



Monitoring
Analytics

MMU Cost-Based Offer Technical Guide

The Independent Market Monitor for PJM

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1 Introduction

The purpose of this guide is to promote correct calculations of cost-based offers by complementing the PJM Cost Development Guidelines (Manual 15). This guide provides the mathematical equations and supporting templates for the calculation of energy offers for thermoelectric generators.

1.1 Market Monitor Position

Competitive market outcomes in the PJM markets in the presence of market power require market power mitigation of supply offers to a competitive level. Schedule 2 of the PJM Operating Agreement requires incremental cost-based offer caps for each unit, submitted by the market seller. The PJM Tariff further calls for the MMU to review all offers to determine whether the level of offer or cost inputs raises market power concerns.

This MMU Cost-Based Offer Technical Guide document provides guidelines for the development of cost-based offers. Although maintenance costs are not short run marginal costs, this guide also includes guidelines for the inclusion of maintenance costs as short run marginal costs in offers, as required by FERC.¹

There are three types of costs identified by the MMU:

- 1) Short run marginal costs. Cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts.
- 2) Avoidable costs, annual costs that would be avoided if energy were not produced over an annual period
- 3) Long term fixed costs, costs associated with an investment in a facility including the return on and of capital.

Short run marginal costs are the only costs relevant to the energy market. The competitive offer level in the energy market is the short run marginal cost of production. The competitive offer level in the ancillary service markets is the short run marginal cost of providing the relevant service, which primarily consists of opportunity costs in the energy market. The competitive offer level in the capacity market is equal to avoidable costs, net of benefits from participating in the energy and ancillary services markets.

¹ 167 FERC ¶ 61,030.

The short run marginal cost of energy is the incremental cost of producing one more MWh of energy. It includes the cost of fuel, emissions abatement, taxes or subsidies that vary directly and in the short run with energy output, and consumables for operations that vary directly and in the short run with energy output. Short run marginal costs do not include long term variable or avoidable costs incurred to maintain the efficiency or availability of the unit, its environmental compliance, or its fuel supply. Avoidable costs belong in offers in the capacity market.

Costs delineated in energy and maintenance contracts that do not reflect the physical costs of production are not part of a competitive market offer. The use of contract rates as the basis for cost-based offers creates opportunities for offers to reflect market power and for double counting of costs across markets.

Each market seller that is required to submit cost-based offers for resources should reflect the short run marginal costs expected to be incurred for the applicable operating hour in the cost-based offer. The market seller shall be responsible for the development and accuracy of all information to support the calculation of the resource's cost-based offer and shall provide such information to PJM and the MMU, either directly or indirectly through an agent or other entity, upon request or as required by applicable PJM Market Rules.

1.2 Energy Market Offers

Schedule 2 of the PJM Operating Agreement defines the components of cost-based offers. Units in PJM are allowed to submit cost-based offers in three parts. Units are allowed to submit an incremental energy cost curve, a no load cost and a start cost. The equations for the calculation of energy market offers are defined in Section 4.

All three parts of energy offers are used by PJM in the unit commitment determination. The incremental energy cost curve is used by PJM in the unit dispatch determination and used to set the LMP and ancillary services opportunity costs. The no load and start cost, in combination with the incremental energy cost curve are used by PJM in the unit commitment determination.

1.3 Fuel Cost Policies

Fuel Cost Policies describe the methods used by owners of units to develop fuel costs and the costs of other inputs used in the development of cost-based offers.

All units are required to have a fuel cost policy approved by PJM. It is the role of the MMU to review fuel cost policies to ensure that they do not raise market power concerns and to ensure that cost-based offers are and will be calculated correctly.

Fuel Cost Policies must specify the mathematical method to calculate cost-based offers. Fuel Cost Policies must include a detailed numerical example of the method and calculations used to determine the cost-based offer for each unit type covered.

The MMU has developed templates for Fuel Cost Policies by fuel type and templates for numerical examples.²

1.3.1 MMU Fuel Cost Policy Review Process

In accordance with its responsibilities in Attachment M and Attachment M – Appendix of the PJM Tariff, the MMU shall review Fuel Cost Policies, including any updates, to determine whether the cost components, cost levels, and cost calculation methods raise market power or manipulation concerns, are consistent with competitive market behavior, consistent with the PJM Market Rules, correctly apply these Cost Development Guidelines, and are otherwise reasonable.

All fuel cost policies must be algorithmic, verifiable and systematic and accurately reflect the short run marginal cost of fuel in order to pass the MMU evaluation.

