# Proposed Enhancements to Energy Price Formation

PJM Interconnection

November 15, 2017

**Note:**

On May 4, 2018, minor wording changes were made and a footnote was added to Appendix D, pages 48 and 50.

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# Executive Summary

## *The Problem: Why Are Price Formation Reforms Needed?*

Since its inception, PJM Interconnection's wholesale energy market has driven efficient resource entry and exit, successfully managed the retirement of a significant number of coal resources and their replacement primarily by natural gas resources, and maintained a reliable grid. The PJM market has also proven adaptable to changes in the industry as market rules have evolved to meet new needs.

Changes in fuel and technology combined with a slow-down in demand growth are influencing the markets and have revealed an opportunity to enhance energy market pricing so that prices accurately reflect the true incremental cost of serving load and minimize the need to recover those costs through out-of-market uplift payments.

PJM's proposed enhancements will ensure price transparency, provide load-serving entities with the ability to hedge price changes and ensure that incentives support an increasingly efficient commitment and dispatch solution. In addition, sending more-accurate market price signals will incent the development of new flexible resource technologies (e.g., batteries and other forms of energy storage) that can inherently follow load and provide more flexibility.

In short, while recognizing the need to ensure that prices reflect the cost of serving load today, PJM proposes to enhance incentives for following load and increasing flexibility to meet future electricity needs.

Previously, the upward pressure on prices masked shortcomings in the energy pricing mechanism. These higher prices were the result of rising demand and the higher costs of marginal units compared to inflexible units,[1] which are not currently eligible to set price. In the past, higher-cost flexible units set price often enough to ensure that all needed resources could earn sufficient revenues in the energy market, when combined with capacity revenues, to drive efficient resource investments.

Today, the continuing penetration of zero marginal cost resources, declining natural gas prices, greater generator efficiency and reduced generator margins resulting from low energy prices have resulted in a generation mix that is differentiated less by cost and more by physical operational attributes.

[1] Inflexible units are those with declining average costs that are unable to economically produce power within a certain range, or that require an economic minimum output. Inflexible units can be of all fuel types, including coal, nuclear and large gas units, which are inflexible based on either their technology or the way they purchase natural gas.

As a result, enhancing energy price formation so the market sends better price signals has become more prominent and worthy of attention.[2]

The current locational marginal price (LMP) method was chosen because it was simple in both concept and implementation. There have always been circumstances under this method where prices could fail to reflect all elements relevant to sending the right market signals. As mentioned above, under the current market rules, inflexible units are not permitted to set price. When the cost of an inflexible unit that is needed to serve demand is precluded from setting price,[3] the LMP does not accurately reflect the true incremental cost to serve load. This LMP limitation can suppress energy and reserve prices and inappropriately increase reliance on the capacity market.

The capacity market ensures the level of resources and availability necessary for reliability but is not designed to incent flexibility. With capacity performance (CP) enhancements, reliability pricing has supplemented energy pricing as an increasingly important market construct to attract the efficient resource investment necessary to meet peak demand needs. However, beyond aggregated resource attributes such as maximum economic generation and forced outage rates, the CP construct is not intended to reward the flexibility attributes that are essential to efficiently meet operational needs (e.g., short starting time, short minimum running time, low minimum economic generation, fast ramping rate).

The energy and reserve markets remain the essential core market constructs to send the right price signals that reflect the incremental cost of electricity and incent the necessary reliability attributes to maintain a reliable grid.

All resources that PJM schedules to serve demand should have the opportunity to set price and earn their competitive returns in the markets. Inaccurate energy market pricing produces price signals that inappropriately reduce the energy market revenues earned by reliable and economical resources that are needed to serve load, and as a result, the markets will not reward useful resource attributes and will not drive efficient resource entry and exit.

The right price in the energy market should not only reflect the true incremental costs of resources required to serve load, but also drive incentives for providing the flexibility needed to operate the system, given the constantly changing nature of its conditions. Inaccurate energy market pricing that does not adequately value the reliability attributes

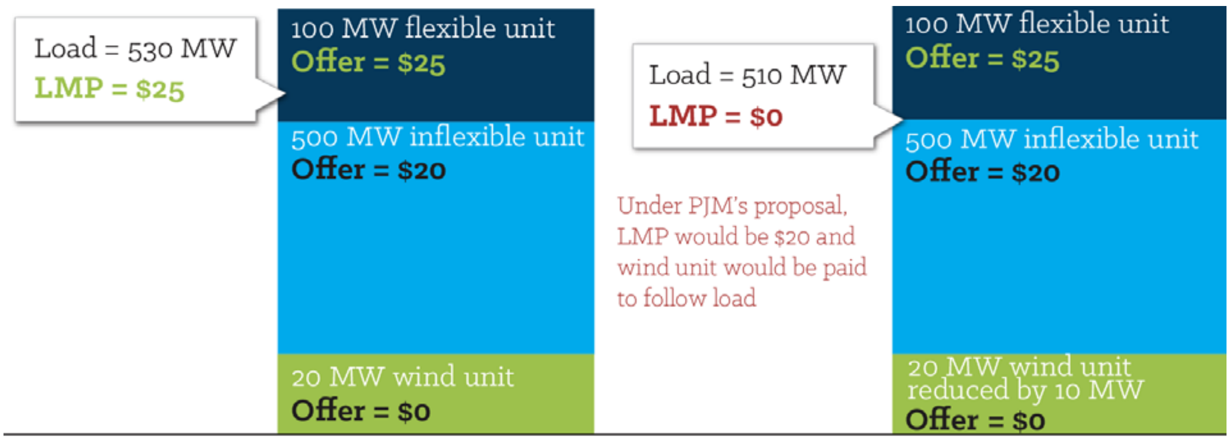
[2] Many of these drivers have been recognized by the Federal Energy Regulatory Commission in its initiation of a series of price formation initiatives. *MISO Order in FERC Docket No. ER12-668-000 (July 20, 2012):* "It is also important that prices send the correct signals to market participants about when more supply or demand response is needed." "Because the SCED algorithm prevents various resources from setting the clearing price, even when those resources represent the last and most costly action taken by MISO, the SCED algorithm may produce an inaccurate price signal." "Allowing more resources to set the clearing price if they are on the margin will help prevent the market price from overreacting to transient illusory shortages and from dropping when a block loaded resource is dispatched to address situations when the system becomes tighter. Thus, the Extended LMP algorithm should enhance market signals by allowing prices to better reflect the cost of actions taken to meet system requirements, a result which we find to be just and reasonable." "In the near term, MISO's proposal should result in prices that better capture the costs considered in committing and dispatching resources. In the long term, it should also send more effective signals about the need for additional resources in the region. By producing a clearing price that better reflects the most expensive action taken to satisfy demand in the region, the Extended LMP algorithm should promote more efficient development of supply and demand resources in the future."

[3] Some inflexible units today recover their costs through uplift payments, and being eligible to set price will not benefit these specific units. However, allowing these units to set prices at the margin reduces the price suppression effects resulting from their current ineligibility to set price and further reinforces the incentives for all units to offer into the energy market at their actual costs. Flexible units will benefit because energy prices do not currently reflect the resources actually needed to serve load when inflexible units are on the margin, and flexible units are therefore seeing lower prices than they otherwise would, and an incentive to be flexible is increased.

provided by needed resources, regardless of fuel type, is likely to result in a less-efficient resource mix to maintain a reliable grid.

Figure 1 helps explain why the current LMP does not accurately represent the true incremental cost or send the right price signals. Given load at 530 MW, a flexible unit at $25/MWh is the marginal unit (the most expensive unit needed to serve load), and LMP is appropriately set at $25/MWh. However, if load drops to 510 MW, and the inflexible units are ineligible to set price, then the LMP would drop to zero, and an uplift payment of $10,000 would be required to make the inflexible units whole.[4] If the inflexible units were eligible to set price, the LMP would be set at $20/MWh by the incremental cost of the most expensive inflexible unit needed to serve load.

Figure 1. Current LMP Does Not Accurately Represent True Incremental Cost




## *The Proposed Solution*

PJM proposes to reform LMP to allow all resources selected for dispatch, both flexible and inflexible units, to set price and thus provide appropriate incentives to support an increasingly efficient commitment and dispatch solution. PJM believes that expanding the eligibility criteria for setting energy market prices to all resources will produce prices that more accurately reflect the true costs to serve load and will value flexibility for following load. These energy-pricing enhancements will also ensure efficient pricing incentives to maintain required levels of load-following capability – that is, the ability to adjust output to match changes in load. Getting prices right is of growing importance, anticipating a continued increase in the penetration of intermittent resources.

## *The Anticipated Results*

Enhancements to energy price formation will improve market price signals that incent units to become more flexible and adjust output when needed to meet dispatch instructions. LMPs will more accurately reflect the true incremental costs to serve load. While energy market costs are likely to go up given this change, as it will compensate resources for providing reliability services that are uncompensated today, market participants will benefit from improved market transparency and efficiency in meeting growing flexibility needs.

[4] In the example in Figure 1, the wind unit is dispatchable down.

Due to the interaction between the energy and capacity markets, there will also be a corresponding reduction in capacity market costs, although this reduction is unlikely to completely offset the increased costs in energy market. Recognizing that the evolving industry with increasingly diverse resources could have bigger impacts beyond the energy market, this PJM proposal will also be an essential first step toward enhanced energy and reserve price formation and will provide long-term benefits, helping to ensure the right energy mix is maintained in the future.

## *Potential Cost Impacts*

As explained in Appendix D, PJM has executed simulations of both the energy and capacity markets to gauge the potential cost impacts of its proposed price formation enhancements. The simulations resulted in an increase in energy market payments that was offset, in part, by reductions in capacity market payments stemming from the increase in net energy market revenues. Overall, the simulations resulted in a net increase in combined energy and capacity market costs of between two and five percent.

## *Shortage Pricing*

In PJM, the term "shortage pricing" is used to refer to the market rules that govern how energy and reserve prices are calculated when there is not enough supply on the system to meet both demand and reserve requirements. Shortage pricing is a critical component of energy market design and presents another important market design opportunity for PJM to enhance the price formation in its energy markets.

An effective shortage pricing model provides clear, transparent, pricing signals to the market to indicate the current operating state of the system and incentivizes market participants to act in a way that promotes system reliability. Prices that escalate commensurate with tightening conditions on the system incentivize "at will" supply such as interchange, non-capacity generation resources, and other supply that is not committed to sell energy to PJM, thereby helping mitigate emergency operating conditions.

By setting energy and reserve prices to levels that accurately reflect system costs and reliability values during shortage conditions, resources that are operating during this period collect additional revenues that go directly towards offsetting going-forward costs. An effective shortage pricing mechanism rewards resources that are supplying energy and other essential grid services during emergency conditions and, therefore, minimizes their reliance on the capacity market for revenue sufficiency. In order to avoid an over-reliance on the capacity market for revenue sufficiency, it is imperative that an effective shortage pricing mechanism be in place even with the existence of a capacity market.

See Part 2: Shortage Pricing for more on PJM's shortage-pricing proposal.

# Part 1: Energy Price Formation

## *Background: Markets in Transition*

For more than 20 years, the PJM wholesale markets have successfully worked to promote competition, produce stable energy prices and attract competitive resource investments to ensure efficient and reliable operations. However, in recent years, the PJM markets have been undergoing a significant transition. While such transitions have also occurred elsewhere, each has resulted in a unique fuel mix. Other independent system operators (ISOs) have transitioned to a fuel mix that contains almost no coal generation and a preponderance of natural gas-fired combustion turbines. PJM, on the other hand, has actually become more balanced with respect to fuel sources, retaining a significant number of coal resources on the system and seeing those that have retired being replaced almost exclusively with combined-cycle natural gas units.

### Shifts in Fuel, Technology, Demand

The wholesale markets have seen an unprecedented fuel and technology shift from coal to natural gas resources, driven by the fast growth of low-cost shale gas and the efficiency improvements of combined-cycle gas turbines. Combined with the continued increase of renewable energy penetration from wind and solar power and decreased electricity demand growth (caused by both economic conditions and the deployment of more energy-efficient appliances, lighting and processes), these developments have resulted in steadily declining energy market prices.

Figure 2 shows the historically low energy prices PJM experienced in 2016. Generally, low prices are desirable and beneficial for consumers — provided they continue to reflect the fundamentals of supply and demand in the market. However, to the extent that prices are suppressed by the analytical methods of the price calculation itself, an opportunity exists to enhance price formation by revising those methods.

Figure 2. Annual Fuel-Adjusted and Load-Weighted LMP (1999–2016)

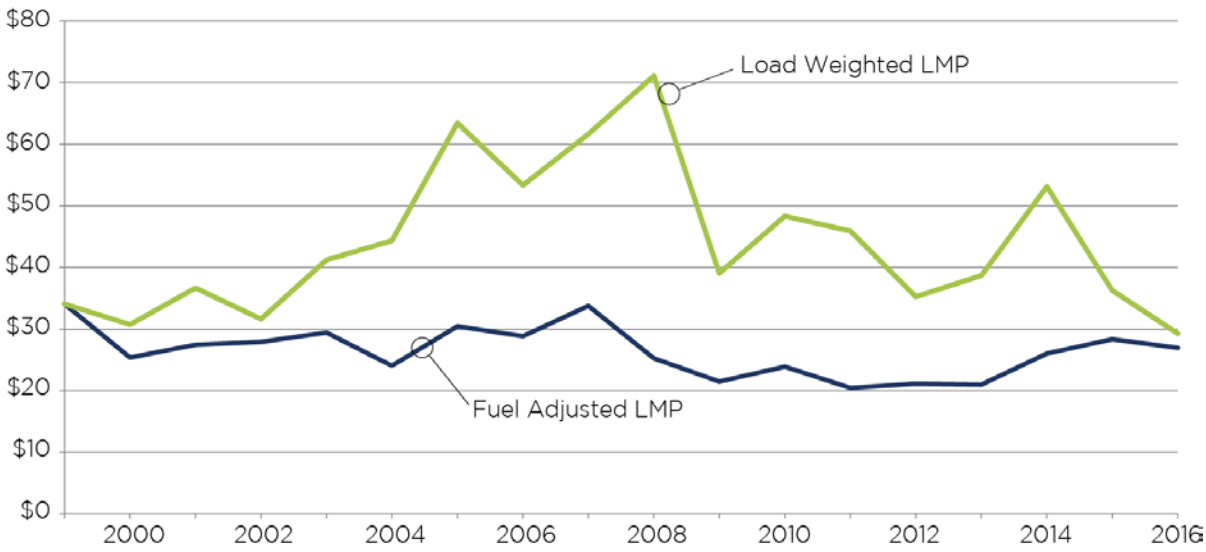
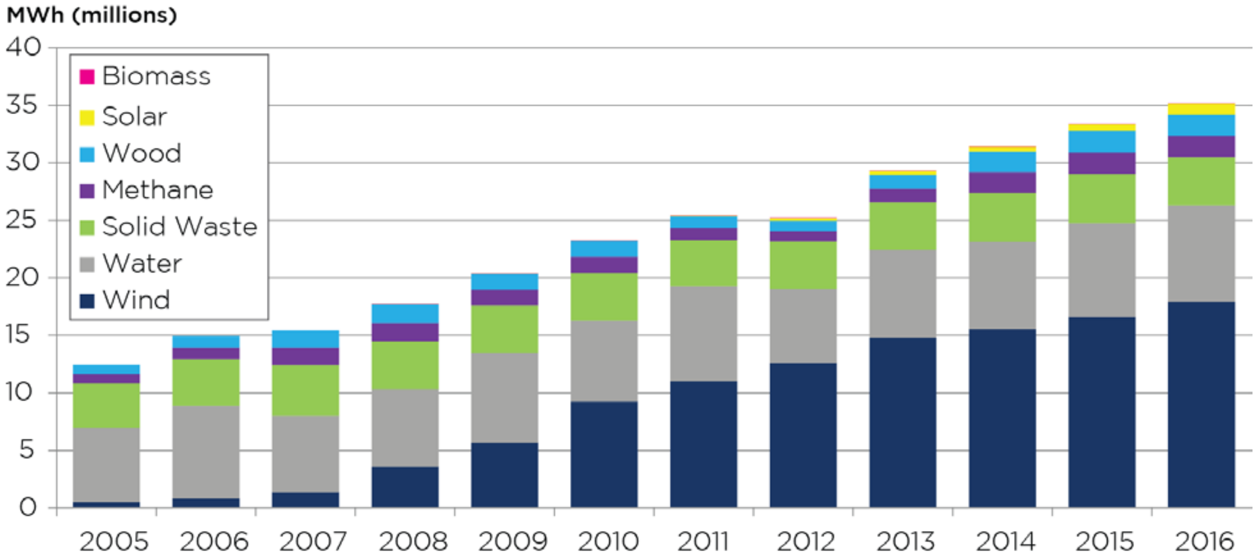


Figure 3 shows that the output of renewable resources measured by the total generation output has increased threefold from 2005 to 2016. With zero marginal costs, the continuing penetration of renewable resources effectively shifts the supply curve to the right (see Figure 4).

