UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc.) Docket No. EL18-33-000

REPLY COMMENTS OF THE
NEW YORK ISO'S MARKET MONITORING UNIT

The Commission issued an order instituting an investigation into elements of the NYISO's practices related to the pricing of fast-start resources that may be unjust and unreasonable ("the December 21 Order"), and the order proposed revisions to address its concerns.[1] On February 12, Potomac Economics filed comments supporting most of the Commission's proposed revisions and opposing one proposed revision.

Potomac Economics moves to file comments in the above-captioned proceeding in reply to comments filed by the California ISO's Department of Market Monitoring ("CAISO DMM") on February 9, 2018.[2]

I. NOTICE AND COMMUNICATIONS

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1 See *Order instituting section 206 proceeding and commencing paper hearing procedures and establishing refund effective date*, 161 FERC ¶ 61,294, (2017).

2 See *Comments of the Department of Market Monitoring for the California Independent System Operator Corporation*, Docket No. EL18-33-000, February 9, 2018, ("CAISO DMM Comments").

II. BACKGROUND AND SUMMARY

Fast-start generators can start-up or shut down in response to real-time conditions, which allows them to participate in the real-time market even from an offline state. Fast-start pricing is a marginal cost pricing method that incorporates the short-term commitment costs that generators incur as a result of being deployed in the real-time market. Without fast-start pricing, wholesale market prices generally do not reflect the full costs of satisfying demand and operating reserve requirements when fast-start units are economic and utilized.

The CAISO DMM asserts that all forms of fast-start pricing are flawed and that its preferred pricing method (i.e., marginal cost pricing that ignores short-term commitment costs of fast-start units) is surplus maximizing and incentive compatible while fast-start pricing methods are not. However, the DMM fails to consider ways in which its preferred pricing method is not incentive compatible and fails to consider how fast-start pricing methods are designed to correct incentive problems that arise under the DMM's preferred pricing method. Moreover, the DMM does not consider how fast-start pricing leads to more efficient incentives for reliable performance, commitment, and investment.

These reply comments are organized as follows. In Section III, we refute the main arguments made by the CAISO DMM. In Section IV, we explain how fast-start pricing methods ameliorate the incentive problems that arise from generators with non-convex costs. In Section V, we summarize our conclusions.

III. REPLY TO GENERAL CRITICISMS OF FAST-START PRICING

The CAISO DMM objects to fast-start pricing based on a claim that fast-start pricing departs from short-run marginal cost principles. As we explain in this section, while we agree that real-time energy prices should reflect short-run marginal costs, the DMM does not properly recognize the short-run marginal cost of meeting load and instead is too rigidly focused on incremental energy costs as the basis for LMPs.

The DMM is proposing that the Commission confine price-setting eligibility to units with flexible operating ranges at the margin, essentially claiming that short-run marginal dispatch costs are the only marginal costs.[3] The DMM focuses its argument on the marginal tradeoff for these generators because they might have the incentive to not follow dispatch when ramped-down to make room when a fast start unit is brought online. While this is logically true, the DMM ignores how its preferred pricing method adversely affects the marginal tradeoff of the fast-start unit by undermining its incentive to offer at marginal cost. As we discuss in the next Section, fast-start pricing was designed to remedy this adverse incentive problem.

The CAISO DMM states:

> ISO/RTO spot markets use marginal cost unit prices that reflect the marginal tradeoffs in the market. When costs are non-convex, make-whole payments are necessary. The combination of marginal cost unit prices and make-whole payments is an application of efficient multi-part pricing. Efficient multi-part pricing follows directly from core economic price theory principles of market surplus maximization and incentive compatibility.[4]

The DMM is correct that non-convex costs (e.g., commitment costs) lead to situations where no single price clears the market and that this requires some sort of multi-part pricing. However, the DMM never explains why the particular multi-part pricing method it favors is best. In fact, fast-start pricing (as contemplated by the Commission) with the attendant make whole payments is also a multi-part pricing method that is clearly superior to the DMM method. As we explain in the next section, fast-start pricing addresses concerns about the marginal tradeoffs

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3 See CAISO DMM Comments at page 3.

4 Id. at page 2.

between committing fast-start resources or ramping up online dispatchable units. It also provides better offer incentives for fast-start units to perform well, as well as better incentives to support commitment of long lead-time units and decisions to import and export power.