- Algorithmic: Must use a set of defined, logical steps. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform (ICE).
- Verifiable: Must provide a fuel price that can be calculated by the MMU after the fact with the same data available to the market seller at the time the decision was made, and complete documentation of that data.
- Systematic: Document a standardized method or methods for calculating fuel costs including objective triggers for each method.

All costs must be short run marginal costs.

1.4 Data Reporting

In order for the MMU to review all cost-based offers for market power concerns in an accurate and timely manner, each PJM member shall report all information required to replicate cost-based offers in the Member Information Reporting Application (MIRA) prior to the submittal of the cost-based offer. This includes having a Fuel Cost Policy on file in MIRA to support the development of and explain the use of the data supplied through MIRA.

² The fuel cost policy templates and numerical example templates developed by the MMU can be found on the MMU website <<http://www.monitoringanalytics.com/tools/tools.shtml>>.

All MIRA data are subject to review by the MMU to ensure the reasonableness and sufficiency of the data for replicating cost-based offers. The MMU may request new information for submission via MIRA and/or further explanation of such data. Generation owners shall respond to such requests in a timely manner.³

The MIRA User Guide provides details regarding the specific reporting items, units of measure, and website functionality.⁴

2 Defining Costs

The specification of costs that do not raise market power concerns requires a clear and transparent definition of the components, and development of the components, of the short run marginal cost of production for the unit. Section 2 provides guidelines for the appropriate definition of the costs includable in a competitive offer. The categories of short run marginal costs are:

- Fuel costs: Include commodity costs, delivery costs (such as variable transportation costs), fuel supplier fees and taxes.
- Operating costs: Include water purchases, water or waste water treatment control reagents, emission control reagents, equipment lubricants, electricity byproducts disposal, electricity consumed during starts.
- Emission allowance costs: Include costs of emission allowances and any regulatory fees that vary directly with energy output.
- Energy market opportunity costs.⁵

2.1 Fuel Costs

Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel. Fuel handling costs and fuel additive costs are included in Variable Operating Costs, see Section 2.2.

2.1.1 Inventory and Replacement Cost Methods

Generation owners calculate fuel costs using either an inventory or replacement cost method.

³ For further information, see OATT Attachment M § VI.E-1 and V.B.

⁴ The MIRA User Guide can be found on the MMU website <<http://www.monitoringanalytics.com/tools/tools.shtml>>.

⁵ See PJM Operating Agreement Schedule 2 (a).

2.1.1.1 Inventory Cost Method

Inventory valuation methods include last in first out (LIFO), first in first out (FIFO), and weighted average accounting of fuel deliveries for a specified time period. The marginal cost of each delivery in the inventory is based on historic purchase invoices or physical deliveries under documented contract terms. Documentation of inventory cost includes all cost components required for delivery to the unit.

2.1.1.2 Replacement Cost Method

Replacement cost is the least cost method for replacing any fuel consumed. Spot market prices, independent third party quotes, or contracts for future delivery are the basis for replacement cost. Spot market prices rely on publicly available internet trading platforms posting executed trades and bid/offers. Independent third party quote documentation includes recorded conversations or written communications (including electronic communication). Replacement cost includes the short run marginal costs of delivery to the unit.

2.1.2 Commodity and Transportation Costs

The commodity cost of fuel reflects the value of the fuel itself. It does not include the cost of transportation, transaction fees, taxes, or other fuel related costs.

Transportation cost is the cost of fuel delivery from the source point to the unit or the spot market basis differential between the publicly available index point and the unit. Transportation costs depend upon pipeline or Local Distribution Company for natural gas, mine sources and mode of transport for coal, and mode of transport for oil. Contracts, tariffs, or invoices serve as documentation of transportation costs.

2.1.3 Dual Fuel Units

Dual fuel units require an hourly determination of costs for each available fuel type. The short run marginal cost of the unit is the lowest short run marginal cost determined across all available fuel types.

2.2 Operating Costs

Operating costs are the short run marginal cost for purchased materials consumed or converted to produce energy, other than fuel. Operating costs do not include the cost of materials required to make the unit available.

2.2.1 MMU Operating Costs Review

Operating costs are the costs of consumables needed to produce energy, and the costs associated with the disposal of byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. Examples may include:

- Water
- Chemicals
- Lube oil
- Fuel handling

Operating costs are similar to fuel costs:

- They have a consistent rate of consumption, analogous to heat rates. For example, water in gallons per MWh.
- They have a cost per unit, analogous to fuel costs. For example, \$0.05 per gallon of water.
- More efficient units (units with lower heat rates) tend to have lower operating costs per MWh.
- New units tend to have lower operating costs per MWh.