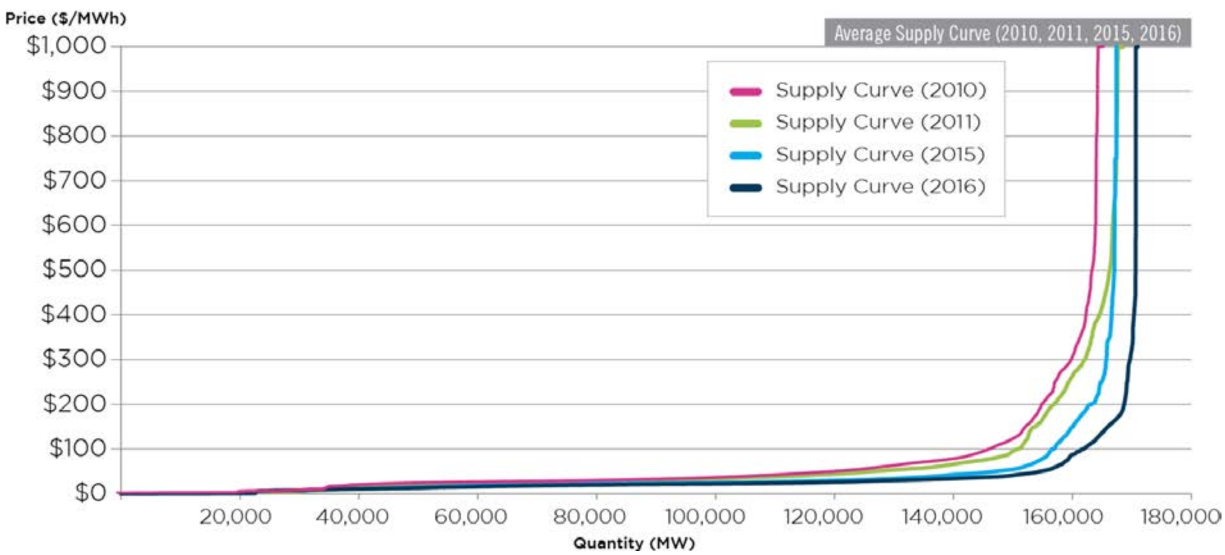
Figure 3. Renewable Energy Growth in PJM




## Low Prices, Flattening Supply Curve, Declining Net Revenue

The Figure 4 price shift reflects the competitive economics of combined-cycle gas turbines assisted by fast-growing, low-cost shale gas, which, in combination with the increase in renewable resources, has led to steadily flattening supply curves in the energy market. The impact of this trend is particularly strong from 120,000 MW to 150,000 MW of load, the range in which peak load levels typically occur in the summer and winter. As Figure 4 shows, in 2015 and 2016, the demand crosses the supply curve all the way through this relatively flat range, never reaching the point at which supply prices begin to increase significantly.

Figure 4. Average Supply Curves (2010, 2011, 2015 and 2016)



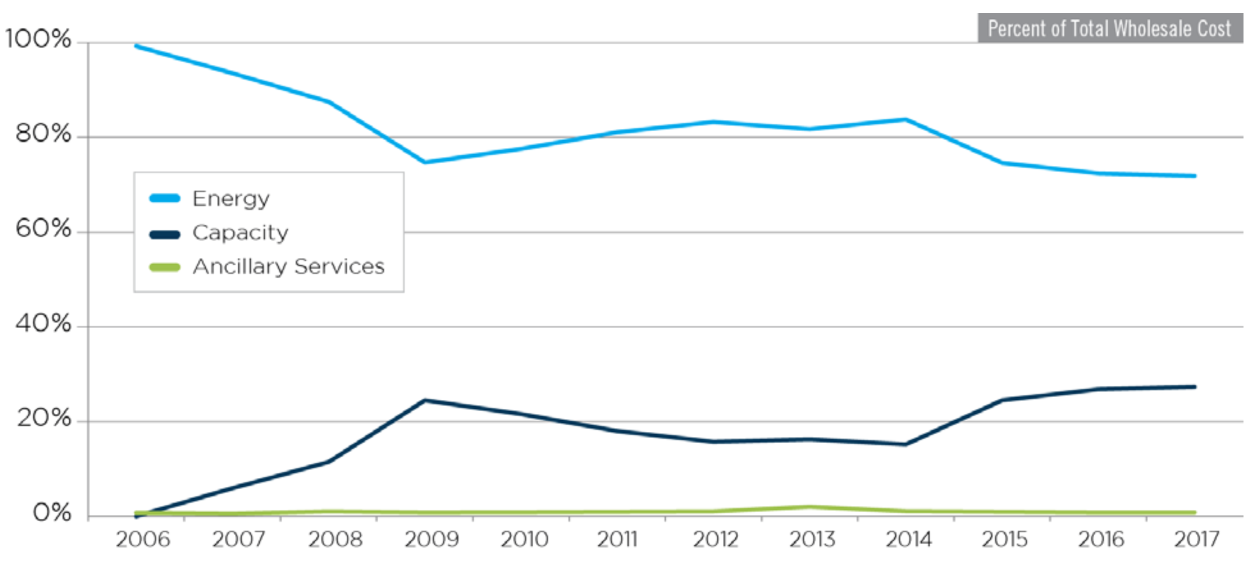
## The Capacity Market Is Not a Substitute for Energy Market Reforms to Incent Flexibility

The capacity market is driven by the resource adequacy requirement to support reliability needs when scarcity pricing is unavailable. The capacity market, with recently implemented capacity performance (CP) enhancements, strengthens investment incentives to ensure the long-term adequacy of resources necessary to support the reliability needs to meet peak demand. The capacity market has supplemented energy pricing as an increasingly important market construct to attract resource investment in order to meet resource adequacy needs efficiently.

As resource adequacy needs grow, the capacity market not only ensures that new resources are added to the system, but also incents more efficient new resources to displace older, less efficient incumbent resources. However, beyond the aggregated resource attributes such as maximum economic generation and forced outage rate, the CP construct is not intended to reward the flexibility attributes that are essential to efficiently meet operational needs (e.g., short starting time, short minimum running time, low minimum economic generation, fast ramping rate). Energy market price formation has always been and should continue to be where flexibility is addressed.

In the current PJM market construct, while the energy and capacity markets serve different functions, their revenues have contributed the predominant share to the recovery of total resource investment costs. Due to the changes in the market conditions described in previous paragraphs, PJM has observed diminishing energy market returns for supply resources. This has resulted in a shift to the capacity market for the greater proportion of returns for generating units' recovery of their total investment costs. As can be seen in Figure 5, this trend has been more pronounced since 2014.[5] However, as noted above, the capacity market does not provide the necessary incentives to ensure sufficient resource flexibility to be able to meet evolving system needs for diverse resources that provide flexibility attributes.

Figure 5. Shift from Energy Market and Ancillary Services Market to Capacity Market




[5] Revenues from the energy and capacity markets were 74.3 percent and 22.9 percent, respectively, of the total generation revenue in 2015, and 71.1 percent and 26.6 percent, respectively, in 2016. The total payments for ancillary services represent 2.8 percent of the total generation revenue in 2015 and 2.3 percent in 2016.

## Questions Raised by Trends

The emerging trends of shifting demand and supply conditions, including stagnating energy demand, lower energy prices, flattening supply curves and the resulting shift to the capacity market for cost recovery, if they persist, could significantly impact the effectiveness of wholesale energy markets in the future. This raises important questions concerning energy price formation:

- If the trends above persist, would the current energy and capacity constructs be adequate to attract the efficient mix of resources investments to meet growing operational needs for flexibility?
- How can energy and reserve market prices more accurately reflect the scarcity value of electricity?
- How can the energy and reserve market prices reflect the value of flexibility and other useful resource attributes?
- How well-aligned are energy-market and reserve-market price formation when a greater proportion of generating units' recovery of total costs is shifting to the capacity market?

As the supply curve is flattening and net demand variability is growing, it becomes increasingly important that energy and reserve prices accurately reflect the system incremental cost, as well as the scarcity value of electricity, two central aspects of efficient price formation.

PJM believes that the reserve markets are a critical element of market design but have not received the same focus as the energy and capacity markets. Jointly optimizing energy and reserve markets with scarcity pricing offer a significant opportunity to enhance the electricity market price formation. Initially, in order to implement the markets more quickly, reserve markets were ignored and the current energy pricing method was chosen because it was simple in both concept and implementation.

As a result, energy prices could fail to reflect elements relevant to sending the right market signals under certain circumstances, and rules for shortage pricing do not accurately reflect the value of energy and reserves during reserve shortages. To fully address price formation issues, reforms are required to PJM's shortage pricing approach as well.

## *The Opportunity: Enhance Market Price Formation*

To enhance the long-term sustainable performance of the competitive market construct, PJM is evaluating market design opportunities to improve energy and reserve pricing. Recognizing the value of an increasingly diverse resource portfolio with distinctive characteristics, PJM is seeking to ensure that the true cost of serving load is reflected in LMP to the fullest extent possible, uplift is reduced, and incentives are maintained. This will ensure that the value of all resources required to serve demand is accurately and transparently reflected in energy and reserve market prices. This proposal follows the principles of sound market design.[6]

[6] See Appendix A for Letter of Support from Dr. William Hogan.

PJM believes that the confluence of the conditions described above presents a unique opportunity to enhance energy market price formation.[7] PJM's long-term goal is to ensure the right market price signals, those which foster efficient resource-investment decisions and enable participation of demand reserves,[8] variable energy resources and distributed energy resources. Energy prices should value all of the resources on the system selected to reliably serve load with the greatest possible accuracy and transparency. Enhancing energy market price formation represents a beneficial and essential step to strengthen the foundation of PJM's markets.

The 2017 Department of Energy (DOE) Staff Report to the Secretary on Electricity Markets and Reliability[9] provided the following recommendation for wholesale markets:[10]

> *FERC should expedite its efforts with states, RTO/ISOs, and other stakeholders to improve energy price formation in centrally-organized wholesale electricity markets. After several years of fact finding and technical conferences, the record now supports energy price formation reform, such as the proposals laid out by PJM[11] and others. Further, negative offers should be mitigated to the broadest extent possible*.

PJM supports the report findings that improved energy market price formation should create price signals that more accurately reflect the true costs of the bulk power supply to meet demand and ensure efficient and reliable operations.

1. In June 2014, the Federal Energy Regulatory Commission (FERC) initiated a price formation proceeding to evaluate issues regarding price formation in the energy and ancillary services markets operated by independent system operators (ISOs)/regional transmission organizations (RTOs). In this proceeding, the FERC established that the goals of price formation are to:
2. Maximize market surplus for consumers and suppliers
3. Provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability
4. Provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system

[7] This entails designing new reserve products as needed, streamlining energy/reserve products in day-ahead and real-time markets and developing reserve demand functions to enable improved scarcity pricing.

[8] Demand reserves refer to a portfolio of ISO-controlled demand response resources that an ISO could use to meet emergency or load-following needs. Demand reserves could be obtained through voluntary customer self-selection from a menu of interruptible service options to be controlled by the ISO in ways that minimize customer costs of service interruption.

[9] *U.S. Department of Energy Staff Report to the Secretary on Electricity Markets and Reliability* (DOE, August 2017). https://energy.gov/staff-report-secretary-electricity-markets-and-reliability.

[10] On Sept. 29, 2017, the DOE issued a proposal directing the FERC to require competitive wholesale power markets to "ensure that certain reliability and resiliency attributes of electric generation resources are fully valued." PJM's proposal, cited by DOE, takes the next step on energy price formation to better ensure that market prices transparently value reliability attributes providing a superior solution with proper price discovery of all resources at the true cost in a fuel-neutral manner.

[11] *Energy Price Formation and Valuing Flexibility* (PJM Interconnection, June 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx.

5. Ensure that all suppliers have an opportunity to recover their costs[12]

Since 2014, the FERC has conducted technical conferences on energy market price formation issues, including the 2016 "Fast-Start" Pricing Notice of Proposed Rulemaking (NOPR).[13] PJM believes that the FERC Fast-Start Pricing NOPR promises important and beneficial change; however, its scope is focused on fast-start units. While enhancements to the LMP calculation in these other ISOs/RTOs have focused on fast-start resources, PJM believes that in the region PJM serves, the need for enhanced energy price formation is related to all resource types.

PJM's resource mix is different from other regions. In particular, natural gas resources in PJM are not limited to fast-start combustion turbines, but rather are represented by significant quantities of larger, combined cycle units. Just over 50 percent of the natural gas fired unit megawatts in PJM are combined cycle units, while only 35 percent of the natural gas unit megawatts are combustion turbines. The remainders are natural gas-fired steam units that do not fit into either category. These resources are competing directly with other resource types, and it therefore does not serve the regional needs to limit the price-setting contribution discussed here to only the fast-start class of units. Rather, price formation in PJM should be neutral to fuel source or resource class so that all units have the opportunity to compete comparably.

## Energy Price Formation

Enhanced energy pricing is an essential, foundational step to achieve efficient energy and reserve market price formation. This step will ensure that the costs of all resources that are selected to serve the system load are accurately reflected in the energy pricing and will provide the right market signals that value all useful resource attributes.

Energy market pricing that adequately values the reliability attributes provided by needed resources, regardless of fuel type, is necessary to maintain a reliable resource mix efficiently. The price signals in the energy market need to reflect the costs of resources required to serve demand and must also drive incentives for providing the flexibility needed to operate the system given the constantly changing nature of its conditions.

Sending accurate price signals to support and incent resource capabilities needed to operate the system is critical for relying on market forces to efficiently maintain a reliable grid. Other ISOs and RTOs have enhanced their energy price formation mechanisms in the relatively recent past. PJM has not and therefore must evolve in order to ensure that its price signals continue to meet their design objectives.

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[12] "Price Formation in Energy and Ancillary Services Markets in Regional Transmission Organizations and Independent System Operators" (June 2014), Docket No. AD 14-14-000. "Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators" (January 19, 2017), FERC Docket No. RM17-2-000.

[13] *Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators* (FERC, December 2016). https://www.ferc.gov/whats-new/comm-meet/2016/121516/E-2.pdf.

## Marginal Cost Pricing and Convex Condition

Energy price formation is built on the foundation of marginal cost pricing. Marginal cost pricing means that the price is set equal to the true incremental cost to produce the last unit of output, or equivalently, the potential increase in system cost if the last-cleared competitive unit were unavailable to serve the demand.

In principle, under the assumption known as the "convex condition," efficient prices equal the short-run marginal costs of production, and marginal cost pricing drives efficient resource investments in competitive markets. When in the convex condition, the average cost (as well as the incremental cost) of production doesn't decline when a generating unit's output increases and doesn't rise when a generating unit's output decreases.

Under the convex condition, the last-cleared unit is always the highest-ranking unit with the highest cost in the merit order. This property conforms to the principle of optimality. The optimal strategy under the convex condition is for each generating unit to bid its true costs and physical operating parameters. This second property conforms to the principle of incentive compatibility.

An inflexible generating unit with a significant minimum operational limit fails the convex condition because when the output decreases below the minimum operational limit, the cost rises, making it uneconomical to run the unit in that range.[14] Under non-convex conditions, units that are economically selected to serve load may incur losses if the price is set at marginal cost. Fundamentally, in the presence of non-convexity, there may be no market prices that can support competitive market solutions without requiring additional payments.[15]

## LMP Pricing Methods

The energy market design based on LMP in PJM follows the basic principles of bid-based, security-constrained, economic dispatch with locational prices, the only known approach that is consistent with an efficient energy market under the principles of open-access and non-discrimination. A crucial element of this model is that the prices and related payments support the efficient dispatch such that market participants are incented to follow the dispatch instructions and submit bids and offers consistent with their actual costs.

