operating income were negative and if the steamfield's pro rata share of that negative amount were greater than steamfield expenses. Practically speaking, the project could not continue

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[8]/For example, under the proportion of profits approach, higher drilling costs will increase the steamfield investment as a proportion of total investment, thereby resulting in a larger share of the project's net operating income being allocated to the resource. Similarly, if resource operation and maintenance costs are higher than anticipated, the geothermal field expenses component of the formula will be increased. Net operating income will be slightly less, but the net effect will be a higher steam value and greater federal royalties.

to operate if net operating income were negative, because revenues would not cover the costs of keeping it in operation. If any debt were outstanding, the project would be in default. However, in order to ensure that this unlikely event would not occur, net operating income has been defined as never being less than zero. In that case, the effective floor steam transfer value would be the steamfield expenses (which will always be a positive amount) divided by the units of production. If MMS considers it necessary to adopt arbitrary floor and ceiling limits, the GRA recommends that essentially the same limits suggested in these comments for the netback approach be used. Under the proportion of profits method, these limits would require the steam value to be between 15% and 40% of total electric revenue.

Finally, to claim that resource costs are not a valid component of a geothermal valuation formula runs counter to the GSA and existing regulations governing geothermal valuation, which provide that costs of exploration and production shall be accounted for. 30 C.F.R. § 206.300(a)(5). The inclusion of resource costs should argue in favor of the proportion of profits approach by better conforming to existing regulations, providing an incentive for efficient use of the resource, and arriving at a more realistic steam transfer value.

<u>Essential Modifications to the Netback Approach</u>

For all of the reasons set forth in the preceding sections, the GRA strongly recommends that MMS abandon the netback approach in favor of the proportion of profits methodology. If, contrary to this recommendation, MMS adopts the netback method, several changes to the netback method are essential to meet legitimate policy and legal objectives for valuation.

First, in order to better reflect the actual costs of the substantial amounts of debt and equity invested in geothermal power production and transmission, deductions should be allowed for <u>both</u> depreciation and interest on a constant investment base. Assuming depreciation is 30-year straightline and return on investment is allowed at 1.5 times S&P's BBB bond rate, these deductions would still not fully cover the true cost of capital invested in the project but would more closely match these costs than the existing deduction options.

Second, the point of valuation should be at the wellhead and deductions should be allowed for gathering and injection systems and other field equipment. As noted previously, anything that is done to the resource after it is extracted enhances its value. Thus, all costs related to the delivery of the resource to the power plant should be deductible. Moreover, when a binary production process is involved, the costs associated with downhole pumps also should be deductible because they also add value. These pumps increase the geothermal fluid pressure to that required to maintain a reliable and efficient process in the power plant. Because these costs are definable and identifiable and are a part of the energy production process, rather than the resource extraction process, all field and gathering expenses (including downhole pumps for binary plants) should be deducted from the power plant expenses.

The GRA's position that all field and gathering costs should be deductible is supported by the GSA. In 16 U.S.C. § 1004(a), it is provided that royalties are to be calculated based on "the amount or value of steam, or any form of heat or energy derived from production under the lease and sold or utilized by the lessee or reasonably susceptible to sale or utilization by the lessee" (emphasis added). The key concept in the GSA is the value of the resource derived at the point of "production," i.e., the wellhead. No authority is provided to add the costs of delivery (or other field expenses) to the production value. In fact, this distinction is recognized in any standard sales contract where the resource seller is obligated to deliver the product (in this case geothermal steam) but will make allowance for the extra costs of delivery. The proposed netback approach violates this principle.

Third, as noted above, all arbitrary deduction limits must be dropped. There is no reason to impose limits on legitimate deductible costs. These limits have no rational relationship to the cost of converting the geothermal resource to electricity. In fact, it appears that they are relics from the Department's early efforts to value casinghead gasoline. *See* Operating Regulations to Govern the Production of Oil and Gas, 47 L.D. 552 (1920), 52 L.D. 1 (1926); Interpretation of Oil and Gas Regulations, 56 L.D. 462 (1937). The consequence of establishing these artificial limits is to inflate the value of the resource.

