Economic Consulting

PRICE FORMATION IN ISOs AND RTOs

PRINCIPLES AND IMPROVEMENTS

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Executive Summary

Assessment of concerns about price formation and prompt action to address the underlying problems identified should be an urgent priority for regulators, Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) in order to preserve and strengthen competitive electricity markets. In the absence of confidence in spot market price signals the structure of competitive markets is undermined. Market participants, especially generators, will not and do not see the price signals necessary to lead them to make operational and investment decisions independently that will, as a whole, meet the reliability needs of the system in the short-run and long-run. Regulators and ISO/RTOs therefore would likely look to inefficient solutions implemented outside of the structure of the spot markets, which over time may further distort and erode competitive price signals.

Two price formation concerns mentioned frequently are the suppression of real-time prices and increasing levels of uplift in several ISOs. The issues are tightly linked: price suppression decreases energy and ancillary services revenue, leading to higher uplift. When uplift occurs due to rules that keep prices too low or suppress volatility, there will be too little incentive for load management, efficient imports, participation by storage technologies, investment in fast response generation, efficient use of energy limited resources, and installation of dual fuel capability. Moreover, providers of lower-cost alternatives will not be able to profitably invest to displace resources receiving uplift, such as through investments to raise ramp rates or decrease minimum load. With price suppression, generators running to serve customers in high-price locations are partially compensated through uplift. The result is price discrimination in payments to suppliers and subsidization of the electricity costs of customers in higher-priced locations by the customer base paying the uplift.[2]

1 Dr. Susan L. Pope is a Managing Director at FTI Consulting. This paper was supported by the Electric Power Supply Association (EPSA). Thanks to my colleagues at FTI and within the electricity industry who provided valuable contributions. The views presented here are not necessarily attributable to any of those mentioned, and any errors are solely the responsibility of the author.

2 Market participants cannot hedge against uplift charges. Thus, an additional motivation for reducing uplift through improvements in energy and ancillary services market formation is to increase the proportion of energy market costs that can be hedged by buyers and sellers through forward contracts.

A goal of improvements to price formation should be to reduce the importance of uplift by improving the performance of the basic energy markets in all hours. If energy and ancillary services prices can be improved so as to align more tightly with the system dispatch, this will reduce the need for uplift and at the same time provide price signals leading to improved reliability and operating efficiency. This objective is embraced by the principle of dispatch-based pricing.

Types of Price Formation Issues

A rough taxonomy assists in organizing discussion of possible problems with price formation. While not exclusive, the categories enable identification of pricing problems with similar underlying causes that may have similar solutions. The paper discusses the following:

A. Problems arising from omissions and approximations in unit commitment and dispatch software models, as well as possibly inefficient operator interventions.

B. Problems arising in the price formation step of the ISO/RTO software, including: difficulty in calculating dispatch-based prices because of the lumpiness (non-convexity) of bids and offers; averaging of settlement prices; and, omissions of information about the dispatch and unit commitment in calculating prices.

C. Problems arising from the definition of electricity market products and bidding rules. This includes: absence of valuation of operating reserves in the day ahead energy market and advance unit commitment steps; inefficient bidding rules that do not mesh with the operational constraints and business risks present in electricity and gas markets ; and, evolving implementation of shortage pricing.

Substantive Recommendations

Five improvements to price formation stand out as possibilities for near-term change. The methodologies summarized below have been worked through and proved in operation in one or more ISOs/RTOs. Other ISOs/RTOs are in the process of working on similar changes. Further analysis of the details of solutions already in use could provide a way to move forward to progressively improve price formation.

1. Include All Active Constraints in Price Formation, Including Those Leading to Operator Actions

Price formation problems arise because the software used for the price calculation – sometimes called the pricing module or the ex post pricing model – does not explicitly represent all active constraints affecting the dispatch and unit commitment. These omitted constraints might have led to operator actions to commit or dispatch units out of merit, leading to uplift costs. When the pricing software sees all of the supply and demand in the physical dispatch, but does not have the information needed to model the constraints that have led to this result, it will not calculate a congestion or scarcity value for the active constraint and include this in locational prices. The result is the suppression of prices in some locations and increased prices in others, or overall understatement of prices across a broad region. Importantly, when the commitment and dispatch costs of managing congestion and/or scarcity are not included in locational prices, these costs are recovered through uplift, which is not applied locationally; this increases uplift and undermines the locational aspect of ISO/RTO pricing systems.

The paper presents several recommendations for explicitly representing active constraints in ISO/RTO pricing software.

- Use "soft constraints" in dispatch and pricing models, rather than relaxing violated constraints, in order to impute a congestion cost for all transmission constraints that are active in the dispatch. Many ISOs/RTOs already do this, but the approach is not consistently applied everywhere.

- Create explicit representations of known constraints, including requirements for different types of reserves, to avoid reoccurring supplemental unit commitments or other out of market actions and to explicitly compensate generation with the capability (e.g., flexibility) to meet the constraints. The constraints have the potential to improve pricing provided that they are high enough to supplant supplemental unit commitment that would otherwise occur and bind in price formation.

- Where possible, develop methodologies for representing voltage constraints in pricing software, *even when these cannot be modeled in all steps of the unit commitment and dispatch software.* This methodology is under development. PJM has identified one cause of their non-emergency uplift as arising from the minimum load costs of units that must be on line to manage voltage/reactive constraints. Improvements in pricing through the modeling of voltage constraints in the pricing software may not be possible in all instances because of other issues (i.e., non-convexities resulting from the minimum loads of units within load pockets), but should be pursued as a way to reduce price suppression.

2. Enable Intra-Day Offer Changes

It is important to modify ISO/RTO bidding rules to allow generation suppliers to adjust their offer prices during the operating day to reflect changing conditions, as well as to allow day-ahead offers to vary between hours. The New York Independent System Operator (NYISO) has allowed within-day offer changes since 1999 to maintain reliability during the winter and in 2010 added the flexibility for generators with day-ahead market schedules to raise their offer prices. It has been working to apply market power mitigation in a manner that recognizes the need for offer price flexibility when costs are changing, particularly gas costs during the winter months when interstate pipelines are constrained and day-ahead gas prices may not accurately reflect the cost of buying gas during the operating day. The Midcontinent Independent System Operator, Inc. (MISO) and California Independent System Operator Corporation (CAISO) also allow intra-day changes in offer prices, and ISO New England Inc. (ISO NE) is in the process of changing this element of its market rules. This change should also be considered in regions such as PJM Interconnection (PJM) that at present do not allow this offer price flexibility.

Limitations on within day adjustments to offers can distort real-time price formation when upstream prices change significantly from day to day or within a day, and also have reliability and efficiency impacts. In ISO NE last winter there was price suppression during periods of limited gas availability, because real-time offer prices did not reflect the price of intra-day gas. This price suppression also has the potential to occur if price caps are too low for gas market conditions.

3. Include Block-Loaded Fast-Start Resources in Prices

If fixed-block fast-start units[3] that are committed to meet incremental load are treated as fixed resources whose offers cannot set price (or can only set price for very short intervals upon their initial dispatch or when operators choose to log their commitment in a particular way), the price will never (or almost never) reflect their offers, even in situations when multiple units are committed to meet load over the hours of a day. Rather, the locational prices likely will be set by the offer costs of lower cost flexible units that are dispatched down on margin to accommodate the full output of the fixed-block unit. From the perspective of dispatch-based pricing, the prices are suppressed whenever they are less than the offer costs of a fixed-block fast-start unit that is needed to serve load.

Since its start-up, the NYISO has had pricing rules to allow fixed-block resources to set prices in hours in which they are required to serve load; this successful approach is called “hybrid pricing.” MISO is in the process of refining and implementing an approach similar to the NYISO’s called Approximated Extended Locational Pricing, or Approximated ELMP. Pricing approaches for fast-start block-loaded units are varied and incomplete in the ISO NE, PJM and CAISO. ISO NE’s external market monitor has recommended for a number of years that it investigate changes to its pricing to allow the deployment costs of fast-start generators to be more fully reflected in the real-time market prices. Under ISO NE’s current pricing rules, fast-start resources are only included in price formation in the interval in which they are synchronized to the transmission system. In PJM, gas turbine generators (also called CTs) cannot set the price in the day-ahead market, and when CT Pricing occurs in real-time, the PJM software does not necessarily treat the CT as dispatchable for its full output. If parameters in the software are set to see only a small part of the CT’s capacity as dispatchable, the CT will still typically remain pinned at its minimum load and therefore will not be included in price formation.

4. Use Quantity-Weighted Hourly Prices

Until recently, in all Federal Energy Regulatory Commission (FERC) jurisdictional regions except for the NYISO and CAISO, suppliers to the real-time dispatch were paid based on a simple average of the prices in each interval of the dispatch hour at the supplier’s location, rather than based on a quantity-weighted hourly average of the interval prices at the

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3 Block-loaded fast-start resources typically consist of combustion turbines that can be on-line in 10 minutes or less and have a minimum run time of less than an hour. There are regional differences in the definitions of fast-start block-loaded resources and the nomenclature of the associated pricing approaches (hybrid pricing, CT pricing, Approximated ELMP, Constrained Output Generator pricing); some regions include off-line fast-start resources in their pricing.

supplier's location or through sub-hourly pricing. The former is equivalent to settling the supplier's injection in each interval at the interval price at its location, which is sometimes called "5-minute pricing."[4] Supplier settlements based on hourly generation and on hourly average LMPs fail to compensate generation for ramping to meet changes in five minute generation and loads, charges inaccurate prices for supply and load with deviations during the interval, and over-pays for power supplied in intervals after prices have declined. Sub-hourly clearing prices or quantity-weighted hourly pricing is extremely important in regions in which flexible generation is needed to accommodate intermittent generation and to adjust to changes to 15 minute interchange schedules. Such prices should be charged to generators for schedule deviations, and paid to flexible generators for providing energy that may be essential for maintaining reliability. Southwest Power Pool (SPP) recently implemented 5 minute pricing and ISO NE is planning to shift to 5 minute pricing later this year.

5. Continue to Improve Shortage Pricing

Shortage pricing is an established methodology for assigning value to operating reserves and regulation when they are in short supply in the real-time dispatch. Reserve and regulation penalty factors and shortage pricing proxy for the effect that price-responsive demand, participating to clear real-time markets through demand-side reductions, would have on the real-time dispatch and pricing for energy and reserves. Reserve and regulation penalty factors and shortage pricing allow prices to rise in a predetermined way when reserve or regulation constraints cannot be met because the system is short of capacity or ramping capability. It is desirable to reflect reserve shortage conditions in energy and ancillary services market prices so as to provide an appropriate price signal for consumer load response, and potentially to provide stronger performance incentives for on-dispatch suppliers during reserve shortage conditions. With shortage pricing, when reserves and regulation have a very high value in real-time, this will flow through into energy prices.

