UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket No. EL08-47-005
	)	

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations, 18 CFR § 385.211 (2009), and the Commission's order of March 23, 2010,[1] in this proceeding, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"),[2] submits these comments on the compliance filing submitted by PJM Interconnection, L.L.C. ("PJM") in the above captioned proceeding on April 22, 2010 ("April 22nd Filing"). This proceeding concerns the calculation of the cost-based offers used to implement local market power mitigation, and specifically, the development of an appropriately detailed and accurate method for the calculation of an opportunity cost component of such cost-based offers. The only purpose of cost-based offers is to implement the local market power mitigation rules in the PJM tariff.

PJM's proposal is flawed because it contains an unnecessary and subjective administrative loophole providing PJM with discretion to override the new rules defining

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1 *PJM Interconnection, L.L.C.*, 130 FERC ¶61,23 ("March 23rd Order"); *see also*, 126 FERC ¶61,145 (February 19, 2009) ("February 19th Order"), *order on clarification*, 127 FERC. ¶61,188 (May 28, 2009).

2 PJM Interconnection, L.L.C. is a FERC approved Regional Transmission Organization. Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT") or the PJM Operating Agreement ("OA").

opportunity cost. In addition, while the general approach developed by PJM and PJM stakeholders for calculating opportunity cost-based offers is appropriate, the proposal should include identified enhancements that would produce more accurate results.

The April 22nd Filing inappropriately includes in the revision to Schedule 2 of the OA("Schedule 2") an alternative approach that would allow the substitution of PJM's subjective judgment for the defined, objective method of calculation. PJM does not explain why this loophole is needed after months of effort to craft a new detailed and objective approach. Nor does the April 22nd Filing explain why PJM should displace the Market Monitor from its current role in case-by-case review for opportunity cost adjustments. This is inconsistent with the recently instituted practice for other inputs to prospective mitigation, which reserves PJM's ability to make a final determination, but does not substitute PJM for the MMU in the initial review process.[3] The Commission should excise the provision for making case-by-case determinations, but if it chooses to retain it, the Commission should retain the Market Monitor's role in performing the initial review. The Commission should also require PJM to clarify, consistent with the Commission's direction, that the provisions included in this filing apply only to a unit whose run times are limited due to "energy and environmental" constraints.

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3 *See infra* section I.A & footnote no. 8.

The Market Monitor has proposed specific enhancements to the calculation of opportunity-cost based offers not included in the April 22nd Filing that PJM, PJM stakeholders and the Market Monitor have developed during the past year, including more accurate treatment of minimum run time restrictions, fuel procurement options, and operational characteristics. With two exceptions, the PJM stakeholders have already approved the inclusion of these enhancements in the market rules.

These enhancements are at various stages of the approval process. (See Table 1 for a list of these enhancements and their status in the PJM membership process.) Some of these enhancements had not been through the entire approval process in time for inclusion in the April 22nd Filing. Consequently, even though PJM, PJM stakeholders and the Market Monitor have successfully agreed on some enhancements that have not yet been through the entire approval process, it is prudent to protect the significant progress achieved to date by obtaining Commission review and acknowledgement for all of the stakeholder-approved and pending market rules and not only the contents of the April 22nd Filing. Accordingly, the Market Monitor respectfully requests that the Commission require modifications to Schedule 2 that would identify each such enhancement and require its inclusion in the market rules.

I. COMMENTS

A. The Commission Should Require PJM to Remove a Provision That Would Allow It to Ignore the Objective Method Set Forth in Its Filing and Substitute Its Subjective Case-by-Case Judgment to Determine Opportunity Cost-Based Offers, and Otherwise Ensure that PJM's Filing Conforms to the March 23rd Order.

PJM decided, just prior to filing, to include a provision in Schedule 2 that introduces a parallel subjective process to develop opportunity cost-based offers that undermines what has been achieved after months of effort in PJM stakeholder process to develop an accurate and objective method. The rules prior to the commencement of this process assigned the determination of an appropriate opportunity cost to the Market Monitor, consistent with its role in monitoring and deterring the exercise of market power. Throughout this process, PJM has insisted that a rigorously objective and non–discretionary approach should replace that approach. The Market Monitor accepted this goal, although not without misgivings about the consequent inability to exercise limited discretion in situations that the rules may have failed to anticipate.

PJM's last-minute reversal of the position it has held for months on the need for strictly objective rules was unexpected and is unexplained in the April 22nd Filing. Also unexplained is PJM's decision to remove the Market Monitor from this process entirely rather than reserve to PJM an ability to make final determinations consistent with its role in tariff administration. Elimination of the Market Monitor's role goes well beyond the role that PJM asserted for itself on compliance with Order No. 719.

The provision included in the April 22nd Filing reads:

> Notwithstanding the foregoing, a Market Participant may submit a request to PJM for consideration and approval of an alternative method of calculating its Energy Market Opportunity Cost if the standard methodology described herein does not accurately represent the Market Participant's Energy Market Opportunity Cost.

This provision allows PJM discretion to ignore the process and definitions filed here and substitute its judgment concerning appropriate costs. The Commission should not approve this nullification of the "foregoing" text, i.e. the tariff basis for the entire process that is the subject of this filing. PJM staff discussing this issue with stakeholders at the April 19, 2010, meeting of the Cost Development Task Force ("CDTF") repeatedly assured stakeholders and the Market Monitor that it would uniformly apply the process developed by the CDTF and would not include any alternatives that provided for discretion. Language that PJM staff disclosed by email for the first time approximately 24 hours prior to filing did not include this provision, and after disclosure of the language by email for the first time on the morning of the filing, PJM staff were unwilling to explain or discuss the issue. Consequently, neither PJM stakeholders nor the Market Monitor have had any opportunity to review or discuss this important change to the approach to compliance on this issue.

The Commission should require PJM to administer the objective process approved in this proceeding. The inclusion of an approach that substitutes PJM case by case judgment for the defined rules contravenes the Commission's requirement that the tariff "clearly and explicitly provide for the inclusion of opportunity costs, especially for energy and environmentally-limited resources,"[4] and "provide a mechanism by which opportunity costs can be included in mitigated bids in order to eliminate the need to evaluate the opportunity cost of resources on a case-by-case basis."[5]

If the Commission nonetheless approves a provision for case by case review, such ex ante review should continue to be performed by the MMU, but only to the extent that the rules do not address the request for opportunity costs. The current tariff assigns this determination to the Market Monitor.[6] Continuation of this role would be consistent with the Market Monitor's role in making determinations that relate to the potential exercise of market power, a role that is acknowledged by PJM.[7]

PJM argues that the Commission's order on PJM's filing to comply with Order No. 719 determined that PJM and not the Market Monitor "has the authority to make the final determinations regarding the appropriate value of offers and rates, including default bids for mitigated generators."[8] PJM's proposal in this case, however, does not concern a "final determination;" it concerns a determination made in the first instance. Indeed, PJM's effort to displace the Market Monitor from its current role and to limit the Market Monitor's ability to monitor the potential exercise of market power illustrates precisely the concerns

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[4] February 19th Order at P 42.

[5] March 23rd Order at P 22.

[6] The revisions to Section 8.1.1 of the Cost Development Guidelines filed by PJM delete the following provision: "Requests for recovery of Opportunity Costs not defined in the Operating Agreement … should be submitted to the PJM MMU for approval."

[7] *See infra* footnote no. 11.

[8] April 22nd Filing at 11 citing *PJM Interconnection, L.L.C.*, 129 FERC ¶61,250 at PP 150–54 (2009).

raised by the Market Monitor about PJM's approach to compliance with Order No. 719.[9] PJM does not appear content to reserve to itself final authority on administering the tariff, nor does it follow through on its pledge to refrain from rendering any judgment on questions of market power, questions concerning which it claimed to have neither an interest nor the required expertise.[10] The determination of opportunity cost is part of defining cost-based offers. The only purpose of cost-based offers and of the opportunity cost component of cost-based offers is to implement the local market power mitigation rules in the PJM tariff.

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[9] *See* Protest and Compliance Proposal of the Independent Market Monitor for PJM filed in Docket No. ER09-1063-000 at 5–6 (May 27, 2009) ("Based on a misreading of Order No. 719's requirements and an apparent dissatisfaction with the structure and tools for market monitoring resulting from the 2007 PJM/MMU Settlement, PJM has proposed changes that would compromise the ability of the Market Monitor to continue to employ this successful approach for developing the inputs to prospective mitigation in PJM. The April 28th Filing would add a new step in most provisions where the Market Monitor's responsibilities to make certain determinations are established. This new step would create the opportunity for PJM to substitute its own market power determinations for those of the Market Monitor. This approach would establish a duplicative "shadow" market monitoring function that vitiates the incentives for Market Participants to continue to fully participate in the existing arrangement. The result will be that the Market Monitor will be less able to deter misconduct ex ante and will have to rely more on post hoc adversarial processes. This will subordinate market monitoring, weaken the effectiveness of market monitoring, will create uncertainty for market participants and could prove damaging to public confidence in organized wholesale electricity markets. PJM's vague concerns about its institutional prerogatives do not warrant this overstepping of the requirements of Order 719.").

[10] *See* Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. to Protests and Comments in Docket No. ER09-1063-000 at 7 (July 28, 2009) ("PJM reiterates that it is not seeking to substitute its market power decisions for those of the IMM or exercise control over the IMM's determinations. Any decision PJM may make to reject an input proposed by the IMM will not be based on PJM rendering opinions on questions of market power. Rather, and as previously noted, such decisions will rest on whether PJM believes it and the relevant market participants are acting in a manner consistent with PJM's Tariff and related business rules.").

The Market Monitor urges the Commission to simply delete the provision added by PJM. This would be consistent with the Commission's policy favoring objective market rules over the exercise of discretion.[11] To the extent that the objective rules do not meet individual parties' concerns, as seems unlikely, they continue to have recourse to the Commission. If, however, the Commission permits this provision, it should condition its approval on PJM's retention of the Market Monitor's current role and confirm PJM's role regarding final responsibility for tariff administration and deference to the Market Monitor on determinations related to the potential exercise of market power.[12]

The Market Monitor also notes that the proposed tariff revisions in Schedule 2 continue to refer to "energy <u>or</u> environmental limitations" rather than "energy <u>and</u> environmental limitations," which is the phrase consistently used by the Commission and by PJM throughout its transmittal letter.[13] The Commission's phrasing is clear while the phrasing in the April 22nd Filing does not follow the Commission's words and the purpose

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11 *See*, *e.g.*, *PJM Interconnection, L.L.C.*, 126 FERC ¶61,275 at P 190 (2009) ("PJM must provide objective tariff provisions that will determine when mitigation measures will be applied."); *PJM Interconnection, L.L.C.*, 117 FERC ¶61,331 at P 115 (2006) ("we will require PJM to file … objective factual criteria to be used by the Market Monitor in reviewing bids"), 122 FERC ¶61,264 (2008).

12 *See Id.* at 7–8 ("PJM does not intend to arbitrarily 'pick and choose which inputs it allows,'[footnote omitted] nor reconsider every, most or even more than a *de minimis* number of calculations or determinations made by the IMM. Instead, PJM will rely on a market participant to notify PJM of any concerns with an IMM determination or input. Based on past experience and recent history, PJM does not expect to disagree with the IMM's determinations on other than rare occasions. Moreover, should any such disagreement occur, the IMM has all resources at its disposal as market monitor to air its concerns further. Finally, any position PJM may take contrary to the IMM is not to suggest PJM is rendering any judgment on questions of market power; opinions of this sort are the province of the IMM and judgments of this sort ultimately rest with the Commission.").