Lack of proper accounting and documentation can lead to difficulty in distinguishing among operating costs, fixed costs, and maintenance costs. Clear and accurate cost accounting is required, including tracking to invoices.

Generators should document the amount of consumables used and their per unit cost in order to validate whether the total operating cost is consistent with the total quantity used and that the total quantity used is consistent with the unit characteristics.

Examples of actual operating costs that are avoidable costs and are not includable in energy market cost-based offers under the FERC definition:

- Water consumption not used for power production and not used for emission control.
- Chemicals used to meet a periodic (e.g. time based) environmental requirement.
- Replacement of lube oil on a periodic schedule.

2.3 Maintenance Adders

The PJM rules allow including maintenance costs in cost-based offers. Competitive offers are equal to short run marginal costs. Maintenance costs are not short run marginal costs. The Market Monitor does not agree with PJM and FERC that

maintenance costs should be includable in cost-based energy offers. Maintenance costs are avoidable costs that should be includable in ACR. On April 15, 2019, FERC approved the inclusion of variable maintenance costs directly related to electricity production.^{6 7}

2.3.1 MMU Maintenance Adders Review

Generators must provide clear and unambiguous supporting documentation for all costs. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts for all costs over the entire period from which costs are derived.

In calculating maintenance adders, generators should only include costs that are the direct result of electric production. For example, activities that must be performed after a defined number of run hours, starts or combination of run hours and starts. Activities that must be performed after a defined number of weeks, months, or years are not the direct result of electric production.

Generators must provide the operational history for the entire period of the calculation. For example, if the maintenance cycle was 10,000 run hours, the unit should calculate maintenance costs using at least 10,000 run hours of operational history.

Costs are not includable in the calculation of current maintenance costs for reasons that include:

- Lack of supporting documentation.
- Irregular maintenance (e.g. forced outages, weather related events, improper unit operation).
- Costs that are capital expenditures to extend the unit's life or improve the unit's performance.

2.4 Emissions Allowance Costs

Many units require SO₂, CO₂, NO_x or other emission allowances to operate based on federal and state environmental regulations. Emission allowance costs may apply annually or seasonally. The cost of using emission allowances may be reflected as either a replacement or an inventory cost. Replacement emissions allowance costs reflect a publicly available spot market price. Inventory emissions allowance costs reflect the average cost incurred to purchase the allowances currently held for the unit.

⁶ 167 FERC ¶ 61,030.

⁷ See Operating Agreement, Schedule 2, Section 4.

The impact of the allowance cost for each type of emission on the cost of producing energy depends on the unit's rate of emission. Emission rates may vary with the type of fuel burned by the unit, with the level of heat input to the unit, and with starts.

Equation 1: Emission Allowance Costs.

$$EC(f) = AP \times \frac{R(f)}{2,000 \text{ lb/ton}}$$

where

$EC(f)$ is the emission allowance cost as a function of fuel input in \$/MMBtu.

AP is the allowance price in dollars per unit of emissions, usually in \$/ton.

$R(f)$ is the rate of emissions as a function of fuel input, generally in lb/MMBtu.

The emission rate, $R(f)$, may differ for starts.

2.5 Station Service Power Costs

The cost of power consumed at the plant for starting the unit is the cost of the energy times the amount of power consumed. The station service rate (\$/MWh) is determined by PJM per Manual 15.

3 Heat Input

3.1 Heat Input Curves

Heat input curves, also called input/output curves, represent the amount of fuel used to produce energy. Heat input curves are developed based on net energy production. Heat input curves can be developed using historical data, performance test data or Original Equipment Manufacturer (OEM) documentation.

Observed fuel heat input and electric output data during normal operation or a performance test provide a direct measure of the heat input curve. A linear regression of the heat input on the energy output can provide an estimated polynomial curve. In the typical case, the heat input curve is a second order polynomial that applies to the entire operating output range of the unit.