U.S. ISOs and RTOs should continue to fine tune the penalty values used to set prices when they are short of reserves or regulation and the definition of the reserve and regulation constraints to which the penalty factors apply, so as to provide appropriate incentives for demand reduction, additional supply (e.g., imports), and the development and offering of increased ramp capability. One or more ISOs also need to make changes so that shortage pricing is implemented in their real-time dispatch, rather than in a look-ahead optimization occurring prior to the dispatch. Shortage pricing will affect real-time energy and reserves prices in fewer days of the year than the other changes recommended here, but when they occur, the methodology provides compensation to suppliers of all kinds who are available to provide reserves, regulation or energy at times when supply is just adequate to meet load.

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[4] For example, suppose a supplier provided 10 MW per interval for the first 8 of 12 intervals and the price in the first 6 intervals of the hour was $500 and the price in the last 6 intervals was $100. The quantity-weighted average price for this supplier would be [(6*500) + (2*100)]/8 = $400. So, it would be paid $400 per MWh for its hourly output of 800 MW, or $3,200. This is the same payment as it would receive with 5 minute settlements.

Practical Suggestions

The following practical suggestions are directed to the process for identifying and implementing improvements to price formation.

Observe the Principle of Dispatch-Based Pricing

The principle of dispatch-based pricing calls for the determination of clearing prices in electricity markets that are as consistent as possible with the actual operation of the transmission system by a system operator seeking to minimize the offer cost of meeting load while adhering to all standards of reliability. In the words of a market participant, dispatch-based pricing translates to the goal, "if the system operator did it [e.g., dispatched a unit or cut an export], it should be included in the pricing."

Focus on Real-Time Pricing

Begin with the goal of improving real-time pricing, with the expectation that this will lead to corresponding improvements in forward market pricing, rather than following the opposite approach and starting with the question of how to improve day-ahead or forward pricing.

Focus on Improving Prices, Rather than on Reducing Uplift

Excessive levels of make-whole uplift are a symptom of a problem with price formation. The only way to reduce this uplift, other than simply shifting the allocation, is to improve the underlying prices.[5]

Adopt Decision Criteria that Do Not Hinge on Quantification of Costs and Benefits

The social benefits of a change in price formation and the impacts on individual market participants will often be extremely difficult to quantify. Costs and benefits typically cannot be estimated in a static model that does not account for changes in the bids and offers of market participants and, more importantly, changes in long run decisions about the timing, location and quantity of investments in new plants and technologies (e.g., energy storage), upgrades to existing plants (e.g., dual-fuel capability or increased ramp speed) and retirement decisions. Opposition to improvements to price formation founded in concerns about short-run price impacts, transition costs, and the difficulty of making changes to software systems should be tempered by consideration of the long-run benefits of the changes, even if these cannot be quantified specifically.

Don't Underestimate the Value of Small Improvements to Price Formation

[5] Make-whole uplift could be hidden through changes in accounting or by the imposition of administrative penalties that impede market responses.

It is important to consider the dynamic impact of changes in price formation that are perceived to be “small” on bids, offers and long-term investment decisions. In some regions, the “problem” has to do with uplift paid to units with both long minimum run times and substantial minimum load costs. A series of “small” improvements to address suppression of real-time prices may ultimately reduce this uplift by creating the incentive for changes to real-time offers and long-term investments which will reduce the frequency with which such units are committed and require uplift.

Monitor Uplift, But Transparency is not a Substitute for Changes to Pricing Rules

ISOs and RTOs can aid informed decision making by providing information about uplift within a short time from the close of a market. Understanding the magnitude of uplift of different kinds is currently very spotty due to the lack of information, and the lack of this information impedes diagnosis of underlying problems and development of solutions. However, market participants will not respond to information about uplift like they respond to energy prices because changes in their behavior will not directly impact the uplift they pay; market response will not cure the problem of uplift. This will require changes in market rules.

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Introduction

On June 19, 2014, the Federal Energy Regulatory Commission (FERC or Commission) announced a staff initiative to discuss price formation in energy and ancillary service markets operated by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). The announcement comes after several years of increasingly vocal concern about price formation in a number of ISOs and the speed with which the ISOs are assessing the concerns, engaging in discussions with stakeholders and implementing change.

Assessment of concerns about price formation and prompt action to address the underlying problems identified should be an urgent priority for regulators and ISOs/RTOs in order to preserve and strengthen competitive electricity markets. Under ISO/RTO market designs, the independent profit-maximizing actions of market participants are intended to be the primary driver of efficient short- and long-run reliable electricity supply for the benefit of customers. Dependable and efficient market prices for energy and ancillary services are absolutely essential for guiding market participants. In the absence of these price signals the structure of competitive markets is undermined. Market participants, especially generators, do not see the necessary price signals to independently make investments when and where needed to meet the reliability needs of the system in the short-run or long-run. Regulators and ISO/RTOs therefore would likely look to inefficient non-market solutions, implemented outside of the structure of the spot markets, which over time may further distort and erode competitive price signals.

The first section of this paper describes what is meant when parties refer to problems with price formation in ISOs and RTOs, principally by reference to FERC's announcement of its workshops on price formation and examples of the concerns under discussion in several ISOs. In the present context, concern about price formation refers, at a high level, to problems market participants have encountered in doing business in centrallydispatched electricity markets because of how energy and ancillary services prices are determined in these markets. The critical issues mentioned frequently are the suppression of real-time energy and ancillary services prices and increasing levels of uplift in several ISOs. When price suppression occurs and generators are made-whole through uplift, there will be too little incentive for load management, efficient imports, participation by storage technologies, investment in fast response generation, efficient use of energy limited resources, and installation of dual fuel capability, and a distortion of decisions about plant retirements.

The second section reintroduces the principle of "dispatch-based pricing" as the goal of economically efficient price formation in ISO/RTO markets. There is no formal definition of dispatch-based pricing. The principle is that *all of the actions taken to reliably supply electricity to customers at least offer cost, whether these are effectuated through a software program or through manual adjustments by the system operator, should be reflected if at all possible in locational market prices*. Locational Marginal Pricing (LMP) is itself a form of dispatch-based pricing and advocacy of dispatch-based pricing is a renewed and urgent call to consistently carry the principle through into all aspects of energy and ancillary services price formation: speaking loosely, if the system operator needs the resource to be on for reliability, its offer should be included in price formation. In discussing improvements to price formation, it is critical to discard the old notion that locational prices should equal *short run* marginal costs only and carry through an expanded definition all the way from the pricing software into the determination of thresholds for price mitigation.

The third section begins with a proposed taxonomy to organize the different issues falling into a discussion of price formation: *problems arising from omissions and approximations in unit commitment and dispatch software models, as well as related operator interventions; problems arising in the price formation step; and problems arising from the definition of electricity market products and bidding rules*. The section then presents specific examples of improvements to price formation – both proved and works in process -- to illustrate ways to address price formation concerns falling into each category of the rough taxonomy.

The objective is to identify possible "low hanging fruit" for those seeking urgent improvements to price formation. Some of the methodologies discussed in section three are templates for change for which the details have been worked through and proved in operation in one or more ISOs/RTOs. Implementation of a market change that has already been proved in another region should be much simpler than developing a wholly new solution to the same pricing concern. Some ISOs are in the process of working on these or similar changes, and it goes without saying that the benefits and challenges of implementing the suggested changes will differ depending on the circumstances in each ISO/RTO, but progress has been slow. Although solutions to pricing concerns depend on the underlying asset mix and on the ISO's/RTO's existing software, examination of the details of solutions already in use provides one way to move forward with what will probably be not one but a set of changes to progressively improve price formation in ISOs/RTOs.

The conclusion presents a set of substantive recommendations and practical suggestions distilled from the discussion in the paper and also summarizes the substantive recommendations. The substantive recommendations are:

- Include all active constraints in price formation, including those leading to out-of-market operator actions;
- Enable intra-day offer changes, and also allow day-ahead bids to differ hourly;
- Include block-loaded fast-start resources in price formation;
- Use quantity-weighted hourly prices in real-time, i.e., 5 minute pricing;
- Continue to improve the penalty factors used for shortage pricing and the integration of shortage pricing into the real-time (i.e., approximately 5 minute) dispatch.

I. The Price Formation Issue

To provide an overview of concerns about ISO/RTO price formation, the following section discusses FERC's announcement of its staff initiative, and provides descriptions of several issues at the top of stakeholders' lists of concerns in the California Independent System Operator, Inc. (CAISO), ISO New England Inc. (ISO NE) and PJM Interconnection (PJM). This is not a full description of the price formation issues in these regions or of the efforts underway to implement changes, nor is the implication that other ISOs and RTOs are exempt from examination of their price formation. However, the level of concern in these three regions is markedly urgent and apprehensive.

FERC

In its notice initiating its staff initiative, FERC discussed the balance between theory and practice required to improve energy and ancillary services price formation. FERC starts with the theoretical, stating: "Ideally, the locational energy market prices in the energy and ancillary services markets would reflect the true marginal cost of production, taking into account all physical system constraints, and these prices would fully compensate all resources for the variable cost of providing service."[6] While FERC does not stop here, it is worth addressing the potential misunderstanding of this theoretical statement, since it could be read to mean that locational prices should equal only *short-*

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6 *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, FERC Notice, June 19, 2014 ("FERC Notice 2014"), at 2, http://www.ferc.gov/industries/electric/indus-act/rto/AD14-14-000.pdf.

run marginal (or variable) costs of production, consisting of only fuel costs and variable operating and maintenance costs. Locational prices will not always equal such *short-run* marginal costs, and this cannot be the meaning of FERC's theoretical statement. FERC-approved tariffs include a number of factors in locational energy prices in addition to *short-run* variable operating costs, such as the opportunity cost of hydroelectric resources, and the lost opportunity costs of generating units whose dispatch is reduced because the system operator needs them to be available to provide regulation or spinning reserves.

Even more importantly, locational prices may also include the marginal value of capacity to load during tight market conditions; this is often called the shortage price,[7] and can be viewed as part of the "true marginal cost of production" when markets are so tight that on the margin additional capacity would be required to maintain reserve requirements.[8] In discussing improvements to price formation, it is critical to discard the old notion that locational prices should equal *short run* marginal costs only and carry through an expanded definition all the way from price formation into the determination of thresholds for price mitigation.[9] In addition, the concept of "physical system constraints" needs to be expanded beyond the limited notion of transmission thermal and interface limits to include all constraints imposed on the unit commitment and dispatch in order to maintain reliability. This expanded concept includes voltage limits, minimum on-line capacity constraints and requirements for reserve, regulating and ramping capacity.