13 March 23rd Order *passim*; April 22nd Filing *passim*.

for this deviation is unexplained. The Commission should direct PJM to revise its filing either to employ the Commission's phrasing or to drop the "energy or" reference altogether.

The Market Monitor includes as Attachment A, revisions to Schedule 2 that address each of these issues.

B. The Method for Calculating Opportunity Costs Should Accurately Measure the Cost of the Lost Opportunity, Including an Accurate Treatment of the Applicable Limiting Period, the Resources' Use of Fuel and the Resources' Operational Limitations.

1. An Accurate Method to Calculate Opportunity Cost-Based Offers Has Been Thoroughly Considered, Completely Developed, and, with One Exception, Approved in Detail in the Stakeholder Process.

Opportunity costs are the value of a foregone opportunity for a generating unit. Opportunity costs may result when a unit: has limited run hours due to an externally imposed environmental limit; is requested to operate for a constraint by PJM; and is offer capped. Opportunity costs are the net revenue from a higher price hour that are foregone as a result of running at PJM's request during a lower price hour. The calculated opportunity cost adder applies only to cost-based offers and is only relevant when a unit is offer capped for local market power mitigation.

The purpose of the calculation method is to calculate the value of the opportunity cost. The method must calculate the margin (LMP minus cost) for every hour in the projected year. Those margins are the hourly opportunity cost.

For example, a unit is limited to 100 run hours for a year based on an environmental regulation. If the unit is required to run by PJM during a low price hour, it can add an opportunity cost to its cost based offer. The value of that opportunity cost adder is the margin from the 100th highest margin hours for the coming year.

In these circumstances, the cost-based offer must include an accurate calculation of opportunity costs. The markets are most efficient when an accurate calculation of the marginal costs of resources with limited run hours results in optimal dispatch.

Opportunity costs may be added to a cost-based offer for resources with a documented externally imposed environmental regulation that limits its run hours over a future period. Environmental regulations can directly limit run times by imposing run hour restrictions or indirectly limit run times by limiting, for example, emissions or heat input. The most efficient way to manage such limitations is via a market signal. A correctly calculated opportunity cost signals the value that an environmentally limited unit would give up by operating during a lower priced hour. That signal is the appropriate value on which to dispatch the unit. The alternative approaches to managing such limitations are not attractive. The only time that the calculation of opportunity costs under this rule has an impact is when a unit has local market power and therefore PJM will use the unit's cost-based offer even if the unit submitted a price-based offer. The goal of the opportunity cost rules is to provide a clear definition of the appropriate market signal. The alternative would be to permit units with local market power the ability to exercise market power through physical or economic withholding.

Working through the Cost Development Task Force ("CDTF"), the Market Monitor, PJM and Market Participants developed an accurate and administratively convenient method to calculate opportunity costs. The latest version of this method is included as Attachment B to this pleading, including the negative margin enhancement that has not been approved by the CDTF. The CDTF developed revisions to the "PJM Manual 15: Cost Development Guidelines" ("Cost Development Guidelines") to include a method that would permit Market Participants to elect to enter their cost-based offer with an opportunity cost component having a value less than or equal to its calculated opportunity cost, adjusted for differences in cost incurred by the resource at the time of the lost opportunity. The method included in the April 22nd Filing uses forward prices for power and fuel costs and an historical basis period to determine the value of future net revenue for run-hour restricted units. This approach calculates opportunity cost at a pricing node using an historical average of the previous three years of LMP and fuel costs, combined with forward prices of power (LMP), fuel, and emission allowances to calculate the expected margin between LMP and cost at a pricing node.

The Market Monitor recommended a number of enhancements to the method initially approved by the members for calculating an opportunity cost-based offer and to increase its accuracy. Since August 17, 2009 the CDTF met and reviewed and discussed each of these proposals in detail. Contemporaneously, the Market Monitor developed the web-based calculator necessary to assist Market Participants' calculation of opportunity costs including these enhancements.[14] With two exceptions that are still under active consideration, the CDTF and the MRC have approved most of the enhancements as shown in Table 1, *infra* section I.B.2. Changes to the Cost Development Guidelines (PJM Manual 15) require approval of the PJM Board, but this was not obtained prior to the April 22nd Filing.

2. Each of the Components Proposed by the Market Monitor Enhances the Accuracy of the Method to Calculate Opportunity Cost-Based Offers and Reduces the Ability of Market Participants to Use These Market Rules as a Vehicle to Exercise Market Power

PJM stakeholders in the CDTF have, to date, voted to include all but two of these components in the Cost Development Guidelines. Consequently, these components are no longer controversial, although four additional components have not been approved by the PJM Board. Table 1 below shows the status in the stakeholder process of each of the proposed components.

Table 1

	CDTF Approval	MRC Approval	MC Approval	Board Approval
Rolling Time Period Restrictions	1/25/2010	3/17/2010	3/25/2010	5/4/2010
Dual Fuel Inputs	1/25/2010	3/17/2010	3/25/2010	5/4/2010

14 The Market Monitor includes as Attachment C a presentation delivered at the March 17, 2010 meeting of the Markets and Reliability Committee ("MRC") that includes screenshots of this interface at pages 8–9.

Spot or Contract Monthly Fuel Flexibility	1/25/2010	3/17/2010	3/25/2010	5/4/2010
Fuel Delivery Adder	Pending[15]			
Minimum Run Time	4/19/2010	Pending[16]		
Start Up Costs	4/19/2010	Pending[18]		
Adjustment for Negative Margins	Pending[17]			

The Market Monitor here explains each of the above components, whether approved or pending, because they are not described in the April 22nd Filing or included in the revisions to the Cost Development Guidelines or accounted for in the revisions to Schedule 2 submitted to the Commission for review.

a. *Rolling Time Period Restrictions*

There are a variety of ways for environmental regulators to establish temporal operational restrictions. The restriction may apply over a calendar period or apply on a rolling basis. A large percentage of resources with environmental limitations have rolling time period restrictions. Consequently, the Market Monitor developed a feature that improves the accuracy of the opportunity cost calculation by creating an option to make this calculation on either a calendar year or a rolling 12-month basis, depending upon the

15 On the agenda for voting at the next scheduled meeting of the CDTF, May 14, 2010.

16 On the agenda for voting at the next scheduled meeting of the MRC, May 18, 2010.

nature of the actual environmental limitation.[17] Stakeholders and the Board have approved the revisions to the Cost Development Guidelines that pertain to rolling time periods and the Market Monitor has developed the systems necessary to accommodate this result. Consequently, this issue is no longer controversial.

b. Dual Fuel Inputs

Many units are capable of burning two types of fuel. In some cases a run hour restriction only applies to the run time using a particular type of fuel. Consequently, the Market Monitor developed a feature that improves the accuracy of the opportunity cost calculation by creating an option to account for both fuels in the calculation.[18] Stakeholders and the Board have approved the revisions to the Cost Development Guidelines that pertain to dual fuel inputs and the Market Monitor has developed the systems necessary to accommodate this result. Consequently, this issue is no longer controversial.

c. Spot or Contract Monthly Fuel Flexibility

Units have the opportunity to procure fuel either on the spot market or pursuant to contractual supply arrangements. If the procurement method changes during the relevant period, then it could impact the resource's costs. Consequently, the Market Monitor developed a feature that improves the accuracy of the opportunity cost calculation by

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17 See Appendix B at 4 (Step 1).

18 See Appendix B at 9 (Step 4).

creating an option to account for variations in fuel procurement.[19] The approach allows members to use either spot market prices or contractual prices and to permit switching between the two approaches within a period of the procurement method changes. Stakeholders and the Board have approved the revisions to the Cost Development Guidelines that pertain to fuel procurement flexibility and the Market Monitor has developed the systems necessary to accommodate this result. Consequently, this issue is no longer controversial.

d. Fuel Delivery Adder

Many units are not located at fuel trading hubs and incur additional costs associated with the delivery of fuel to the unit. These variable delivery costs are part of fuel costs. Consequently, the Market Monitor developed a feature that improves the accuracy of the opportunity cost calculation by providing an option to include the additional costs associated with the delivery of fuel.[20] The approach would allow market participants to determine the cost of delivery, subject to review by the Market Monitor. This proposal has not been approved in the stakeholder process because the item was inadvertently dropped from the CDTF agenda. The Market Monitor has developed the necessary language for the manuals and the systems necessary to account for this adjustment. There is no reason to expect that this simple adjustment would be controversial. The CDTF is scheduled to vote

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19 See Appendix B at 10 (Step 5).

20 See Appendix B at 10 (Step 5).

on this proposal on Friday, May 14, 2010. The Commission should direct that PJM include this component either as described in the revisions to the Cost Development Guidelines included in Attachment B or as later approved by the CDTF.

e. Minimum Run Time

Many units submit offers with a minimum run time parameter greater than one hour. The April 22nd Filing does not account for minimum run time parameters greater than one hour and assumes all units will be available to operate in the highest value hours despite minimum run time parameter restrictions. Most units operating in PJM have a minimum run time restriction. In the enhancement proposed by the MMU, cost-based minimum run times must be consistent with a defined Parameter Limited Schedule matrix.[21] A unit must be dispatched for the duration of a future block of hours equal to or greater than its minimum run time. As a result, the opportunity cost calculation must account for blocks of hours equal to or greater than the minimum run time rather than separate individual hours. A failure to appropriately account for minimum run time will compromise the accuracy of the calculation. The Market Monitor has developed the manual revisions and systems necessary to accurately account for minimum run time.[22]

The CDTF approved this enhancement at its meeting of April 19, 2010, and it is now pending at the MRC. Approval of this enhancement will not prevent the CDTF's continued

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21 OA Schedule 1 § 6.6(c).

22 *See* Attachment B at 13–14 (Step 8).

evaluation of proposals that accurately and efficiently incorporate other operational characteristics. This component is scheduled for a vote at the next meeting of the MRC, May 18, 2010.

Accordingly, the Commission should direct that PJM include this component either as described in the revisions to the Cost Development Guidelines include in Attachment B or as later developed by the CDTF.

f. Start Up Costs

Resources typically include start up costs in their offers. Start up costs are costs of operation and have an impact on whether and how a unit is dispatched. Dispatchers will consider the overall relative costs when dispatching resources to meet demand in high priced hours. No opportunity is lost to a unit with high start up costs if a dispatcher would dispatch another unit based on overall incremental costs. To account for differences in unit operations, cold start up costs for combined cycle and combustion turbine units and hot start up costs for steam units will be used. Consequently, the Market Monitor developed a feature that improves the accuracy of the opportunity cost calculation by accounting for start up costs.[23]

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[23] *See* Attachment B at 13–14 (Step 8).

The CDTF approved this enhancement at its meeting of April 19, 2010, and it is now pending at the MRC. This component is scheduled for a vote at the next meeting of the MRC, May 18, 2010.

Accordingly, the Commission should direct that PJM include this component either as described in the revisions to the Cost Development Guidelines include in Attachment B or as later developed by the CDTF.

g. *Adjustment for Negative Margins in Calculating Three-Year Average*

In order to calculate the opportunity cost for each hour of the coming year, LMPs and costs must be estimated for each hour of that year. The calculation method uses published forward curves for the price of electricity at the PJM Western Hub and input fuel prices.