If MMS retains arbitrary limits, they should be substantially restructured. Because costs vary so much from project to project, an overall annual limit for all deductible costs should be used instead of separate caps on each cost category (*i.e.*, processing, transmission). This would provide lessees with sufficient flexibility to account for all legitimate deductions, regardless of a specific project's configuration, according to the costs actually incurred. For example, an overall limit that would not allow deductions in a particular year to exceed a specified portion of a project's annual gross proceeds would accomplish essentially the same result that MMS seeks without penalizing a lessee that has disproportionately large costs in any one of the deductible categories. The GRA recommends that a limit of 80-85% be used for this purpose.

Fourth, if MMS insists on establishing a "floor" for the resource transfer value through a limit on deductions, a "ceiling" on value also should be established. Failure to do so will result in the United States receiving a return that is not accurate or fair and that is much greater than the true relative worth of the resource. For example, under MMS' proposed methodology, the resource value that results during the later years of a California Standard Offer #4 contract generally would represent more than two-thirds of the project's gross proceeds.[9/] Given the level of investment and the extent of effort needed to convert geothermal resources to electricity, such a royalty value is not justified and is fundamentally at odds with a policy objective of encouraging investment in geothermal projects. Thus, if MMS intends to continue to adhere to the netback approach and impose arbitrary limits on deductions, a resource value cap of 40% of gross proceeds should be established. Even this limit is too high, but it would, at least, prevent the extreme results possible under the proposed netback methodology from coming about.

Fifth, a deduction should be allowed for reclamation costs associated with the power plant. The dismantling of power plants and the restoration of the leased land is an integral cost of operating a geothermal facility. A typical federal lease usually contains language such as:

[9/]The California Public Utilities Commission has established a series of standard power purchase agreements for use by utilities and independent power producers. Standard Offer #4 provides for fixed energy and capacity payments escalating at pre-determined rates.

> The Lessee shall reclaim all surface disturbances as required, remove or cover all debris or solid waste, and, so far as possible, repair the offsite and onsite damage caused by his activity or activities incidental thereto.

The costs associated with the reclamation responsibility are not speculative and can be amortized over the life of the power plant. Just as the cost of building the power plant is a necessary part of doing business, so is the cost of removing it. Even assuming the absence of the above quoted language in federal leases, the reclamation cost will be incurred in those situations where the power plant is off-lease or where the government does not own the surface lands. Thus, virtually all geothermal power plants are subject to these costs. Reclamation costs are recognized as deductible (less appropriate salvage credits) under federal oil and gas leases because of the lessee's obligations to abandon and restore leases, and a similar approach should be adopted for geothermal projects.

Sixth, the cost of purchased electricity to operate well pumps and other field equipment should be allowed as a processing cost deduction. This expense is not attributable to the extraction of the resource. Instead, it is an inherent cost of generating electricity. Identifiable and separate portions of pumping operations, and the related expense of electricity, are attributable to: 1) raising geothermal fluid from the well to the surface (i.e., producing the fluid); and

2) compressing the fluid to the high pressure that is required to maintain an efficient and reliable process in the power plant (i.e., manufacturing electricity). The costs of electricity for compression involved in the manufacturing step should be fully deductible.

Seventh, in determining the processing deduction, MMS should base its valuation on net output. In geothermal energy production, electricity produced during processing is used internally to assist in the generation process (especially in binary energy conversion technology). This "parasitic" power never becomes a part of the actual metered output. If this internally generated power were not used for this purpose, a comparable amount of electricity would have to be purchased, and the cost of the purchased electricity would be considered a deductible generating expense. Internally generated power should be given the same treatment.

Reducing processing deductions for parasitic power is based on MMS' belief that this power could have been sold had the power not been used internally, thus creating a "balancing" of revenue (not subject to royalty) and the processing deduction. This rationale is inappropriate because it compares "phantom revenues" with very real processing costs. In most cases, such revenue could never be realized because the developers already are selling the maximum electricity allowable under their utility contracts. These developers have oversized their generation facilities to accommodate the parasitic load. Other developers are constrained by their ability to transmit power to the utility. Simply put, the most appropriate approach is to compare real revenue with real processing costs.