Under convex conditions, the current LMP pricing method supports efficient dispatch. The current pricing method has served the PJM markets well for many years, even though additional payments have been required almost daily due to non-convex conditions. Most prominent are circumstances where the problem expands to include commitment decisions with start-up costs and associated constraints such as minimum output levels and minimum run-times. Under these non-convex conditions, locational marginal prices alone cannot always be guaranteed to support the efficient outcome without requiring additional associated payments that must be recovered as part of an "uplift"

[14] In electricity markets, non-convexity arises for other technical reasons, such as fixed start-up/no-load costs, economies of scale and inflexibilities such as minimum-generation or block-loading requirements.

[15] The real price formation issue raised by the concern with inflexibility is non-convexity, as explained in the body of the paper. Although it could be a semantic difficulty, it would be more accurate to describe the problem as convex vs. non-convex instead of flexible vs. inflexible, when the latter may cause confusion. The observation that ineligibility of inflexible units suppresses prices is valid in some circumstances, but strictly speaking, is not true in general. For example, ramp constraints can impose inflexibility, but the constraints are convex and the plants can participate in the pricing model with no special treatment. Such distinction could be important in a broader policy forum.

charge. The shifting resource profiles, evolving external supply conditions and reduced infra-marginal rents described above have brought the limitations of the current method of LMP calculation to the forefront within the PJM region.

In wholesale electricity markets with LMP, two different LMP pricing methods have been used to support competitive market solutions under the condition of non-convexity: restricted LMP and extended LMP.

### *Restricted LMP Method*

The restricted LMP method, which is currently used in PJM, was chosen for the initial implementation of the energy markets primarily because of its simplicity in both concept and implementation. The restricted LMP method ignores the presence of non-convexity in its price-setting logic and assumes that certain units, or certain output ranges of units, are ineligible to set price when they fail the convex condition. It employs a single security-constrained economic dispatch (SCED) model for both dispatch and pricing purposes. In the SCED model, only flexible units are eligible to set price, and the costs for inflexible units are excluded in the pricing run used to calculate the market clearing prices.

As a result, there have always been circumstances where prices could fail to reflect all elements relevant to sending the right market signals. When certain inflexible units that are needed and deemed economical to be committed and dispatched to serve load, but are ineligible to set price in the same SCED model (as shown in Figure 1), the restricted LMP inappropriately lowers energy prices. An uplift payment to the inflexible units is required in order to ensure that their costs are fully recovered. These uplift payments are detrimental to the overall operation of the market, because market participants that must pay these costs are unable to predict or hedge against them.

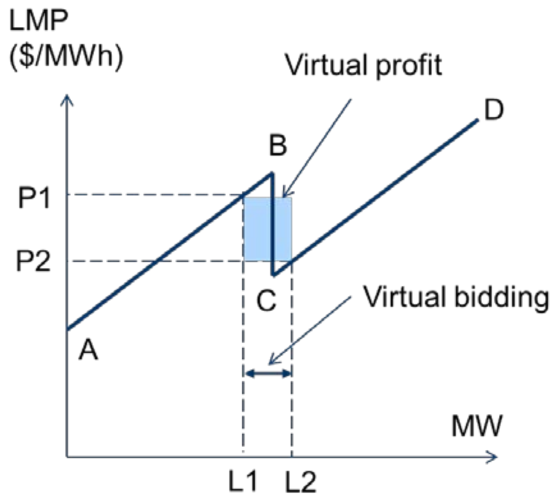
In addition, the restricted LMP method does not assure that the marginal prices are increasing when demand increases, and a declining marginal price curve could create non-transparent arbitrage opportunities for virtual bidding that may potentially increase uplift payments in the day-ahead and real-time markets.

Figure 6 illustrates such a possibility. Assume that the line ABCD represents the marginal price curve as the system load increases, and that the real-time load is L1, and it equals the day-ahead load forecast. Under these assumptions, the day-ahead and real-time market would converge in equilibrium to the same price, P1, without virtual bidding. However, the declining marginal price curve from B to C gives rise to an arbitrage opportunity for virtual bidding, because virtual demand, or a DEC bid, could be used to raise the day-ahead load from L1 to L2 and at the same time, lower the day-ahead price from P1 to P2.

Suppose that the virtual transaction has no impacts on the real-time market outcome; the virtual bidder will earn a profit represented by the shaded area. Similarly, if we assume that the actual real-time load would be L2, then a trading strategy using virtual supply could be used instead to gain the same profit. In more realistic situations with transmission constraints, more complicated trading strategies could be developed using the up-to-congestion (UTC) device at fairly low risks. Such virtual profit would create extra uplift without benefits.[16]

[16] In the absence of such arbitrage opportunity, virtual bidding generally enhances price convergence and beneficial to market efficiency. See Hogan, William (2016). "Virtual Bidding and Electricity Market Design." *The Electricity Journal.*

Figure 6. Arbitrage Opportunity with Virtual Bidding




Uplift payments create, at the margin, a pay-as-bid incentive for units to include inflexible parameters in their offers and receive uplift based on those inflexible parameters.[17] As a result, there is an incentive for the unit to offer as inflexibly as possible while still getting committed by PJM in order to maximize its uplift payments and therefore its profits. Significant effort has been invested in minimizing these uplift costs over time, including putting limitations on the physical parameters that generating units may submit as part of their offers into the market. However, efficient dispatch processes can only minimize the resulting uplift so much.

PJM has been required to create rules to limit physical parameters over the years due to the incentives created by the uplift payments. Currently, resource operators have an incentive to make units less flexible while still being committed by PJM in order to increase the uplift payments they can collect, creating further price suppression effects on the flexible units. Under the PJM proposal this incentive is weakened substantially because, to the extent all units will be eligible to set price and the price is no longer suppressed, an inflexible unit will gain no financial benefit from making units less flexible to the system while increasing the chance of being not committed.

[17] The 2017 Quarterly State of the Market Report for PJM (January–September, Page 206) noted that "But when PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations." by Monitoring Analytics, LLC, Independent Market Monitor for PJM.
http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017q3-som-pjm.pdf

## Extended LMP Method

The need for extended LMP arises from non-convex conditions where there are no uniform prices that reflect the true incremental cost and support the efficient commitment and dispatch solution.[18] In the extended LMP method, prices that reflect the true incremental costs are obtained by relaxing the conditions that cause non-convexities, in a procedure known as convex relaxation.[19]

A defining characteristic of the extended LMP method is that it bifurcates the SCED model into two separate runs: the dispatch run and the pricing run. While the dispatch run is the same as in the restricted LMP method, the pricing run is a convex relaxation of the SCED dispatch run. In the pricing run, the inflexible generation units compete with the flexible units and are eligible to set the energy price when they are needed to meet the demand. With appropriately designed uplift payments, extended LMP can support efficient commitment and dispatch solutions, since market participants should have no incentive to deviate from the solution and (to a large extent) have no incentive to submit offers that differ from their real costs.

An economical inflexible unit selected to serve load would compete with a flexible unit and be allowed to set price. When prices reflect the incremental costs of the marginal units needed to serve load, all resources with lower costs benefit. Under the restricted LMP method, an inflexible resource is paid its costs, but a competing, lower-cost flexible resource may be backed down to accommodate that inflexible resource's minimum generation. As a result, all flexible resources are paid less for energy and are paid no uplift to cover their opportunity cost of not generating because of the inflexible resource's high economic minimum generation level; the current system penalizes flexible units while making whole inflexible ones.

Under the extended LMP method, however, the earnings of flexible generators would not be suppressed by inflexible units, in part because of adjustments to the LMP and in part by payments of lost opportunity costs as uplift. As a benefit, the extended LMP method effectively rewards flexibility, reducing reliance on the uplift payments with improved price signals that incent resource performance in market operations. These incentives will be necessary in the future, as the PJM system continues to experience further penetration of intermittent resources.

The extended LMP pricing method would be compatible with other reforms that are part of the price formation discussion in PJM. Specifically, the enhanced pricing model accommodates improved scarcity pricing, which should play a prominent role in adapting to changing market conditions with increasing supplies of intermittent or distributed resources.

[18] The usual argument for the standard LMP approach avoids this discussion by assuming that there are no non-convexities that affect the total cost of the dispatch and that the LMP prices are all that is needed to support the dispatch. When this assumption is not true, some additional payment is required to avoid creating incentives for market participants to deviate from the economic dispatch.

[19] The theory of extended LMP pricing method is related to what is known as the convex hull relaxation with the property of minimum uplift. However, the minimum uplift approach is computationally difficult to implement. Of the methods that have been studied, the integer relaxation approach provides a convex relaxation that results in outcomes very close to the convex hull relaxation, but ones that avoid the highly challenging operational complexities associated with convex hull relaxation. The extended LMP method discussed here will include integer relaxation as the proposed direction for PJM.

## PJM's Proposed Method: Extended LMP

PJM finds it prudent to move forward using a sound conceptual basis consistent with fundamental principles. Further research into alternative methods since the establishment of the energy markets has revealed that the other methods, if computationally feasible, would yield results that are more compatible with the desired incentives needed to support the efficient commitment and dispatch solution than the restricted LMP method.

PJM is proposing the extended LMP pricing approach to form market prices that more accurately reflect the true costs of all units and support efficient commitment and dispatch solutions. The resulting prices are proposed to be augmented with solution support settlements to improve performance incentives and drive efficient and reliable operations while reducing the use of make-whole payments.

Leading energy market economists have made important contributions to improving on the basic LMP framework to account more fully for the cost of serving load in the energy price under non-convex conditions. Dr. Brendan Ring, later joined by Prof. William Hogan, Dr. Susan Pope and Dr. Paul Gribik, began work on extending the basic LMP to minimize uplift payments that create inefficient market incentives. Their collective work, along with other scholarly contributions, laid the foundation for extended LMP, which was implemented in a limited form by the Midcontinent Independent System Operator (MISO) in 2015.[20]

Although the use of locational prices is still in effect, the choice of an extended LMP pricing method has impacts on the amount of the uplift. PJM believes that the right locational prices should minimize the need for uplift payments. The extended LMP method with convex hull relaxation represents the ideal case that both supports the dispatch and minimizes the uplift.[21] However, this approach presents computational requirements that would be challenging under the best of circumstances, and it is even more difficult to apply in the short intervals required for the real-time spot market.

The extended LMP method with integer relaxation is a natural approximation to the minimum-uplift method based on convex hull relaxation. In the dispatch model, the variable representing the commitment of the resource has an integer value of zero or one and the solution determines dispatch set points for online units. In the pricing model, the integer variables may be relaxed to a value between zero and one for price calculations. After relaxing the complicating commitment constraints present in the dispatch model, the pricing model restores the convex conditions to ensure that the marginal price of the system will not decrease when demand increases.[22]

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[20] See, for example, B. J. Ring, "Dispatch Based Pricing in Decentralized Power Systems," Ph.D. thesis, Department of Management, University of Canterbury, Christchurch, New Zealand, 1995; W. W. Hogan and B. J. Ring, "On Minimum-Uplift Pricing for Electricity Markets," March 19, 2003; A. L. Motto and F. D. Galiano, "Equilibrium of Auction Markets with Unit Commitment: the Need for Augmented Pricing," *IEEE Transactions on Power Systems*, Vol. 17, No. 3, August 2002, pp. 798–805; R. Sioshansi, R. O'Neill, and S. Oren, "Economic Consequences of Alternative Solution Methods for Centralized Unit Commitment in Day-Ahead Electricity Markets," IEEE Transactions on Power Systems, Vol 23, No. 2, (2008) pp. 344-352; and P. R. Gribik, W. W. Hogan, and S. L. Pope, "Market-Clearing Electricity Prices and Energy Uplift," (December 31, 2007, available at https://sites.hks.harvard.edu/fs/whogan/Gribik_Hogan_Pope_Price_Uplift_123107.pdf

[21] For the extended LMP method, see Gribik, P. R., W. W. Hogan, and S. L. Pope (2007) "Market-Clearing Electricity Prices and Energy Uplift," John F. Kennedy School of Government, Harvard University.

[22] See Appendix B for more on PJM's proposed integer relaxation method and examples.

Physical generation units are inherently "lumpy." In other words, they typically need to be brought online at a minimum output level and are required to be operated for a minimum amount of time before they can be turned off. In the current restricted LMP calculation, because of this "lumpiness," when a more expensive unit is dispatched with a minimum output greater than the amount of energy actually needed to serve demand, the extra megawatts from that unit can cause prices to fall instead of increase (see Figure 4), even as the more expensive unit is dispatched to serve increasing demand. This effect prevents prices from reflecting the increased system incremental costs needed to serve the increasing demand.

The relaxed model PJM proposes offers three notable advantages. First, it allows PJM to obtain improved or more accurate LMP using a pricing model that is relatively easy to calculate. Second, under certain conditions, the prices from the relaxed model would produce the same minimum-uplift as convex hull relaxation. In general, the integer-relaxation prices should be close to providing the minimum uplift results. Third, the enhanced pricing method could be easily extended in practice to accommodate future energy and reserve market design and dispatch algorithm enhancements.[23]

## Sound Principles of Market Design

Enhancements to energy pricing should be consistent with sound principles of market design. Any method that PJM follows needs to meet the following design criteria:

1. **Efficient commitment and dispatch.** Given the true costs and operating parameters, the market solution should produce an efficient commitment and dispatch.
2. **Solutions supported by prices and settlements.** Given the efficient commitment and dispatch, the prices and settlements should support the solution, and given the prices and payments, the market participants should have no incentive to deviate from the dispatch.[24]
3. **Incentive-compatible conditions.** To the extent possible, the price and settlement rules should be incentive compatible. Bidding the real costs and physical operating parameters would earn maximum profit for the individual market participants, and thus they should have no incentive to submit offers that differ from their real costs.[25]
4. **Minimized uplift payments.** To the extent possible, the use of uplift payments should be minimized.
5. **Computationally feasible.** The method must be computationally feasible.

Table 1 provides a qualitative assessment of alternative LMP pricing methods based on the above design criteria. Among the three methods assessed, the extended LMP method with integer relaxation that PJM proposes is close to the ideal extended LMP method with convex hull relaxation and is computationally feasible.

[23] See Chao, H. (2017) "Integer Relaxation for Electricity Market Clearing," PJM Interconnection.

[24] The self-scheduled units are generally not as flexible as the pool-scheduled units to follow the dispatch instructions.

[25] Today, since the inflexible units are not eligible to set price, they may not update offers as diligently as the flexible units to accurately reflect their real costs and characteristics.

Table 1. Qualitative Assessment of Alternative LMP Pricing Methods

| Design Criteria | Restricted LMP Method (Current Method) | Extended LMP Method (Integer relaxation – Proposed Method) | Extended LMP Method (Convex hull relaxation) |
|---|---|---|---|
| Efficient commitment and dispatch | High | High | High |
| Solutions supported by prices and settlements | Medium | High | High |
| Incentive-compatible conditions | Low | High | High |
| Minimized uplift payments | Low | Medium | High |
| Computationally feasible | High | Medium | Low |

### Compensating Flexible Units for Following Load

The integer relaxation approach to the price-setting algorithm and the resulting ability for some inflexible units to set energy market prices will require solution support compensation as uplift to flexible units that are dispatched to ensure the balance between generation and load is maintained. Compensating flexible resources will ensure that there is no incentive to deviate from the economic dispatch signals such resources receive.

In addition to the option of applying the extended LMP method to multiple periods in a dynamic setting, PJM is evaluating the need to incent flexible resources for load-following service on the basis of their opportunity cost of not providing energy, similar to other reserve products.[26] PJM believes that this crediting mechanism could be further developed to be consistent with a single clearing price product for providing load-following service in ways that would allow resources to compete to provide this service, including alternative resources that would not otherwise follow economic dispatch signals, such as demand response and storage. As with other products in the competitive markets, competition to provide this service would reduce its cost. As this would be a new product not currently present in the PJM market, allocation of its cost would need to be decided. PJM proposes considering an allocation of a portion of that cost to inflexible units, as inflexible units benefit from the flexibility of other resources since that flexibility allows PJM to dispatch around the inflexible units.

## *Conclusion: Improved Accuracy, Transparency and Efficiency*

PJM believes that expanding the eligibility criteria for setting energy market prices to all resources will produce prices that more accurately reflect the costs of serving load, improve performance incentives, and foster new technologies and emerging designs with flexibility attributes. Customers will benefit from the improved market transparency and efficiency in meeting growing flexibility needs.