While the practical issues FERC discusses are relevant, and faster computers and better models may be needed to address some price formation issues, the primary obstacle is reaching agreement to allow locational prices to reflect an expanded view of marginal cost, rather than resisting every deviation from a limited definition of short-run variable cost. This means, for example, paying fast-start units a price that is no less than the price of demand response activated during shortage conditions. Some solutions will require the development of better and faster software models, but the most important factor limiting change is the will to consistently and thoroughly implement this expanded concept of marginal cost pricing.

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7 The terminology for shortage pricing varies and is sometimes synonymous with scarcity pricing. This paper follows the convention in the NYISO, where shortage pricing occurs when reserve constraints bind, while scarcity pricing occurs with the activation of demand response.

8 "If high prices in a particular energy market reflect scarcity, these economic rents generally are efficient and serve to provide incentives for construction. However, regulators may limit recovery of high prices during these periods due to the unpalatability of even temporarily high prices and/or suspicion of inappropriate market gaming. Thus regulators may deter suppliers from making needed investments in new capacity by imposing price caps and limiting recovery of legitimate costs and delivery of adequate returns." The Electric Energy Market Competition Task Force, Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy, Energy Policy Act Final Report, August 8, 2006, at 80, http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf.

9 Dispatch-based pricing, as discussed in detail below, *is* this expanded definition of marginal cost pricing, as it calls for the formation of a price signal consistent with the value of supply in meeting the economic and reliability needs of the transmission system in each market interval.

In its announcement, FERC proposes to organize the issues falling into a discussion of price formation into workshops under the following four topics, which are repeated here to further describe the scope of the topic: [10]

- **Use of uplift payments**: "Use of uplift payments can undermine the market's ability to send actionable price signals. Sustained patterns of specific resources receiving a large proportion of uplift payments over long periods of time raise additional concerns that those resources are providing a service that should be priced in the market or opened to competition."[11] FERC is correct that uplift is a symptom of the need to improve energy and ancillary services pricing for the resources that are receiving uplift. Uplift is a symptom rather than a cause of price formation problems, though, and efforts to improve pricing should focus on correcting the causes.[12]
- **Offer price mitigation and offer price caps:** ". . .These protocols require that the RTO/ISO's measure of marginal cost be accurate and allow a resource to fully reflect its marginal cost in its bid. To the extent existing rules on marginal cost bidding do not provide for this, bids and resulting energy and ancillary service prices may be artificially low."[13] Similarly, rules exist in some ISOs and RTOs that restrict suppliers from changing their offer prices during the operating day when their costs, opportunity costs or supply change, even if the supplier lacks market power and its offers would not be subject to mitigation.[14]
- **Scarcity and shortage pricing:** ". . . To the extent that actions taken to avoid reserve deficiencies are not priced appropriately or not priced in a manner consistent with the prices set during a reserve deficiency, the price signals sent when the system is tight will not incent appropriate short- and long-term actions by resources and loads." FERC should explore the details of how ISOs and RTOs are implementing versions of shortage pricing; for example, under some of these implementations not all suppliers of energy and ancillary services in an interval will be paid the shortage price.
- **Operator actions that affect prices:** ". . . [T]o the extent RTOs/ISOs regularly commit excess resources, such actions may artificially suppress energy and ancillary service prices or otherwise interfere with price formation."

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10 FERC Notice 2014, at 3.

11 *Id.*

12 Focusing on reduction in uplift or changes in uplift allocation could run counter to improving the efficiency of the electricity market, as uplift could be lessened through any of a number of uneconomic market designs.

13 *Id.*

14 This concern applies to offers for incremental energy, and also to restrictions imposed on changes to minimum load or start-up costs which can cause units to be committed uneconomically when fuel costs change.

The first workshop on September 8, 2014, on uplift, confirmed the need for leadership and a clear agenda about how to make rapid progress to improve price formation. A purpose of this paper is to contribute to this effort by providing information about a short list of rules and operating practices for improved price formation that are already in use in some but not all ISOs/RTOs. The substantive recommendations and practical suggestions in the following sections directly address the topics on FERC's list and concerns expressed during the first workshop.

CAISO

In the CAISO a recent concern with price formation has been the behavior of real-time prices as dispatchable resources ramp up and down in the middle of the day to meet the profile of net load not served by either wind or solar generation. The net load graph looks to some like the profile of a duck, leading to the nickname "the belly of the duck" to refer to the dip in net load during the daytime when solar production peaks. Concerns have arisen because, as dispatchable resources are called on to ramp down quickly when solar production increases, and then ramp up quickly as daylight fades, real-time prices can spike down in the morning and up in the evening within the intervals of an hour, as shown in Figures 1 and 2 below.[15]

[15] Scott Harvey, "Pricing and Price Signals: What is the problem we are trying to solve?", April 22, 2014 presentation to CAISO Market Pricing Forum ("Harvey 2014(a)"), at 8-10, Figures 1 and 2, http://www.caiso.com/Documents/2_Pricing-PriceSignals.pdf. Prices may spike downward if low cost production must be dispatched down and enters the price formation process because higher cost units are on-line but do not enter set prices because they are constrained by their downward ramp rate. Prices may also spike up in the evening as high cost quick start units must operate for short amounts of time as lower cost units are ramping up.

Figure 1[16]

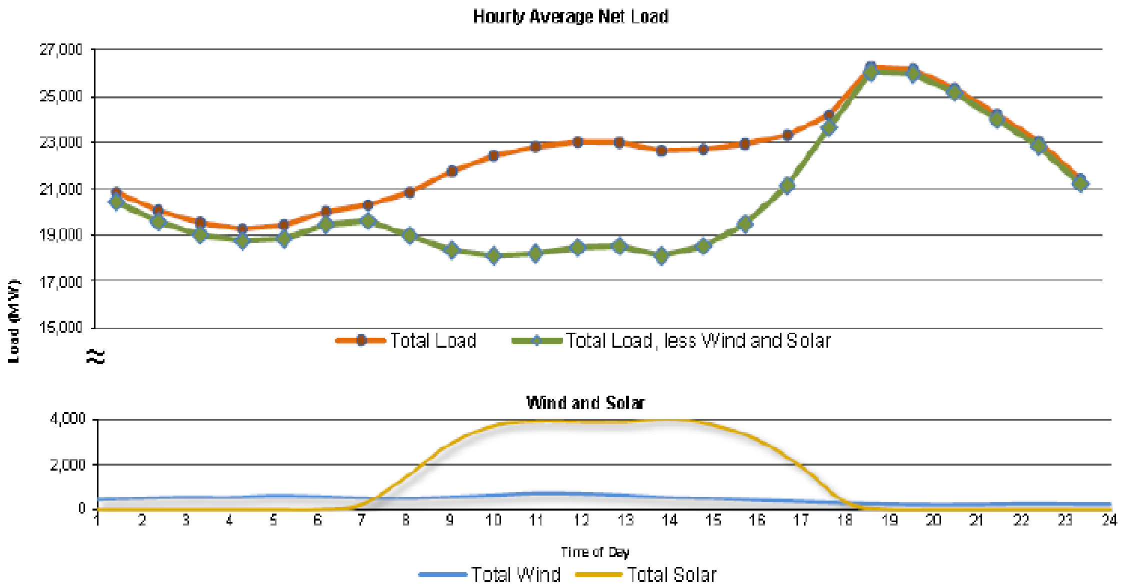
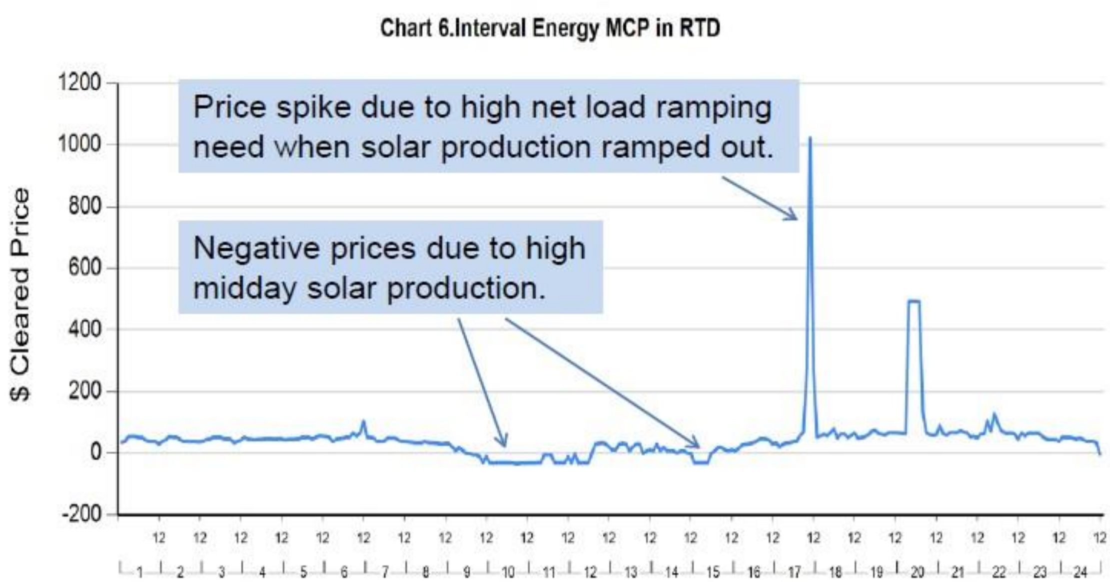


Figure 2[17]



16 California ISO, Market Performance and Planning Forum, March 13, 2014, at 21, http://www.caiso.com/Documents/Agenda-Presentation_MarketPerformance-PlanningForumMar13_2014.pdf.

17 *Id.* at 22.

Diagnosis of whether the behavior of prices during the belly of the duck is a problem or not, and whether any changes in pricing need to be made to address the price volatility, is on-going in the CAISO.[18] An overarching issue for the CAISO is a lack of transparency and therefore a full understanding of the reasons for the commitment of generation units that are receiving uplift.[19]

The CAISO has stakeholder processes underway to examine issues relevant to pricing during the morning and evening ramps, but progress has been slowed by attention to other priorities, such as the start of the Energy Imbalance Market (EIM). In particular, the CAISO started a stakeholder process to look at contingency modeling enhancements in the spring of 2013, with the goal of reducing the use of exceptional dispatches to address minimum online capacity constraints.[20] The CAISO also started a stakeholder process almost three years ago to develop a modification of the real-time dispatch to procure ramping capability in real-time, called the Flexible Ramping Product, but suspended this effort in favor of implementing the flexible ramping constraint.[21] Even if the CAISO implements other changes to improve its real-time pricing, the Flexible Ramping Product would provide compensation to units with capacity on-line to provide ramp capability.[22] The start date of the initiative is an indication of how long the CAISO and its stakeholders have recognized the need to provide a stronger market-based price incentive for increases in the quantity of supply available to ramp quickly.[23] It is not clear when these stakeholder processes will conclude and, without knowing the details, whether they will result in improvements to price formation.[24]

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18 In response to the concern about pricing during the morning and evening ramps as well as concerns about the magnitude of uplift, the CAISO held a Market Pricing Forum in April of this year to share views about price formation issues and to provide information about how price formation works in other ISOs.