The forward energy prices are available by month for PJM's West Hub. The forward fuel prices are available by month or by season or quarter and multiple locations.

It is not possible to have margins for individual units at their specific buses using only forward data. In order to develop margins and therefore opportunity costs for individual units at their specific buses, historical data must be used. The historical relationships between hourly prices at the West Hub and the monthly prices at the West Hub are used as the basis for hourly margins. The historical relationships between individual bus prices and the West Hub price are used as the basis for bus specific margins. The historical relationships between daily real time fuel prices and the forward prices are also used to develop the basis for daily, bus specific margins, together with transportation basis differentials.

The result is an hourly LMP estimate for each generator bus, a daily fuel cost estimate for each generator bus and therefore an hourly margin for each bus. (The net margin also accounts for emissions costs, the ten percent adder, VOM and FMU adders.) The hourly LMP and the fuel costs are the result of using the historical ratios multiplied by the forward curve data. The margins which result from comparing these hourly LMP and fuel cost data reflects the forward data, adjusted using historical data, to the specific generator bus. The only purpose of using the historical data is to translate the forward curve data to specific hours and buses.

If the resultant margin is negative for a specific generator bus, it means that this calculation method results in a negative margin for that bus and hour, based on the forward data translated to specific hours and buses. A negative margin means that there is no opportunity cost associated with that hour. For a method that used a single historical year, the answer is clear. If the margin is negative, the opportunity cost is zero.

The approved method uses an average of three years on the basis of the assumption that it would be more representative to use an average of three years rather than a single year. For the approved method, which uses three years of data as the basis to calculate the margin for an hour at a specific bus, the same logic should hold that holds for a single year. If all three hours have calculated negative margins, there is no opportunity cost. If the average of all three hours is a negative margin, there is no opportunity cost. It is inconsistent with the basic method to ignore the results of individual hours in calculating the opportunity cost. The currently approved method would do exactly that by ignoring negative margins in the calculation of the average.

A negative margin results when the result for the calculation (Projected LMP minus Dispatch Cost) is a margin in which cost is greater than LMP. This does not mean the projected LMP was negative, nor does it mean a generator was or was not dispatched by PJM in this hour. Negative margins in a single hour simply mean that the projected LMP is lower than the projected dispatch cost of a unit for this particular hour, for the designated projected year.

The CDTF continues to consider this issue. The CDTF is scheduled to vote on this proposal on Friday, May 14, 2010.

Accordingly, the Commission should direct that PJM include this component either as described in the revisions to the Cost Development Guidelines included in Attachment B[24] or as later developed by the CDTF to achieve equal or greater accuracy. Moreover, this enhancement can be included in Schedule 2 simply by specifying that setting negative

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[24] See Appendix B at 15 (Step 9).

margin values equal to zero occurs after and not before calculation of the three-year average.[25]

C. The Tariff Revisions Should Include Provisions That Require Accurate Treatment of the Applicable Regulatory Limitation, the Resources' Use of Fuel and the Resources' Operational Limitations.

Each of the components described *supra* in Section I.B.2 is important to ensure an accurate calculation of opportunity cost-based offers. Although the details of the method for implementation may change, the need for the opportunity cost method to account for these considerations should not be discretionary. Schedule 2 should identify all of the conceptual components of the opportunity portion of a cost-based offer even if the administrative details remain in the Cost Development Guidelines. The Market Monitor provides proposed revisions to Schedule 2 in Attachment A to this pleading that would achieve this result. Accordingly, the Market Monitor requests that the Commission direct inclusion of these requirements in Schedule 2 of the OA.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission consider this protest and the alternative and supplemental revisions to Schedule 2 of the OA and the Cost Development Guidelines as it resolves the issues raised in this proceeding.

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25 *See* Appendix A ("If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative after averaging over three years, the resulting Energy Market Opportunity Cost shall be zero.").

Respectfully submitted,

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Dated: May 13, 2010

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 13th day of May, 2010.

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Attachment A

SCHEDULE 2

COMPONENTS OF COST

(a) Each Market Participant obligated to sell energy on the PJM Interchange Energy Market at cost-based rates may include the following components or their equivalent in the determination of costs for energy supplied to or from the PJM Region:

For generating units powered by boilers
Firing-up cost
Peak-prepared-for maintenance cost

For generating units powered by machines
Starting cost from cold to synchronized operation

For all generating units
Incremental fuel cost
Incremental maintenance cost
No-load cost during period of operation
Incremental labor cost
Other incremental operating costs

For a generating unit that is subject to operational limitations due to energy ~~or~~**and** environmental limitations imposed on the generating unit by Applicable Laws and Regulations (as defined in the PJM Tariff), the Market Participant may include in the calculation of its "other incremental operating costs" an amount reflecting the unit-specific Energy Market Opportunity Costs expected to be incurred **on an hourly basis**. Such unit-specific Energy Market Opportunity Costs are calculated by forecasting **hourly** Locational Marginal Prices based on future contract prices for electricity using PJM Western Hub forward prices, taking into account historical variability and basis differentials for the bus at which the generating unit is located for the prior three year period immediately preceding the relevant compliance period, and subtract therefrom the forecasted **hourly** costs to generate energy at the bus at which the generating unit is located **taking into account historical variability and basis differentials**. **If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative for any of the years, the average shall include the negative result and if the average difference over three years is negative, the resulting Energy Market Opportunity Cost shall be zero.** ~~, as specified in more detail in~~ PJM Manual 15, Section 8: Cost Development Guidelines **shall set forth the foregoing method in greater detail, and shall, in order to ensure as accurate a calculation as possible, include, at a minimum, provisions accounting for (i) limitations imposed on the basis of rolling time periods; (ii) whether a resource has capability to use multiple fuels, and, for each fuel, the flexibility for procurement on a spot or monthly contract basis and associated delivery charges; and (iii) the resource's minimum run time and startup costs**. ~~**If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative, the resulting Energy Market Opportunity Cost shall be zero. Notwithstanding the foregoing, a Market Participant may submit a request to PJM for consideration and approval of an alternative method of calculating its Energy Market**~~

~~**Opportunity Cost if the standard methodology described herein does not accurately represent the Market Participant's Energy Market Opportunity Cost.**~~

(b) All fuel costs shall employ the marginal fuel price experienced by the Member.

(c) The PJM Board, upon consideration of the advice and recommendations of the Members Committee, shall from time to time define in detail the method of determining the costs entering into the said components, and the Members shall adhere to such definitions in the preparation of incremental costs used on the Interconnection.

Attachment B

MMU Redline

PJM Manual 15:

Cost Development Guidelines

Revision: XX

Effective Date: XX

Prepared by

Cost Development Task Force

Section 8a: Opportunity Cost Calculation

Welcome to the *Opportunity Cost Calculation section of* the ***PJM Manual for Cost Development Guidelines***. In this section, you will find the following information:

- A description of the Opportunity Cost Component
- A detailed explanation of the steps in the Opportunity Cost Calculation

Opportunity Cost Component

The following methodology is approved for ~~computing~~ calculating opportunity costs associated with an externally imposed environmental regulation based run-hour restriction on a generation unit. Examples would include a limit on emissions for the unit imposed by a regulatory agency or legislation, a direct run hour restriction in the operating permit, or a heat input limitation defined by a regulatory decision or operating permit. Generators may follow this methodology at their option or may develop and submit alternative methods specific to their units for approval. Requests for recovery of opportunity costs either using other methods or not defined in the Operating Agreement of PJM Interconnection, L.L.C. should be initially submitted to the PJM MMU for approval per Manual 15 Section 8.

Opportunity costs are a distinct component of the cost-based offer. As is the case with any ~~computation~~ calculation of the cost-based offer in Manual M-15, market participants may elect to enter their cost-based offer at a value less than the ~~computed~~ calculated cost-based offer. However, they may not exceed the ~~computed~~ calculated value.

Opportunity costs calculated with this method ~~will~~ may change frequently~~. Given that~~ as electricity and fuel ~~futures~~ forwards ~~can~~ may change daily~~, the opportunity costs computed can likewise change daily~~. Generation owners who include opportunity costs in their cost-based offers must recalculate their opportunity cost no less frequently than once~~- per week~~every 7 days.

Definitions

- **N**=number of hours in the month (on-peak/off-peak)
- **y**=year
- **m**=month
- **d**=day of the month
- **h**=hour
- **Peak**=off-peak hours only or on-peak hours only

- **FY**=future year
- **BUSLMP**=LMP at the unit's bus
- **PJMWesternHub**=PJM Western Hub LMP
- **Trading Day**=In respect of a particular futures market a day on which that Market open for trading
- **Dm**=Delivery Month; Month the commodity contract is to deliver the commodity in the future.
- **Base year**= one of the three historical years used to create ~~volatility~~variability in the fuel and power forecasts
- **Peak**=Peak hours are from 7:00 AM to 11:00 PM (the hour ending 0800 to the hour ending 2300) prevailing local time. Peak days are Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays.
- **Off-peak**=Off-peak hours are from midnight to 7:00 AM (the hour ending 0100 to the hour ending 0700) and 11:00 PM to midnight (the hour ending 2400) Mondays through Fridays; also, all day Saturdays and Sundays (the hour ending 0100 to the hour ending 2400) and North American Electric Reliability Council holidays
- **Frequently mitigated unit (FMU)=** A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.

~~WEB PORTAL:~~

~~Unit participants will submit their input data for the Monitoring Analytics' opportunity cost calculator through a web portal. That information will be stored in a database, and once a day, it will be processed a program in order to determine unit-specific opportunity costs. Those calculations for opportunity cost can be explained in nine steps.~~

STEP 1: ~~Derive~~ Calculate Historical Monthly LMP Basis Differential between the generation bus and western hub

> *Inputs required for STEP 1:*
> *Platts-ICE Forward Curve for "PJM west" from the recent trading day,*
> *Three years of historical hourly real-time LMPs at the generation bus, ~~and~~*
> *Three years of historical hourly real-time PJM Western Hub LMPs*

The mismatch between the location of the forward contract delivery point (Western Hub) and the relevant generator bus can be accounted for in the historic, monthly average basis differential for both peak and off-peak hours. This basis differential can be expressed as the average, over all peak or off-peak hours in a month, of the ratio of the hourly bus LMP to the hourly Western Hub LMP. If this ratio is greater than one, it means the bus LMP is greater than the Western Hub LMP on average. If this ratio is less than one, it means the bus LMP is less than the Western Hub LMP on average.