With regarding to the effects of fast-start pricing on performance incentives, the CAISO DMM states:

> [Fast-start pricing] would not give producers and consumers the incentive to follow dispatch. Deviation penalties and payments to not deviate from the scheduling run dispatch do not restore incentive compatibility because producers and consumers would have an incentive to submit bids that do not represent their true costs and valuations.[5]

The DMM is correct that fast-start pricing requires the use of deviation penalties and payments so that generators have an efficient incentive to follow instructions, but so does a pricing system that does not employ fast-start pricing. Indeed, the DMM's multi-part pricing requires the use of make-whole payments that are a form of what it calls a "payment to not deviate from the scheduling run dispatch" and which, using the DMM's own words "do not restore incentive compatibility because producers and consumers would have an incentive to submit bids that do not represent their true costs and valuations." Thus, the DMM never explains why it believes these incentive issues are a problem under fast-start pricing but not under its preferred pricing method.

IV. BENEFITS OF FAST-START PRICING

The most efficient pricing method is one that sets price as close as possible to the true marginal costs of satisfying the system's needs, which will provide efficient signals and, as a result, tend to reduce the need for make-whole payments. This is the principle behind the

[5] Id. at Page 6.

"minimum uplift pricing" concepts that have been the basis for fast-start pricing.[6] In this section, we explain how fast-start pricing reduces the use of make-whole payments, resulting in payments that are more efficient and less discriminatory (i.e., more uniform) than under the DMM's preferred pricing method.

Long lead-time units have commitment costs that often take one or more days to recoup at the market-clearing prices. As a result, every ISO in the U.S. has a day-ahead market that allows long-lead time units to sell energy and ancillary services in a manner that is contingent on recouping start-up and other commitment costs. However, in the real-time market, the needs of the system must be satisfied by dispatching online generation and deploying fast-start units.

Day-ahead markets allow long lead-time units to submit offers for a bundle of hours that are struck by the market only if the units are economic and will recover commitment costs over the scheduled run time. Long lead-time units have some flexibility in real time to increase or decrease production, but such adjustments are unrelated to the unit's commitment costs. Hence, the commitment costs of long lead-time units should not be considered in real-time LMPs any more than the cost of building the generator in the first place.[7] However, offline units that can start fast enough to participate in the real-time market and be deployed economically incur commitment costs as a result of real-time market conditions. Hence, these costs are marginal in real time and it is, therefore, appropriate to consider the commitment costs of fast-start units in the real-time prices.

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6 For example, see *Market-Clearing Electricity Prices and Energy Uplift* by Paul R. Gribik, William W. Hogan, and Susan L. Pope, December 31, 2007.

7 Accordingly, we have opposed proposals for ISO markets to incorporate the commitment costs of long lead-time units into real-time LMPs. See "Reply Comments of Potomac Economics" in Docket No. RM18-1-000 (Grid Reliability and Resilience Pricing).

We support fast-start pricing for units that are deployed economically in the real-time market because this method improves:

- The performance of the day-ahead market and commitment of resources;
- The incentives to import and export efficiently; and
- The incentives to offer competitively and perform reliably.

A. Improved Day-Ahead Market Performance and Interchange

Real-time prices play a critical role in facilitating actions and outcomes outside of the real-time dispatch. Hence, it is very important that the real-time prices fully reflect the marginal costs of satisfying the real-time demand. When real-time prices are understated, they will undermine key actions by market participants in both the short-run and long-run timeframes.

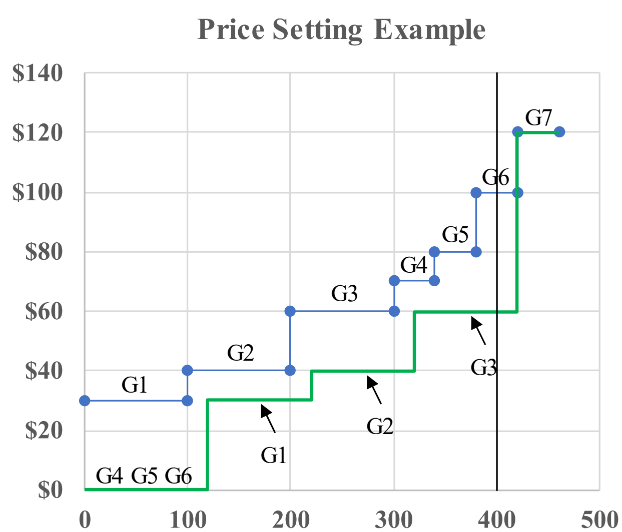
In the short-run, understated real-time prices will provide inefficient incentives to schedule energy in the day-ahead market, which can cause the day-ahead market to fail to schedule lower-cost economic resources that would reduce or eliminate the need to rely on high-cost peaking resources in real time. Hence, real-time prices that fully reflect the efficient costs of satisfying real-time market demand will lead the day-ahead market to produce more complete and more efficient energy schedules and associated generator commitments.

Additionally, understated real-time prices establish poor incentives to import and export power in the real-time market. If an RTO is committing peaking resources with all-in costs of $75, but setting energy prices at $50, it may fail to motivate additional net imports from areas with supply available at costs less than $75. These additional net imports may allow the RTO to stop committing the high-cost peaking resources and/or turn off high-cost peaking resources that are already online.