While the energy cost, net of capacity credit offset, will likely increase, more accurate pricing will support efficient investment with diverse resource attributes meeting growing operational needs for flexibility in the long term.[27] The proposed energy pricing method is not likely to produce a dramatic change or have as significant an impact as

[26] See Appendix C for a historical review of how resource flexibility offered into the PJM markets has changed over the past three years.

[27] See Appendix D for an approximate estimate of the net impact of PJM's proposed enhancements of price formation.

improved shortage pricing. Nonetheless, it is a beneficial and essential step toward comprehensive enhancement of energy and reserve price formation.

PJM recognizes that, as with any change, there are many issues to discuss and constituency concerns to be considered. PJM will continue to seek feedback and information from the Independent Marketing Monitor and stakeholders to address these and other issues. PJM is concerned, however, that without these changes, the markets will struggle to continue their successful track record of efficiently maintaining reliability, driving efficient resource entry and exit, and enhancing the resilience of the bulk power grid.

# Part 2: Shortage Pricing

## *Background: FERC Order 719*

In PJM, the term “shortage pricing“ is used to refer to the market rules that govern how energy and reserve prices are calculated when there is not enough supply on the system to meet demand and reserve requirements. PJM’s shortage pricing rules were implemented in 2012 as a result of FERC Order 719.[28] In that order, the FERC required each ISO/RTO either to illustrate their current compliance with the FERC’s stated criteria for shortage pricing or to amend their Tariffs and procedures to implement market rule changes that would be compliant with the FERC’s governing principles.

In response to the compliance obligation set forth in Order 719, PJM filed with the FERC indicating that it did not believe its current provisions for shortage pricing met the FERC’s criteria and that it planned to engage in discussions with its stakeholders to design a new shortage pricing mechanism that would be compliant.

On June 18, 2010, PJM made a compliance filing with the FERC that contained provisions to implement a shortage pricing mechanism that conformed to the principles set forth by the FERC in Order 719. The FERC issued an order accepting that filing on April 19, 2012, and PJM implemented its proposal on October 1, 2012.

### The Importance of Shortage Pricing

Shortage pricing is a critical component of energy market design. It provides a method to escalate energy and reserve prices to levels at or near the values at which meaningful demand-side participation can occur either through the actual curtailment of load or through distributed generation. An effective shortage pricing methodology escalates energy prices to this point at the most critical times of need, which is consistent with the times when the ISO/RTO cannot collectively meet the energy and reserve needs of the system. Absent this mechanism, it is extremely unlikely that the cost of wholesale supply resources would rise to the level required for demand to participate in the market, thus removing any incentive for demand-side participation.

An effective shortage pricing model provides clear, transparent pricing signals to the market to indicate the current operating state of the system and incentivizes market participants to act in a way that promotes system reliability. Prices that escalate commensurate with tightening conditions on the system help mitigate emergency operating conditions by incenting “at will” supply such as interchange, non-capacity generation resources, and other supply that is not committed to sell energy to PJM.

Shortage pricing is also critical to ensuring that competitive resources have the opportunity to make sufficient revenues via the markets to cover both their fixed and variable costs. By setting energy and reserve prices to levels that accurately reflect system conditions during shortage conditions, resources that are operating during this period collect additional revenues that go directly towards offsetting going-forward costs. This way, an effective shortage pricing mechanism rewards resources that are supplying energy and other essential grid services during emergency

[28] FERC Order 719, https://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf.

conditions, minimizing their reliance on the capacity market for revenue sufficiency. In order to avoid an over-reliance on the capacity market for revenue sufficiency, it is imperative that an effective shortage pricing mechanism be in place even given the existence of a capacity market.

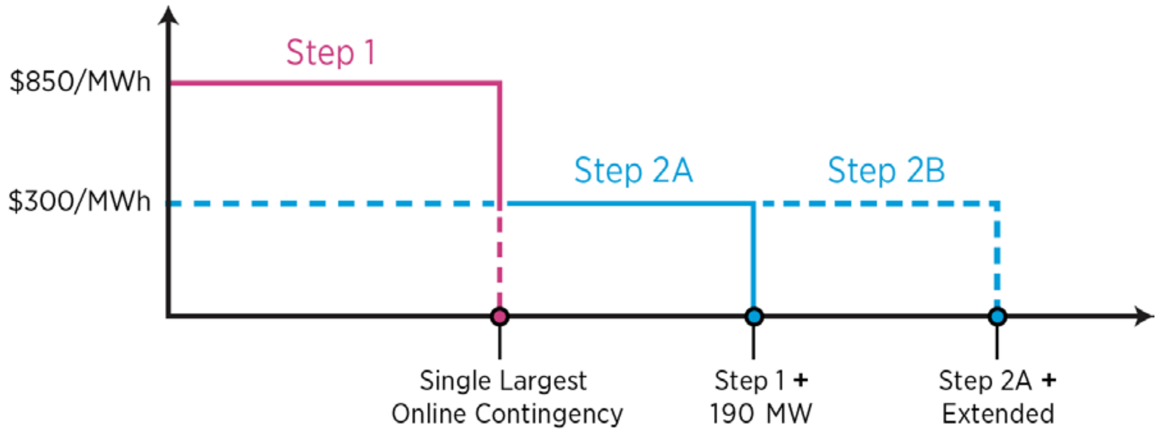
## *Co-optimization and the Operating Reserve Demand Curve*

Since its implementation in 2012, PJM's shortage pricing mechanism has remained relatively unchanged. The core components of the shortage pricing mechanism are the implementation of operating reserve demand curves (ORDCs) and the co-optimization of energy, synchronized reserves and non-synchronized reserves. This model is widely accepted throughout the industry and has been adopted by other ISO/RTOs, such as ISO New England, New York ISO, and the Midcontinent ISO. While the general methodology has become the industry standard, the specifics around the implementation vary depending on the needs and operational practices of each region. Details such as which reserve products can trigger shortage pricing and the levels and shapes of the ORDCs differ across the ISO/RTOs.

Under this methodology, the combination of the co-optimization of energy and reserves and the use of an ORDC produces shortage prices when energy and reserve requirements collectively cannot be met.

An example of the ORDC used by PJM for 10-minute synchronized reserves is shown in Figure 7.

Figure 7. ORDC Used by PJM for 10-minute Synchronized Reserves




On the horizontal axis there are three points, identified as "Step 1," "Step 2A," and "Step 2B." These points correspond to varying levels of 10-minute synchronized reserves. Each level of reserve has a price associated with it on the vertical axis that represents the maximum cost willing to be incurred to meet that level of reserves.

For example, if 10-minute synchronized reserves were the only product required, the ORDC in Figure 7 indicates that there is a maximum willingness to pay of $850/MWh to maintain the amount of synchronized reserves associated with Step 1. It then follows that the ORDC indicates that, for the levels of reserve associated with Steps 2A and 2B,[29] there is a willingness to pay of $300/MWh.

The term co-optimization refers to the fact that the optimization algorithm used to dispatch the system and calculate prices is optimizing more than one product simultaneously. In the case of PJM's real-time dispatch and pricing tools, those products are energy, 10-minute primary reserves and 10-minute synchronized reserves.

Prior to implementing the co-optimization used currently, PJM's dispatch and LMP calculation engines sought to optimize solely energy. The reserve needs of the system were met using other tools specifically focused on optimizing those commitments on a forward basis, and those commitments were then fed into the dispatch and LMP engines as fixed commitments.

When the dispatch engine was executed, it would dispatch energy in the most optimal way without changing reserve commitments. Energy prices were then calculated consistent with the dispatch of energy and the predetermined reserve commitments. Under co-optimization, the dispatch and LMP calculation engines now optimize energy and reserve products simultaneously. This results in a more optimal dispatch of the system and prices that are consistent with that dispatch.

The use of energy and reserve co-optimization along with ORDCs allow for the expression of reserve shortages in the energy price. This occurs because the LMP calculation under co-optimization considers both the reserve and energy needs of the system simultaneously. When the LMP is calculated, if dispatching the next megawatt of energy causes a reserve shortage, the price from the ORDC will be used to determine the energy price in addition to the cost of the resource serving the next megawatt of load. The LMP (the cost to serve the next megawatt of load) will then reflect the cost of the marginal resource providing energy to serve that load plus the price from the ORDC corresponding to the requirement that is short.

## *PJM's Shortage Pricing Implementation*

In PJM, the reserve products for which ORDCs are modeled and that can trigger shortage pricing are total 10-minute reserves, also known as primary reserves, and 10-minute synchronized reserves. Primary reserves include all 10-minute reserve capability including offline resources that can be started within 10 minutes. The synchronized reserve requirement can only be met by online resources that have available capacity that can be converted to energy within 10 minutes.

The nominal requirements for primary reserve and synchronized reserve are set at 150 percent and 100 percent of the largest online contingency, respectively. However, these requirements are nested and not cumulative. When procuring reserves, PJM commits 150 percent of its largest online contingency in total 10-minute reserves if at least 100 percent of the largest online contingency can be procured as synchronized reserves. For example, if the largest online contingency is 1,000 MW, PJM would procure 1,500 MW of primary reserves, of which 1,000 MW would be

[29] Step 2B on the ORDC is implemented as an optional step. This step is only included when PJM system operators intentionally take an action in real-time to carry reserves beyond the normal requirements indicated at Step 1 and Step 2A.

synchronized reserves. When PJM cannot meet either of those requirements, reserve and energy prices are calculated reflective of such shortages.

## *Opportunities to Enhance Shortage Pricing*

Given the criticality of shortage pricing to the success of the overall market design, it is important that it be robust. PJM believes that there are opportunities to enhance its current shortage pricing methodology to build on the benefits of effective shortage pricing but also to harmonize with the preceding energy price formation proposal. PJM has identified the following issues as potential areas to enhance its shortage pricing mechanism:

1. **Escalate energy and reserve prices prior to shortages.** Shortage pricing does not take effect until there is a shortage of 10-minute primary reserves or 10-minute synchronized reserves. From a reliability perspective, this is a severe operating state. PJM believes that escalating energy and reserve prices prior to such 10-minute reserve shortages will incentivize market response to avoid these circumstances.

2. **Articulate value of reserves through demand curve.** The current ORDCs do not meaningfully value reserves in excess of the normal operating requirement. While these curves do contain a smaller second step at $300/MWh, this step was implemented as a method to protect against price swings from transient shortages rather than a focused attempt to value reserves on the system. Similar to the variable resource requirement curve used in the capacity market, PJM believes that there is a reliability value to operating reserves even when they exceed the largest online contingency in real-time, and the value of those reserves should be articulated through the demand curve.

3. **Update ORDC pricing based on reliability value.** The current ORDCs have prices that are based on historic costs to provide these services rather than their reliability value. This results in relatively low prices for such services that are inconsistent with their importance to grid reliability.

### Redefining the Operating Reserve Demand Curves: Loss of Load Probability

The Loss of Load Probability (LOLP) calculation is commonly utilized in planning models to estimate the probability of shedding load given the uncertainties associated with load, capacity and transmission forecasts. These uncertainties tend to be large in planning models given that the planning horizon is usually years in advance. A similar LOLP calculation can be used to derive ORDCs (as described in the next subsection) by measuring the same set of uncertainties used in planning models, but quantified based on a time-horizon consistent with real-time operations.

Modeling the uncertainties associated with load, capacity and transmission forecasts can be accomplished by examining the historical errors of such forecasts. These errors can then be used as the parameters of closed-form distributions (normal distribution, for example) to characterize the uncertainties associated with them. Assuming that the transmission uncertainty is negligible or that it is captured within the capacity uncertainty, the LOLP can be defined as,

$$\text{LOLP} = \text{Probability}\ (C - L < X)$$

where C is capacity, L is load and X is the lowest amount of reserves PJM would carry prior to initiating emergency procedures.

Using the closed-form distributions characterizing the uncertainties of the C and L forecasts, the calculated LOLP provides the answer to the following question: If the difference between capacity and load (i.e., operating reserves) is a given value, what is the probability of shedding load in real-time?

## Deriving a New Operating Reserve Demand Curve

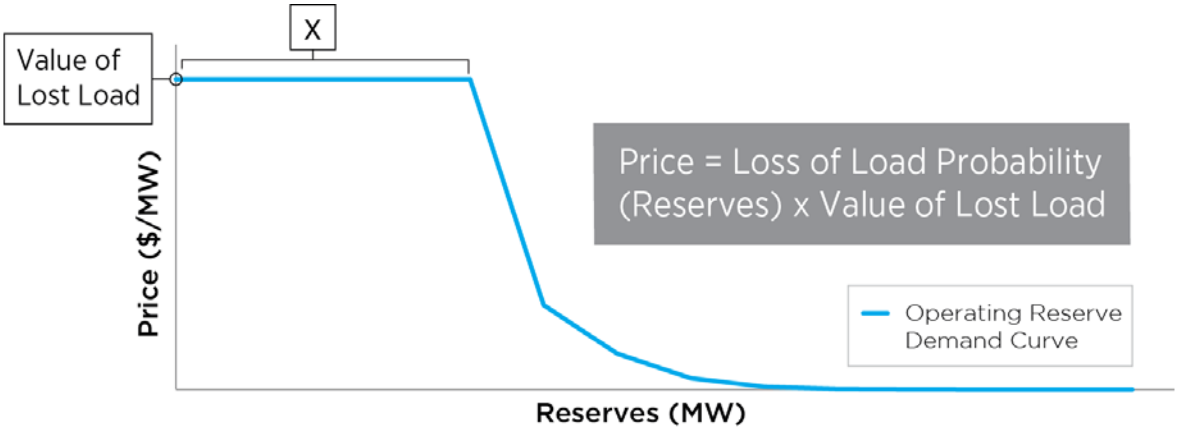
Traditional planning models use the loss-of-load event concept to describe the case when operating reserves are less than a defined threshold. These models assign a value of lost load (VOLL) as the marginal value for this threshold reserve level since a 1 megawatt reserve increment would prevent shedding 1 megawatt of load. Establishing an ORDC requires determining the incremental value of reserves at a range operating reserve levels. To do this, the loss of load and VOLL concepts can be used.

The first step in determining the ORDC is to calculate the LOLP function based on the uncertainties experienced in real time. Intuitively, as operating reserve levels increase, the LOLP decreases because there are more reserves available to respond to uncertainty on the system. Conversely, as reserve levels decrease, the LOLP will increase because there are fewer reserves available to respond to uncertainty. In the planning example cited above, when operating reserves fall below the defined threshold, the LOLP approaches 1. The incremental value of this threshold operating reserve level is equal to the VOLL as a result of multiplying the LOLP by the VOLL (1 x VOLL = VOLL). Similarly, the incremental value for other operating reserve levels can be calculated by multiplying the LOLP for such operating reserve levels by the VOLL. The resulting demand curve for operating reserves has the general shape presented in Figure 8.

Figure 8. Demand Curve for Operating Reserves


Note that there may be differences between the operating reserves threshold that defines a loss-of-load event used in planning models (usually 0 megawatts, as shown in Figure 8, y-axis intersection) and the real-time operating reserve threshold used in the derivation of ORDCs. In the latter case, the threshold value is likely to be greater than 0 megawatts since PJM operates to a specific minimum reserve requirement (see X value in Figure 9).

Figure 9. Demand Curve for Operating Reserves with Minimum Reserve Requirement




Redefining PJM's ORDCs using this methodology would enhance PJM's shortage pricing mechanism by assigning a value to reserves consistent with their reliability benefit to the system. Additionally, this ORDC model allows reserves to be committed in excess of the nominal requirement when it lowers the LOLP but assures that the cost of such reserves will never exceed the reliability benefit.

## *Conclusion*

Shortage pricing presents an important market design opportunity for PJM to enhance the price formation in electricity markets. Shortage pricing reduces the "missing money" problem and thus the reliance on the capacity market revenues to attract efficient resource investments. Shortage pricing facilitates demand response and distributed generation during reserve shortage periods when it is most needed. Shortage pricing can also interact with transmission congestion and provide better signals for transmission investment. Improved shortage pricing would substantially enhance market performance. For these reasons, PJM believes that it is critical that the aforementioned facets of the shortage pricing mechanism be reviewed and enhanced.