19 The pricing patterns are likely the result of many factors, and analysis requires some data available only to the ISO, such as the reasons for the commitment of units with long start-up times during Residual Unit Commitment (RUC) if capacity with short start-up times is available, and the reasons for excess commitment of quick start units during the operating day through the operation of the flexiramp constraint. Harvey 2014(a) at 19.

20 California ISO, “Contingency Modeling Enhancements Issue Paper,” March 11, 2013, http://www.caiso.com/Documents/IssuePaper-ContingecyModelingEnhancements.pdf.

21 This stakeholder process started around November 2011. California ISO, Flexible Ramping Product, http://www.caiso.com/informed/pages/stakeholderprocesses/flexiblerampingproduct.aspx.

22 This may be missing compensation for some flexible generation.

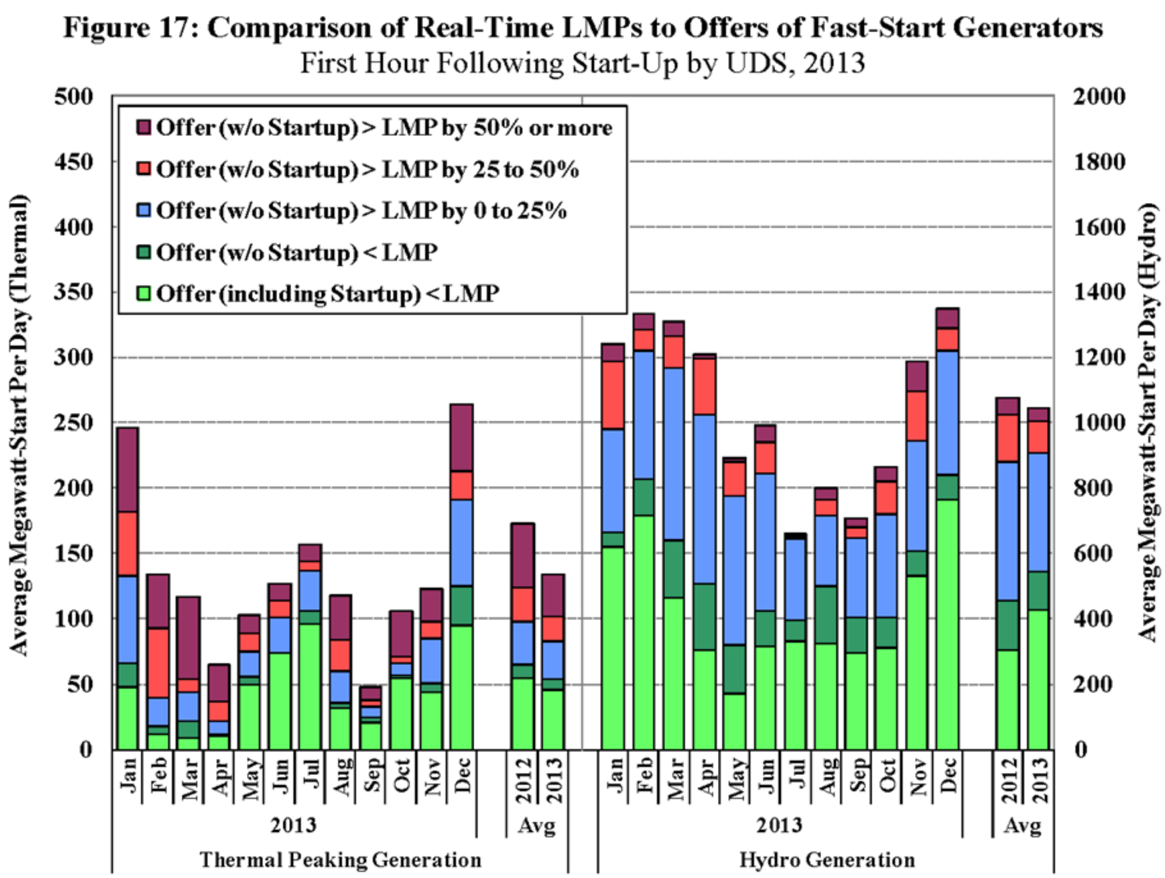
23 Similarly, the CAISO has not followed through on stakeholders’ vote to place priority on assessing ELMP. *See, e.g.*, California ISO, 2013 Stakeholder Initiatives Catalog as of January 28, 2014, at 21, http://www.caiso.com/Documents/Draft2013StakeholderInitiativesCatalogRevisedJan28_2014.pdf. *See also* Calpine Corporation, Comments of Calpine Corporation on 2013 Stakeholder Initiatives Catalog, submitted February 13, 2014, at 1, http://www.caiso.com/Documents/CPN-Comments-DraftStakeholderInitiativesCatalogRevisedJan28_2014.pdf.

24 The pricing issues during the evening ramp may also reflect limitations of when and how the CAISO pricing takes into account constrained output generators (COGS).

ISO NE

Analysis by the ISO NE's External Market Monitor, Potomac Economics, supports the concerns of a number of market participants about modeling and pricing practices in New England that are causing suppression of the real-time prices.[25] Figure 3 below, copied from their June 2014 report, illustrates this price suppression through presentation of data on the average number of megawatts of thermal and hydro generation started per day in New England that was paid an LMP less than its offer price (excluding startup cost) in 2013.[26]

Figure 3[27]



25 Alexander Osipovich, "US power firms slam ISO New England over market 'flaws'," December 18, 2013 (Osipovich 2013), http://www.risk.net/energy-risk/news/2319718/us-power-firms-slam-iso-new-england-over-market-flaws.

26 David B. Patton, Pallas LeeVanSchaick, and Jie Chen, 2013 Assessment of the ISO New England Electricity Markets, June 2014 ("Patton et al. 2013 Assessment"), at 103, http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf.

27 *Id.*

The column on the right shows that on average in 2013, approximately 1,050 MW of fast-start hydro generation was called each day and, of that, approximately 500 MW was paid an LMP less than its offer price (excluding start-up) in the first hour following start-up. Similarly, well over half of the fast-start thermal capacity called on average each day in 2013 was paid an LMP less than its offer excluding start-up.[28]

Although the fast-start resources in Figure 3 receive uplift if needed to cover the difference between their offer and energy and reserve market revenue across the entire day, when they consistently receive uplift, they earn no margin to recover their fixed cost. The price formation accompanying the commitment and dispatch of generation shown in Figure 3 can, and has, diminished the incentive to invest in fast-start dispatchable resources in New England, because even if the units respond quickly when needed, prices may not rise when they are infra-marginal to compensate them for the high value of their energy at that time. The External Market Monitor states:

> Fast-start generators are routinely deployed economically, but the resulting costs are often not fully reflected in real-time prices. In 2013, 60 percent of the fast-start capacity that was started in the real-time market did not recoup its offer. This leads fast-start resources with flexible characteristics to be substantially under-valued in the real-time market, despite the fact that they provide significant economic and reliability benefits. If the average total offers of these units were fully reflected in the energy price, the average real-time LMP would increase approximately $3.34 per MWh in 2013. If these price increases were reflected in the calculation of NCPC uplift charges, we estimate that they would have been $9.3 million lower in 2013.[29]

When fast-start units receive uplift payments, it means that their offers were not reflected in real-time prices during at least part of their minimum run time and the price impacts cascade beyond the fast-start units themselves. Price suppression decreases the energy and operating reserves revenue of non-fast start units therefore leading them to rely on uplift and the capacity market for a greater portion of their fixed cost recovery. Price suppression also decreases the incentive for the energy imports and dispatchable demand which can and do play an important role in maintaining reliability during hours of tight supply.[30]

In addition to pricing during the dispatch of fast-start resources, other factors are contributing to price suppression in ISO NE. A particular concern is that real-time demand response procured in the forward capacity market is not dispatched by the real-

[28] The numbers stated in the text are read, approximately, from Figure 3.
[29] Patton et al. 2013 Assessment at 22.
[30] The suppressed prices will also decrease the price signal for imports to the ISO at times when imports might have been available more cheaply than generation from fast-start internal sources.

time dispatch software, and cannot set real-time energy or reserve prices.[31] All generation and imports serving load, as well as generation providing reserves when the demand response is activated, is paid a price lower than the demand-side resources;[32] the same is true for imports that could help to relieve a shortage situation. Price suppression also arises from the supplemental unit commitment of non-fast start resources after the close of the day-ahead market; the reasons for this unit commitment also need to be examined by other ISOs and RTOs.[33]

This spring the ISO NE initiated a series of technical pricing workshops to explain and examine its real-time price formation.[34] The presentations have clarified some of the causes of price suppression in ISO NE, but the ISO has not yet proposed any new changes. ISO NE has implemented a number of market design changes recently, motivated by reliability problems this past winter, and is pursuing others in on-going working groups.[35] In particular, the ISO has increased their reserve constraint penalty factors, which has the potential to increase reserve and energy prices when reserve constraints are binding.[36] ISO NE also has a target date of December 2014 to implement a number of changes to increase the flexibility of energy offers, including allowing suppliers to vary supply offer values hourly, update offers in real-time and submit negative offers down to ($150). These changes will better enable suppliers to reflect actual real-time costs and operating conditions in their real-time offers, and this should flow through to real-time prices that better reflect real-time conditions.[37] In

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31 The External Market Monitor summarizes the problem: "[t]he activation of demand response in real time can inefficiently depress real-time prices substantially below the marginal cost of the foregone consumption of the demand response resources, particularly during shortages or near-shortage conditions." *Id.* at 96.

32 Demand response resources are expected to have much higher marginal costs than generators, but these costs are not included in the calculation of real-time prices and therefore generators and imports serving load and providing reserves receive a lower price. *Id.*

33 David B. Patton, Pallas LeeVanSchaick, and Jie Chen, 2012 Assessment of the ISO New England Electricity Markets, May 2013 (Patton et al. 2012 Assessment), at xviii-xix, http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2012_emm_rprt_final.pdf.

34 *See, e.g.*, Ron Coutu and Matthew White, Real-Time Price Formation: Technical Session #4, ISO New England, May 19, 2014 (ISO NE Price Formation 2014), http://www.iso-ne.com/support/training/courses/energy_mkt_ancil_serv_top/price_information_technical_session_session4.pdf.