Equation 2: Second Order Polynomial Heat Input Curve.

$$H(MW) = X_2 \times MW^2 + X_1 \times MW + X_0$$

where:

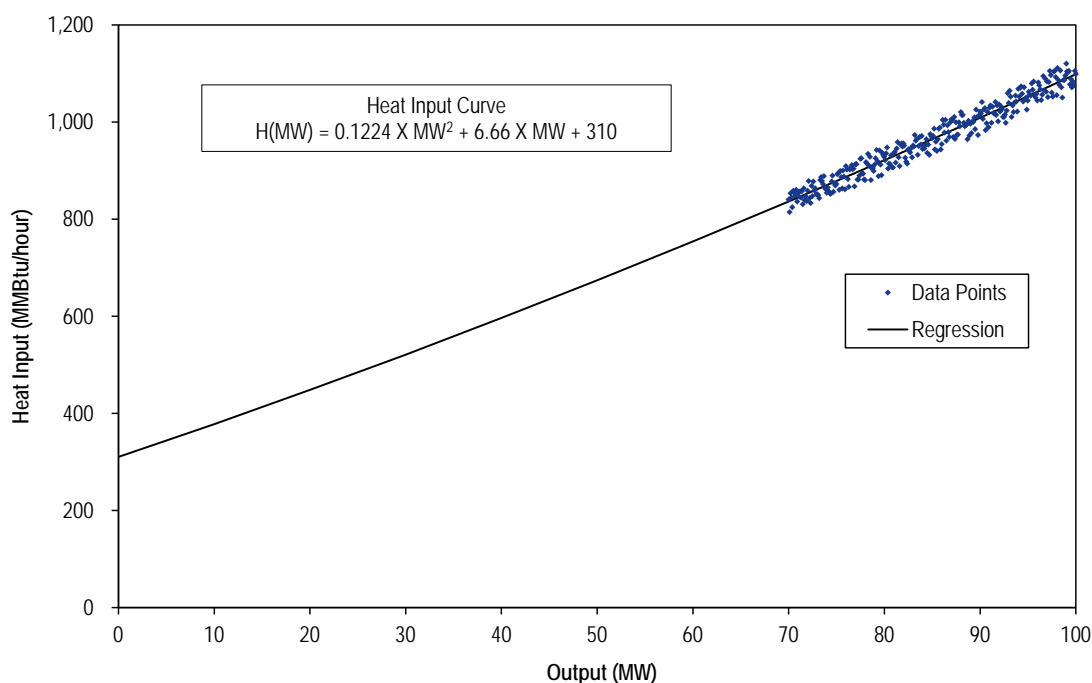
$H(MW)$ is the fuel input in MMBtu per hour required to generate power in MW over a defined period.

MW is the output level of the unit.

X_2 , X_1 and X_0 are the polynomial coefficients to be estimated through a linear regression.

Figure 1 shows a sample heat input curve example for a 100 MW unit.

Figure 1: Heat Input Curve Example.



Appendix A contains the data points used to develop the heat input curve of Figure 1.

Heat input curves are used to develop incremental heat rates and no load heat. The incremental heat rate curve is the derivative of the heat input curve. The no load heat is the intercept of the heat input curve.

3.1.1 Incremental Heat Rate

The incremental heat rate curve is the change in heat input required to produce the next MW of output. It varies with the output level. In mathematical terms, it is the first derivative of the heat input function. In PJM, units can have offers based on incremental heat rates using a sloped function or a stepped function.

3.1.1.1 Sloped Incremental Heat Rate Curve

The sloped function is the continuous first derivative of the heat input function. Units offered using a sloped function must select the “use offer slope” option in Markets Gateway. Generators offered using a sloped function must start their incremental offer curve with a zero MW segment. The incremental heat rate at zero MW is the y axis intercept of the incremental heat rate function (the incremental heat rate when MW = 0.).

Equation 3: Sloped incremental heat rate function for a second order polynomial heat input curve.

$$H'(MW) = 2 \times X_2 \times MW + X_1$$

where:

$H'(MW)$ is the incremental heat rate as a function of MW output level in MMBtu/MWh.

MW is the output level of the unit.

X_2 and X_1 are the coefficients of the heat input curve.

Appendix A contains a numerical example of a cost-based offer calculated using a sloped incremental heat rate curve.

3.1.1.2 Stepped Incremental Heat Rate Curve

The stepped incremental heat rate curve is derived from heat input curves, and direct measurements at different discrete output levels. Units offered using a stepped function must not select the “use offer slope” option in Markets Gateway. Generators offered using a stepped function should submit a nonzero first MW segment.

Equation 4: Stepped incremental heat rate function.

$$H'(MW_i) = \frac{H(MW_i) - H(MW_{i-1})}{MW_i - MW_{i-1}}$$

where:

$H'(MW)$ is the incremental heat rate as a function of MW output level in MMBtu/MWh.