The PJM proposal will enhance shortage pricing through:

- Better alignment between reserve pricing and reliability value
- Implementing a real-time, 30-minute operating reserve product to enhance shortage pricing by sending price signals to incent response prior to a shortage of 10-minute reserves, thereby mitigating severe shortages of 10-minute reserves

# Appendix A: Letter of Support from Dr. William Hogan

**HARVARD Kennedy School**
JOHN F. KENNEDY SCHOOL OF GOVERNMENT

October 23, 2017

Mr. Stu Bresler
Senior Vice President Operations & Markets
PJM Interconnection
2750 Monroe Blvd
Audubon, PA 19403

SUBJECT: PJM Price Formation

Dear Mr. Bresler:

I participated with the PJM staff and Board members in the discussion of an important initiative in the evolution of the PJM energy market. PJM staff is proposing to reform the existing pricing model in order to ensure that the incremental cost of serving load is reflected in LMP to the fullest extent possible, uplift is reduced and incentives are maintained. This follows the principles of sound market design. Enhanced energy market price signals will strengthen performance incentives in PJM's markets and is complementary to other reforms being considered by PJM. Given my knowledge of the PJM resource profile, this reform would be an appropriate step forward in price formation for the PJM region.

The market design in PJM follows the basic principles of bid-based, security-constrained, economic dispatch with locational prices. This design is the only approach that is consistent with an efficient energy market under the principles of open-access and non-discrimination. A crucial element of this model is that the prices and related payments support the efficient dispatch. In particular, it serves to achieve the goal that market participants who take prices as given would have no incentive to deviate from the dispatch, and would help make bids and offers consistent with their underlying costs.

The foremost element of this market design is the use of locational marginal prices. Under certain simplifying assumptions, these locational marginal prices provide all that would be needed to support the efficient dispatch.

Relying on the locational marginal prices has served the PJM markets well for many years, even though in some circumstances additional payments have been required.

I have discussed with PJM staff the circumstances that deviate from the simplifying assumptions required for locational marginal prices alone to provide full support for efficient operations. Most prominent are conditions where the problem expands to include commitment decisions with start-up costs and associated constraints such as minimum output levels and minimum run-times. Under these conditions, locational marginal prices alone cannot always be guaranteed to support the efficient outcome and additional associated payments are made that must be recovered as part of an "uplift" charge. The additional payments in aggregate equal the foregone profits from following the dispatch. PJM has explained that within the PJM region, its resource profile, flattening price curves and reduced infra-marginal rents have brought the limitations of the locational marginal prices to the forefront and that the PJM market as a whole would benefit from the proposed enhancements for price formation.

The use of locational prices is still indicated, but the choice of these prices has effects on the amount of the uplift. There is an argument for choosing the locational prices, that cover the bulk of the energy revenues, to come as close as possible to minimizing the need for the additional uplift payments. As I have discussed with PJM staff, this ideal case both supports the dispatch and minimizes the uplift.[30] However, this approach presents computational requirements that would be challenging under the best of circumstances, and even more difficult to apply in the short intervals required for the real-time spot market.

A natural approximation to the minimum-uplift model is available in the "integer relaxation," as PJM intends to propose. This approach employs a pricing model that relaxes the complicating commitment constraints and restores the simplifying assumptions to ensure that the marginal price of the system will not decrease when demand increases. The locational marginal prices from this relaxed model would be easy to obtain. Under certain conditions, the prices from the integer relaxation would be the associated minimum-uplift prices. In general, the integer-relaxation prices should be close to providing the minimum uplift results.

Importantly, the enhanced price formation PJM intends to propose would be compatible with other reforms that are part of the larger discussion in PJM. For example, the enhanced pricing would be extended in practice to deal with multi-period problems where ramp rates and other flexibilities are important. Furthermore, the enhanced pricing model could accommodate improved scarcity pricing which should play a prominent role in adapting to changing market conditions with increasing supplies of intermittent or distributed resources.

I support the energy pricing method PJM intends to propose. But I do not expect it likely to produce a dramatic change or have as significant an impact as improved scarcity pricing. Currently PJM's rules for shortage pricing do not accurately value energy and reserves during reserve shortages. Based on the current penalty factors, the value of energy and reserves do not approach the estimated value of lost load (VOLL). Additionally, PJM's demand curves do not articulate the reliability value of reserves to the system. To fully address price formation, reforms are required to PJM's shortage pricing approach as well. Nonetheless, PJM's proposal to implement integer relaxation is a beneficial and essential first step toward solving the bigger issue of a more comprehensive enhancement of energy

30 This is known as the "minimum uplift" or "convex hull" approach. See (Gribik, Hogan, & Pope, 2007).

and reserve price formation. And given the circumstances faced by PJM as described above, I am supportive of this approach as a reasonable and appropriate step to be proposed by PJM as a means to address needed price formation reforms in the PJM market.

Very truly yours,

William W. Hogan[31]
Raymond Plank Professor of Global Energy Policy
John F. Kennedy School of Government
Harvard University
Mail Box 84
79 John F. Kennedy Street
Cambridge, MA 02138

## Reference

Gribik, P. R., Hogan, W. W., & Pope, S. L. (2007). Market-Clearing Electricity Prices and Energy Uplift. http://www.hks.harvard.edu/fs/whogan/Gribik_Hogan_Pope_Price_Uplift_123107.pdf

[31] Note: These comments are those of William Hogan, and do not necessarily represent the views of anyone else. The work has been supported by PJM and FTI Consulting.

# Appendix B: Integer Relaxation Model and Examples

In economic or mathematical terms, the price formation issue raised by supply inflexibility is termed "non-convexity."[32] In electricity markets, non-convexity arises from technical features such as economies of scale, lumpiness, fixed start-up/no load costs, minimum economic generation and inflexibility, such as block-loading requirements.

In a landmark paper in the economic literature on the marginal cost pricing theory, Coase (1946) explained that in the presence of declining average costs or non-convexity, marginal cost pricing is flawed, for it would lead to inefficient allocation and distribution of resources and could cause further inefficiencies because of the administrative mechanism used to cover losses.[33]

In LMP-based market design, the implementation of bid-based security-constrained economic dispatch with locational prices follows the optimality and equilibrium principles based on the duality theory. Under convex conditions, the dispatch and pricing solutions are equal to the primal and dual solutions of the same SCED run, ensuring that the LMPs support the optimal dispatch solutions without the need for uplift payments. A non-convex condition unavoidably gives rise to a situation with what is called a duality gap, implying that prices alone would not be sufficient to support the dispatch solution without uplift payments. The best one can do is to reduce the total uplift to be equal to the duality gap.

Two known approaches for energy pricing under non-convexity are the restricted LMP method and the extended LMP method. The restricted LMP pricing method is simple both in concept and in implementation. In essence, the restricted LMP method ignores the non-convex inflexible units and relies on only one SCED run for both pricing and dispatch solutions. But this simplistic approach creates adverse economic incentives. Apparently, there is an incentive for units to bid in inflexible operating parameters in order to collect uplift payments. In the current restricted LMP pricing method, the relationship between the dispatch and the price is based on a restricted or partial primal-dual relationship that may not support an efficient solution, for solving the unit commitment and economic dispatch problem involves a mixed integer program, where admits a more general dual formulation, called the Lagrangian dual. As a result, the current energy pricing method often creates a large number of units that are needed to serve load but are inappropriately classified as uneconomic. This restricted approach produces price suppression effects and inappropriately increases reliance on the capacity market.

[32] Although it is valid in certain circumstances, inflexibility does not imply non-convex in general. For example, ramp constraints can impose inflexibility, but the constraints are convex and the plants can participate in the pricing model with no special treatment. It is more accurate to describe the issue as convex vs non-convex than flexible vs. inflexible, when the latter causes confusion. The distinction could be important in a broader policy forum such as the forthcoming discussion at FERC on resiliency.

[33] "The marginal cost controversy" *Economica* (1946); reprinted in *The Firm, the Market and the Law*, by Ronald Coase, The University of Chicago Press, Chicago, IL.

The need for extended LMP arises because under non-convex conditions, no prices can simultaneously reflect dispatch and support the solution.[34] The extended LMP method remedies these problems through the convex relaxation to obtain efficient prices from solving the more general dual model and enhances the economic incentive for marginal units to follow the dispatch instruction. A defining characteristic of the extended LMP method is that it bifurcates the SCED model into the dispatch run and the pricing run. The convex relaxation allows the costs of all resources, including both flexible units and inflexible units with non-convexity conditions, to be incorporated in the pricing model for setting market prices in a manner consistent with competitive market incentives that support the efficient unit commitment and economic dispatch solution.

The extended LMP method with convex-hull relaxation represents the ideal case that both supports the dispatch and minimizes the uplift.[35] However, this approach is difficult to implement in practice because it presents computational requirements that would be challenging under the best of circumstances, and it is even more difficult to apply in the short intervals required for the real-time spot market.

## *Integer Relaxation*

The extended LMP method based on integer relaxation is a natural approximation to the minimum-uplift method based on convex hull relaxation. With integer relaxation, the constraint that each unit commitment variable must be an integer value equal to zero or one is relaxed with partial commitment. This approach employs a pricing model that relaxes the complicating commitment constraints and restores the convex conditions to ensure that the marginal price of the system will not decrease when demand increases. The locational marginal prices from this relaxed model would be easy to obtain. Under certain conditions, the prices from the integer relaxation would be the associated minimum-uplift prices.[36] In general, the integer-relaxation prices should be close to providing the minimum uplift results.

For illustrative purposes, a mathematical model of the integer relaxation approach is presented. For simplicity of notation, we consider the standard model of the electricity unit commitment and economic dispatch problem with fixed demand and no operating reserve requirements. Without loss of generality, generators are treated as a single representative generator at each node in the grid, having the same index as the node. Including demand bids, operating reserves and joint determination of energy and reserve prices raises no fundamental issues. Similarly, application in real-time would require rolling the solution forward, which can be accommodated, but would complicate the notation.[37]

Notation:

[34] The usual argument for the standard LMP approach avoids this discussion by assuming no non-convexities that affect the total cost of the dispatch, and that the LMP prices alone will support the dispatch. When this assumption fails, some additional payment is required to avoid creating incentives for market participants to deviate from the economic dispatch.

[35] For the extended LMP method, see Gribik, P. R., W. W. Hogan, and S. L. Pope (2007) “Market-Clearing Electricity Prices and Energy Uplift,” John F. Kennedy School of Government, Harvard University.

[36] See Chao, H. (2017) “Integer Relaxation for Electricity Market Clearing,” PJM Interconnection.

[37] The real-time pricing model includes multiple periods and look ahead. Prices are calculated for a time window containing the day of the real-time market on a rolling basis as day progresses. Use actual prices in current time windows for settlement and forecast prices for informational purposes only.

$K = \left[\beta_{ij}^{k}\right]$: the power transfer distribution factors

$b = \left(b_{ij}\right)$: the transmission line capabilities

$d_t = \left(d_{1t},...,d_{nt}\right)$: the net load (net of self-scheduled or must-run generation) at time t[38]

$g_t = \left(g_{1t},...,g_{nt}\right)$: the generation output levels of pooled-scheduled units at time t

$G_{it}^{M}, G_{it}^{m}$ : the maximum and minimum levels of economic generation of unit $i$ at time $t$

$u_{it} \in \{0,1\}$: the start-up decision for unit $i \in N \equiv \{1,...,n\}$

$w_{it} \in \{0,1\}$: the on-off state for unit $i \in N \equiv \{1,...,n\}$

$c_i^{SU}$ : the start-up cost for unit $i$

$c_i^{NL}$ : the no-load cost for unit $i$

$C_i(g,w)$ : the variable cost for unit $i$

The variable cost function for unit $i$ represents the result of least cost production formulated as follows:

$$C_i(g,w) \equiv \underset{x}{Minimize} \left\{ \sum_{l=1}^{L} c_{il}\, x_l \middle| \sum_{l=1}^{L} x_l = g, 0 \le x_l \le w\delta_l \right\}$$

where $\delta_l$ is the megawatt step size of the incremental capacity $l$ .

Note that the variable cost function is homogeneous of degree one.

## The Dispatch model

The standard optimal unit commitment and economic dispatch model is formulated below as a mix integer program (MIP),

$$\underset{g,u,w}{Minimize} \sum_{i=1}^{n}\sum_{t=1}^{T} C_i\left(g_{it}, w_{it}\right) + c_i^{SU} u_{it} + c_i^{NL} w_{it} \tag{1}$$

subject to:

[38] Self-scheduling reveals participant's willingness to behave as a pure price taker. Self-scheduled units are not included in the economic dispatch choices and therefore are not treated as dispatch choices that set prices in the pricing model.

$$\mathbf{e}^{\mathbf{t}}(\mathbf{d}_{\mathbf{t}} - \mathbf{g}_{\mathbf{t}}) + Loss_t(\mathbf{d}_{\mathbf{t}} - \mathbf{g}_{\mathbf{t}}) = 0 \quad (2)$$

$$K(\mathbf{d}_t - \mathbf{g}_{\mathbf{t}}) \leq \mathbf{b} \quad (3)$$

$$w_{it} G_i^m \leq g_{it} \leq w_{it} G_i^M \quad (4)$$

$$-w_{it} Ramp_i^D \leq g_{it} - g_{i,t-1} \leq w_{it} Ramp_i^U \quad (5)$$

$$w_{it} - w_{i,t-1} \leq u_{it} \quad (6)$$

$$g_{it} \geq 0 \text{ and } u_{it}, w_{it} \in \{0,1\} \quad (7)$$

The objective function in (1) represents the total cost including the variable, start-up and no-load costs. Equation (2) represents the demand and supply balance condition where $Loss(\cdot)$ denotes the transmission loss function. Constraints (3) represent the transmission line limits, where $K(\cdot)$ denotes the power flow distribution factors based on the physical Kirchhoff laws. Constraints (4) represent the minimum and maximum economic generation limits. Constraints (5) represent the upward and downward ramping limits. Constraints (6) represent the transitional condition for changing unit on-off status. Constraints (7) represent the feasibility set for unit commitment and dispatch variables.

The unit commitment and economic dispatch instructions are based on the optimal solution of the dispatch model denoted by $(\mathbf{g}^*, \mathbf{u}^*, \mathbf{w}^*)$. By definition, all units are economical if they are committed and dispatched in the dispatch solution and non-economical if otherwise.

## *The Pricing Model*

In the pricing model, the optimal unit commitment and economic dispatch problem is rewritten as follows,

$$\underset{g,u,w}{Minimize} \sum_{i=1}^{n} \sum_{t=1}^{T} C_i\ (g_{it}, w_{it}) + c_i^{SU} u_{it} + c_i^{NL} w_{it} \quad (8)$$

subject to:

$$\mathbf{e}^{\mathbf{t}}(\mathbf{d}_{\mathbf{t}} - \mathbf{g}_{\mathbf{t}}) + Loss_t(\mathbf{d}_{\mathbf{t}} - \mathbf{g}_{\mathbf{t}}) = 0 \quad (9)$$

$$K(\mathbf{d}_t - \mathbf{g}_{\mathbf{t}}) \leq \mathbf{b} \quad (10)$$

$$w_{it}G_i^m \leq g_{it} \leq w_{it}G_i^M \tag{11}$$

$$-w_{it}Ramp_i^D \leq g_{it} - g_{i,t-1} \leq w_{it}Ramp_i^U \tag{12}$$

$$w_{it} - w_{i,t-1} \leq u_{it} \tag{13}$$

$$g_{it} \geq 0 \text{ and } u_{it}, w_{it} \in [0,1] \tag{14}$$

Note that the only difference between the pricing model and the dispatch model can be found in the constraints (14) and (7) where the unit commitment variables $(\mathbf{u}, \mathbf{w})$ are allowed to vary continuously between zero and one in the pricing model but are treated as integer variables in the dispatch model. The solution of the pricing model determines the locational marginal prices, $\mathbf{p}^*$.

## The Settlement Model

In the settlement process, the following problem is solved,

$$\underset{g,u,w}{Maximize} \sum_{i=1}^{n}\sum_{t=1}^{T} p_{it}^* g_{it} - C_i\,(g_{it}, w_{it}) - c_i^{SU} u_{it} - c_i^{NL} w_{it} \tag{15}$$

subject to (2) – (7).