35 Kevin Kirby, ISO New England Winter Operational Experiences and Regional Actions, ISO New England, May 16, 2013, http://www.ferc.gov/CalendarFiles/20130516134342-2-ISO-NE.pdf.

36 An additional problem is likely that ISO NE operators start extra units, call on a block of dispatchable load, or curtail exports in advance of reserve constraints binding, which depresses energy prices and means that reserve penalty factors do not apply. PJM has noted a similar problem with operator action in anticipation of possible shortage conditions.

37 Kevin Seliga, Stephen George, and Mario DePillis, Energy Market Offer Flexibility Customer Training Webinar, ISO New England, June 17-18, 2014, http://www.iso-ne.com/support/training/courses/energy_mkt_ancil_serv_top/energy_market_offer_flexibility_06_2014.pdf. *See also ISO New England Inc. and New England Power Pool*, Docket No. ER13-1877, Compliance Filing re Energy Market Offer Flexibility Changes, January 17, 2014, http://www.iso-ne.com/regulatory/ferc/filings/2014/jan/er13-1877-001_ener_mkt_offer_1-17-

addition, the ISO is implementing 5-minute real-time market settlements for dispatchable resources to improve the incentives for flexible resources that can ramp up and down quickly.[38] Despite these changes, though, ISO NE has not proposed solutions to a number of the factors discussed above that continue to suppress prices.

PJM

Attention to price formation in PJM has been motivated primarily by increases in the level of uplift.[39] When there are problems with price formation, one of the symptoms can be increases in uplift, which rises when market prices do not cover the offer costs of generation that is committed to manage transmission constraints or meet requirements for ancillary services. The table below shows the sources of PJM's bid-cost guarantee uplift in 2013.

2014.pdf, and A. Joseph Cavicchi, "The Polar Vortex: Implications for Improving the Efficiency of Wholesale Electricity Spot Market Pricing," March 2014, https://www.epsa.org/forms/uploadFiles/29D4100000011.filename.Compass_Lexecon_Polar_Vortex_Implications_paper_3_31_2014.pdf.

38 Matthew Brewster, "Subhourly Real-Time Market Settlements," ISO New England, January 14-15, 2014, http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/jan14152014/a06_iso_presentation_01_15_14.ppt

39 PJM recently established an energy market uplift cost task force that is actively examining the causes of uplift and examining market design changes that will minimize uplift. *See, e.g.*, PJM Interconnection, PJM Price-Setting Changes, December 20, 2013 (PJM Price-Setting Changes 2013), http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02c-price-setting-option.ashx.

Table 1

	PJM-2013[40]				
Month	***Day Ahead***	***Real-Time***	***Reactive***	***Opportunity Cost***	***Total***
Jan	5,928,13	67,758,16	23,604,23	11,481,30	108,771,83
Feb	4,980,867	62,395,543	17,624,984	4,730,662	
Mar	6,302,47	10,288,21	14,350,13	7,127,31	38,068,13
Apr	5,712,618	17,635,540	13,670,581	5,781,873	
May	5,403,22	14,006,29	17,214,14	8,518,35	45,142,01
June	6,584,357	10,816,722	22,055,238	7,029,836	
July	8,306,00	23,655,28	19,633,77	19,492,27	71,087,33
Aug	4,159,470	8,819,526	27,827,070	5,666,954	
Sept	6,005,48	19,918,88	27,534,90	10,974,08	64,433,35
Oct	2,473,705	9,505,540	41,721,300	3,085,323	
Nov	2,799,52	15,565,02	42,743,90	2,144,87	63,253,32
Dec	5,224,275	34,868,398	43,464,829	1,108,647	
2013-	*$63,8180,12*	*$295,233,13*	*$311,445,10*	*$87,141,499*	*$757,699,86*

These data, showing the extremely large uplifts occurring in some months, have helped PJM to begin to assess the underlying causes of their uplift; attention has focused on the quantity of reactive uplift, real-time uplift, and the total uplift occurring during winter months. PJM has identified one of the major causes of their non-emergency uplift as arising from the minimum load costs of units that must be on line to manage voltage/reactive constraints; these costs are part of the "Reactive" column of Table 1.[41] The resource commitments which result in significant non-emergency uplift are generating units that cannot set spot market prices because they are operating at their minimum load, but which are committed to provide energy in association with these operational constraints; long minimum run times contribute to the problem.[42] Uplift occurs because when such a unit is committed, its minimum load adds a block of supply to the supply curve and the underlying operational constraint does not bind in price formation, reducing locational prices. It is important to note that because the commitment of these units results in price suppression, uplift likely increases for all

40 Adam Keech, Uplift in PJM (Uplift in PJM(a)), at 2, http://www.caiso.com/Documents/4_PJM_MarketOverview.pdf.

41 This problem is partially transitional, due to the retirement of coal units that were assumed to remain in service for purposes of transmission system planning.

42 Adam Keech, Uplift in PJM, PJM Interconnection, February 21, 2014 (Uplift in PJM(b)), at 9.

generation serving load during these commitment periods; the increase in uplift is not limited to the generating units that must be committed to manage the voltage/reactive constraints. In order to address this problem, PJM is examining the possibility of allowing inflexible units that are on-line to manage a transmission constraint to be included in the setting of LMPs.[43] At this time, it is not clear how this proposal would be implemented and whether it would reduce non-emergency uplift, especially if the changes do not incorporate congestion pricing for the underlying transmission constraint. PJM also has been working on improvements to incorporate the constraints that are causing generators to be on-line into their real-time and day-ahead software, and have recently implemented a new SENECA Interface. These changes should improve their pricing so long as the constraint representation is consistently implemented in their commitment, dispatch and pricing software.

PJM also has found that non-emergency uplift arises because "[o]perators deploy emergency procedures in advance of peak conditions based on expectations," that are off.[44] Again, while the description of the problem in the context of PJM focuses on uplift, this is equivalent to stating that these emergency procedures are suppressing prices and price volatility, leading to increased uplift. PJM has been frank that operators prefer to be long rather than short on resources in order to preserve reliability, although they are careful to say that this does not mean that operators are not concerned with market impacts.[45] To address this issue, PJM is proposing to price resources scheduled in excess of current requirements for day-ahead spinning reserves under certain load and operational conditions.[46] *Depending on how it is implemented*, this proposal could improve price formation in PJM; in particular, it will need to lead to higher prices for both reserves and energy due to the higher requirement binding during price formation, while not leading to any increase in unit commitments relative to the extra commitments operators are making today under the same operating conditions.

The partial summary of activities at FERC and within several ISOs in this section illustrate the variety of complex and interrelated issues encompassed within a discussion of price formation. Diagnosis of the problems and the design of solutions must tie technical understanding of electricity system operation to conceptual understanding of how price formation should work to support market efficiency. The ISOs/RTOs are attempting to address the issues of most concern in their regions but progress has been slow and priorities are difficult to maintain. Given the intense concern about price formation in a number of regions, it is time to focus on consistently implementing pricing improvements that have been proved in practice.

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43 PJM Price-Setting Changes 2013 at 5.
44 Uplift in PJM(b) at 15.
45 *Id.* at 16.
46 PJM Interconnection, PJM ERPIV Proposal: Reserve Pricing, June 25, 2014, http://www.pjm.com/~/media/committees-groups/committees/mic/20140625-energy/20140625-item-05a-pjm-proposal-overview.ashx.

II. Dispatch-Based Pricing Principle

Dispatch-based pricing provides a principled approach to assessing and developing methodologies to address the price formation concerns discussed in the previous section. The principle of dispatch-based pricing expands the definition of marginal cost pricing, departing from the equation of prices with short-run variable costs in all market intervals. The alternative principle is that locational prices should be consistent with the locational value of supply in meeting the economic and reliability needs of serving load each market interval. Under dispatch-based pricing, prices will continue to reflect short-run variable costs in many intervals and in many locations, because suppliers will continue to be under pressure to offer their short-run variable costs as they compete to be dispatched.

This section provides a conceptual explanation of the principle of dispatch-based pricing, its relationship to uplift, and its application in real-time and day-ahead markets. Dispatch-based pricing is a principle or goal, rather than a formalized theory or model. It can be used to guide the process to improve price formation in the ISOs/RTOs, but does not dictate the exact formulas that should be used or required by each ISO/RTO. The following section provides examples of the application of dispatch-based pricing principles to address specific problems with price formation, such the use of hybrid pricing to address non-convexities arising from the commitment of fixed-block fast-start generating units.

Theoretical Basis

The principle of dispatch-based pricing calls for the formation of locational clearing prices in electricity markets to be as consistent as possible with the actual operation of the transmission system by a system operator seeking to minimize the offer cost of meeting load while adhering to standards of reliability.[47] Under this general approach, real-time prices are determined *from* the dispatch quantities, transmission system configuration and underlying bids and offers, even when the physical dispatch includes operator actions that might not be perfectly optimized.[48] The goal is to determine a set of locational prices that would give incentives for independently profit-maximizing market participants to supply energy and ancillary services in real-time in the same

[47] William W. Hogan, "Contract networks for electric power transmission," *Journal of Regulatory Economics*, *4*(3), at 211–242, http://www.springerlink.com/index/wh70283126518105.pdf. The goal of dispatch-based pricing is to determine "prices consistent with the actual usage by applying the marginal tests of economic dispatch."

[48] For example, when applied to the real-time market dispatch-based pricing would take the dispatch quantities for energy, dispatchable demand, imports and exports for all products (i.e., energy and market-based ancillary services), and then determine a set of locational prices for the products from data on the quantities of each product dispatched in different locations, the grid configuration and the underlying offers.

quantities as those called for by the system operator under the actual conditions of the dispatch.

Microeconomic theories of duality and incentive compatibility support the concept of dispatch-based pricing. From an economic perspective, prices are "dispatch compatible" if competitive market participants, when presented with the set of prices, but without being told their dispatch quantities for each product, would choose to supply the same amount of each product for the dispatch as the system operator requested in order to maximize their profits.[49] This powerful economic principle needs to be continually kept in mind when proposing changes to prices in power markets. The question to pose is, "If prices were changed in ____ way, and all other aspects of price formation were not changed, then what would a competitive market participant choose to do to maximize profits over time and across products, assuming his/her choices were not bounded by new rules or altered by new forms of uplift?" If the change in a pricing rule would give market participants profit incentives that would take their voluntary choices further from the dispatch quantities the system operator is calling for, rather than closer, even if this would only occur under particular operational conditions, it is a signal for further discussion. Problems arise when pricing rules for energy and ancillary services are changed without thinking broadly about the incentives created for profit-seeking companies considering their alternatives over multiple products and time periods.