MW_i and MW_{i-1} are two output segment endpoints.

$H(MW)$ is the heat input as a function of MW output level in MMBtu.

Appendix A contains a numerical example of a cost-based offer calculated using a stepped incremental heat rate curve.

3.1.1.3 Heat Input Curve Discontinuities

More complex heat input curves may include discontinuities in the curve and segments of the curve may have different functional forms. The most common discontinuities are due to power augmentation methods including duct firing in combined cycles.

Appendix A contains an example of a heat input curve with discontinuities.

3.1.2 No Load Heat

The no load heat is the estimated amount of fuel needed to theoretically operate a unit at zero MW. The no load heat is the constant term (X_0) of the heat input curve.

In order to correctly represent the total heat input using no load heat and incremental heat rates, all units must be offered with a zero MW segment. For units offered using a stepped curve, Markets Gateway automatically starts the curve at zero MW. For units offered using sloped curve, the market seller must include a zero MW segment endpoint.

3.1.3 Start Heat Input

The start heat is the estimated amount of fuel needed to start a unit, from shutdown mode to breaker close, plus the assumed amount of fuel needed to shut down a unit after breaker open at the end of operation.

The start heat of units with multiple generators (e.g. combined cycles) is the amount of fuel needed to start all combustion turbines and any shutdown fuel for both CT and ST components.

4 Cost-Based Offer Calculation

4.1 Definition

Cost-based offers in the energy market shall be capped at the short run marginal cost of energy. The short run marginal cost of energy is the incremental cost of producing one more MWh. It includes the cost of fuel, emissions abatement, emissions allowances, defined taxes, defined subsidies, defined energy market opportunity costs and consumables for operations, when those items vary in the short run with energy output. It is represented to PJM as a three part offer including the Incremental Energy Cost Curve, the No Load Cost, and the Start Cost.

4.2 Incremental Energy Cost Curve

The Incremental Energy Cost Curve represents the cost of providing an additional MWh from a synchronized unit. It consists primarily of the short run marginal cost of fuel, as determined by the unit's incremental heat rate. It also includes the short run marginal cost of consumables for operation, emissions allowances, taxes, tax credits, and energy market opportunity costs.

Equation 5: Incremental Energy Cost Curve.

$$C'(MW) = H'(MW) \times [FC(MW) + VOM_{fuel}(MW) + EC(MW)] + VOM_{output}(MW) + OC(MW)$$

where:

$C'(MW)$ represents the short run marginal cost curve for the unit, varying with the MW output of the unit, in \$/MWh.

$H'(MW)$ is the incremental heat rate curve at MW, as defined in Section 3.1.1, in MMBtu/MWh.

FC is the fuel cost at MW, as defined in Section 2.1, in \$/MMBtu.

$VOM(MW)$ is the sum of the variable operating cost and the maintenance adder at MW, as defined in Section 2.2 and Section 2.3, in \$/MMBtu. VOM can be included either in \$/MMBtu (VOM_{fuel}) or in \$/MWh (VOM_{output}).

$EC(MW)$ is the cost of emission credit allowances at MW, as defined in Section 2.3, in \$/MMBtu.