In the longer-run, understated real-time prices that feed back into the day-ahead market and forward contract markets can undermine efficient maintenance, investment and retirement decisions by generators and loads.

B. Improved Offer Incentives

Since fast-start units have non-convex costs, a robust fast-start pricing regime must involve some element of multi-part pricing. However, this is not unique to fast-start pricing, as the current LMP markets and the DMM's preferred pricing method also utilize multi-part pricing by compensating generators based on energy and ancillary services prices plus various make-whole payments. All multi-part pricing structures will affect suppliers offer incentives, but the following example illustrates why fast-start pricing provides more efficient incentives than the multi-part pricing method preferred by the DMM.



The figure on the right shows a market with three 100 MW fully dispatchable generators at $30, $40, and $60 per MWh (labeled G1, G2, and G3) and four 40-MW block-loaded fast start units with costs of $70, $80, $100, and $120 per MWh (labeled G4, G5, G6, and G7). The cost for these block-loaded units includes commitment costs. The blue line shows all units ranked in order of cost per MWh. If load is equal to 400 MW, the efficient outcome is for two dispatchable units (G1 and G2) and three fast start units (G4, G5, and G6) to be fully deployed while the $60 dispatchable unit (G3) produces 80 MW (since the $100 unit, G6, cannot generate less than 40 MW). The green line shows the costs that are used to set price under the DMM's preferred approach, which treats G4, G5, and G6 as fixed injections once they have been committed. The figure shows that the fast-start pricing method would allow G6 to set the LMP at $100, while the DMM's preferred pricing method would set an LMP at $60.

The following table summarizes the payments to each generator under the DMM's preferred multi-part pricing method versus a multi-part pricing consisting of fast-start pricing with make-whole payments. Under the DMM's preferred method, each unit would receive the $60 LMP, but the three fast-start units (G4, G5, and G6) would each receive a make-whole payment to fill the gap between their as-offered cost and the LMP for a total of $2,800. Under the fast-start pricing method, each unit would receive the $100 LMP, but the $60 dispatchable unit would receive a make-whole payment of $800 to account for the lost opportunity cost of not producing an additional 20 MW at $100.

Example of Settlement with Generators
DMM's Preferred Method versus Fast-Start Pricing Method

			DMM's Preferred Method			Fast-Start Pricing		
Unit	**Output**	**Cost per MWh**	**LMP Revenue**	**Make Whole**	**Total per MWh**	**LMP Revenue**	**Make Whole**	**Total per MWh**
G1	**100**	**$30**	**$6,000**	**$0**	**$60**	**$10,000**	**$0**	**$100**
G2	**100**	**$40**	**$6,000**	**$0**	**$60**	**$10,000**	**$0**	**$100**
G3	**80**	**$60**	**$4,800**	**$0**	**$60**	**$8,000**	**$800**	**$110**
G4	**40**	**$70**	**$2,400**	**$400**	**$70**	**$4,000**	**$0**	**$100**
G5	**40**	**$80**	**$2,400**	**$800**	**$80**	**$4,000**	**$0**	**$100**
G6	**40**	**$100**	**$2,400**	**$1,600**	**$100**	**$4,000**	**$0**	**$100**
G7	**0**	**$120**	**$0**	**$0**	**--**	**$0**	**$0**	**--**
Total	**400**			**$2,800**			**$800**	

The DMM's preferred method pays each generator a rate between $60 and $100 per MWh, which includes the LMP settlement and the make-whole payment. The higher-cost units receiving more revenue than lower-cost units for providing the same product. The wide variation in payment rates undermines uniform-price auction incentives (which generally encourage generators to offer at marginal cost) and leads some generators to have discriminatory-price auction incentives (which provide strong incentives for a generator to raise its offers above marginal cost). In this example, four generators (G3, G4, G5, and G6) could each increase their total compensation dollar-for-dollar by raising their offer price. So the widespread use of make-whole payments under the DMM's preferred method tends to undermine a key objective of the uniform-price auction mechanism, which is to induce suppliers to offer at marginal cost.

The fast-start pricing method also relies on make whole payments, but there is much less variation in payment rates across different generators. In the example, each generator receives $100 per MWh except the $60 generator (G3) which receives an average of $110 per MWh of output because it also receives a make-whole payment for its lower output level. Since the $30, $40, $70, and $80 generators (G1, G2, G4, and G5) are inframarginal, they do not have strong incentives to raise their offers above marginal cost. If the $60 generator knows in advance that it will be ramped down, it may have an incentive to lower its offer since this would increase its make whole payment. Although fast-start pricing does not eliminate all inefficient incentives resulting from multi-part pricing, it provides much better incentives for offering at marginal cost since there are fewer units that receive make whole payments.