Platts-ICE Forward Curve for “PJM west” (PJM Western Hub) must be collected for this first step (http://www.platts.com/). ~~–~~These PJM Western Hub Forwards are multiplied by a historical basis adjustment ratio for delivery to the generator’s bus ~~creates~~ to calculate monthly delivered bus prices. The three prior calendar year’s historical data is used to make this calculation. For example, when ~~comput~~calculating opportunity costs for July 2, 2009 for a unit without a rolling 12-month run-hour restriction, use historical LMP data from July 2nd (2006, 2007 and 2008) to December 31st (2006, 2007, and 2008). For units with a rolling 12-month run-hour restriction, use historical LMP data from the previous three years, beginning on the date calculated and ending two days previous. For example, when ~~comput~~calculating opportunity costs for July 2, 2009 for a unit with a rolling 12-month run-hour restriction, use historical LMP data from July 2nd (2006, 2007 and 2008) to June 30th (2007, 2008, and 2009). ~~For example, when computing opportunity costs in 2009, use historical LMP data from 2006, 2007 and 2008.~~ Begin by taking the hourly bus prices for the three prior ~~calendar~~ years at the generator’s bus, and for every hour, divide that hour’s price by the corresponding price at PJM Western Hub. The historic hourly basis differential in hour h, day d, month m, and year y is

$$\mathrm{HourlyBasisDifferentialRatio}_{y,m,d,h} = \frac{\mathrm{BUSLMP}_{y,m,d,h}}{\mathrm{PJMWHLMP}_{y,m,d,h}}.$$

Example 1.1: Three hourly basis differential ratios values for the same hour in each of three historical years:

$$HourlyBasisDifferentialRatio_{June\ 3,2006\ H11} = \frac{BUSLMP_{June\ 3,2006\ H11}}{PJMWHLMP_{June\ 3,2006\ H11}}$$

$$\cancel{HourlyBasisDifferentialRatio_{June\ 3,2007\ H11} = \frac{BUSLMP_{June\ 3,2007\ H11}}{PJMWHLMP_{June\ 3,20076\ H11}}}$$

$$HourlyBasisDifferentialRatio_{June\ 3,2007\ H11} = \frac{BUSLMP_{June\ 3,2007\ H11}}{PJMWHLMP_{June\ 3,2007\ H11}}$$

$$\cancel{HourlyBasisDifferentialRatio_{June\ 3{,}2008\ H11} = \frac{BUSLMP_{June\ 3{,}2008\ H11}}{PJMWHLMP_{June\ 3{,}20086\ H11}}}$$

$$HourlyBasisDifferentialRatio_{June\ 3{,}2008\ H11} = \frac{BUSLMP_{June\ 3{,}2008\ H11}}{PJMWHLMP_{June\ 3{,}2008\ H11}}$$

Once the hourly basis ratios are calculated for every hour during the three-year history, for each historic month take the sum of the on-peak hourly basis differentials in the month, and divide by the number of peak hours in the month (observations). ~~Similarly~~In addition, for every month, sum the off-peak hourly basis ratios, and then divide by the number of off-peak hours within that month. These monthly basis differentials adjust PJM Western Hub monthly peak and off-peak forward prices to expected peak and off-peak monthly forward prices delivered to the generator’s bus.

$$\text{MonthlyPeakBasisDifferentialRatio}_{y,m}^{peak} = \frac{\sum_{\text{peak hours}}\left(\text{HourlyBasisDifferentialRatios}_{y,m,d,h}^{peak}\right)}{\text{Number of Peak Hours in month m}}$$

$$\text{MonthlyOffPeakBasisDifferentialRatio}_{y,m}^{peak} = \frac{\sum_{\text{off-peak hours}}\left(\text{HourlyBasisDifferentialRatios}_{y,m,d,h}^{off-peak}\right)}{\text{Number of Off} - \text{Peak Hours in month m}}$$

NOTE: When PJMWHLMP is zero and the BUSLMP is zero, then the ratio value is one. If PJMWHLMP is zero and the BUSLMP is not zero then value is null and it is not included in the average.

Example 1.2: Monthly Peak Basis Differentials for the three historical periods:

$$MonthlyPeakBasisDifferentialRatio_{June\ 2006}^{peak} = \frac{\sum_{peak\ hours}(Hourly\ Basis\ Differential\ RatiosJune\ 2006)}{Number\ of\ peak\ hours\ in\ June\ 2006}$$

$$MonthlyPeakBasisDifferentialRatio_{June\ 2007}^{peak} = \frac{\sum_{peak\ hours}(Hourly\ Basis\ Differential\ Ratios\ June\ 2007)}{Number\ of\ peak\ hours\ in\ June\ 2007}$$

$$MonthlyPeakBasisDifferentialRatio_{June\ 2008}^{peak} = \frac{\sum_{peak\ hours}(Hourly\ Basis\ Differential\ Ratios\ June\ 2008)}{Number\ of\ peak\ hours\ in\ June\ 2008}$$

$$MonthlyPeakDifferentialBasisRatio^{peak}_{June\ 2008} = \frac{\sum_{peak\ hours}(Hourly\ Basis\ Differential\ Ratios\ June\ 2008)}{Number\ of\ peak\ hours\ in\ June\ 2008}$$

Multiply monthly peak and off-peak basis differential ratios by the respective monthly peak and off-peak PJM Western hub forwards to ~~derive~~ calculate forecasted monthly peak and off-peak bus prices.

$$\cancel{\text{Forecasted Monthly Bus Price}^{peak}_{fy,m} = \left[(\text{PJMWestern Hub}^{peak}_{fy,m}) * (\text{MonthlyPeakBasisRatio}^{peak}_{y,m}) \right]}$$

$$\text{Forecasted Monthly Bus Price}^{peak}_{fy,m} = \left[(\text{PJMWestern Hub}^{peak}_{fy,m}) * (\text{MonthlyPeakBasisDifferentialRatio}^{peak}_{fy,m}) \right]$$

Example 1.3: Forecasted monthly bus prices for three historical periods:

$$\cancel{Forecasted\ Monthly\ Bus\ Price^{OFFpeak}_{June\ 2010, base\ 2006} = \left[(PJMWH^{OFFpeak}_{for\ delivery\ June\ 2010}) * (MonthlyOffPeakBasisDifferentialRatio^{OFFpeak}_{June\ 2006}) \right]}$$

$$Forecasted\ Monthly\ Bus\ Price^{OFFpeak}_{June\ 2009, base\ 2006} = \left[(PJMWH^{OFFpeak}_{for\ delivery\ June\ 2009}) * (MonthlyOffPeakBasisDifferentialRatio^{OFFpeak}_{June\ 2006}) \right]$$

$$\cancel{Forecasted\ Monthly\ Bus\ Price^{OFFpeak}_{June\ 2010, base\ 2007} = \left[(PJMWH^{OFFpeak}_{for\ delivery\ June\ 2010}) * (MonthlyOffPeakBasisRatio^{OFFpeak}_{June\ 2007}) \right]}$$

$$Forecasted\ Monthly\ Bus\ Price^{OFFpeak}_{June\ 2009, base\ 2007} = \left[(PJMWH^{OFFpeak}_{for\ delivery\ June\ 2009}) * (MonthlyOffPeakBasisDifferentialRatio^{OFFpeak}_{June\ 2007}) \right]$$

$$\cancel{Forecasted\ Monthly\ Bus\ Price^{OFFpeak}_{June\ 2010, base\ 2008} =}$$

$$\cancel{\left[\left(PJMWH^{OFFpeak}_{for\ delivery\ June\ 2010}\right) * \left(MonthlyPeakBasisRatio^{OFFpeak}_{June\ 2008}\right)\right]}$$

$$Forecasted\ Monthly\ Bus\ Price^{OFFpeak}_{June\ 2009, base\ 2008} = \left[\left(PJMWH^{OFFpeak}_{for\ delivery\ June\ 2009}\right) * \left(MonthlyOffPeakBasisDifferentialRatio^{OFFpeak}_{June\ 2008}\right)\right]$$

Outputs from STEP 1:

Three peak and off-peak monthly BUS LMP forecasts for each month remaining in the compliance period

STEP 2: ~~Derive~~ Calculate hourly ~~volatility~~variability scalars to incorporate hourly ~~volatility~~variability into the LMP forecast

Inputs for STEP 2:

Three years historical hourly real-time LMPs ~~prices~~ at the generation bus

The monthly ~~futures~~ forward prices quoted only consider the average peak and off-peak prices for the month and do not consider hourly LMP ~~volatility~~variability. Step 2 ~~derives~~ calculates ~~will develop~~ an hourly ~~volatility~~variability scalar. This scalar will later be multiplied ~~against~~ by the monthly bus LMP ~~the~~ forecast calculated in Step 1 to ultimately ~~derive~~ forecast an hourly bus LMP ~~forecast~~ that incorporates historic hourly peak and off-peak LMP ~~volatility~~variability as well as monthly peak and off-peak basis differentials with PJM Western Hub.

First, for each historic month ~~compute~~ calculate the average peak and off-peak price at the unit's bus for each remaining month in the compliance period.

$$\text{MonthlyAverageBusLMP}^{\text{peak}}_{\text{y,m}} = \frac{\sum_{\text{peak hours}}\left(\text{HourlyBusLMP}^{\text{peak}}_{\text{y,m,d,h}}\right)}{\text{Number of Peak Hours in month m}}$$

$$\text{MonthlyAverageBusLMP}^{\text{off-peak}}_{\text{y,m}} = \frac{\sum_{\text{off-peak hours}}\left(\text{HourlyBusLMP}^{\text{off-peak}}_{\text{y,m,d,h}}\right)}{\text{Number of Off} - \text{Peak Hours in month m}}$$

Next, for every hour, take the hourly bus LMP divided by the relevant monthly average peak or off-peak bus LMP ~~computed~~ calculated above. If the hour is an on-peak hour, divide by the average peak LMP ~~price~~ for the month.

$$\sout{HourlyVolatilityScalar^{peak}_{y,m,d,h} = \frac{BUSLMP^{peak}_{y,m,d,h}}{MonthlyAverageBusLMP^{peak}_{y,m}}}$$

$$HourlyVariabilityScalar^{peak}_{y,m,d,h} = \frac{BUSLMP^{peak}_{y,m,d,h}}{MonthlyAverageBusLMP^{peak}_{y,m}}$$

If the hour is off-peak, divide that hour by the average monthly off-peak ~~average price~~ LMP for the corresponding month.

$$\sout{HourlyVolatilityScalar^{off-peak}_{y,m,d,h} = \frac{BUSLMP^{off-peak}_{y,m,d,h}}{MonthlyAverageBusLMP^{off-peak}_{y,m}}}$$

$$HourlyVariabilityScalar^{off-peak}_{y,m,d,h} = \frac{BUSLMP^{off-peak}_{y,m,d,h}}{MonthlyAverageBusLMP^{off-peak}_{y,m}}$$

Example 2.1: ~~Volatility~~Variability scalar for the each of the three historical years:

$$\sout{HourlyVolatilityScalar_{June3,2006\ H24} = \frac{BUSLMP_{June\ 3,2006\ H24}}{Average\ Offpeak\ June\ 2006\ BUSLMP}}$$

$$\sout{HourlyVolatilityScalar_{June3,2007\ H24} = \frac{BUSLMP_{June\ 3,2007\ H24}}{Average\ Offpeak\ June\ 2007\ BUSLMP}}$$

$$\sout{HourlyVolatilityScalar_{June3,2008\ H24} = \frac{BUSLMP_{June\ 3,2008\ H24}}{Average\ Offpeak\ June\ 2008\ BUSLMP}}$$

$$HourlyVariabilityScalar_{June3,2006\ H23} = \frac{BUSLMP_{June\ 3,2006\ H23}}{Average\ Offpeak\ June\ 2006\ BUSLMP}$$

$$HourlyVariabilityScalar_{June3,2007\ H23} = \frac{BUSLMP_{June\ 3,2007\ H23}}{Average\ Offpeak\ June\ 2007\ BUSLMP}$$

$$HourlyVariabilityScalar_{June3,2008\ H23} = \frac{BUSLMP_{June\ 3,2008\ H23}}{Average\ Offpeak\ June\ 2008\ BUSLMP}$$

Output from STEP 2:
Three ratio values per hour for each of the historical years used for ~~volatility~~variability

STEP 3: Create three sets of hourly forecasted bus values

Inputs to STEP 3:
Output from STEP 1: On-peak/off-peak monthly bus LMP Forecasts
Output from STEP 2: Hourly ~~volatility~~variability scalars

Step 3 creates three hourly forecasts from the ~~volatility~~variability scalars developed in step 2 and the monthly bus LMP forecasts ~~prices~~ developed in Step 1. Multiply the hourly ~~volatility~~variability scalars developed in step 2 by the corresponding forecasted monthly bus ~~price~~ LMPs calculated in step 1.