The design of successful organized electricity markets, built on bid-based, security-constrained economic dispatch and locational marginal pricing (LMP), goes a long way towards achieving dispatch-based pricing.[50] But, as FERC recognized in its announcement of the staff initiative, the actual operation of the electricity system involves technical features that are difficult or maybe even impossible to include in the security-constrained dispatch or in pricing models. As a result, real-time prices do not always provide incentives for market participants to supply and consume exactly the real-time quantities the system operator has called for, i.e., the real-time prices are not fully dispatch-compatible. For example, out-of-market operator adjustments to software solutions, such as supplemental unit commitments to maintain reliability, may be needed and can cause problems with price incentives if they are not reflected in the price determination. An added complication is that the operational and technical challenges are not static; for example, they have been changing with the development and penetration of new technologies, such as intermittent wind and solar generation, and the actual and planned retirement of some generation. Furthermore, uplift and

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49 The concept of incentive compatibility arises in microeconomic theorems of duality, which not coincidentally also forms the basis for models of economic dispatch.

50 All U.S. ISOs and RTOs currently use LMP to determine settlement prices, with nodal prices for generators. PJM implemented LMP pricing in 1998, the New York ISO in 1999, and ISO New England switched to LMP pricing in 2003. The MISO implemented LMP pricing in 2005, the Southwest Power Pool in 2007, the CAISO switched to LMP pricing in 2009 and ERCOT switched to LMP pricing in late 2010. The energy imbalance market under discussion for most of the Northwest Power Pool (NWPP) entities outside of California would also utilize LMP pricing.

pricing problems are occurring at the juncture of unit commitment and dispatch decisions, leading to the need for a way to reflect unit commitment decisions in pricing under some circumstances.

The principle of dispatch-based pricing recognizes that the idealized theory of energy and ancillary services pricing cannot presently be achieved, but points toward how to continue to move toward more incentive-compatible efficient pricing.[51] In a recent paper, William Hogan provides a concise mathematical formulation of the well-established application of dispatch-based pricing to calculating LMPs after the fact from ISO and RTO dispatch solutions, and extends the mathematical formulation to address a number of aspects of electricity system operation which are not yet, or not consistently, included in price formation.[52] The most significant recent application of dispatch-based pricing is the use of operating reserve demand curves to improve pricing during and before shortage conditions develop.[53] Hogan's paper also describes how the mathematical formulation can be applied to improve price formation for reliability unit commitment (RUC) and for voltage constraints. The final illustration is of Extended LMP (ELMP), also known as convex hull pricing (CHP).

The principle of dispatch-based pricing is the goal of providing prices that are as consistent as possible with the actual conditions of the dispatch and underlying unit commitment and, by doing so, to provide more efficient incentives for load management, plant availability, imports and exports between regions, participation by storage technologies, investment in fast response generation, use of energy limited resources, installation of dual fuel capability, investments in pipelines, and decisions about plant retirements. Market rules that are preventing prices from consistently reflecting the actual constraints that are binding and actions that are taken in the unit commitment and dispatch are exacerbating price suppression and uplift, and compounding the bigger problem of decreased and distorted incentives for investments in new or upgraded capacity resulting from these pricing problems.

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51 In the idealized theory, market clearing energy and ancillary services prices, augmented by shortage prices in the absence of adequate real-time price responsive demand to clear markets during periods of shortage, would be all that is needed to employ competitive markets to drive efficient operation of the electricity system. William W. Hogan, "Electricity Market Design and Efficient Pricing: Applications for New England and Beyond," June 24, 2014 (Hogan 2014), at 1, http://www.hks.harvard.edu/fs/whogan/Hogan_Pricing_062414.pdf.

52 "Ex post LMP illustrates dispatch-based pricing because it is a technique to approximate prices that are as close as possible to being those that would arise from efficient dispatch, and thus consistent with efficient dispatch." Hogan 2014 at 6.

53 Hogan explains important features of the operating reserve demand curve implementation, including how it can assist the critical task of distinguishing high prices due to scarcity from high prices arising from the exercise of market power, how it can readily be "augmented" to increase reliability and reduce uplift, and how operating reserve demand curve pricing can be extended to include demand response and other energy-limited resources as sources of reserves.

Dispatch-Based Pricing, Uplift and Capacity Payments

"Make-whole" uplift and capacity payments are features of most, but not all (with respect to capacity payments) electricity markets in U.S. ISOs and RTOs arising because system operators cannot maintain electricity reliability based only on LMP settlements of their markets for energy and ancillary services as currently designed. Make-whole uplift is the result of the need to augment supplier compensation to address gaps in dispatch compatibility in the day-ahead and real-time markets, i.e., to ensure that suppliers do not have a price incentive to perform in a manner contrary to their dispatch instructions.[54] Capacity payments are made, similarly, because of concerns that compensation in the day-ahead and real-time markets needs to be augmented to ensure that market participants behave over the long-run so as to enable the system operator to maintain reliability, i.e., to provide some insurance that they will invest in sufficient generating capacity to meet forecasts of future demand.[55] Both of these forms of pricing supplement the idealized theory of operating centralized electricity spot markets based on energy and ancillary services pricing alone.

Make-whole uplift arises to compensate for inconsistencies between the supplier behavior that would be profit maximizing, taking as given energy and ancillary services prices, and the supplier behavior directed by system operators to serve load efficiently and reliably. Lumpiness and discontinuities in generation supply curves (i.e., non-convexities), long start-up times and minimum run times drive the need to augment energy and ancillary services prices with make-whole uplift. If energy and ancillary services prices can be formed so as to align decentralized actions with the system dispatch, this will reduce but not eliminate the need for make-whole uplift and at the same time provide price signals leading to improved reliability and operating efficiency.[56]

Because residual uplift will remain due to non-convexities, the goal of improving price formation by applying dispatch-based pricing principles is not equivalent to the goal of completely eliminating uplift. Improvements to price formation in the direction of dispatch-based pricing will not completely eliminate the need for make-whole uplift in day-ahead and real-time markets; this is not currently possible in conjunction with the

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54 Make-whole uplift is calculated in different ways in different ISOs/RTOs. In particular, some ISOs/RTOs may constrain supplier behavior through administrative rules and penalties in some circumstances, rather than paying uplift.

55 For purposes of this paper, the terms "uplift" and "make-whole uplift" have the same meaning and refer to the sum of: 1) payments made when an ISO commits, dispatches or schedules a resource and the resource operates as directed, but does not recover its total commitment costs from energy and ancillary services market revenues; and, 2) payments made to compensate constrained-down resources for lost opportunity costs.

56 As discussed below, it will not be possible to completely eliminate uplift. Uplift occurs, for example, because of weather-related errors in load forecasts and the commitment of a generating unit that in retrospect is not required in real-time. Raising prices in this situation would only increase uplift because of the impact on constrained-off payments, i.e., lost opportunity costs.

formation of efficient cost-based dispatch and real-time and day-ahead energy and ancillary services prices.[57] Recognizing that the payment of uplift to suppliers will continue, some have sought to eliminate uplift as a charge to customers. Charges to *recover* the cost of the make-whole uplift payments could be eliminated as a line item on customer settlement statements, but this is a billing change and the allocation of the uplift recovery, even if bundled within a different charge, can impact the marginal incentives of the market participants who pay it.

Although some uplift arising from issues of non-convexity and forecast errors will remain, efforts to continually improve price formation in the direction of dispatch-based pricing is the right approach to reduce the persistent problem of uplift arising from out-of-market interventions by system operators. Regulators face pressure when proposed improvements to price formation have the potential to increase prices or price volatility in the short-run, even if such changes are economically efficient. It may appear to be easier to achieve the desired (or required) real-time supplier behavior through out-of-market actions and administrative rules rather than through price signals and "spread the average costs [of the not-reflected-in-the-market price actions] as an uplift allocation. But in markets where participants have discretion to follow the incentives, this superficially easy fix creates perverse incentives that can cause larger unintended consequences."[58]

Reliance on uplift when there is an alternative available to incent the desired actions by market participants through improvements to price formation is a decision to accept distorted market prices, and creates incentives for buyers and sellers to deviate from efficient behavior.[59] Distortions will occur in the operation of existing resources and also in capital allocation and will interfere with the locational element of ISO market price signals for energy and ancillary services. When uplift occurs due to software models and rules that keep prices too low or suppress volatility, there will be too little incentive for load management, efficient imports and exports, participation by storage technologies, investment in fast response generation, efficient use of energy limited resources, installation of dual fuel capability, and contracts for firm fuel supply. Providers of lower-cost alternatives will not be able to profitably invest to displace resources receiving uplift, such as through investments to raise ramp rates or decrease minimum load. Units chronically receiving uplift will have a reduced incentive to reduce their costs or improve their performance because any decrease in their costs will be

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57 Attempts to eliminate uplift by rolling it into energy prices immediately run into a conundrum, as increasing one price in an attempt to reduce uplift will generate the need for uplift elsewhere to forestall ensuing incentives to deviate from economic dispatch. *See, e.g.*, ISO NE Price Formation 2014 for an explanation of this point.

58 Hogan 2014 at 2. For example, PJM has recently had issues with the allocation of uplift charges for virtual bidders, which has led to unintended consequences as a result of a decrease in certain types of virtual bidding. *See, e.g.*, PJM Interconnection, Docket No. ER13-1654, Attachment I: Report on the Impacts of Virtual Transactions, February 7, 2014, http://www.pjm.com/~/media/documents/ferc/2014-filings/20140207-er13-1654-000.ashx.

59 Hogan 2014 at 1-3.

matched by a decrease in their uplift payments. When uplift arises due to price suppression, locational increases in energy and ancillary services prices may be partially replaced by an uplift charge for the generators that must run to serve customers in high priced locations, with the uplift charge generally spread across a broad group of customers. The result is price discrimination in payments to suppliers and subsidization of the electricity costs of customers in higher-priced locations by the customer base paying the uplift charges (and probably increased capacity prices as well).[60]

Dispatch-based pricing seeks to reflect energy and ancillary services commitment and dispatch decisions accurately in spot market prices, thereby reducing both these price distortions and make-whole uplift. The specific recommendations for improvements to price formation in the sections that follow are suggestions for possible paths forward.