Let the optimal solution to the settlement model be denoted by $(\mathbf{g}^{**}, \mathbf{u}^{**}, \mathbf{w}^{**})$. Given the prices $\mathbf{p}^*$, the optimal profit for unit $i$ is defined as

$$\Pi_i^{**} = \left( \sum_{t=1}^{T} p_{it}^* g_{it}^{**} - C_i\,(g_{it}^{**}, w_{it}^{**}) - c_i^{SU} u_{it}^{**} - c_i^{NL} w_{it}^{**} \right)$$

Similarly, given the prices $(\mathbf{p}^*)$, the actual profit at the dispatch solution for unit $i$ is defined as

$$\Pi_i^{*} = \left( \sum_{t=1}^{T} p_{it}^* g_{it}^{*} - C_i\,(g_{it}^{*}, w_{it}^{*}) - c_i^{SU} u_{it}^{*} - c_i^{NL} w_{it}^{*} \right)$$

The uplift for unit $i$ is defined as the difference between the actual energy profits and the optimal profits:

$$Uplift_i = \Pi_i^{**} - \Pi_i^{*}$$

## *Examples*

Two analytical examples serve to illustrate the extended LMP approach (with integer relaxation) and its benefits relative to the restricted LMP method. These examples are not intended to be a prediction of the results in the PJM market but to illustrate the impacts in terms of consumer payments, generator receipts, total uplift payments and the net revenues for the flexible units.

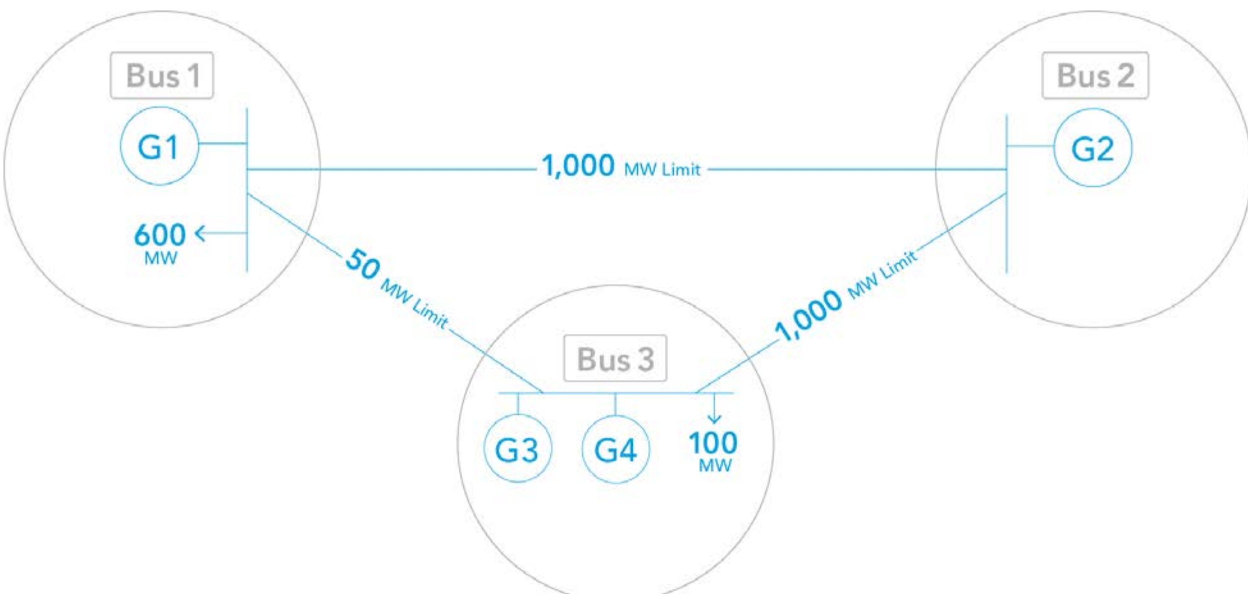
The organization of the remainder of this section is as follows. For each of the two examples, we will present, in order:

1. The technical input assumptions for a three-bus network
2. The dispatch run SCED problem formulation and solution
3. The pricing run SCED problem formulation and solution using integer relaxation
4. The settlement results for the restricted LMP and the extended LMP methods with some brief observations on the results

### Example 1

A three-bus system is shown in Figure 10, and its corresponding generator offer parameters are listed in Table 2. The load is distributed between the left and the middle buses with 600 MW at Bus 1 and 100 MW at Bus 3. There is a physical limit of 50 MW for the transmission line between Bus 1 and Bus 3.

Figure 10. Example 1 — Three-bus System




All line reactances are 0.1 p.u.

Table 2. Example 1 — Generator Offer Parameters

| Generator | 1 | 2 | 3 | 4 |
|---|---|---|---|---|
| Min Gen (MW) | - | 100 | - | 100 |
| Max Gen (MW) | 500 | 100 | 1,000 | 100 |
| Start-up Cost | - | $100 | - | $100 |
| Alpha ($/MWh) | $20 | $75 | $20 | $40 |
| Beta ($/MWh/MW) | $0.1 | - | $0.1 | - |

Table 2 shows that generators G1 (Bus 1) and G3 (Bus 3) are flexible units, and G2 (Bus 2) and G4 (Bus 3) are inflexible units that must be block-loaded at 100 MW. Each inflexible unit has a fixed start-up cost of $100 with a constant incremental cost ($75/MWh for G2 and $40/MWh for G4). Each flexible unit has zero start-up cost and a linear variable cost that starts at $20/MWh and increases at $0.1/MWh per megawatt of generation output. The marginal and total variable cost functions for the flexible units are as follows:

$$Marginal\ Cost_i = \alpha_i + \beta_i * P_i$$

$$Total\ Cost_i = \alpha_i * P_i + 0.5 * \beta_i * P_i^2$$

### Dispatch Run — SCED Problem Formulation

For the system shown in Figure 10 and Table 2, the SCED problem formulation for the dispatch run is derived from the unit commitment run by fixing the unit commitment variables. The SCED comprises: 1) the objective function of minimizing total system production cost and 2) the constraints including the nodal balance equations, the generator operating limit constraints and the line-flow limit constraints as shown in the following.

$$minimize$$

$$20 * P_1 + 0.5 * 0.1 * P_1^2 + 100 * I_2 + 75 * P_2 + 20 * P_3 + 0.5 * 0.1 * P_3^2 + 100 * I_4 + 40 * P_4 \quad (1)$$

$$s.t.$$

$$P_1 - F_{1,2} - F_{1,3} = 600 \quad (2)$$

$$P_2 + F_{1,2} - F_{2,3} = 0 \quad (3)$$

$$P_3 + P_4 + F_{1,3} + F_{2,3} = 100 \quad (4)$$

$$0 \le P_1 \le 500 \quad (5)$$

$$100 * I_2 \le P_2 \le 100 * I_2 \quad (6)$$

$$0 \le P_3 \le 1{,}000 \quad (7)$$

$$100 * I_4 \le P_4 \le 100 * I_4 \quad (8)$$

$$-10 * \theta_2 - F_{1,2} = 0 \quad (9)$$

$$10 * \theta_2 - 10 * \theta_3 - F_{2,3} = 0 \tag{10}$$

$$-10 * \theta_3 - F_{1,3} = 0 \tag{11}$$

$$-1{,}000 \leq F_{1,2} \leq 1{,}000 \tag{12}$$

$$-1{,}000 \leq F_{2,3} \leq 1{,}000 \tag{13}$$

$$-50 \leq F_{1,3} \leq 50 \tag{14}$$

$$I_2 = 1 \tag{15}$$

$$I_4 = 0 \tag{16}$$

where:

$P_i$ is the power output of generator $i$

$F_{j,k}$ is the flow on the line from bus $j$ to bus $k$

$\theta_j$ is the phase angle of the voltage at bus $j$

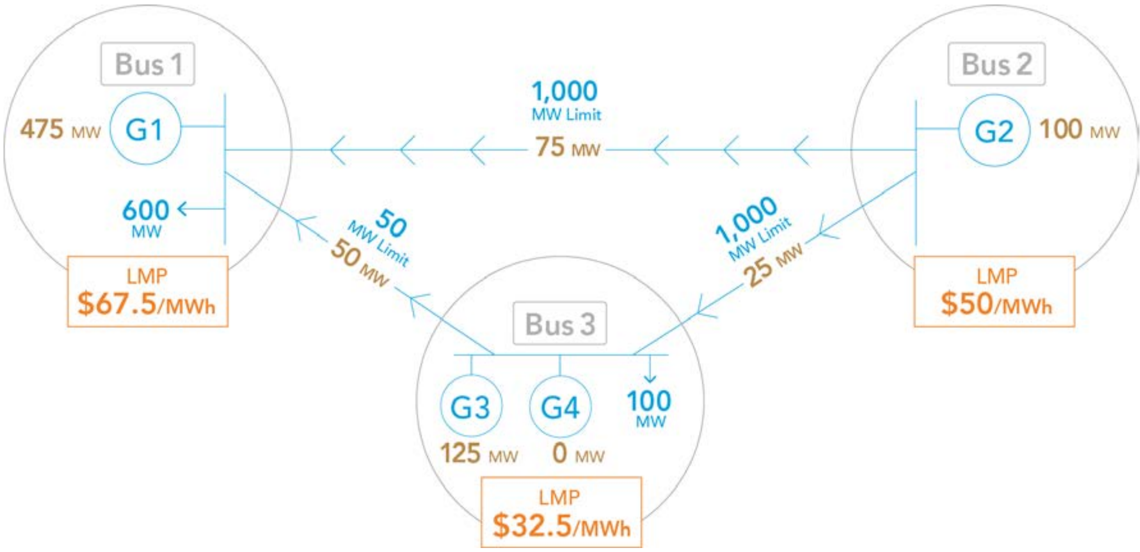
$I_i$ is the commitment of generator $i$

(1) is the objective function to minimize total system production cost
(2)–(4) are the nodal balance equations
(5)–(8) are the generator operating limit constraints
(9)–(11) are the line flow equations
(12)–(14) are the line flow limit constraints
(15)–(16) are the generator commitment constraints

### Dispatch Solution

The solution to the dispatch run is shown in Figure 11. The prices at all locations are being suppressed due to the commitment of the inflexible generator G2 at its fixed output of 100 MW.

Figure 11. Example 1 — Dispatch Run Solution




### Pricing Run — Integer Relaxation — SCED Problem Formulation

For the system shown in Figure 10 and Table 2, the SCED problem formulation for the pricing run with integer relaxation is derived from the unit commitment run by relaxing the generator commitment constraints as shown below.

*minimize*

$$20 * P_1 + 0.5 * 0.1 * P_1^2 + 100 * I_2 + 75 * P_2 + 20 * P_3 + 0.5 * 0.1 * P_3^2 + 100 * I_4 + 40 * P_4 \quad (33)$$

*s.t.*

$$P_1 - F_{1,2} - F_{1,3} = 600 \quad (34)$$

$$P_2 + F_{1,2} - F_{2,3} = 0 \quad (35)$$

$$P_3 + P_4 + F_{1,3} + F_{2,3} = 100 \quad (36)$$

$$0 \leq P_1 \leq 500 \quad (37)$$

$$100 * I_2 \leq P_2 \leq 100 * I_2 \quad (38)$$

$$0 \leq P_3 \leq 1{,}000 \quad (39)$$

$$100 * I_4 \leq P_4 \leq 100 * I_4 \quad (40)$$

$$-10 * \theta_2 - F_{1,2} = 0 \quad (41)$$

$$10 * \theta_2 - 10 * \theta_3 - F_{2,3} = 0 \quad (42)$$

$$-10 * \theta_3 - F_{1,3} = 0 \quad (43)$$

$$-1{,}000 \leq F_{1,2} \leq 1{,}000 \quad (44)$$

$$-1{,}000 \leq F_{2,3} \leq 1{,}000 \quad (45)$$

$$-50 \leq F_{1,3} \leq 50 \quad (46)$$

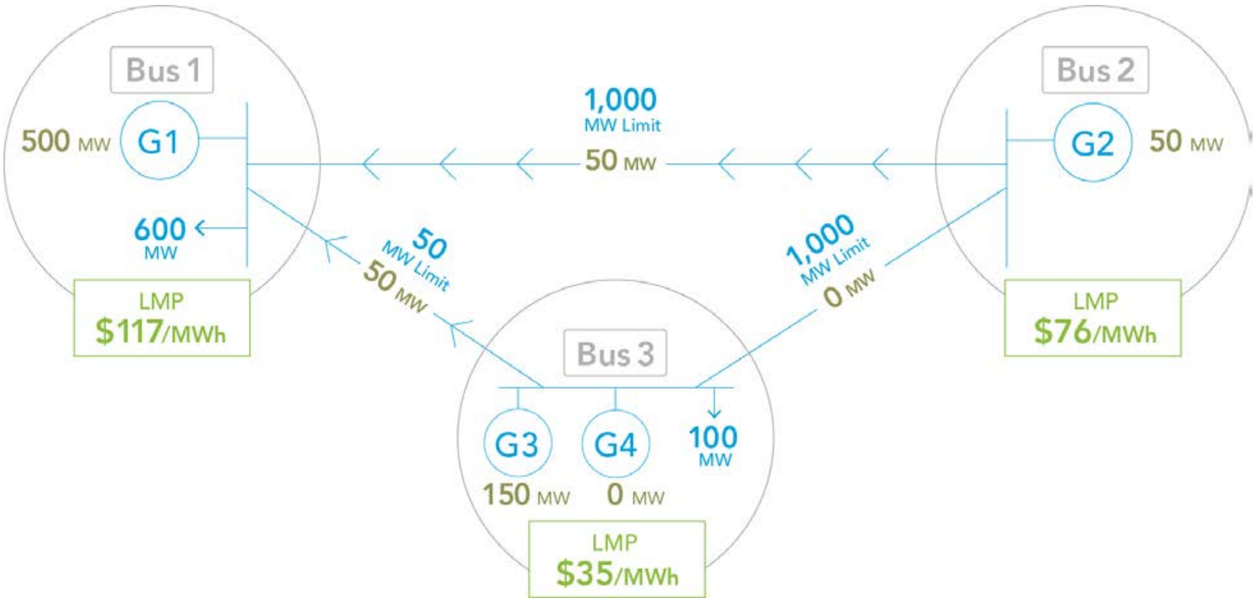
$$0 \leq I_2 \leq 1 \quad \cancel{I_2 = 0 \; or \; 1} \quad (47)$$

$$0 \leq I_4 \leq 1 \quad \cancel{I_4 = 0 \; or \; 1} \quad (48)$$

### Pricing Solution — Integer Relaxation

The solution to the pricing run with integer relaxation is shown in Figure 12. The LMPs at all locations have increased compared to the dispatch run solution since generator G2 is now considered flexible for pricing purposes and can set price.

Figure 12. Example 1 — Pricing Run with Integer Relaxation Solution




### Settlement

The settlements for the restricted LMP method and the extended LMP method with integer relaxations are shown in Table 3 and Table 4, respectively. The tables show the uplift payment, the amount paid by load, the revenue received by each generator, the bid production cost for each generator, each generator's net revenue and total congestion revenue.

Table 3 shows that, for the restricted LMP case, the LMPs at Bus 1 and Bus 3 are set by the marginal cost of the flexible units, respectively, at $67.50/MWh and $32.50/MWh, while the price at Bus 2 is $50/MWh, which is lower than the incremental cost of the inflexible local generator G2, causing an uplift payment of $2,600 to make the generator whole.

Table 3. Example 1 — Restricted LMP Settlement

| Bus | 1 | 2 | 3 | | System |
|---|---|---|---|---|---|
| Generator | 1 | 2 | 3 | 4 | |
| Load (MW) | 600 | - | 100 | | 700 |
| Generation (MW) | 475 | 100 | 125 | - | 700 |
| LMP ($/MWh) | $67.50 | $50.00 | $32.50 | | |
| Uplift | - | $2,600 | - | - | $2,600 |
| Load Payment | $42,729 | - | $3,621 | | $46,350 |
| Generator Revenue | $32,063 | $7,600 | $4,062 | - | $43,725 |
| Generator Cost | $20,782 | $7,600 | $3,281 | - | $31,663 |
| Generator Net Revenue | $11,282 | - | $781 | - | $12,063 |
| Congestion Revenue | - | - | - | - | $2,625 |

Table 4. Example 1 — Extended LMP with Integer Relaxation Settlement

| Bus | 1 | 2 | 3 | | System |
|---|---|---|---|---|---|
| Generator | 1 | 2 | 3 | 4 | |
| Load (MW) | 600 | - | 100 | | 700 |
| Generation (MW) | 475 | 100 | 125 | - | 700 |
| LMP ($/MWh) | $117.00 | $76.00 | $35.00 | | |
| Uplift | $619 | - | $31 | - | $650 |
| Load Payment | $70,757 | - | $3,593 | | $74,350 |
| Generator Revenue | $56,194 | $7,600 | $4,406 | - | $68,200 |
| Generator Cost | $20,782 | $7,600 | $3,281 | - | $31,663 |
| Generator Net Revenue | $35,413 | - | $1,125 | - | $36,538 |
| Congestion Revenue | - | - | - | - | $6,150 |

Table 4 shows that for the extended LMP case with integer relaxation, the LMP at Bus 2 is set by the incremental cost of the inflexible unit at $76/MWh. The integer relaxation accounts for both the fixed start-up and variable costs in the economic calculation of the market clearing price.