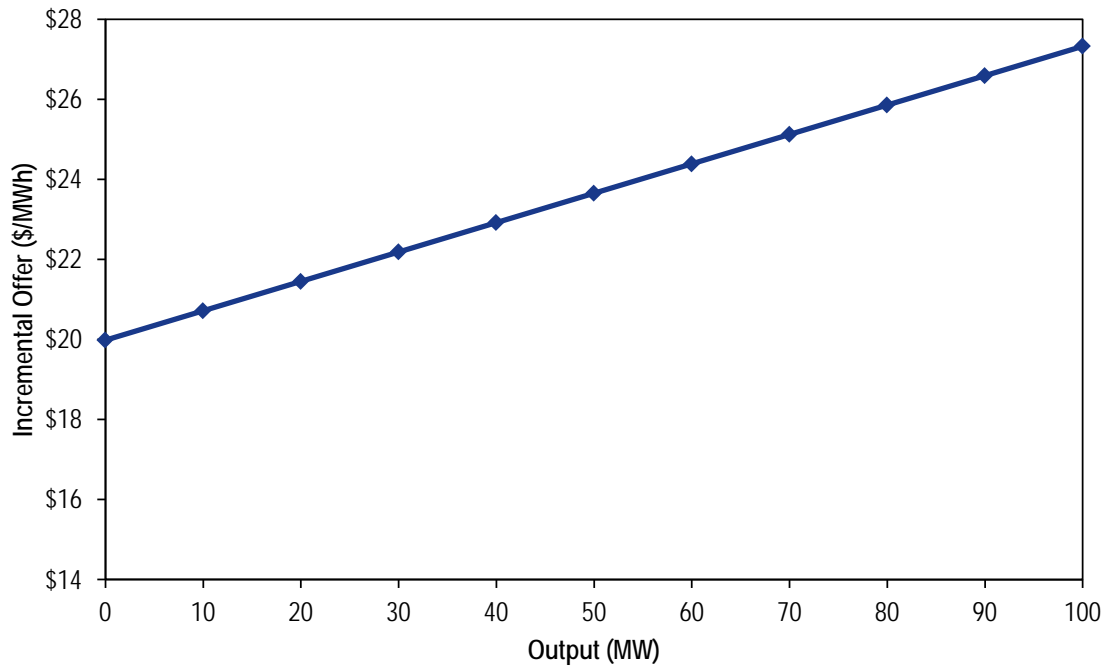
$OC(MW)$ is the opportunity cost at MW, as defined in Section 12 of Manual 15, in \$/MWh.

4.2.1 Incremental Energy Cost Curve Shapes

Incremental energy cost curves can be offered in PJM using a sloped curve or a stepped curve.

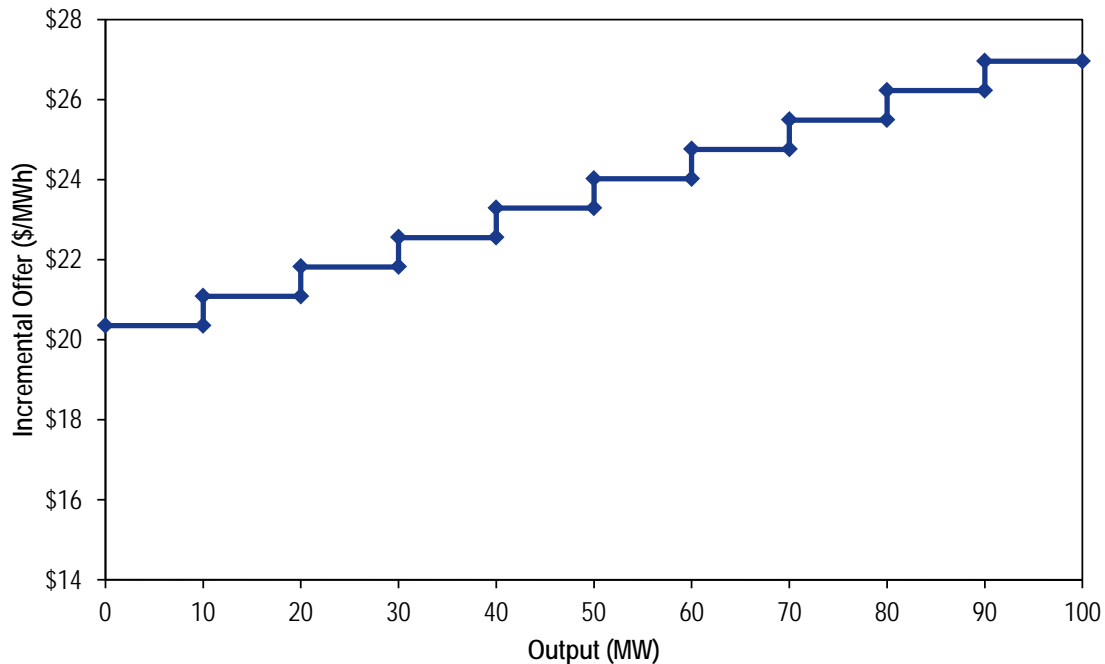
When offered with a sloped curve, PJM connects the MW segments of the curve using a sloped line from cost(i) to cost (i+1) from MW(i) to MW(i+1). Figure 2 shows a sloped incremental offer curve. Cost-based offers submitted with a sloped curve must start at zero MW in order to correctly represent the incremental cost curve which always starts at zero MW.

Figure 2: Incremental Offer Curve (Slope).