Payments for capacity are a second type of compensation arising in most ISOs and RTOs to augment energy and ancillary services prices. Capacity markets and capacity payments are intended to address the “missing money” problem.[61] There is a concern that the software and rules for unit commitment, dispatch and pricing in ISO and RTO day-ahead and real-time markets may not allow energy and ancillary services prices to rise to a high enough level, for long enough, for the compensation from these markets to support new generation investment or upgrades to existing investment sufficient to meet long-term reliability standards.[62] Capacity markets and capacity payments have been introduced to supply the missing money that is estimated to be needed to motivate private investors to build sufficient capacity to meet future electricity demand; there continue to be adjustments to the parameters of these markets to improve their ability to meet this goal.[63]

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[60] Market participants cannot hedge against uplift charges. Thus, an additional motivation for reducing uplift through improvements in energy and ancillary services market formation is to increase the proportion of energy market costs that can be hedged by buyers and sellers through forward contracts. This forward contracting helps buyers manage variations in their electricity costs and also provides a counterparty for supplier investments. Also, the allocation of the uplift cost recovery itself can lead to further inefficiencies. The uplift cost allocation is often complicated and, when the uplift is non-trivial, buyers and sellers will have the incentive to distort their bids and offers so as to avoid paying a share of the cost, such as in the allocation of uplift to virtual bidders in PJM. In the extreme, the uplift will end up being paid by a shrinking pool of market participants who pay an increasingly large share of the uplift each. On the other hand, the impact of the allocation of uplift on the marginal incentives of market participants will be small when uplift is small, even if this allocation is not perfect.

[61] The characterization as “missing money” comes from Roy Shanker. *See, e.g.*, Roy J. Shanker, Comments on Standard Market Design: Resource Adequacy Requirement, Federal Energy Regulatory Commission, Docket RM01-12-000, January 10, 2003.

[62] *See, e.g.,* Paul L. Joskow, “Capacity Payments in Imperfect Electricity Markets: Need and Design,” *Utilities Policy, 16(3)*, 2008, at 160-161, available at http://web.mit.edu/ceepr/www/publications/reprints/Reprint_190_WC.pdf.

[63] *See, e.g.*, *New York Independent System Operator, Inc.*, Docket No. ER13-1380-000, Proposed Tariff Revisions to Establish and Recognize a New Capacity Zone and Request for Action on Pending

The design of capacity markets faces difficult challenges in meshing the long-term objective of insuring capacity sufficiency with the real-time objective of making sure this capacity is available during periods of shortage. Markets designed with a longer-term time-step, such as a year, provide a price signal for longer-term investments. However, annual price signal designs face the challenge of insuring that a capacity obligation incurred in an annual capacity market will be available in real time under shortage conditions. ISOs have attempted to address this issue in a variety of ways, principally with administrative rules requiring such availability or with rules to define the "unforced" quantity of capacity eligible to receive a capacity payment. The ISO NE recently took an additional step to attempt to improve the real-time performance of capacity resources by creating a real-time settlement for under- and over-performance, called the pay-for-performance program.[64] *The best alternative to such enforcement mechanisms is to bolster the efficiency of real-time prices, so that all suppliers will have a strong market incentive to be available when load is high and/or supply is scarce.*

While capacity payments and capacity markets are a reasonable "belts and suspenders" approach to insuring long-term reliability, the role should be that of an adjunct to efficient energy and ancillary services prices, not a substitute.[65] The design of pricing rules for uplift and capacity should proceed with a firm understanding that these forms of compensation are secondary to and complement the incentives provided by real-time and day-ahead pricing of energy and ancillary services, and should be designed so as to disrupt the incentives provided by real-time and day-ahead pricing as little as possible.[66] For instance, supplier failure to perform in real-time should be addressed, in the first instance, by reforming market rules that currently prevent real-time prices from reflecting market conditions during periods of shortage, as well as leading up to shortages. *A goal of improvements to price formation should be to reduce the importance of uplift and capacity payments by improving the performance of the basic energy markets in all hours.*[67]

Ideally, uplift and capacity payments should address only the pricing issues that remain after mining all possible improvements to real-time pricing. A goal of improvements to price formation should be to increase the proportion of supplier revenue occurring through the provision of energy and ancillary services and to decreasing the revenue recovery required through uplift and capacity payments.

Compliance Filing, April 30, 2013. *See also ISO New England Inc. and New England Power Pool*, Docket No. ER14-1639-000, Demand Curve Changes, April 1, 2014.

64 *See, e.g.*, David Patton, EMM Response to Questions on Performance Initiatives Proposal, February 19, 2013. PJM is also exploring methods to incorporate stronger performance incentives. *See, e.g.*, PJM Interconnection, PJM Capacity Performance Updated Proposal, October 7, 2014, http://pjm.com/~/media/documents/reports/20141007-pjm-capacity-performance-proposal.ashx.

65 Hogan 2014 at 4.

66 *Id.* at 5.

67 Scott Harvey, "Is the California ISO Becoming an Uplift Market? Pricing, Uplift and Commitment," May 19, 2014 (Harvey 2014(b)), at 5-6.

Because changes to energy and ancillary services price formation will lead in many cases to compensating changes in make-whole uplift and capacity payments, it is essential to assess the full monetary effect of any proposed pricing change from the perspective of the total change in payments to suppliers (or charges to customers), inclusive of make-whole uplift and capacity payments. Some of the practical improvements to price formation discussed below will increase energy and ancillary services prices in some hours and locations and decrease them in others. Even if the overall effect were to increase the energy revenue a supplier earned during real-time intervals in which there was a shortage of operating reserve, for example, this would not necessarily mean that there would be an increase in the total operating revenue the supplier would earn in a year, since increases in energy and ancillary services revenue would be offset in part or in whole by a decrease in the uplift the supplier would receive (net of any increase in compensation from energy and reserve markets) and also by any change in market clearing capacity prices (which could also fall on the expectation of increased operating reserve and energy revenue). The impact of any change to price formation on an individual supplier will, thus, be difficult to estimate, due to interactions in the determination of its different revenue streams: energy, ancillary service, uplift and capacity. *The important point is that an improvement to price formation to address price suppression will not lead to an increase in the profits of all suppliers by the full amount of the increase in price.* Uplift and capacity payments, if well designed, will change to dampen and offset the overall impact of changes in energy and ancillary service prices on the total yearly payments customers make for electricity supply.

In fact, if a reduction in price suppression has the desired effect of decreasing uplift, the net result for many suppliers should be little change in total compensation, although more of the compensation would be from energy and ancillary services prices and less from uplift. Moreover, even if there were an increase in total compensation from energy, ancillary services and uplift for some or all suppliers, this would be expected to lead to a decrease in the capacity price paid to all capacity suppliers. *And an increase in the energy, ancillary services and uplift compensation flowing to the marginal bidder in the capacity auction would reduce the capacity price paid by all load in an ISO/RTO with a capacity market.* Just as suppression of locational prices is likely to lead to an increase in the capacity prices paid to all suppliers of capacity, removal of the suppression of locational prices would be expected to decrease capacity prices.

Consideration of the customer impact of improvements to price formation also should take into account the long-term benefits from improvements to the economic efficiency of electricity markets; incentives for efficient investment and innovation are the ultimate goal of improving price formation. Changes in investment and innovation will drive long-run reductions in the cost of electricity but can only be discussed qualitatively, which is unsatisfying for consumers who would like to know the full economic impact of any proposed change to pricing rules. It requires confidence in competitive markets to trust that efficiency enhancing changes to price formation, following the principles of dispatch-based pricing, will allow prices to signal and call forth supply when and where it is needed in both the short- and long-run.

Real-Time and Day-Ahead Markets

Improvements to price formation should focus on the real-time market, as this is tied to actual physical operation and the price signals in this market are central to assuring market participant actions are consistent with real-time reliability. Real-time prices should be formed to be consistent with the physical realities of the real-time least-cost security constrained dispatch; this is where the principles of dispatch-based pricing come to bear. Under two-settlement systems, offers and prices in the day-ahead market will follow and respond to those in real-time, especially with day-ahead virtual bidding driving convergence. Because market participants engaging in forward transactions will price them based on their expectations of the real-time price, improvements to real-time pricing will be reflected very quickly in pricing in forward markets.

Although the focus should be on real-time, day-ahead markets are also important because the day-ahead market design can affect real-time prices and whether there are systematic differences between day-ahead and real-time prices.[68] The starting point for convergence between day-ahead and real-time prices is to use the same modeling assumptions for the day-ahead and real-time markets (e.g., transmission model, constraint representation and reserve and regulation constraints), except to the extent that there are differences resulting from the time-step of the two models (e.g., there is no dragging or over-generation in the day-ahead market, forecasts used in real-time may differ from those expected at the time of the day-ahead market, and the day-ahead market may solve for losses while the real-time model takes losses as an input). *Starting from the basis of identical modeling at a high-level, systematic differences between day-ahead and real-time prices, like uplift, are a flag for possible problems with price formation.*[69] Price convergence means that the prices in the day-ahead and real-time markets should be very similar whenever day-ahead expectations of real-time operation (e.g., load level, weather, resources in-service, loop flow, etc.) are very close to what happens during actual real-time operation. When actual operation differs from expectations, day-ahead and real-time prices will be different, but this is not a signal of a pricing problem unless this difference is systematic and predictable. Market designs leading to frequent reliability unit commitments and supplemental commitments of units with substantial minimum loads and minimum run times following the close of the day-ahead market can lead to suppression of real-time prices and problems with price convergence.

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[68] For example, see the following discussion of the impact on real-time prices of the exclusion of RUC commitments from the formation of day-ahead schedules and prices.

[69] It is not expected that day-ahead and real-time prices will converge every day; differences will occur whenever the day-ahead forecast of a real-time parameter is different from what actually happens in real-time.

This section has reintroduced the principle of dispatch-based pricing to forge a connection between economic principles and the reality of electricity system operation in order to move beyond an idealized concept of "true marginal cost." The principle is sufficiently general to be applied to advance the discussion and direct the development of formal approaches to many issues falling into the price formation discussion.[70]

III. Applications of Dispatch-Based Pricing

Sorting the Price Formation Issues

To organize the discussion of problems and possible solutions, this section presents a rough sorting of problems of price formation. While not exclusive, the categories enable identification of pricing problems with similar underlying causes that could have related solutions when approached from a perspective of dispatch-based pricing. The following sections discuss each of these categories of price formation problem in detail and present one or more specific dispatch-based solutions that have been used in practice.