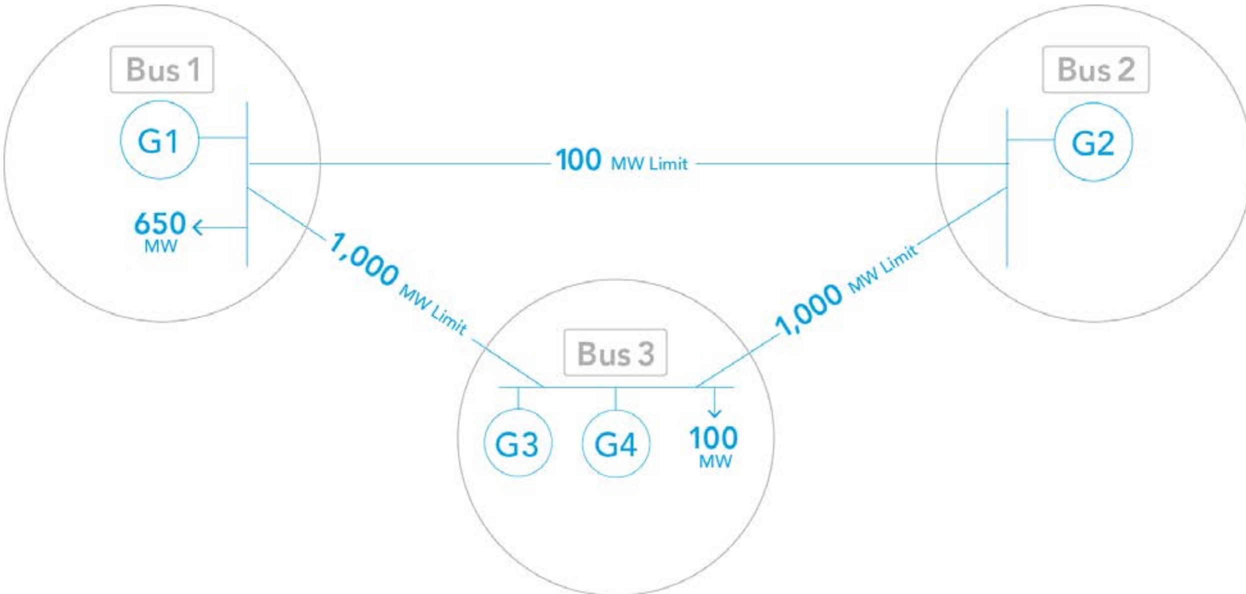
Comparing with the restricted LMP case, the energy prices with the extended LMP case are uniformly higher. The highest price is $117/MWh at Bus 1, because taking into account the binding constraint of the transmission line between Bus 1 and Bus 3, the lowest cost generation combination to serve one MWh of incremental load at Bus 1 is to increase the higher cost generation at Bus 2 by 2 MWh and to simultaneously lower the lower cost generation at Bus 3 by 1 MWh, so that the incremental cost equals 2 x $76/MWh - $35/MWh = $117/MWh.

Comparing Table 3 with Table 4, total uplift decreased from $2,600 in the restricted LMP case to $650 in the extended LMP case with integer relaxation. In addition, generator net revenues increased from $12,063 in the restricted LMP case to $36,538 in the extended LMP case with integer relaxation.

## Example 2

The following example illustrates a case where LMPs both increase and decrease at some locations in the extended LMP solution compared to the restricted LMP solution. A three-bus system is shown in Figure 13 and its corresponding generator offer parameters are listed in Table 6. The load is distributed between the left and the middle buses with 650 MW at Bus 1 and 100 MW at Bus 3. There is a 100 MW physical limit for the transmission line between Bus 1 and Bus 2.

Figure 13. Example 2 — Three-bus System




All line reactances are 0.1 p.u.

Table 5. Example 2 — Generator Offer Parameters

| Generator | 1 | 2 | 3 | 4 |
|---|---|---|---|---|
| Min Gen (MW) | - | 100 | - | 100 |
| Max Gen (MW) | 450 | 100 | 250 | 100 |
| Start-up Cost | - | $100 | - | $100 |
| Alpha ($/MWh) | $30 | $10 | $20 | $10 |
| Beta ($/MWh/MW) | $0.1 | - | $0.1 | - |

Table 5 shows that, similar to Table 2, generators G1 (Bus 1) and G3 (Bus 3) are flexible units, and G2 (Bus 2) and G4 (Bus 3) are inflexible units that must be block-loaded at 100 MW, although the incremental costs for the inflexible units are now assumed to be lower than in Table 3 at $10/MWh. The marginal and total variable cost functions for the flexible units are as follows:

$$Marginal\ Cost_i = \alpha_i + \beta_i * P_i$$

$$Total\ Cost_i = \alpha_i * P_i + 0.5 * \beta_i * P_i^2$$

### Dispatch Run – SCED Problem Formulation

For the system shown in Figure 13 and Table 5, the SCED problem formulation for the dispatch run is derived from the unit commitment run by fixing the unit commitment variables. The SCED comprises: 1) the objective function of minimizing total system production cost and 2) the constraints including the nodal balance equations, the generator operating limit constraints and the line-flow limit constraints as shown in the following.

$$minimize$$

$$30 * P_1 + 0.5 * 0.1 * P_1^2 + 100 * I_2 + 10 * P_2 + 20 * P_3 + 0.5 * 0.1 * P_3^2 + 100 * I_4 + 10 * P_4 \quad (49)$$

$$s.t.$$

$$P_1 - F_{1,2} - F_{1,3} = 650 \quad (50)$$

$$P_2 + F_{1,2} - F_{2,3} = 0 \quad (51)$$

$$P_3 + P_4 + F_{1,3} + F_{2,3} = 100 \quad (52)$$

$$0 \leq P_1 \leq 450 \quad (53)$$

$$100 * I_2 \leq P_2 \leq 100 * I_2 \quad (54)$$

$$0 \leq P_3 \leq 250 \quad (55)$$

$$100 * I_4 \leq P_4 \leq 100 * I_4 \quad (56)$$

$$-10 * \theta_2 - F_{1,2} = 0 \quad (57)$$

$$10 * \theta_2 - 10 * \theta_3 - F_{2,3} = 0 \quad (58)$$

$$-10 * \theta_3 - F_{1,3} = 0 \quad (59)$$

$$-100 \leq F_{1,2} \leq 100 \quad (60)$$

$$-1{,}000 \leq F_{2,3} \leq 1{,}000 \quad (61)$$

$$-1{,}000 \leq F_{1,3} \leq 1{,}000 \quad (62)$$

$$I_2 = 1 \quad (63)$$

$$I_4 = 1 \quad (64)$$

where:

$P_i$ is the power output of generator $i$

$F_{j,k}$ is the flow on the line from bus $j$ to bus $k$

$\theta_j$ is the phase angle of the voltage at bus $j$

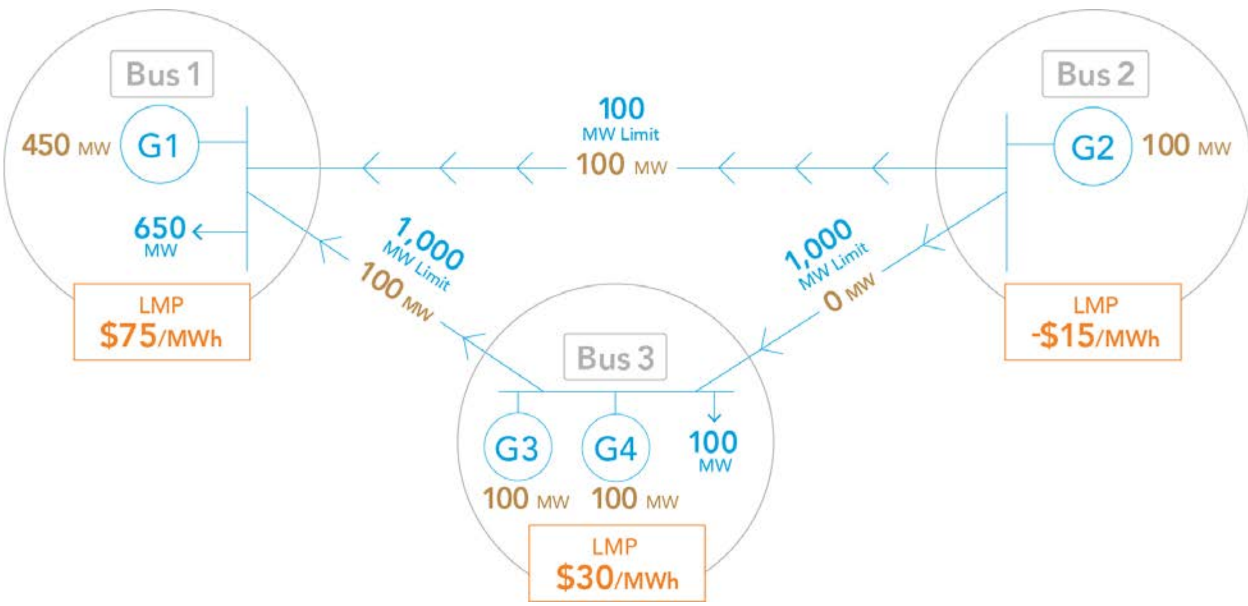
$I_i$ is the commitment of generator $i$

(49) is the objective function to minimize total system production cost
(50)–(52) are the nodal balance equations
(53)–(56) are the generator limit constraints
(57)–(59) are the line flow equations
(60)–(62) are the line flow limit constraints
(63)–(64) are the generator commitment constraints

### Dispatch Solution

The solution to the dispatch run is shown in Figure 14. Due to congestion on the line between buses 1 and 2, and the inflexibility of generator G2, generator G1 is being dispatched up, resulting in a higher LMP at bus 1 and a negative LMP at bus 2.

Figure 14. Example 2 — Dispatch Run Solution



### Pricing Run — Integer Relaxation — SCED Problem Formulation

For the system shown in Figure 13 and Table 5, the SCED problem formulation for the pricing run with integer relaxation is derived from the unit commitment run by relaxing the generator commitment constraints as shown below.

$minimize$

$$30 * P_1 + 0.5 * 0.1 * P_1^2 + 100 * I_2 + 10 * P_2 + 20 * P_3 + 0.5 * 0.1 * P_3^2 + 100 * I_4 + 10 * P_4 \tag{81}$$

$s.t.$

$$P_1 - F_{1,2} - F_{1,3} = 650 \tag{82}$$

$$P_2 + F_{1,2} - F_{2,3} = 0 \tag{83}$$

$$P_3 + P_4 + F_{1,3} + F_{2,3} = 100 \tag{84}$$

$$0 \leq P_1 \leq 450 \tag{85}$$

$$100 * I_2 \leq P_2 \leq 100 * I_2 \tag{86}$$

$$0 \leq P_3 \leq 250 \tag{87}$$

$$100 * I_4 \leq P_4 \leq 100 * I_4 \tag{88}$$

$$-10 * \theta_2 - F_{1,2} = 0 \tag{89}$$

$$10 * \theta_2 - 10 * \theta_3 - F_{2,3} = 0 \tag{90}$$

$$-10 * \theta_3 - F_{1,3} = 0 \tag{91}$$

$$-100 \leq F_{1,2} \leq 100 \tag{92}$$

$$-1{,}000 \leq F_{2,3} \leq 1{,}000 \tag{93}$$

$$-1{,}000 \leq F_{1,3} \leq 1{,}000 \tag{94}$$

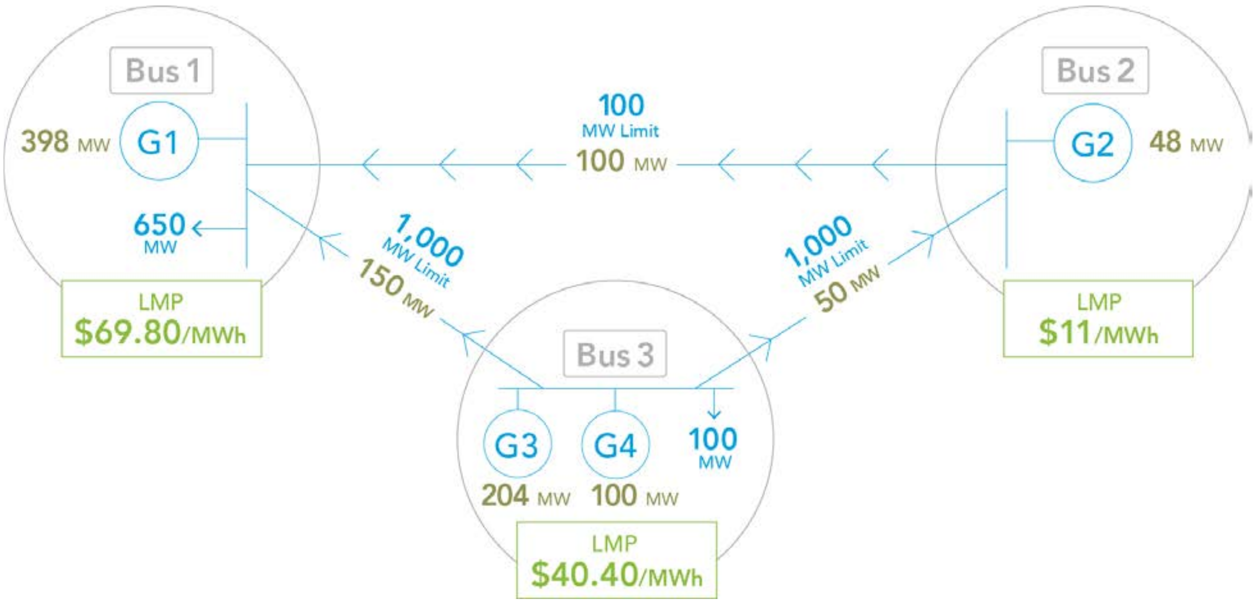
$$0 \leq I_2 \leq 1 \quad \cancel{I_2 = 0\ or\ 1} \tag{95}$$

$$0 \leq I_4 \leq 1 \quad \cancel{I_4 = 0\ or\ 1} \tag{96}$$

### Pricing Solution — Integer Relaxation

The solution to the pricing run with integer relaxation is shown in Figure 15. Since generator G2 is no longer required to be dispatched at its economic maximum limit, it can be dispatched down. This allows the output of generator G1 to be decreased and the output of generator G3 to be increased, resulting in a decrease in the LMP at bus 1 and an increase in the LMP at buses 2 and 3.

Figure 15. Example 2 — Pricing Run with Integer Relaxation Solution




### Settlement

The settlements for the restricted LMP method and the extended LMP method with integer relaxation are shown in Table 6 and Table 7, respectively. The tables show the uplift payment, the amount paid by load, the revenue received by each generator, the bid production cost for each generator, each generator's net revenue and total congestion revenue.

Table 6 shows that for the restricted LMP case, the LMPs at Bus 1 and Bus 3 are set by the marginal cost of the flexible units at, respectively, $75/MWh and $30/MWh, while the price at Bus 2 is negative at -$15/MWh causing an uplift payment of $2,600 to make the generator G2 whole. The reason for the negative price is that when the inflexible block-loaded unit G2 is online, it creates an artificial binding constraint on the transmission line between Bus 1 and Bus 2. As a result, the load at Bus 1 must be met by the flexible local generation G1 at a higher price of $75/MWh. For each MWh that could be reduced from the generator G2 at Bus 2, it could be replaced by 2 MWh from G3 and offset 1 MWh from G1. As a result, the total system cost would be reduced by $15/MWh ($75/MWh – 2 x $30/MWh = $15/MWh).