The ~~expected or~~ forecasted LMP for hour h, day d, month m, based on year y that is a peak hour is

$$\cancel{\mathrm{ForecastedBUSLMP}^{peak}_{y,m,d,h} = \mathrm{HourlyVolatilityScalar}^{peak}_{y,m,d,h} * \mathrm{ForecastedMonthlyBusPrice}^{peak}_{fy,m}}$$

$$\mathrm{ForecastedBUSLMP}^{peak}_{y,m,d,h} = \mathrm{HourlyVariabilityScalar}^{peak}_{y,m,d,h} * \mathrm{ForecastedMonthlyBusPrice}^{peak}_{fy,m}$$

The ~~expected or~~ forecasted LMP for hour h, day d, month m, based on year y that is an off-peak hour is

$$\cancel{\mathrm{ForecastedBUSLMP}^{off-peak}_{y,m,d,h} = \mathrm{HourlyVolatilityScalar}^{off-peak}_{y,m,d,h} * \mathrm{ForecastedMonthlyBusPrice}^{off-peak}_{fy,m}}$$

$$\mathrm{ForecastedBUSLMP}^{off-peak}_{y,m,d,h} = \mathrm{HourlyVariabilityScalar}^{off-peak}_{y,m,d,h} * \mathrm{ForecastedMonthlyBusPrice}^{off-peak}_{fy,m}$$

Example 3.1: Forecasted bus LMPs for one hour for each of the three historical base years:

Assume that it is April 5, 2009. To create the set of three forecasted prices for each hour of June 3, 2009:

$$ForecastedBUSLMP_{June\ 3,2009\ H00,base\ 2006} = \cancel{HourlyVolatilityScalar_{June\ 3,2006\ H00}} * ForecastedMonthlyBusPrice^{offpeak}_{June\ 2009}$$

$$ForecastedBUSLMP_{June\ 3,2009\ H00,base\ 2007} = \cancel{HourlyVolatilityScalar_{June\ 3,2007\ H00}} * ForecastedMonthlyBusPrice^{offpeak}_{June\ 2009}$$

$$ForecastedBUSLMP_{June\ 3,2009\ H00,base\ 2008} = \cancel{HourlyVolatilityScalar_{June\ 3,2008\ H00}} * ForecastedMonthlyBusPrice^{offpeak}_{June\ 2009}$$

$$ForecastedBUSLMP^{baseyear2006}_{June\ 3,2009\ H00} = HourlyVariabilityScalar_{June\ 3,2006\ H00} * ForecastedMonthlyBusPrice^{offpeak}_{June\ 2009}$$

$$ForecastedBUSLMP^{baseyear2007}_{June\ 3,2009\ H00} = HourlyVariabilityScalar_{June\ 3,2007\ H00} * ForecastedMonthlyBusPrice^{offpeak}_{June\ 2009}$$

$$ForecastedBUSLMP^{baseyear2008}_{June\ 3,2009\ H00} = HourlyVariabilityScalar_{June\ 3,2008\ H00} * ForecastedMonthlyBusPrice^{offpeak}_{June\ 2009}$$

Outputs from STEP 3:
Three hourly bus LMP forecasts for each ~~per~~ hour remaining in the compliance ~~year~~period

STEP 4: Create a daily fuel ~~volatility~~variability scalar

Inputs to STEP 4:
Three years historical delivered daily fuel prices at the generator bus ($/mmBtu)
Fuel weights if dual fuel

Step 4 creates a daily fuel ~~volatility~~variability scalar using historical daily delivered fuel prices (as used to develop a unit's TFRC) from the previous three ~~calendar~~ years. Take each daily bus-delivered fuel price and divide it by the monthly average bus--delivered fuel price to create a ratio for every day in the three-year history. For units that have dual fues; the daily delivered fuel prices ~~need to~~will be multiplied by their respective weights and then added together. N_m is the number of days in month m.

$$\cancel{\mathrm{DailyFuelVolatilityScalar}_{y,m,d} = \frac{\mathrm{DeliveredFuelPrice}_{y,m,d}}{\frac{\left(\sum_{n=1}^{N_m}\left(\mathrm{DeliveredFuelPrice}_{y,m}\right)\right)}{N_m}}}$$

~~**Example 4.1: Three daily fuel volatility scalars values developed for June 3 in each of three historic years:**~~

$$\cancel{DailyFuelVolatilityScalar_{June,3,2006} = \frac{DeliveredFuelPrice_{June\ 3,2006}}{Average\ June\ 2006\ DeliveredFuelPrice}}$$

$$\cancel{DailyFuelVolatilityScalar_{June,3,2007} = \frac{DeliveredFuelPrice_{June\ 3,2007}}{Average\ June\ 2007\ DeliveredFuelPrice}}$$

$$\cancel{DailyFuelVolatilityScalar_{June,3,2008} = \frac{DeliveredFuelPrice_{June\ 3,2008}}{Average\ June\ 2008\ DeliveredFuelPrice}}$$

Units with Single Fuel Type:

$$DailyFuelVariabilityScalar_{y,m,d} = \frac{DeliveredFuelPrice_{y,m,d}}{\frac{\left(\sum_{n=1}^{N_m}\left(DeliveredFuelPrice_{y,m,d=n}\right)\right)}{N_m}}$$

Where N_m is the number of days in month m.

Units with Dual Fuel Types:

$$DailyFuelVariabilityScalar_{y,m,d} = \frac{(DeliveredFuelPriceFuelTypeA_{y,m,d} * WeightFuelTypeA) + (DeliveredFuelPriceFuelTypeB_{y,m,d} * WeightFuelTypeB)}{\frac{\left(\sum_{n=1}^{N_m}\left((DeliveredFuelPriceFuelTypeA_{y,m} * WeightFuelTypeA) + (DeliveredFuelPriceFuelTypeB_{y,m} * WeightFuelTypeB)\right)\right)}{N_m}}$$

Example 4.1: Three daily fuel variability scalar values developed for June 3, 2009 for a unit with a single fuel type:

$$DailyFuelVariabilityScalar_{June,3,2006} = \frac{DeliveredFuelPrice_{June\ 3,2006}}{Average\ June\ 2006\ DeliveredFuelPrice}$$

$$DailyFuelVariabilityScalar_{June,3,2007} = \frac{DeliveredFuelPrice_{June\ 3,2007}}{Average\ June\ 2007\ DeliveredFuelPrice}$$

$$DailyFuelVariabilityScalar_{June,3,2008} = \frac{DeliveredFuelPrice_{June\ 3,2008}}{Average\ June\ 2008\ DeliveredFuelPrice}$$

If there is no fuel cost record for a given date, use the previous available value.

Output from STEP 4: Three years of historic daily scalars for fuel ~~volatility~~variability

STEP 5: Create three daily delivered fuel forecasts

Inputs for STEP 5:
Platts Forward curve for Fuel from the most recent trading day, for delivery in the compliance period ($/mmBtu) with a daily delivery charge adjustment
Output from STEP 4: Three years historic daily scalars for fuel ~~volatility~~variability
Fuel weights if dual fuel
Fuel monthly contract price isf applicable

Step 5 takes fuel ~~futures~~ forwards based on a unit's fuel type and/or contract fuel price (as approved by the MMU) and the daily delivered fuel scalars from step 4 and multiplies them together to ~~create~~ calculate a fuel forecast that corresponds on an average monthly basis to the fuel ~~futures~~forwards, yet maintains historical ~~volatility~~variability. The selected fuel forward price should be from the most recent trading day, for delivery in the compliance period. Once determined, a fuel forward index must be used for the duration of the compliance period. For units that have multiple fuels; the daily delivered fuel scalar will be multiplied by the fuel forward price and their respective weights per fuel type and added together. For units with some or all of their fuel coming from monthly contracts, the daily delivered fuel term will properly weight the monthly contract price and the daily delivered fuel forecast price for each day in a given month. The current daily delivery charge adjustment will be applied through the compliance period.

$$\cancel{\text{Daily DeliveredFuel}_{fy,m,d} = \text{DailyFuelVolatilityScalar}_{y,m,d} * \text{FuelForward}_{fy,m}}$$

~~**Example 5.1: Create three daily delivered fuel forecasts from the volatilities of three historic years:**~~

$$DailyDeliveredFuelForecast^{baseyear2006}_{June\ 3,2009,base\ 2006} = DailyFuelVolatilityScalar_{June\ 3,2006} * FuelForward_{June\ 2009}$$

$$DailyDeliveredFuelForecast_{June\ 3,2009,base\ 2007} = DailyFuelVolatilityScalar_{June\ 3,2007} * FuelForward_{June\ 2009}$$

$$DailyDeliveredFuelForecast_{June\ 3,2009,base\ 2008} = DailyFuelVolatilityScalar_{June\ 3,2008} * FuelForward_{June\ 2009}$$

Units with Single Fuel Type:

$$\cancel{Daily\ DeliveredFuel_{fy,m,d} = DailyFuelVariabilityScalar_{y,m,d} * (WeightSpot_m * FuelForward_{fy,m} + WeightContract_m * ContractPrice_m)}$$

$$Daily\ DeliveredFuel_{fy,m,d} = DailyFuelVariabilityScalar_{y,m,d} * (WeightSpot_m * (FuelForward_{fy,m} + DeliveryAdjustment) + WeightContract_m * (ContractPrice_m))$$

Units with Dual Fuel Types:

$$\cancel{DailyDeliveredFuel_{fy,m,d} = DailyFuelVariabilityScalar_{y,m,d}} * (WeightSpot_m * (FuelForwardFuelTypeA_{fy,m} * WeightFuelTypeA + FuelForwardFuelTypeB_{fy,m} * WeightFuelTypeB) + WeightContract_m * ContractPrice_m)$$

$$DailyDeliveredFuel_{fy,m,d} = DailyFuelVariabilityScalar_{y,m,d} * ((FuelForwardFuelTypeA_{fy,m} * WeightFuelTypeA_m * WeightSpotFuelTypeA_m) + (FuelForwardFuelTypeB_{fy,m} * WeightFuelTypeB_m * WeightSpotFuelTypeB_m))$$

$$DailyDeliveredFuel_{fy,m,d} = DailyFuelVariabilityScalar_{y,m,d} * [WeightFuelTypeA_m * (WeightContractFuelTypeA_m * ContractPriceFuelTypeA_m + WeightSpotFuelTypeA_m * (DeliveryAdjustmentFuelTypeA + FuelForwardFuelTypeA_{fy,m})) + WeightFuelTypeB_m * (WeightContractFuelTypeB_m * ContractPriceFuelTypeB_m + WeightSpotFuelTypeB_m * (DeliveryAdjustmentFuelTypeB + FuelForwardFuelTypeB_{fy,m}))]$$