Eighth, if the netback method is adopted, standards (rather than undefined MMS discretion) should be developed that would authorize the lessee to use a different valuation approach in certain circumstances. Under the GSA and the proposed regulations, alternative methods are available, but on terms that are nowhere defined and apparently are known only to MMS. Under the GRA's proposed approach, if a lessee's valuation proposal meets a predetermined criterion, MMS will be required to apply the proportion of profits method or some other formula recommended by the lessee. An appropriate standard for this purpose would be:

> The value calculated from netback must allow money invested in power production and transmission to earn an internal rate of return equal to 1.5 times S&P's BBB bond rate as calculated from the project's discounted cash flows.

If the netback calculation is accurately applying cost deductions, the allowed interest rate value should represent the internal rate of return on investment in power production and transmission as measured by discounted cash flows. If the netback value does not represent the expected rate, the valuation does not accurately reflect the relative worth of the resource. The GRA's proposed standard would determine if this is the case. If it is, the lessee should be allowed to use a different methodology that produces a more accurate result. Our proposed criterion would make it possible for the lessee to demonstrate to MMS, under an objective and documented test, that the netback approach fails to determine value accurately when applied to a particular project and that a different methodology, which produces more realistic results, should be used instead.

Another appropriate standard for achieving this purpose would be to utilize the proportion of profits method when the capital cost of the electrical generation portion of the plant exceeds 50% of the cost of the entire facility. This standard would avoid the subtractive error problem described on pages 25 - 26, supra, which becomes a factor when the capital cost is more than 50% of the entire cost. The use of capital investment as the basis for this standard is appropriate because it is the difference in capital costs as a fraction of total costs that distinguishes geothermal projects from oil and gas projects and causes the netback method to fail.

Finally, capacity payments should not be included in the measure of gross proceeds from which the netback deductions are subtracted. At the very least, the capacity payments made during periods of downtime, such as maintenance periods, should not be included in gross proceeds because these payments are completely independent of resource utilization; there is no power production and no resource consumption. The proportion of capacity payments attributable to these periods of downtime can be accounted for by measuring the downtime hours as a fraction of total hours for the period to arrive at an outage factor. This outage factor can then be multiplied by the total capacity payment to arrive at the amount of capacity payment that is not included in gross proceeds.

Similarly, capacity payments in general are not directly related to the value of the resource, and therefore should not be included in gross proceeds. Capacity payments are entirely a function of the characteristics of the generating plant (its size, operation schedule, and reliability), and not the characteristics of the resource. A very recent decision by the Court of Appeals for the Fifth Circuit interpreting royalty obligations pursuant to offshore oil and gas leases held that royalties were due only on the value of the resource actually used, and not on the abstract value peripherally associated with the resource. The Court stated:

> royalties are not due on "value" or even "market value" in the abstract, but only on the value of <u>production saved, removed, or sold</u> from the leased property. Likewise, the agency's regulations do not refer to "gross proceeds" in the abstract, but only to gross proceeds that accrue to the lessee from the disposition or sale of <u>produced substances</u>, that is, gas actually removed and delivered to the pipeline. Consequently, royalties are not owed unless and until actual production, the severance of minerals from the formation, occurs.

Diamond Shamrock Exploration Co. v. Hodel, 853 F.2d 1159, 1165 (5th Cir. 1988)(emphasis in original). This case supports the proposition that, in geothermal leases, royalties should be owed only on amounts stemming directly from the use of the resource. Because capacity payments stem from the characteristics of the generating plant and not the resource, these payments should not be included in the measure of gross proceeds from which royalties are calculated.

The Weighted Average of Gross Proceeds Approach

In certain circumstances, it may be appropriate to use this approach. Occasionally, geothermal lessees purchase meaningful quantities of like-quality resources from the same field through arm's length transactions. Lessees should not be required to pay more for geothermal resources from their own leases than they pay to obtain like-quality resources from another lease. To eliminate any problems that could arise accounting for differences between power plant efficiencies, this approach should incorporate the following efficiency factor:

$$\text{efficiency} = \frac{\text{pounds of steam input}}{\text{KWH of power output}}$$

This calculation could be made each year to allow for modifications to the involved plants. Adjusting the resource prices as a result of this plant efficiency calculation should make it possible, in those situations where additional geothermal resources are purchased by the lessee, to calculate royalty on the basis of an arm's length contract.