When offered with a stepped curve, PJM connects the MW segments of the curve using a horizontal line from $MW(i-1)$ to $MW(i)$ at $cost(i)$ and a vertical line from $cost(i)$ to $cost(i+1)$ at $MW(i)$. Figure 3 shows a stepped incremental offer curve. Cost-based offers submitted with a stepped curve start at zero MW since $MW(i-1)$ equals zero MW when i equals one.

Figure 3: Incremental Offer Curve (Stepped).

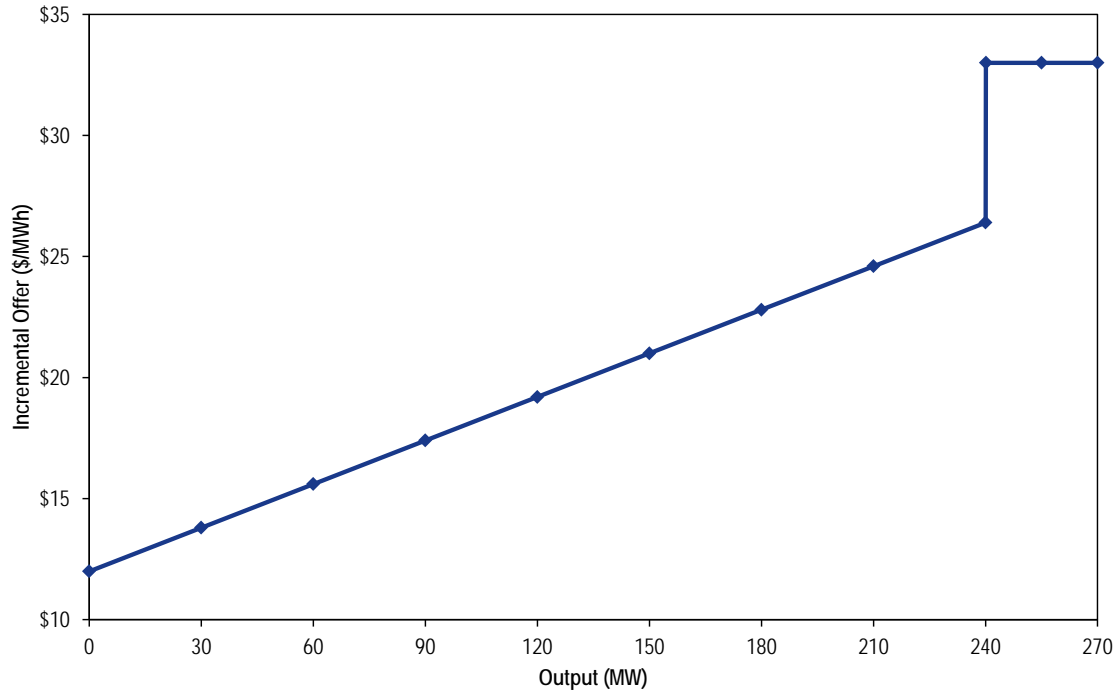


4.2.2 Incremental Energy Cost Curve Discontinuities

Incremental energy cost curves may also include discontinuities. Such discontinuities result from a change in the underlying relationship between heat input and energy output. Typically, additional fuel is added at and above a defined MW output level. The most common discontinuities are due to power augmentation methods, including duct firing in combined cycles and the addition of supplemental fuel.