Example 5.1: Create three daily delivered fuel forecasts from the variability of three historic years:

$$DailyDeliveredFuelForecast_{June\ 3,2009}^{baseyear2006} = DailyFuelVariabilityScalar_{June\ 3,2006} * FuelForward_{June\ 2009}$$

$$DailyDeliveredFuelForecast_{June\ 3,2009}^{baseyear2007} = DailyFuelVariabilityScalar_{June\ 3,2007} * FuelForward_{June\ 2009}$$

$$DailyDeliveredFuelForecast_{June\ 3,2009}^{baseyear2008} = DailyFuelVariabilityScalar_{June\ 3,2008} * FuelForward_{June\ 2009}$$

Outputs from STEP 5:
Daily generator-bus delivered fuel forecast

Step 6: ~~create~~ Create generating units dispatch cost for each of the three forecasts

Inputs for STEP 6:
~~Expected future f~~Full load seasonal (May-September / October~~rr~~ – April) heat rate ~~for the compliance period~~

Fuel Prices output from Step 5
Unit SO_2, CO_2, and NO_x Emission Rates (lbs/mmBtu)
~~(Note that the CO_2 adder is in effect only for incurring carbon emission charges)~~Futures prices for SO_2, CO_2 and NO_x from Evolution Markets (\$/ton) modified to \$/lb (Note that the CO_2 adder is in effect only for incurring carbon emission charges)
Maintenance Adder, VOM and FMU as defined in M-15

In step 6, take the unit characteristics, future emission allowance prices, the three daily fuel forecasts and create a daily unit dispatch cost for the three forecasts using the appropriate heat rate for the forecast day. Either the current FMU adder or the 10% scaling factor may be used but not both. ~~-~~For each day in the three fuel forecasts, a unit dispatch cost is calculated as follows:

$$\mathrm{UnitDispatchCost}_{\mathrm{fy,m,d}}^{\mathrm{base\ year}} =$$
$$\Big\{\Big[UnitHeatRate\left({}^{mmbtu}/_{mwh}\right) * DailyDeliveredFuelForecast(\$/mmbtu)_{fy,m,d}^{base\ year}\Big] +$$
$$\Big[UnitHeatRate\ (mmbtu/mwh) * UnitNOxEmissionRate(lbs/mmbtu)$$
$$* Cost\ of\ NOx\left({}^{\$}/_{lb}\right)\Big] +$$
$$\Big[UnitHeatRate\ (mmbtu/mwh) * UnitSO_2EmissionRate(lbs/mmbtu)$$
$$* Cost\ of\ SO_2\left({}^{\$}/_{lb}\right)\Big] +$$
$$\Big[UnitHeatRate\ (mmbtu/mwh) * UnitCO_2EmissionRate(lbs/mmbtu)$$
$$* Cost\ of\ CO_2\left({}^{\$}/_{lb}\right)\Big] + VOM + \Big\} + \text{ either a 10\% margin or FMU adder}$$

Example 6.1: Daily dispatch cost:

Unit heat rate=10.345 mmBtu/MWh
Unit NOx emission rate =0.328 lbs/mmBtu
Unit SO_2 emission rate=1.2 lbs/mmBtu
Unit CO_2 emission rate=117 lbs/mmBtu
DailyDeliveredFuelForecast=\$3.01/mmBtu
Combined NOx Allowance cost=\$1375/ton
SO_2 Allowance cost=\$200/ton

CO_2 emission cost = \$8/ton
VOM & Maintenance Adder=\$2.22/MWh
FMU= \$0.00/MWh

$$\cancel{UnitDispatchCost =}$$

$$\cancel{\left[\left(\frac{10.35mmbtu}{mwh}\right) * \left(\frac{\$3.01}{mmbtu}\right)\right] +}$$
$$\cancel{\left[\left(\frac{10.35mmbtu}{mwh}\right) * \left(\frac{0.328\ lbs}{mmbtu}\right) * \left(\frac{\$1375.00}{ton}\right) * \left(\frac{ton}{2000\ lbs}\right)\right] +}$$
$$\cancel{\left(\left[\left(\frac{10.35\ mmbtu}{mwh}\right) * \left(\frac{1.2\ lbs}{mmbtu}\right) * \left(\frac{\$200}{ton}\right) * \left(\frac{ton}{2000}lbs\right)\right]\right) +}$$
$$\left[\left(\frac{10.345mmbtu}{mwh}\right) * \left(\frac{117lbs}{mmbtu}\right) * \left(\frac{\$8}{ton}\right) * \left(\frac{ton}{2000lbs}\right)\right]$$
$$+ \left(\frac{\$2.22}{MWh}\right) + \left(\frac{\$0}{MWh}\right)$$

$$UnitDispatchCost =$$

$$\left[\left(\frac{10.345mmbtu}{mwh}\right) * \left(\frac{\$3.01}{mmbtu}\right)\right] +$$
$$\left[\left(\frac{10.345mmbtu}{mwh}\right) * \left(\frac{0.328\ lbs}{mmbtu}\right) * \left(\frac{\$1375.00}{ton}\right) * \left(\frac{ton}{2000\ lbs}\right)\right] +$$
$$\left(\left[\left(\frac{10.345\ mmbtu}{mwh}\right) * \left(\frac{1.2\ lbs}{mmbtu}\right) * \left(\frac{\$200}{ton}\right) * \left(\frac{ton}{2000}lbs\right)\right]\right) +$$
$$\left[\left(\frac{10.345mmbtu}{mwh}\right) * \left(\frac{117lbs}{mmbtu}\right) * \left(\frac{\$8}{ton}\right) * \left(\frac{ton}{2000lbs}\right)\right]$$
$$+ \left(\frac{\$2.22}{MWh}\right) + \left(\frac{\$0}{MWh}\right)$$

$$\cancel{\text{UnitDispatchCost}_{fy,m,d}^{\text{base year}} = \left(\frac{\$31.16}{MWh}\right) + \left(\frac{\$2.34}{MWh}\right) + \left(\frac{\$1.25}{MWh}\right) + \left(\frac{\$4.85}{MWh}\right) + \left(\frac{\$2.22}{MWh}\right) = \$41.82/MWh}$$
$$\text{UnitDispatchCost}_{fy,m,d}^{\text{base year}} = \left(\frac{\$31.14}{MWh}\right) + \left(\frac{\$2.33}{MWh}\right) + \left(\frac{\$1.24}{MWh}\right) + \left(\frac{\$4.84}{MWh}\right) + \left(\frac{\$2.22}{MWh}\right) = \$41.77/MWh$$

Outputs for step 6:
Three forecasts based on historic year factors for daily generator dispatch cost

Step 7: Calculate the run hours used-to-date for the current calendar or rolling year

Inputs for Step 7:
Generator real-time run hours for current compliance period

Step 7 calculates the run hours of a generator used in the compliance period to date. Accumulate the running time from the start of the calendar or rolling year to midnight the previous day and round the total run time up to the nearest hour. For example, when ~~computcalculating~~calculating opportunity costs for a calendar year on July 5, 2009, calculate total run hours from January 1, 2009 to July 4, 2009 11:59:59PM and then round up to the nearest hour. ~~So a~~A run time of 3 hours and 50 minutes would round up to 4 hours.

Output from step 7: Generator run hours used to date

Step ~~7~~8: Calculate the margin for every hour in the three hourly forecasts

Inputs for Step ~~7~~8:
Daily Generator Dispatch Cost from Step 6
Hourly Generator bus LMP forecast from Step 3
Generator run hours used to date from Step 7
All future outage information
Unit-specific minimum run time parameter restriction
Unit-specific cold start up costs
Unit Economic Maximum
~~*Daily Generator Dispatch Cost from Step 6*~~
~~*Hourly Generator bus LMP forecast from Step 3*~~

Step 8 calculates the hourly margins the generator would receive by comparing the cost offer developed in step 6 against the hourly forecasted bus LMPs developed in step 3. To remove planned outages, for any future date that the unit will be offline, set the outage hours to unavailable for all three forecasts. For units with minimum run time restrictions, this step calculates total margins in blocks of adjacent hours, based on the sum of the margins of each block and the minimum run time parameter restriction of a unit. Blocks may include additional incremental hours, if these hours are found to be more valuable than an additional block, up to double a unit's minimum run time. Adjacent hour blocks with equal or greater hours than double a unit's minimum run time will be split into multiple blocks. For units with start-up costs, the value of that cold start-up cost divided by economic maximum will be subtracted from the total margin of each block that contains a new start, but not from each subsequent incremental hour added to the block, in order to correctly value hours that do not incur start costs.~~-~~ Calculate the total margins for all blocks of hours in the three forecasts:

$$TotalMarginBlock_{block}^{base\ year} = \sum_{t=block}^{t=block+MinRunTime-1} ForecastedBUSLMP_{y(t),m(t),d(t),h(t)}^{base\ year} - UnitDispatchCost_{y(t),m(t),d(t)}^{baseyear}$$

~~Step 7 calculates the hourly margin the generator would receive by comparing the cost offer developed in step 6 against the hourly forecasted bus LMPs developed in step 3. This methodology assumes no minimum run time, no ramping time restrictions and no startup cost. Calculate the hourly margin for every hour in the three forecasts:~~

$$HourlyUnitMargin_{y,m,d,h}^{base\ year} = \max\left[0, \left(ForecastedBUSLMP_{y,m,d,h}^{base\ year} - UnitDispatchCost_{y,m,d}^{baseyear}\right)\right]$$

Where $block$ ranges from 1 to $[totalNumberofHours - MinRunTime + 1]$ and $y(t), m(t), d(t), h(t)$ are the year, month, day and hour corresponding to the tth overall hour of the time period spanning from the date calculated to the end of the compliance period forecasted.