Although MMS may be correct that the weighted average approach seldom will be used, the GRA believes that MMS must establish in these regulations the time frame within which the "weighted average" will be determined. Defining this schedule in the regulations should avoid disputes between MMS and lessees in the future. The GRA recommends that the time frame be on an annual basis. Id. at 356.

The Alternative Fuels Approach

The GRA agrees with MMS that the alternative fuels approach seldom will be useful. This is because of widely varying fuel conversion costs and efficiencies, differences between fossil fuels (which have market based values) and geothermal resources, and substantially different economic risk factors among geothermal projects. The alternative fuels approach would require so many complex and subjective judgments to be made in the course of calculating comparative values (e.g., difference in heat rates in converting fuel to electricity, capital costs of power plants using alternative fuels, different operating and maintenance costs, transmission requirements from remote locations, social and environmental benefits, etc.) that it is not a practical option in most cases. If it is applicable in a given situation, however, the lessee should be able to elect to use it.

Summary

In summary, the GRA strongly recommends that the proportion of profits approach be adopted as the principal methodology to be used for valuing geothermal resources in non-arm's length transactions. It is the only methodology under consideration that is conceptually capable of accounting for the unique characteristics of each geothermal project and establishing a realistic resource value. The proposed netback approach, on the other hand, is fundamentally mismatched with geothermal production and utilization practices. As a result, the netback approach grants to the federal government a royalty return which is higher than that to which it is entitled and creates strong disincentives for the development of federal geothermal resources. At the very least, if the netback methodology is adopted, substantial revisions must be made to eliminate its most serious deficiencies.

SPECIFIC ISSUES

In response to specific questions raised by MMS in the preamble to the proposed regulation, the GRA offers the following comments.[10/]

[10/] All page citations are to 54 Fed. Reg. (Jan. 5, 1989).

1. *Question*: Should use of a "majority price" for valuing geothermal resources be rejected because of the complexity of the factors involved? (p. 356, col. 2).

   Response: A majority price may be useful in certain limited situations, and the lessee should be allowed to demonstrate to MMS that such an approach is appropriate. If it is used, correcting factors for resource quality and contract rent must be taken into account.

2. *Question*: Should the netback procedure be modified or rejected for purposes of valuing geothermal resources? (p. 356, col. 3).

   Response: This question is addressed in the preceding section. The GRA favors rejecting the netback approach. If it is to be modified, the GRA's suggested changes are discussed on pp. 37 - 46, *supra*.

3. *Question*: Should the 1.5 x the S&P BBB Industrial Bond Rate be used as the rate of return for determining transmission and generating deductions? (p. 356, col. 3).

Response: This question is addressed in the preceding section. The GRA opposes the use of the netback approach, which incorporates this rate of return deduction. If netback is retained, the GRA believes that the rate of return should reflect real costs actually encountered in at specific projects. The 1.5 times S&P's BBB rate is preferable, however, to MMS' previous use of the prime rate.

4. Question: Is the proportion of profits method appropriate for valuing geothermal resources? (p. 357, col. 1).

Response: This question is addressed in the preceding section. The GRA believes that the proportion of profits approach is the best available method for determining geothermal values.

5. Question: Is the alternative fuels method appropriate for valuing geothermal resources? (p. 357, col. 1).

Response: This question is addressed in the preceding section. The GRA does not consider this to be a practical alternative in most cases, but it should be available if circumstances justify its use.

6. _Question_: Some geothermal lessees have argued that a capacity payment should not be included as a part of the value of electricity because such a payment reflects the power plant's ability to deliver electricity and depends on the characteristics of the plant itself and not on the resource. Thus, all or some portion of capacity payments may still be required even though, in certain cases such as forced outages, there would be no delivery of electricity. On the premise that a capacity payment may trigger a royalty obligation without there being any geothermal production, should capacity payments be included as a part of the value of electricity? In addition, to what extent is geothermal production "shut in" when no electricity is delivered but capacity payments are still received? (p. 357, cols. 2 and 3).