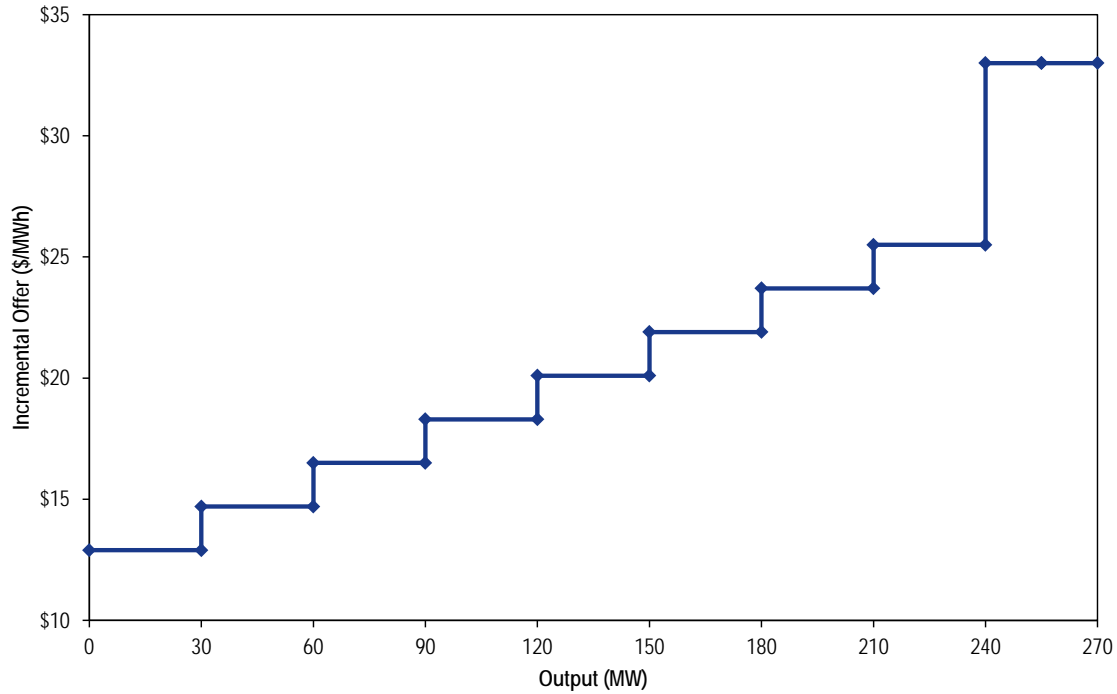
Units that have discontinuities in the incremental heat input curves and offer with a sloped curve must include them by using small MW increments (e.g. 0.1 MW) in their incremental MW segments. This is necessary to reflect discontinuities in a resource's cost after a defined MW segment. Figure 4 shows a sloped incremental offer curve with a discontinuity.

Figure 4: Sloped Incremental Offer Curve with Discontinuity.



Units that have discontinuities in the incremental heat input curves and offer with a stepped curve can reflect such discontinuity in each MW segment without creating small MW increments. Figure 5 shows a stepped incremental offer curve with a discontinuity.

Figure 5: Stepped Incremental Offer Curve with Discontinuity.



Appendix A contains a numerical example of a cost-based offer calculated using a sloped and stepped incremental heat rate curves with a discontinuities.

4.3 No Load Cost

The No Load Cost is the hourly energy cost required to theoretically operate a unit at zero MW. It is developed using the costs included in Section 2 and the intercept of the heat input curve in Section 3.

Equation 6: No Load Cost.

$$NL = H(0) \times (FC + VOM(0) + EC(0)) + VOM_{hour}$$

where:

NL is the no load cost in \$/hour.

$H(0)$ is the no load heat input, the intercept of the heat input curve, in MMBtu.

FC is the fuel cost at MW output of zero, as defined in Section 2.1, in \$/MMBtu. For units that use a different starting fuel (e.g. coal units), the fuel in the no load cost calculation cannot be the fuel used during startup and synchronization, but must be the fuel used during normal operation.

$VOM(0)$ is the sum of the variable operating cost and maintenance adder at zero MW, as defined in Section 2.2 and Section 2.3, in \$/MMBtu.

VOM_{hour} is the sum of the variable operating cost and maintenance adder at zero MW, as defined in Section 2.2 and Section 2.3, in \$/hour.

$EC(0)$ is the cost of emission credit allowances at zero MW, as defined in Section 2.3, in \$/MMBtu.

4.4 Start Cost

The start cost is the cost required to bring a unit from an offline state to synchronization with the grid. It includes fuel costs, emissions allowance costs, short run marginal costs of consumables for starting, and power consumption costs.

Equation 7: Start Cost.

$$SC(T) = \left[\sum_f SH_f(T) \times (FC_f + VOM_f + EC_f) \right] + SP(T) \times SSR + SMA$$

where:

$SC(T)$ is the start cost in \$/start as a function of the unit's temperature state, T .

f indexes the number of fuel types required to start.

$SH_f(T)$ is the start heat requirement for fuel f given for temperature state T , as defined in Section 3.1.3, in MMBtu.

FC_f is the fuel cost for fuel f , as described in Section 2.1, in \$/MMBtu.

VOM is the sum of the variable operating cost and maintenance adder for fuel f , as defined in Section 2.2 and Section 2.3, in \$/MMBtu.

EC_f is the emissions allowance cost incurred while burning fuel f , as defined in Section 2.4, in \$/MMBtu.

$SP(T)$ is the station service power load during starts for temperature state T , as defined in Section 2.5, in MWh.

SSR is the station service rate in \$/MWh.

SMA is the start maintenance adder in \$/start.

T is the boiler temperature state. Hot, intermediate or cold.