The $totalNumberofHours$ variable represents the output from Step 7: Generator Run Hours used to date. This variable is the number of hours left in the compliance period to be forecasted, and is based on the date calculated and whether or not the unit has a rolling 12 month run-hour restriction.
~~If the HourlyUnitMargin < 0, then the HourlyUnitMargin is normalized to zero because the unit would not wish to run in any hour in which its dispatch cost exceeds LMP.~~

~~E~~Example 8.1: ~~Comput~~Calculating total margins with a minimum run time of one hour (i.e. no minimum run time restriction), using historical data from the past three calendar years~~xample 7.1: Computing hourly margins~~

$$HourlyUnitMargin_{June\ 3,2009\ H07}^{base\ 2006} = ForecastedBUSLMP_{June\ 3,2009\ H07}^{base\ 2006} - UnitDispatchCost_{June\ 3,2009}^{base2006}$$

$$HourlyUnitMargin_{June\ 3,2009\ H07}^{base\ 2007} = ForecastedBUSLMP_{June\ 3,2009\ H07}^{base\ 2007} - UnitDispatchCost_{June\ 3,2009}^{base2007}$$

$$HourlyUnitMargin_{June\ 3,2009\ H07}^{base\ 2008} = ForecastedBUSLMP_{June\ 3,2009\ H07}^{base\ 2008} - UnitDispatchCost_{June\ 3,2009}^{base2008}$$

$$HourlyUnitMargin_{June\ 3,2009\ H07}^{base\ 2006} = \max[0, (\$53.23 - \$41.66)] = \$11.57$$

~~$HourlyUnitMargin^{base\ 2007}_{June\ 3,2009\ H07}$=max [0, ($55.44 - $57.88)] = $0.00~~
~~$HourlyUnitMargin^{base\ 2008}_{June\ 3,2009\ H07}$=max [0, ($49.78 - $49.72)] =$0.06~~

$$TotalMarginBlock^{base\ 2006}_{block\ 3679} = \sum_{t=block}^{t=block+MinRunTime-1} ForecastedBUSLMP^{base\ year}_{y(t),m(t),d(t),h(t)} - UnitDispatchCost^{baseyear}_{y(t),m(t),d(t)} = \sum_{t=3679}^{t=3679+1-1} ForecastedBUSLMP^{base\ 2006}_{y(t),m(t),d(t),h(t)} - UnitDispatchCost^{base\ 2006}_{y(t),m(t),d(t)} = ForecastedBUSLMP^{base\ 2006}_{y(3679),m(3679),d(3679),h(3679)} - UnitDispatchCost^{base\ 2006}_{y(3679),m(3679),d(3679)} = ForecastedBUSLMP^{base\ 2006}_{June\ 3,2009\ H07} - UnitDispatchCost^{base\ 2006}_{June\ 3,2009} = \$53.23 - \$41.66 = \$11.57$$

- Similarly,

$$TotalMarginBlock^{base\ 2007}_{block\ \#3679} = ForecastedBUSLMP^{base\ 2007}_{June\ 3,2009\ H07} - UnitDispatchCost^{base\ 2006}_{June\ 3,2009} = \$55.44 - \$57.88 = -\$2.44$$

$$TotalMarginBlock^{base\ 2008}_{block\ \#3679} = ForecastedBUSLMP^{base\ 2008}_{June\ 3,2009\ H07} - UnitDispatchCost^{base\ 2006}_{June\ 3,2009} = \$49.78 - \$49.72 = \$0.06$$

At this point, the blocks of hours would be ranked according to the value of their total margins

Output from step ~~7~~8: Three sets of ranked blocks of total margin forecasts including each hour in the compliance period, adjusted to include start-up costs for each block that contains a new start, with all future outage hours removed ~~Three hourly margin forecasts for each hour in the compliance period.~~

~~Step 8: Outages and dates passed~~

~~Input to Step 8: All future maintenance outage information~~

~~For any future date that the unit will be offline, or for any date that has passed, set the margin equal to zero. Therefore, for each of the three forecasts, set all dates that the unit will be unavailable to have zero margins.~~

~~Output from step 8:~~
~~Three hourly margin forecasts for each hour in the compliance period with all future outages and previous days having margins equal to zero.~~

Step 9: ~~Rank the hourly margin forecasts for each of the three years from largest to smallest value~~Determine the opportunity cost adder

Input for Step 9: *Three ~~hourly margin forecasts from step 8 adjusted for outages and days passed~~sets of ranked blocks of total margins forecasts*

~~For~~ For each of the three years, the opportunity cost for that year will be the average total margin of the lowest value block added before the run hour limit was reached. The three opportunity costs will then be averaged to get the opportunity cost adder available to the generator. If the opportunity cost adder is less than 0, the opportunity cost adder will be set to 0. The opportunity cost adder which may be applied to each point on a unit's bid curve will be entered separately into eMkt by the participant.~~each of the three years, rank the hourly margin forecasts from largest to smallest value. Number each by their rank order. The three numbers that correspond to the minimum run hour are averaged together to get the maximum opportunity cost available to the generator.~~

~~Example 9.1: A unit with 700 run hours:~~

~~$\text{700th Margin}_{\text{base2006}}$ = \$2.10/MWh~~
~~$\text{700th Margin}_{\text{base2007}}$ = \$0.00/MWh~~
~~$\text{700th Margin}_{\text{base2008}}$ = \$0.06/MWh~~

~~$\text{The average value of the block which includes the 700th hour}_{\text{base2006}} = \$2.10/\text{MWh}$~~
~~$\text{The average value of the block which includes the 700th hour}_{\text{base2007}} = -\$2.14/\text{MWh}$~~
~~$\text{The average value of the block which includes the 700th hour}_{\text{base2008}} = \$0.06/\text{MWh}$~~

~~700th hour maximum opportunity cost component = $\frac{\$2.10+\$0.00+\$0.06}{3}$ = \$0.72/MWh~~

Example 9.1: A unit with 700 run hours left:

$$\text{The average value of the block which includes the 700th hour}_{\text{base2006}} = \$18.33/\text{MWh}$$
$$\text{The average value of the block which includes the 700th hour}_{\text{base2007}} = -\$6.14/\text{MWh}$$
$$\text{The average value of the block which includes the 700th hour}_{\text{base2008}} = \$1.59/\text{MWh}$$

700th hour opportunity cost adder = $\frac{\$18.33+(-\$6.14)+\$1.59}{3} = \$4.59/\text{MWh}$

Attachment C

Opportunity Cost Calculator

CDTF
April 19, 2010

Joe Bowring
Vik Modi
Bill Dugan

Monitoring Analytics

Opportunity Cost Definition

- Opportunity costs are the value of a foregone opportunity.
- Opportunity costs may result when a unit:
  - Has limited run hours due to an externally imposed environmental limit
  - Is requested to operate for a constraint by PJM and is offer capped.
- Opportunity costs are the net revenue from a higher price hour that are foregone as a result of running at PJM's request during a lower price hour.

Opportunity Cost Definition

- **Opportunity costs may be added to a cost-based offer for units with a documented externally imposed environmental regulation based run-hour restriction.**
- **Examples Include:**
  - **Limit on total emissions**
  - **Direct run-hour restriction**
  - **Heat input limitation**
- **Market Participants may elect to enter their cost-based offer with an opportunity cost component which may be a value less than or equal to their calculated opportunity cost.**

Opportunity Cost Calculation Method

- Methodology uses forward prices for power and fuel costs and an historical basis period to determine the value of future net revenue for run-hour restricted units
- Opportunity cost is calculated using an historical average of the previous three years, combined with forward prices of fuel, electricity, and emission allowances to project the year's LMP at a pricing node.

Issue

- The Manual M-15 which is currently in place (Approved Manual) does not establish a method for the calculation of opportunity cost that is as accurate as it could be.
- The MMU has recommended specific changes to the manual in order to improve the method and make it more accurate.
- The CDTF has reviewed the MMU's proposed changes in detail at multiple meetings and calls.
- The CDTF voted to approve the MMU approach and then the CDTF voted not to approve the specific proposal.
- The MMU is requesting that the MRC review the MMU proposal and approve the MMU proposal.

Primary Differences Between MMU Method and the Approved Manual

	MMU
Rolling Time Period Restrictions	√
Dual Fuel Inputs	√
Spot or Contract Monthly Fuel Flexibility	√
Minimum Run Time	√
Start Up Costs	√
Adjustment for Negative Margins	√
Delivery Adder	√

MMU Calculation Tool

- **The MMU currently has an operating web based tool to calculate opportunity cost as described in the MMU red line to Manual M-15**
- **Inputs gathered by web portal**
- **Login with eFuel account**
- **Easy to use**
- **Historical / futures data gathered from PJM and MMU databases**
  - **No need for users to input**
- **Changes to calculator can be implemented and tested with no impact on users**
  - **No requirement for additional data entry**

MMU Input Screen

Administration Opportunity Cost Operation Data Validation Card Data Reports Tools Logout Help

Opportunity Cost Calculator

Retrieve Effective Date: **Apr/01/2010** Unit: 55555555-TestUnit5 Currently showing data with effective date of : **04/01/2010** and modified by : **0001modiv**

Field	Value
Unit ID	55555555
Has 12-Month Rolling Run-Hour Restriction?	No
Minimum Run Time (hours)	24
Startup Costs (dollars)	.00
Econ. Max (MW)	.00
Summer Average Heat Rate (mmbtu/mwh)	11.8000
Winter Average Heat Rate (mmbtu/mwh)	11.8000
NOX Emission Rate - annual (lbs/mmbtu)	.30000
NOX Emission Rate - seasonal (lbs/mmbtu)	.30000
SO2 Emission Rate (lbs/mmbtu)	.98000
CO2 Emission Rate (lbs/mmbtu)	.00000
VOM ($/mwh)	3.500
FMU ($/mwh)	.00
Scaling Factor (%)	10.00
Delivery charge adder for Fuel Type A ($/mmbtu)	.0000
Delivery charge adder for Fuel Type B ($/mmbtu)	.0000

Year	Month	Percent of Fuel type A	Percent of Fuel type B	Percent Fuel type A is Contract	Percent Fuel type B is Contract	Percent Fuel type A is Spot	Percent Fuel type B is Spot	Contract Price for Fuel type A	Contract Price for Fuel type B
2010	Jan	75.00	25.00		100.00	100.00			13.0000
2010	Feb	75.00	25.00		100.00	100.00			13.0000
2010	Mar	75.00	25.00		100.00	100.00			13.0000
2010	Apr	75.00	25.00		100.00	100.00			13.0000
2010	May	75.00	25.00		100.00	100.00			13.0000
2010	Jun	75.00	25.00		100.00	100.00			13.0000
2010	Jul	75.00	25.00		100.00	100.00			13.0000
2010	Aug	75.00	25.00		100.00	100.00			13.0000
2010	Sep	75.00	25.00		100.00	100.00			13.0000
2010	Oct	75.00	25.00		100.00	100.00			13.0000
2010	Nov	75.00	25.00		100.00	100.00			13.0000
2010	Dec	75.00	25.00		100.00	100.00			13.0000

Platt's Forward Fuel Index for Fuel Type A :

CL11A-Coal - ILLB 11800B 2.65S RAIL

Platt's Forward Fuel Index for Fuel Type B :