Response: The first part of this query is addressed in the preceding section. _See_, pp. 44 - 46, _supra_. Compensation for capacity is not directly related to the value of the resource and therefore should _not_ be included in gross proceeds.

In response to the second part of this query, the extent to which geothermal production is "shut in" when no electricity is delivered but capacity payments are still received varies from one project to another. The duration of the outage plays a significant role in the decision to close the throttle valves or to close the waste valves. The environmental considerations of venting to the atmosphere (when permitted) or injecting must be weighed against the impact of thermal cycle shock and in some cases freeze damage, either of which could cause environmental or resource damage.

7. Question: What valuation method should be used when the lessee has an arm's length generating agreement with a third party but still receives revenue from the sale of electricity? Such a situation would arise, for example, where a lessee has an electricity sales contract but a third party generates the electricity. (p. 357, col. 3).

Response: Even where the lessee receives revenue from the sale of electricity, there nonetheless will be an arm's length contract with the owner of the power plant that can be used for valuation purposes. If such a contract does not exist, the proportion of profits approach should be used.

8. Question: Should there be a one-time election to use the return on capital investment method for those facilities placed into service before March 1, 1988? (p. 358, col. 1).

Response: Yes.

9. Question: Should depreciation be based on a fixed time period commensurate with the first sales agreement or some other time period? If some other time period is appropriate, what conditions and considerations should be taken into account to either extend or decrease the depreciation period? (p. 358, col. 1).

Response: Adjustment to the depreciation time period should be allowed in the following circumstances:

a. Actual reservoir performance is not able to support the optimal performance of the power plant as originally projected; or

b. The power plant is technologically obsolete within a very short period of time and upgrading requires substantial infusions of new capital investment. Under such circumstances, and with the approval of MMS, the original investment should be allowed to be depreciated within a shorter period of time.

10. <u>Question</u>: MMS proposes that a power plant and transmission line be depreciated only once. Should allowance be made for recapitalization and redepreciating a power plant or transmission line with a change in ownership? (p. 358, col. 2).

<u>Response</u>: This should be allowed. Failure to do so will serve as a disincentive for new investment in geothermal projects by discouraging third parties from paying a premium over the original cost of the plant. The higher premium may be justified because new construction will usually be accomplished at a higher cost. The depreciation amount should be the purchase price to the new owner, and the depreciation period should be the remaining life of the power purchase contract.

11. <u>Questions on least expensive alternative fuels</u>:

a. MMS proposes to use the least expensive, reasonable alternative fuel approach to valuing direct utilization geothermal resources. Does this method accurately reflect the value of geothermal resources used in direct utilization processes? If not, what alternative methods could be used? Should efficiency factors be applied in valuing direct utilization resources? (p. 358, col. 2).

b. The alternative fuel approach as proposed would rely on a qualification that the fuel chosen must be one that would normally be used in a given direct utilization process at the location of use. Is this qualification warranted? If so, what criteria should be used to determine the most reasonable alternative fuel? (p. 358, col. 3).

c. What criteria should be used to value the cost of the alternative fuel? (p. 359, col. 1).

d. Should any processing allowances be granted for geothermal resources in direct utilization processes? (p. 359, col. 3 - p. 360, col. 1).

Response: The MMS proposal to use the least expensive reasonable alternative fuel approach for valuing direct utilization of geothermal resources reflects the approach that would be taken by an operator free to choose between geothermal use or other alternative technologies. The determination of the cost of a particular technology involves the sum of the costs of capital improvement and regular operating expenses.

An operator allowed to choose a technology will not simultaneously choose relatively high capital cost and high annual expenses. The use of geothermal resource typically requires relatively high capital investment which is justified on the assumption of low feedstock value and therefore lower operating expense. The substitution of a more valuable feedstock in order to estimate the resource value will increase the cost to the operator beyond what he would prudently pay unless an adjustment is made to reflect his investment having been larger than what would have been required for the alternative fuel.