It is no accident that fast-start pricing produces smaller make-whole payments than the CAISO DMM's preferred pricing method (in this example $800 compared to $2,800). That is because a key feature of fast-start pricing methods is that they are specifically designed to produce a more uniform set of prices that more accurately reflect the costs of satisfying the market's demands than the DMM's preferred method. Thus, even though non-convex costs require electricity markets to adopt multi-part pricing, fast-start pricing preserves more of the beneficial incentives of the uniform-price auction mechanism. In the fast-start pricing example above, there is no LMP that would lead to lower total make-whole payments than $100 per

MWh. Indeed, there is a significant body of literature about how fast-start pricing methods are specifically designed to minimize make-whole payments, thereby increasing uniformity of prices across the market[8] and having the LMPs reflect a greater portion of the short-run cost of serving load.

Fast-start pricing produces better marginal incentives than the DMM's preferred pricing method in the stylized example above, but we also find that fast-start pricing provides better incentives in practice. For example, the last time we evaluated the extent to which make whole payments are required when fast-start units are started in the NYISO, the NYISO was using a partial fast-start pricing method known as "hybrid pricing" and we found that a make-whole payment was required for 50 percent of the in-merit start-ups.[9] While hybrid pricing allowed fast-start units to set price during some conditions, make-whole payments were still frequently necessary because LMP revenues were often lower than the costs of the fast-start unit, providing strong incentives for the fast-start units to increase their offer prices above marginal costs. This is one reason why we have supported enhancements to the NYISO's fast-start pricing method in recent years.

On the other hand, it is relatively infrequent for dispatchable generators to face marginal tradeoffs that could lead to inefficient incentives under the current fast-start pricing implementation in the NYISO. For example, from November 2017 to February 2018, one or more dispatchable generators faced such a marginal tradeoff (i.e., it received a physical schedule that was inconsistent with the level that would be profit-maximizing given the clearing price while accounting for ramp rate limitations) in just 25 percent of intervals, and the most frequently that any single generating facility faced such an inconsistency was in just 10 percent

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8 For a list of papers on this topic, see *Market-Clearing Electricity Prices and Energy Uplift* by Paul R. Gribik, William W. Hogan, and Susan L. Pope, December 31, 2007.

9 See 2015 NYISO State of the Market Report at page A-139.

of the intervals when the facility was online. Hence, potentially inefficient marginal incentives occur so infrequently for any particular dispatchable generator in the NYISO that it is very unlikely to have a significant effect on their behavior or offer incentives. While this result may seem counter-intuitive, it is because dozens of units are online at any given time, but usually only one or two are at the margin where their incentives may be inefficient. Moreover, the particular marginal generating facility changes from interval to interval, so it is unlikely to affect the incentives of any particular generator if these intervals are infrequent and difficult to anticipate.

Ultimately, we find that inefficient marginal incentives are more frequent and predictable when fast-start units are not able to set price than under the fast-start pricing method. This is clearly illustrated by the example, as well as from actual market outcomes in the NYISO.

V. CONCLUSION

In recent years, the Commission, wholesale market operators, and other parties have increasingly recognized that efficient real-time prices provide incentives for suppliers to perform reliably and for investors to build and maintain resources that provide the most value to consumers and that efficient real-time pricing is particularly important during shortages and other constrained operating conditions. We strongly support the Commission's efforts to improve real-time pricing in centralized wholesale markets, particularly through the use of fast-start pricing methods.

Much of the original impetus for fast-start pricing was the recognition that in markets where fast-start units are used on a daily basis, block-loading them and rendering them ineligible to set price (as in the CAISO DMM's preferred pricing method) was not incentive compatible for such units. It causes such units to rely heavily on make-whole payments, creating the incentive for them to raise offer prices above marginal costs in order to increase their make-whole payments.

Furthermore, the CAISO DMM's preferred pricing method would not provide efficient incentives to import and export power, or to schedule energy in the day-ahead market, which would undermine the efficiency of the day-ahead market schedules and commitments. Understated real-time prices would also weaken generators' incentives to perform reliably. Finally, depressed LMPs diminish incentives to invest in resources with flexible operating characteristics. While this may not be important in markets like CAISO that rely on integrated resource planning, efficient investment incentives are critical in markets that are designed to incent new market-based investment.

We respectfully request that the Commission consider these comments and recommendations in determining the final changes needed to NYISO's fast-start pricing to ensure that its prices are just and reasonable.

Respectfully submitted,

/s/ David B. Patton

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March 14, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. §385.2010).

Dated this 14th day of March 2018 in Fairfax, VA.

/s/ David B. Patton