OL04B-Oil - No.2 NYH Swap

Outage Input

Start: **Jan/08/2010** 08:00

End: **Jan/08/2010** 08:00

Add Outage Remove Outage

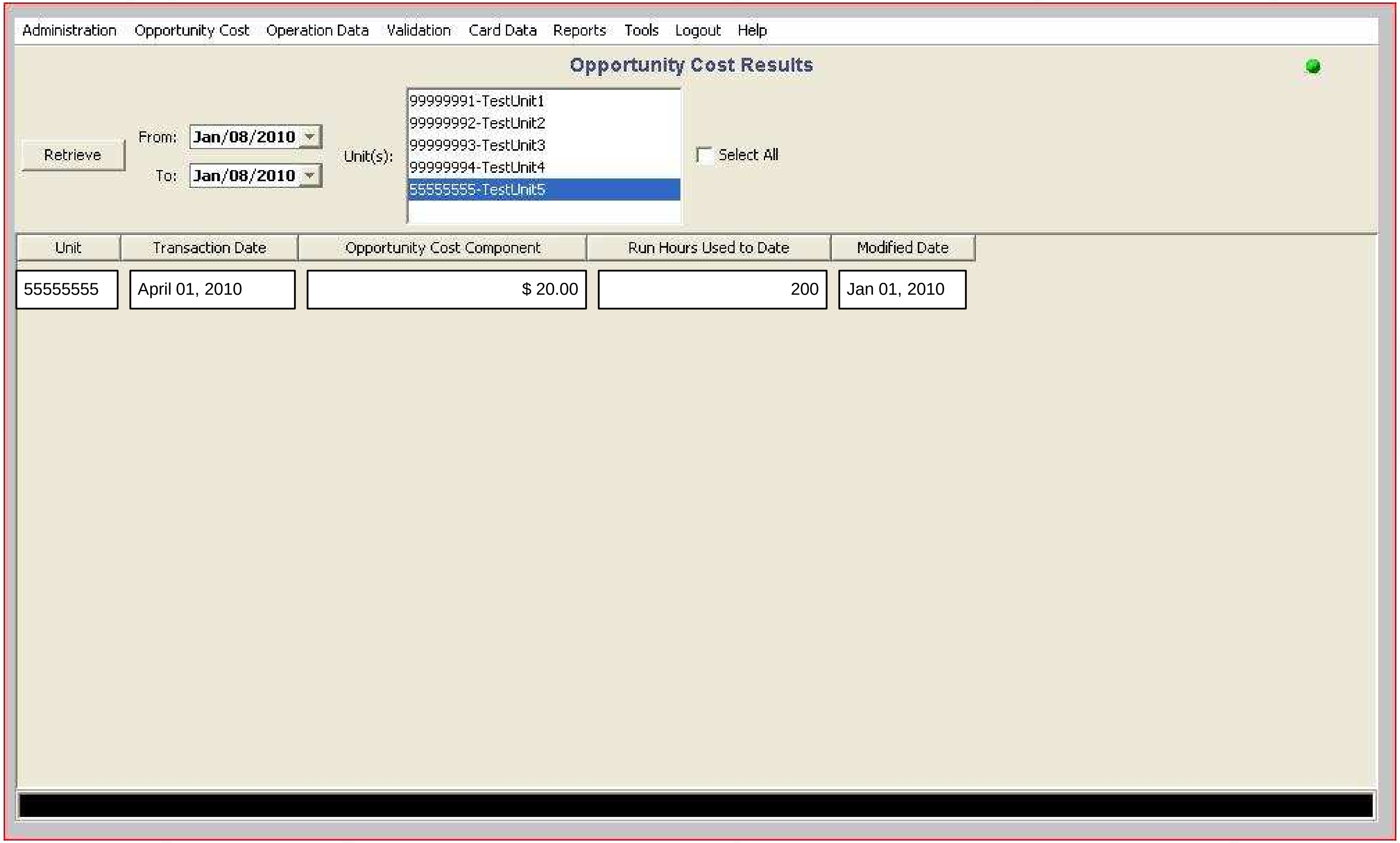
Start	End
03/19/2010 22:00	04/05/2010 08:00
11/26/2010 22:00	12/06/2010 06:00

Run Hour Limitation: 2000

Run Hours Used to Date: 500

Save Opportunity Cost Data

Sample MMU Output Screen



Automatic Updates

- Calculator saves inputs from previous days, including outages
- Automatically updates hours run, without required input from participants
- Recalculates opportunity cost adder daily, without required input from participants
- No need for participant changes unless units change fuel or outage schedule
- Daily automatic updates posted overnight

Ability to Handle Rolling Time Period Restrictions

- **Approved Manual does not address rolling time period restrictions**
- **This feature has been recommended for implementation by the CDTF**
- **Large percentage of units having emission limitations have rolling time period restrictions**
- **Proposed change to manual:**
  - **Account for restrictions based on calendar year or rolling 12 months, depending on actual environmental limits**

Dual Fuel Inputs

- **Approved Manual does not address use of dual fuel inputs**
- **This feature has been recommended for implementation by the CDTF**
- **Proposed change to manual:**
  - **Permits use of dual fuels for units that may burn multiple fuels**
  - **For units with restrictions on consumption of specific fuels, this method allows accounting for both fuels in the same calculation.**
  - **Example:**
    - **Run hour restriction of combined gas and oil output**
    - **Unit has restriction only when burning secondary fuel**

Spot or Contract Monthly Fuel Flexibility

- **Approved Manual does not address flexibility to use spot or contract monthly fuel costs**
- **This feature has been recommended for implementation by the CDTF**
- **Proposed change to manual:**
  - **Flexibility to choose spot price for one fuel and contract price for another fuel or another time period**
  - **Allows members to identify when a contract will end**
    - **If contract ends in the middle of a compliance period, permits use of spot prices or new contract prices**
  - **No need for participants to input fuel spot prices**

Minimum Run Time

- Approved Manual does not account for minimum run time limits
- Proposed change to manual:
  - Account for minimum run time parameter limit for each unit
  - Minimum run time has an impact on calculated opportunity costs
  - Inclusion of minimum run time parameter improves accuracy of calculation based on actual unit parameters
  - For minimum run time, the adder is the average hourly adder for a block of hours, rather than the minimum hourly adder for the remaining run hours

Start Costs

- **Approved Manual does not account for start costs**
- **Proposed change to manual:**
  - **Account for start costs for each unit**
  - **Start costs are a cost of operation and have an impact on calculated opportunity costs**
  - **Inclusion of start costs improves accuracy of calculation based on actual unit costs**

Proposed Start Costs by Unit Type

- **Treatment of start costs based on unit types:**
  - **Combined Cycle units modeled as cycling units may use “Hot” start costs rather than “Cold” start costs**
  - **CT and Steam units should use “Cold” start costs as these units are likely to use this cost in actual dispatch**
  - **Exception process based on documented operating practices/history**

Negative Margins

- Calculation of opportunity costs uses both future fuel and electricity prices and historical data to calculate the margin (LMP minus cost) by hour and by bus
- Three years of historical data is used to provide hourly detail and bus detail because future data is not adequately granular
- Negative margins occur during specific hours and at specific buses when cost was greater than LMP
- Hours of negative margin do not reflect hours when a generator was running

Negative Margins

- **Approved Manual does not account for negative margins**
  - o **Sets negative margin equal to zero prior to averaging**
- **Proposed change to manual:**
  - **Negative margins reflect actual margins from prior years and should be included in calculation**
  - **Accurately accounts for actual market results by hour/bus**
  - **Example:**

700th Margin (2006) = -$100
700th Margin (2007) = -$100
700th Margin (2008) = $75

Maximum Opportunity Cost Component
MMU Method = Max(0, -$41.67) = $0
Approved Manual Method = $25

Fuel Delivery Adder

- **Approved Manual does not account for delivery charges of fuel**
- **As units are not located at trading hub, this adder is needed to enhance accuracy of fuel prices**
- **Delivery adder is provided by market participants, subject to MMU review**
- **Proposed change to manual:**
  - **Fixed delivery adder is added to forward prices in calculation.**

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Attachment D

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Review of MMU Proposed Approach to Treatment of Negative Margins in Opportunity Cost Calculations

Opportunity costs are the value of a foregone opportunity for a generating unit. Opportunity costs may result when a unit: has limited run hours due to an externally imposed environmental limit; is requested to operate for a constraint by PJM; and is offer capped. Opportunity costs are the net revenue from a higher price hour that are foregone as a result of running at PJM's request during a lower price hour. The calculated opportunity cost adder applies only to cost-based offers and is only relevant when a unit is offer capped for local market power mitigation.

The purpose of the calculation method is to calculate the value of the opportunity cost. The method must calculate the margin (LMP minus cost) for every hour in the projected year. Those margins are the hourly opportunity cost.

For example, a unit is limited to 100 run hours for a year based on an environmental regulation. If the unit is required to run by PJM during a low price hour, it can add an opportunity cost to its cost based offer. The value of that opportunity cost adder is the margin from the 100^{th} highest margin hours for the coming year.

In order to calculate the opportunity cost for each hour of the coming year, LMPs and costs must be estimated for each hour of that year. The calculation method uses published forward curves for the price of electricity at the PJM Western Hub and input fuel prices.

The forward energy prices are available by month for PJM's West Hub. The forward fuel prices are available by month or by season or quarter and multiple locations.

It is not possible to have margins for individual units at their specific buses using only forward data. In order to develop margins and therefore opportunity costs for individual units at their specific buses, historical data must be used. The historical relationships between hourly prices at the West Hub and the monthly prices at the West Hub are used as the basis for hourly margins. The historical relationships between individual bus prices and the West Hub price are used as the basis for bus specific margins. The historical relationships between daily real time fuel prices and the forward prices are also used to develop the basis for daily, bus specific margins, together with transportation basis differentials.

The result is an hourly LMP estimate for each generator bus, a daily fuel cost estimate for each generator bus and therefore an hourly margin for each bus. (The net margin also accounts for emissions costs, the ten percent adder, VOM and FMU adders.) The hourly LMP and the fuel costs are the result of using the historical ratios multiplied by the forward curve data. The margins which result from comparing these hourly LMP and fuel cost data reflects the forward data, adjusted using historical data, to the specific generator bus. The only purpose of using the historical data is to translate the forward curve data to specific hours and buses.

If the resultant margin is negative for a specific generator bus, it means that this calculation method results in a negative margin for that bus and hour, based on the forward data translated to specific hours and buses. A negative margin means that there is no opportunity cost associated with that hour. For a method that used a single historical year, the answer is clear. If the margin is negative, the opportunity cost is zero.

The approved method uses an average of three years on the basis of the assumption that it would be more representative to use an average of three years rather than a single year. For the approved method, which uses three years of data as the basis to calculate the margin for an hour at a specific bus, the same logic should hold that holds for a single year. If all three hours have calculated negative margins, there is no opportunity cost. If the average of all three hours is a negative margin, there is no opportunity cost. It is inconsistent with the basic method to ignore the results of individual hours in calculating the opportunity cost. The currently approved method would do exactly that by ignoring negative margins in the calculation of the average.

A negative margin results when the result for the calculation (Projected LMP minus Dispatch Cost) is a margin in which cost is greater than LMP. This does not mean the projected LMP was negative, nor does it mean a generator was or was not dispatched by PJM in this hour. Negative margins in a single hour simply mean that the projected LMP is lower than the projected dispatch cost of a unit for this particular hour, for the designated projected year.

Example 1, no negative margins:

Highest hour in 2007: $100 margin
Highest hour in 2008: $75 margin
Highest hour in 2009: $50 margin

(100 + 75 + 50) / 3 = 75

Average Margin and Final Opportunity Cost Adder: $75

Example 2, with negative margin:

Highest hour in 2007: -$100 margin

Highest hour in 2008: $75 margin
Highest hour in 2009: -$50 margin

(-100 + 75 + -50) / 3 = -25

Average Margin and Final Opportunity Cost Adder: -$25, becomes $0

Example 3, negative margins converted to zero margins:

Highest hour in 2007: -$100 margin, becomes $0 margin
Highest hour in 2008: $75 margin
Highest hour in 2009: -$50 margin, becomes $0 margin

(0 + 75 + 0) / 3 = 25

Average Margin and Final Opportunity Cost Adder: $25

The example above illustrates the substantial differences between rounding up to zero, and including a negative value in the calculation. Using a single year for the opportunity cost adder lacks the hourly fluctuations that an average of three year history might have. LMP being greater than dispatch cost should not be rounded to zero, as it is essential in coming to an accurate opportunity cost adder. Including negative margins in the average of three years, rather than rounding up to zero before calculating the adder is used to maintain the use of yearly projections to the final opportunity cost adder.

If a unit were to actually have a zero margin, it would mean:

LMP – Dispatch Cost = 0

Rounding any negative margin up to zero indicates projected LMP was equal to projected dispatch cost in a given hour, and a unit *should* run on economics for that yearly projection. However, including negative margins accurately indicates a unit *should not* run in that given hour, and it would not be economic to do so. A unit that would not be economic to run in a given projection year should reflect that when averaging three years of projections.