An appropriate adjustment would be to subtract from the calculated cost of the required alternative fuel an amount equal to the allowed return on capital cost of a facility designed to burn the alternative fuel plus the actual capital cost of the development of the geothermal resource. The cost of the alternative fuel would be equal to the total quantity required to fully substitute for the geothermal energy utilized multiplied by the price for purchase for the plant site. The amount of fuel required would be based on average efficiencies for similar systems. Take for example a space heating system that obtains 1,000,000 BTUs per hour from a well 1,000 yards away and could utilize fuel oil as an alternate source of energy:

For example:

Fuel Oil	120,000 BTUs per gallon
Hot water generator	82% efficiency on fuel oil
Hot water generator	Capital cost of $30,000
Geothermal supply system	Capital cost of $50,000 for well
Geothermal supply system	Capital cost of $100,000 for pipeline
Geothermal supply system (electricity)	Pumping cost of $20,000 per year

Calculations:

Required fuel in gallons	=1,000,000/120,000/0.82 =10.2 gallons per hour =89,352 gallons per year
Cost of required fuel	=$67,014/yr. at $0.75/gal
Reduced elect. consumption	=$20,000 per year
Capital cost adjustment factor	=0.15 (150,000-30,000) =$18,000
Annual value of geothermal used	=$67,014 - $18,000-$20,000 =$29,014
Royalty at 10%	=$2,901

12. Question: For purposes of valuing geothermal byproducts, MMS proposes to rely on the value of conventional marketable commodities. This is in contrast to the approach used for fluid geothermal resources, which cannot be compared with similar

resources produced at different locations. Is this an appropriate approach for byproduct valuation? Are there more accurate alternative methods for valuing byproducts? (p. 359, col. 2).

Response: It is inappropriate to assume that byproducts are always in marketable condition upon extraction. In some cases, extraordinary costs will be entailed, and the regulations should provide an allowance when it is foreseeable that out-of-the-ordinary expenses will be incurred in placing the byproduct in marketable condition. If a royalty value is assigned to byproducts, deductions should be allowed when the byproducts have negative values, *i.e.*, when they have to be disposed of in accordance with specified environmental standards.

13. Question: What is the appropriate approach to determining a byproduct transportation allowance? (p. 359, col. 2).

Response: At the beginning of a byproducts extraction process transportation costs may be higher than the value of recoverable minerals. Recovery processes, as recognized by the MMS, are at an early stage of development. To facilitate extraction, MMS should be flexible and should not use an approach that imposes artificial caps on value. Consistent with the position the GRA has taken on steam transfer values, MMS' methodology must be able to account for project-specific costs. Allowable transportation deductions, for example, should not exclude real estate purchases. Most geothermal facilities are located in out-of-the-way places, and lessees have had to acquire rights-of-way and construct roads to their leases. A proportionate share of the cost of acquisition and maintenance of easements, therefore, should be deductible as transportation costs. If MMS intends to exclude any expenses from the deductible category, it should do so only based upon strong justification communicated in advance to the lessee. In this case, the burden should be on MMS to demonstrate why the specific deduction should not be allowed.

14. Question: MMS currently considers all pipelines connecting wellheads and power plants or other direct utilization facilities as part of a field gathering system. Thus, all costs of gathering are regarded as production related costs that are not shared by the United States. However, MMS recognizes that long distance transportation is sometimes involved. Should

MMS grant transportation allowances for the lessee's cost of delivering the resources to a point of utilization off the lease? (p. 359, col. 3).

Response: The gathering system provides the means to transport the resource from the production facilities to the point of conversion. As discussed previously, the GRA believes that all gathering costs should be deductible. *See* p. 44, *supra*. For resources that are low volume or distant from the point of utilization, the cost of gathering will be higher than otherwise. Without gathering and transport, the resource could not be used economically. Providing an allowance for these costs therefore will more accurately value the resource. These costs are analogous to those for processing to put a resource into a condition beyond that which is considered marketable.