Table 6. Example 2 — Restricted LMP Settlement

| Bus | 1 | 2 | 3 | | System |
|---|---|---|---|---|---|
| Generator | 1 | 2 | 3 | 4 | |
| Load (MW) | 650 | - | 100 | | 750 |
| Generation (MW) | 450 | 100 | 100 | 100 | 750 |
| LMP ($/MWh) | $75.00 | ($15.00) | $30.00 | | |
| Uplift | - | $2,600 | - | - | $2,600 |
| Load Payment | $51,003 | - | $3,347 | | $54,350 |
| Generator Revenue | $33,750 | $1,100 | $3,000 | $3,000 | $40,850 |
| Generator Cost | $23,625 | $1,100 | $2,500 | $1,100 | $28,325 |
| Generator Net Revenue | $10,125 | - | $500 | $1,900 | $12,525 |
| Congestion Revenue | - | - | - | - | $13,500 |

Table 7. Example 2 — Extended LMP with Integer Relaxation Settlement

| Bus | 1 | 2 | 3 | | System |
|---|---|---|---|---|---|
| Generator | 1 | 2 | 3 | 4 | |
| Load (MW) | 650 | - | 100 | | 750 |
| Generation (MW) | 450 | 100 | 100 | 100 | 750 |
| LMP ($/MWh) | $69.80 | $11.00 | $40.40 | | |
| Uplift | $135 | - | $541 | - | $676 |
| Load Payment | $45,956 | - | $4,130 | | $50,086 |
| Generator Revenue | $31,545 | $1,100 | $4,581 | $4,040 | $41,266 |
| Generator Cost | $23,625 | $1,100 | $2,500 | $1,100 | $28,325 |
| Generator Net Revenue | $7,920 | - | $2,081 | $2,940 | $12,941 |
| Congestion Revenue | - | - | - | - | $8,820 |

Similar to example 1, comparing Table 6 with Table 7, total uplift decreased from $2,600 in the restricted LMP case to $676 in the extended LMP case with integer relaxation. In addition, generator net revenues increased from $12,525 in the restricted LMP case to $12,941 in the extended LMP case with integer relaxation. The load payment decreased from $54,350 in the restricted LMP case to $50,086 in the extended LMP case with integer relaxation. In this example, the restricted LMP method produces ironic results with a negative price but a higher load payment because the congestion revenue is artificially raised (from $8,820 to $13,500) by not allowing generator G2 to set price.

In summary, by allowing all resources to be eligible to set price, the extended LMP method may result in higher or lower consumer payments or generator receipts, but in general, the total uplift payments are lower and the net revenues for the flexible units tend to be higher, thereby incenting this flexibility attribute.

# Appendix C: Current Resource Flexibility

As explained in the main body of this paper, resource flexibility is critical to ensuring that generation and load can be balanced efficiently during real time operations. This section examines how resource flexibility offered into the PJM markets has changed over the past three years. Since 2011, over 25,000 MW of generation retired due to the EPA mercury and air toxics standards (MATS) rule, and the New Jersey Department of Environmental Protection High Energy Demand Day (HEDD) rule. While most of these were coal units, over 7,000 MW of these units were natural gas and oil-based peaking plants.

In addition, PJM implemented a new operating procedure in June 2015 to mitigate the effect of inflexible combustion turbine gas units (CTs) to reduce uplift. This was an out-of-market procedure that required CTs that were not flexible (i.e., greater than two-hour minimum run or greater than two-hour time to start), and scheduled in the Day-Ahead market to operate in real time.

## *Insufficient Economic Incentive for Flexibility*

The amount of inflexible CTs scheduled in the Day-Ahead Market is still over 900 MW each day. These are CT resources that have the physical capability of scheduling with more flexibility (minimum runtime and time to start) but have no economic incentive to offer additional flexibility to the market. Capacity performance (CP) addressed this issue for emergency days (days where hot weather and cold weather alerts are called) but normal operations still see scheduling outside their physical capability.

### Turbines Run with Less-Flexible Parameters than their Capability

Many of the CTs offer in Day-Ahead Market and run in real time with less flexible parameters than parameters of which they are physically capable. Again, this indicates that insufficient economic incentive exists to either buy gas on a more flexible basis or routinely maintain or staff the units to be more flexible.

In the values included below, bid-in price is the price schedule units offer in on non-emergency days, and the proxy is the physical capabilities based on the original equipment manufacturer data. Minimum Runtime (MinRun) is the minimum number of hours the unit must operate before it is cycled offline. Minimum Downtime (MinDown) is the minimum number of hours the unit must remain offline once it is shut down before it can be started again.

Combustion Turbines Bid-in Price vs. Proxy for 2017 Results (CP and non-CP) by Technology Type

- CT Technology type - AERO 2017
  - 40.3 percent (50 of the 124) CTs have an average MinRun longer than the proxy value of 1 hour.
  - 27.4 percent (34 of the 124) CTs have an average MinDown longer than the proxy value of 1.1 hour.
- CT Technology type - Frame 2017
  - 27.8 percent (74 of the 266) CTs have an average MinRun longer than the proxy value of 2 hours.
  - 47.7 percent (127 of the 266) CTs have an average MinDown longer than the proxy value of 1.25 hours.

Many of the combined cycle gas units (CCs) also offer in Day-Ahead Market and run in real time with less-flexible parameters than they are physically capable of. Again, this indicates that there is insufficient economic incentive to either buy more flexible gas or routinely maintain or staff the units to be more flexible.

In values included below, bid-in price is the price schedule units offer in on non-emergency days, and the proxy is the physical capabilities based on the Original Equipment Manufacturer data.

Combined Cycle Units' Bid-in Price vs. Proxy for 2017

- Only 5 out of 51 CCs had a MinRun equal to PJM's proxy value of 4 hours.
  - On average, 90.2 percent have a value longer than the proxy.
- 6 out of 51 CCs had a MinDown less than PJM's proxy value of 3.5 hours.
  - On average, 88.2 percent have a value longer than the proxy.

## No Interest in Flexible Product Offering

Texas Eastern gas pipeline held an open season proposing a more flexible product for gas-fired generation resources. The service was proposed under a new energy reliability service rate schedule. Shippers had the option of working with Texas Eastern to customize services to meet their particular needs. To date, none of the gas units in PJM's region have expressed interest in this new flexible product, further indicating that insufficient economic incentive exists for resources to take advantage of this newly offered service.

Some of the key components of the offering are listed below.

Capacity is reserved for Shipper's full Maximum Daily Quantity on a Basis of 24 hours per Gas Day, 7 Days a Week via a Variety of Service Offerings

- Reserved no notice transportation with the option of non-ratable hourly flow flexibility
- "Quick-start" no-notice service enabling shippers to begin deliveries two hours prior to a commensurate supply nomination
- Enhanced maximum hourly quantity for assured non-ratable gas deliveries
- Park and loan no-notice services

# Appendix D: Cost Impacts

## Summary

The purpose of this appendix is to explain the process PJM used to approximate the net impact of implementing its proposed enhancements to the method by which energy market prices are calculated and to summarize the results.

The estimated net impact of the proposed changes is an expected increase in total energy and capacity market costs of between $440 million and $1.4 billion annually, or between 2 and 5 percent, compared to total simulated energy and capacity market costs of approximately $28 billion. This net impact is composed of an increase in energy market costs of approximately $2.7 billion, offset by a decrease in capacity market costs of between $1.2 billion and $2.2 billion. As explained below, this decrease in capacity payments reflects only the direct impact of increased energy market revenues in the capacity market, and does not include the beneficial impacts of retaining additional resources due to enhanced energy market price formation.

## Energy Market Simulations

To accomplish the energy market analysis, PJM used a modified version of the perfect dispatch engine and actual market and operating data from 2016. PJM presents in this appendix the results of two simulations: status quo and relaxation of economic minimum for all units scheduled by PJM (i.e., not self-scheduled).[39] Because the perfect dispatch engine is not identical to the software that PJM uses to clear its markets, the status quo was simulated to determine a baseline from which other pricing proposals could be measured.

The objective of these simulations was to measure the impact on real-time energy prices and uplift payments.

### Perfect Dispatch

Perfect dispatch retroactively optimizes dispatch and real-time pricing by minimizing bid production cost using actual real-time load, interchange, the PJM system topology, transmission constraints and generator bid-in parameters. Perfect dispatch optimizes unit commitment over a 24-hour look-ahead horizon while simultaneously and incrementally determining dispatch points for dispatchable units in sequential 15-minute time steps.[40] For purposes of this study, the perfect dispatch engine was modified to allow PJM to hold unit commitment constant while altering the economic minimum between the dispatch and pricing solutions.

In the dispatch solution, all units were treated in the same manner as they are today. Self-scheduled units that have some dispatchable range were dispatched economically, and those that are non-dispatchable were treated as fixed injections. The economic minimum output levels on self-scheduled units were not relaxed during the LMP calculation step.

[39] Due to technical limitations, PJM was not able to simulate the full integer relaxation approach proposed within this document. The simulation data contained herein results solely from reducing the economic minimum limit on all resources and does not contain any amortization of startup and no-load costs. As PJM continues to refine its methodology throughout the ensuing stakeholder process, further simulations will be performed to provide more detail and insight into PJM enhanced price formation methodology.

[40] For more detailed information on the perfect dispatch engine, see: http://power-gem.com/Perfect_Dispatch_Paper_final.pdf

## Dispatch and Pricing Process

In today's model, PJM's real-time software applications compute the system dispatch and prices using the same methodology. The Real-time Security Constrained Economic Dispatch (RT SCED) engine determines the dispatch and the Location Pricing Calculator (LPC) calculates prices. The only differences between these applications is that the LPC runs on a set schedule every five minutes, whereas the RT SCED engine can be run on command, and the LPC calculates prices for the entire network model rather than the subset that the RT SCED views.[41] Unit parameters are held constant between the pricing and dispatch solution and only flexible units are eligible to set LMP.[42]

To simulate the impact of allowing all units scheduled by PJM to be eligible to set price rather than just flexible ones, the modified Perfect Dispatch engine separated the dispatch and pricing solutions into two different runs: a dispatch run and a pricing run. In the dispatch run, all generator bid-in parameters were left unchanged and Perfect Dispatch determined the optimal dispatch point for online units. The megawatts from this dispatch run were used for final settlement calculations.

Perfect Dispatch then determined LMPs by simulating a second SCED run over the same time period, holding unit commitments constant from the dispatch run, with economic minimums relaxed to zero on all online units scheduled by PJM. Unit start-up costs and no-load costs were not included in the LMP calculation due to software limitations at the time the analysis was performed. This run is referred to as the pricing run and is the price used for final settlement calculations.

## Lost Opportunity Cost Credit

To compensate flexible generators for following dispatch when the dispatch instructions from the dispatch run are inconsistent with LMPs from the pricing run, a lost opportunity cost credit is necessary. The purpose of this market mechanism is to compensate flexible resources for their lost opportunity cost if the desired dispatch point from the dispatch run is less than their profit maximizing dispatch determined in the pricing run. Generators would therefore have the incentive to follow dispatch instructions under this construct, thereby maintaining generation and load balance.

## Results

In the pricing scenario (relaxation of economic minimum for all units scheduled by PJM), generation-weighted LMP increased, relative to the status quo. As noted in Table 8, the simulation produced an increase in total energy costs as a result of allowing more expensive units to recover their bid production costs through LMPs instead of through uplift. To make generators incentive neutral to the higher LMPs and compensate units for the lost opportunity cost of following dispatch instructions instead of chasing price, a solution support credit (i.e., the lost opportunity cost) is necessary, the simulated impact of which is included in the fourth line of Table 8.

[41] The RT SCED only views a subset of the entire network model for performance reasons.

[42] Current PJM market rules allow for a small number of inflexible units to set price when operating for transmission constraints. For more information see Section II. Pricing of Fast-Start Resources: http://pjm.com/-/media/documents/ferc/filings/2016/20160217-ad14-14-000.ashx

The increase in generation-weighted LMP from the status quo is greater during on-peak hours, relative to off peak. This, in part, reflects greater demand during these periods. Similarly, the increase in energy payments is greatest during peak hours and accounts for roughly two-thirds of total energy payments in the simulation. This is the result of higher LMPs during the peak period. Most of the costs to compensate resources for following dispatch when dispatch instructions deviate from pricing incentives is accrued during the peak period.

## *Capacity Market Simulations*

### Single-Year Simulations

To complete the picture with respect to total changes in cost as a result of PJM's proposal, PJM also simulated the impact of the increased energy market revenue on capacity market results. There were two components to the impact of the increased energy market revenues on the capacity market results:

5. A reduction in the net cost of new entry (Net CONE) value that forms the basis for the variable resource requirement (VRR) curve

6. Estimated changes in resource offer behavior given the increase in energy market revenues

PJM conducted several simulations of the capacity market results using combinations of these two effects. As shown in Table 8, the minimum simulated reduction in capacity payments occurs with a shift in the VRR curve with some reduction in supply offers while the maximum simulated reduction in capacity payments resulted from the combination of the VRR curve shift and the entire average increase in energy market revenues applied as a reduction in supply offers into the capacity market.

Because the capacity market utilizes a three-year, rolling average of energy market revenues with respect to determining the Net CONE value used to set the VRR curve, this effect would be observed gradually over a three-year period. However, this was the less impactful of the two components and was far outstripped by the impact of the reduction in supply offers given the anticipated increase in energy market revenues. It is more difficult to predict the timing of observing these supply offer impacts in the capacity market since it is reasonable to expect that suppliers may determine their capacity market offers on the basis of anticipated as opposed to historical energy market revenues.

Table 8 compares generation-weighted LMP, total energy payments, uplift, additional costs to compensate resources for following dispatch instructions[43], and the reduction in capacity market payments for the status quo vs. the simulations of this proposal.

Table 8. Energy Market and Capacity Market Simulation Results

| *(dollars in millions, except LMPs)* | Status Quo | Proposal Simulation Results | Net Change |
|---|---|---|---|
| Generation-Weighted LMP ($/MWh) | $26.00 | $29.50 | $3.50 |
| Total Energy Payments | $20,600 | $23,300 | $2,700 |
| Uplift | $190 | $110 | ($80) |
| Additional Costs to Compensate Resources for Following Dispatch | - | $20 | $20 |
| Capacity Market Costs | $7,000 | $4,800 – $5,800 | ($1,200 – $2,200) |
| Net Impact[44] | $27,790 | $28,230 – $29,230 | $440 – $1,440 (2–5% increase) |

## Longer-term Effects

In addition to the single-year impacts describe above, and stemming from the increase in energy market revenues that would be received by resources under PJM's proposal, PJM believes there would also be a longer-term impact on resource retention.

Given the low energy market prices currently being experienced, it is reasonable to expect that a significant quantity of resources on the system are or will shortly become at risk for retirement. Therefore, while PJM is currently clearing the RPM Base Residual Auctions with a reserve margin of around 24 percent,[45] absent the proposed changes to energy market price formation, that margin can be expected to shrink significantly over the coming years.

PJM believes that it is reasonable to assume that over time, this reserve margin could shrink to a value that approximates the minimum PJM installed reserve margin (IRM) of around 16.6 percent. If PJM's proposed enhancements to energy market price formation are implemented, though, PJM believes that the correction represented by resource retirements will not be as significant as it would otherwise be without the proposed changes, and therefore PJM will continue to experience some level of surplus resources on the system that exceed the minimum required IRM. This effect is difficult to quantify given the difficulty in forecasting the megawatt quantity of resources that will be able to avoid retirement given the proposed energy market changes. However, retaining even

[43] "Additional Costs to Compensate Resources for Following Dispatch" contains lost opportunity cost credits paid to online units only. At this time PJM is not proposing to compensate offline units in this manner.

[44] Due to technical limitations, PJM was not able to simulate the full integer relaxation approach proposed within this document. The simulation data contained herein results solely from reducing the economic minimum limit on all resources and does not contain any amortization of startup and no-load costs. As PJM continues to refine its methodology throughout the ensuing stakeholder process, further simulations will be performed to provide more detail and insight into PJM enhanced price formation methodology.

[45] *2020/2021 RPM Base Residual Auction Results* (PJM Interconnection), http://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx?la=en.

just one percent of additional resources on the system would result in billions of dollars annually in avoided capacity payments by load.