15. Question: **Should costs be allowed for hydrogen sulfide abatement and other facilities that mitigate environmental hazards as part of the determination for generating deductions under the netback procedure? (p. 359, col. 3).**

Response: The costs of abatement and reinjection facilities and other environmental costs should be included. Abatement and disposal processes are either an integral part of the generating facilities or are located immediately "down stream" from where electricity is produced. Consequently, these costs should be included as a part of the generating deduction. This is appropriate because steam that has a higher level of contaminants is more expensive to use and of less value to the power generator. By way of analogy, high sulfur crude oil can be "purchased" at a lower price because it is more expensive to process.

ADDITIONAL RECOMMENDATIONS

This section sets forth the GRA's recommendations for changes to the proposed regulations that are not reflected in the preceding discussion.

Definition of "Gross Proceeds"

The proposed definition of "gross proceeds" in 30 C.F.R. § 206.351 is too broad. Payments to the lessee for services such as wheeling, effluent injection, hydrogen sulfide abatement and other operating expenses have no relationship to the geothermal resource and should not be included in the definition. It should be clarified that tax refunds are not to be included.[11/] Including tax refunds in this definition means that, even though a royalty already has been paid, the United States is entitled to additional payments on the amount that the lessee was overtaxed. Such a result is unfair and has nothing to do with defining resource value.

Audits

Section 206.352(b)(1)(i) proposes that the value the lessee reports for royalty purposes "is subject to monitoring, review, and audit." Although the proposal to require audits is acceptable, the terms "monitoring" and "review" are not defined and present the possibility of unnecessary involvement by MMS in the lessee's operations. Lessees should be provided with the opportunity to arrange for an independent third party audit, for example, rather than an audit to be performed only by MMS. The requirements for "monitoring" and "review" serve no purpose that cannot be fulfilled by an audit and should be deleted unless a need for them can be demonstrated. If the review and monitoring requirements are retained, they should be defined in a way that will minimize interference with lessee operations. A similar concern arises under § 206.353(e)(1).

11/The GRA notes that gross proceeds also includes, but is not limited to, reimbursements by purchasers for production taxes and other taxes.

Data Retention and Availability

Section 206.352(d)(2) requires the lessee to make its contracts for sale, generation, and transmission available to, among others, state representatives and "authorized persons." There is no reason this disclosure requirement should be extended to state representatives, and we recommend that this provision be deleted. In addition, "authorized persons" should be defined to mean an individual acting on behalf of MMS under contract, cooperative agreement, or other authorization.

Similar concerns on both of these points arise under § 206.353(e)(2), and the same comments apply.

Depreciation

Sections 206.353(b)(2)(iv)(A) and 206.354(b)(2)(iv)(A) would require use of straight-line depreciation. The GRA recommends that the lessee be allowed to use either straight-line or accelerated depreciation methods. Accelerated depreciation most closely tracks the physical and technological deterioration of geothermal facilities and therefore would be more accurate.

Refunds

Section 206.352(e) provides for a credit to be given to the lessee if MMS has been overpaid, but does not require interest to be paid. MMS requires interest payments by the lessee when additional royalties are due because of miscalculations or other problems. Id. An equitable approach would provide for similar compensation to the lessee when the United States has had the benefit of holding excessive payments made by the lessee to satisfy MMS requirements.

Insurance Cost Deduction

The allowed deductions should include insurance costs. The operation of geothermal power plants is a relatively high risk undertaking and insurance costs are an essential cost of doing business that in no way reflect the value of the resource. These costs are expressly mentioned in the Valuation Guidelines but are not discussed in the corresponding provisions of the proposed regulations. See Valuation Guidelines, at 6, 10.

Construction Period Interest on Debt and Return on Equity Invested Prior to Operations

The rulemaking should clarify that construction interest on debt and return on equity (at the approved rate) invested prior to commercial operation are allowable capital costs because both reflect valid, necessary pre-operating costs.

Codification of Valuation Determination Procedures

The GRA requests that MMS codify in the final regulations the procedures that will be used to determine the value of geothermal resources for each lessee's proposal. The procedure that is used presently is generally acceptable, but it should be formalized so that there will be no confusion concerning the respective responsibilities of the lessee and MMS. The final regulations should set forth the following procedure:

1. The lessee provides to the RVSD a proposed royalty valuation based on the proportion of profits approach or another acceptable methodology. Pending the completion of the valuation determination, the lessee is permitted to pay royalties according to the proposed approach.

2. Within 45 days, the RVSD provides a detailed draft decision on the lessee's proposal, complete with substantive analysis of the proposed methodology.

3. A follow-up meeting is held to discuss the draft decision, if requested by the lessee within 20 days of the receipt of the draft decision.

4. Within 60 days of the meeting, or the receipt by the lessee of the draft decision if no meeting is requested, the lessee submits a final valuation proposal.

5. The RVSD's final decision is issued within 45 days of the receipt of the final proposal.

6. Within 30 days of receipt of the final RVSD decision, the lessee may file a notice of appeal with the Director of MMS. If an appeal notice is not filed, the RVSD decision shall become final. If an appeal notice is filed, the lessee shall have 60 days within which to file its appeal and request a hearing before the Director.

7. The final decision of the Director may be appealed to the Interior Board of Land Appeals.

Codifying these procedures will facilitate the processing of the valuation proposals. The development of time requirements will assist lessees in planning their submissions to MMS and in making business judgments that are based upon the timing and amount of royalty payments.

CONCLUSION

For the foregoing reasons, the GRA and its member companies request that MMS adopt the proportion of profits approach and make the other changes discussed in these comments. We greatly appreciate the careful attention that MMS is giving to the question of geothermal royalty valuation, and we would be pleased to provide you with any additional information that may be useful.

Submitted on behalf of the
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APPENDIX

APPENDIX

Confidential Information
Included

APPENDIX

COMPARISON OF PROPOSED MINERALS MANAGEMENT SERVICE NET BACK CALCULATION VS. ACTUAL NEGOTIATED PRICE CONDITIONS - FEDERAL ROYALTY VALUATION

OVERVIEW

A very recent opportunity emerged for the negotiation of steam price for sales to an electric generating station to be located on a federal leasehold in northern California. Steam price was negotiated on an arm's length basis. The intended power plant owner has proposed an electric sales agreement with a California utility and has provided the cost basis for the proposed plant, which is included in this analysis.

This analysis uses the proposed federal royalty valuation methodology (netback) to arrive at a computed steam price, and then compares that value to actual steam price value governed by market conditions as reflected in arm's length negotiation. The analysis further compares the pretax rate of return of the steamfield and the power plant at the steam price computed by the proposed method.

The result of this comparison clearly illustrates that the rate of return so disproportionately favors the steamfield economics that the plant owner (purchaser of steam valued by the netback price calculation) has a negative rate of return.

BASIS OF COST

This is based on a liquid dominated geothermal resource, and steam sales at the wellhead. The power plant owner provides the steamfield gathering system and injection system exclusive of injection wells. The steamfield owner provides roads, pads, and producing and injection wells. A portion of the steam price is allocated to retire capital and expense related to injection wells. Some of the key factors reflected in this comparison are:

- 40 Mw net power plant
- On line 1990
- Capacity factor 85%
- Power plant capital cost $62 MM, inclusive of gathering and injection systems
- Transmission facilities cost $7 MM
- Operating expense, inclusive of ad valorem tax, per netback tables
- Steamfield capital cost $20.3 MM inclusive of production wells, injection wells, roads and pads

RESULTS

Year	Steam Price Mills/Kwhr Net Back	Steam Price Mills/Kwhr Negotiated
1990	33.6	20.3
1991	35.5	21.0
1992	37.5	21.7
1993	39.5	22.5
1994	41.5	23.3
1995	43.6	24.1
1996	45.8	24.9
1997	47.3	25.8
1998	48.8	26.7
1999	50.5	27.7

ATTACHMENTS:

Exhibit A - Net Present Values and IRR of Steamfield, Power Plant, Combined Field and Plant Based on Netback Calculations

Exhibit B - Netback Calculation Tables