1) Problems arising from omissions and approximations in unit commitment and dispatch software models, as well as related operator interventions. The degree to which these issues cause problems with price formation depends on how the unit commitment and dispatch results are taken into account in price software models used in the price formation step.
    a) Omissions and approximations in unit commitment and dispatch software models
    b) Potentially inefficient operator interventions

2) Problems arising in the price formation step of the ISO/RTO software.
    a) Difficulty in calculating dispatch-based prices because of the lumpiness (non-convexity) of bids and offers
    b) Averaging of settlement prices
    c) Omissions of information about the dispatch and unit commitment in calculating prices

3) Problems arising from rules defining electricity market products and bidding rules.
    a) Absence of valuation of operating reserves in the day ahead energy market and advance unit commitment steps
    b) Inefficient bidding rules that do not mesh with the operational constraints and business risks present in electricity and gas markets

[70] Hogan 2014.

c) Mechanisms for shortage pricing that are not fully integrated with the energy dispatch and do not adequately compensate suppliers operating during periods of scarce capacity.

i. Unit Commitment and Dispatch Software Modeling Challenges

In this section, two general categories of unit commitment and dispatch software modeling challenges are described and the following specific solutions are discussed: transmission constraint relaxation; pricing of voltage constraints; introduction of new reserve constraints; and representation of ramping constraints.

Omissions and Approximations in Unit Commitment and Dispatch Software Models

First, there are price formation issues arising from omissions and approximations in the engineering-economic optimization of unit commitment and dispatch. When modeling limitations lead to a unit commitment and/or dispatch that is potentially unreliable, system operators are supposed to, and do, respond and modify the commitment and dispatch through out-of-market actions, such as supplemental unit commitments after (and sometimes before, if long lead time unit start are deemed necessary) the day ahead energy market. Problems occur when price formation is inconsistent with the commitment and dispatch that actually occur, inclusive of these operator actions, and is thus inconsistent with the underlying operational issues that led to the actions. Assuming that the approximations and operator interventions are reasonably close to efficient, pricing problems are unlikely to arise solely because the unit commitment and dispatch software is incomplete or includes approximations; the pricing problems primarily arise because, in addition, the pricing software does not correctly account for the actions taken to address the omissions and approximations, or because the operator interventions are not efficient, in the sense that they were not least-cost at the time they were made. Importantly, an appropriate pricing approach will depend on the time frame: for instance, day-ahead prices should take into account the day-ahead commitment and dispatch, but real-time prices would treat the day-ahead unit commitment as fixed.[71]

Transmission Constraint Relaxation

In some ISOs, transmission constraints binding in the dispatch may be "relaxed" without penalty when they cannot be solved by the real-time dispatch model. When this occurs, the constraint will no longer bind in the real-time dispatch and there will be no congestion cost associated with the constraint even though the constraint could not be

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71 ISOs/RTOs also make commitment decisions in time periods in which there are no settlement prices and, even if the decisions appear to be economic at the time they are made, they may turn out to be uneconomic at real-time prices.

solved.[72] While it is intended that the constraint should continue to bind after relaxation, this will only occur if the constraint is not relaxed too much.[73] This practice, which has been reported to occur in several ISOs, suppresses LMPs because the constraint that has been relaxed is not represented as binding in price formation, while the extra generation that has been committed to manage the constraint *is* included in price formation. When this occurs, prices are suppressed and fail to signal to the market where congestion is occurring.[74]

All ISOs/RTOs except for PJM now employ "soft constraints" in their dispatch and pricing in order to avoid taking unnecessarily costly actions to avoid violating constraints. This approach is an improvement to the efficiency of the dispatch that also has the benefit of including in LMPs a congestion component for transmission constraints that are violated in the dispatch. The approach is consistent with the principle of dispatch-based pricing because the intention is to provide pricing that is more consistent with the physical operation of the transmission system, including actions (i.e., redispatch, or activating demand response) to avoid or reduce the violation of transmission constraints. For example, the NYISO uses a Transmission Shortage Cost, defined as "The maximum reduction in system costs resulting from an incremental relaxation of a particular Constraint that will be used in calculating LBMP," in their dispatch and pricing

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72 Constraints may, similarly, be solved through unit commitment outside of the day-ahead energy market, by calling blocks of emergency demand response in real-time and by cutting export schedules. All of these actions may resolve a transmission constraint but the transmission constraint will not have a congestion cost if, as a result of the action, it is no longer binding in the software model run to determine prices.

73 A related issue occurs if heuristics are employed in the event that two or more constraints are potentially binding on margin. In this circumstance, PJM and possibly other ISOs have apparently not been able to solve the dispatch and, as a result, include only one of the constraints in the dispatch and pricing models and resolve the conflicting constraint(s) through out of market dispatch. In some ISOs, only operator-flagged constraints are apparently included in dispatch and pricing, so not all of the constraints are solved and priced by the software. A list of excluded contingencies appears in PJM Interconnection, Market Efficiency Study Process and Project Evaluation Training, April 17, 2014, at 16, http://www.pjm.com/~/media/committees-groups/committees/teac/20140417-market/20140417-2014-market-efficiency-training.ashx.

74 In 2011, Potomac Economics, the Independent Market Monitor for MISO, reported that about $245 million in congestion was unpriced in the MISO due to a "constraint relaxation algorithm," which represents more than 30% of the total congestion value in MISO in 2011. Potomac Economics, 2011 State of the Market Report for the MISO Electricity Markets, June 2012 ("MISO 2011 SOM"), at 43-44, http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf. The market monitor also reported that 19% of total congestion resulted from the imposition of a "transmission deadband" that causes a constraint to appear to be violated before it reaches its physical capacity. *Id.* at 43-44. MISO ceased this practice in early 2012. *See also*, Southwest Power Pool (SPP) Market Monitoring Unit, SPP 2011 State of the Market, July 9, 2012, at 10, http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf. Last spring, the Commission approved the CAISO's proposal to reduce the trigger for its transmission constraint relaxation parameter from $5,000 to $1,500 per MWh. *California Independent System Operator Corporation*, Docket No. ER13-1060-000, 143 FERC ¶61,110 (2013), http://www.ferc.gov/EventCalendar/Files/20130509152959-ER13-1060-000.pdf.

models.[75] Under the approach, every megawatt-hour of violation of a transmission constraint imposes a penalty on the objective function for the dispatch optimization in the amount of the transmission shortage cost. The dispatch therefore automatically searches for ways to avoid violating the constraint with a cost less than the transmission shortage cost (this is also called the "penalty factor"). If the constraint is violated, the shortage cost of the violation is included in the price formation for energy and ancillary services; it increases the prices for any supply that could relieve the constraint. The values set for transmission shortage costs are set in different ways in the different ISOs/RTOs, and are unavoidably approximations of the value of an increment of transmission.[76] Nevertheless, the approach is an example of a change to price formation in order to tighten the relationship between prices and the physical dispatch.

Pricing of Voltage Constraints

Voltage constraints provide an illustration of the possibility of forming prices so as to include the congestion impacts of a constraint, even when it is not possible to model or solve the constraint in the unit commitment or dispatch. Because voltage constraints are highly nonlinear and depend on both real and reactive power flows, they are very difficult to include in existing economic commitment and dispatch software. As a result, the commitment and dispatch of generation supply to manage voltage constraints tends to depend on the discretion of system operators. However, *once the system operator has exercised this discretion and the voltage constraint is known* it might be represented in price formation, along with a linear representation of the effect of local generation on the constraint. When this can be done, and the constraint binds in the pricing step, the congestion cost of the constraint, as determined by the generation the system operator moves on margin to manage the constraint, will be included in prices.[77] A simple example is the reduction of limits on interface constraints during certain operating conditions. Without modeling the underlying constraint in price formation, prices are suppressed when system operators use supplemental commitments to bring generation on-line to manage voltage constraints, and other constraints that are not represented in the pricing software.[78]

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75 NYISO Services Tariff Attachment B at 17.1.4.

76 MISO has implemented stepped penalty factors for transmission constraints to avoid generating uplift by committing units to resolve minor constraint violations. ISO NE and NYISO are reportedly looking into this methodology as well. *See, e.g.*, Michael DeSocio, Graduated Transmission Demand Curve (GTDC), New York Independent System Operator, December 18, 2013, http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2013-12-18/12%2018%202013%20Graduated%20Transmission%20Demand%20Curve%20-%20MC%20(updated).pdf.

77 Hogan 2014 at 26.

78 For some local voltage constraints, price formation will not be improved by including the underlying constraint in the pricing model because of problems with non-convexity. This situation occurs when a unit is committed at minimum load to manage the constraint but, once the unit is committed to this level, the constraint does not bind in the dispatch or pricing models. Forcing the underlying constraint to bind in the pricing model under these circumstances would send an inaccurate price

Potentially Inefficient Operator Interventions

It is not always the case that operator interventions are an approximately efficient response to a reliability issue not addressed in the commitment and dispatch software. Moreover, it is generally not easy to determine when there has been an operator error, as opposed to an appropriate operator response to an operational issue omitted from the software optimization, or to a change in real-time conditions falling outside of the RTO-forecasted load or contingency analysis. Evaluation of the efficiency of operator interventions is difficult because it must be based on the information available to the operator at the time, rather than on information that becomes available after the fact.

With hindsight, some ISOs and their market monitors have been able to determine the percentage of instances in which supplemental commitments, which are an intervention that can have particularly problematic price impacts, were not actually required.[79] For example, a report by the ISO NE external market monitor explains some of the operational issues potentially leading to sub-optimal supplemental unit commitment:

> After reviewing the supplemental commitments and the surplus capacity levels that resulted from realtime operating conditions, we found that roughly 44 percent of the supplemental resource commitments in 2012 were needed to maintain system level reserves in retrospect.[80] The fact that some of the reliability-committed capacity was not needed in retrospect is typically due to the following factors.
>
> First, ISO-NE has a limited quantity of fast-start generating resources, which help ensure that sufficient capacity will be available if unexpected conditions arise. This leads the ISO in some cases to rely on slower-starting units that must be notified well in advance of the operating hour when uncertainty regarding load, imports, and generator availability is high. Most of the commitments of slow-starting units are made overnight, more than 12 hours before the forecasted peak.

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signal. The best way to address this problem is likely through the development of additional resources that can be dispatched in real-time, particularly demand response, or possibly the development of the full ELMP solution.

79 A supplemental commitment occurs when the system operator instructs a unit to come on-line after it has completed its day-ahead unit commitment.

80 This is a simple evaluation that treats any surplus capacity (online and available offline capacity less the need to meet system load and reserve requirements) as “not needed” for the system. This simple evaluation tends to understate the necessity of supplemental commitments because: 1) the evaluation is based on hourly integrated peak rather than the higher instantaneous peak, and 2) the ISO cannot commit just a portion of a unit. For example, if the ISO needs an additional 200 MW of capacity to satisfy system reliability needs and commits the most economic unit with a capacity of 300 MW. In this evaluation, 100 MW of capacity would be deemed as “not needed.” (Footnote part of quoted text).

Second, ISO-NE is heavily reliant upon gas-fired generating capacity, which can become unavailable due to the limitations of the natural gas system. Consequently, the ISO may commit oil-fired and/or dual-fueled capacity in order to protect the system in the event that the supply of natural gas is interrupted to some units.

Third, there are two assumptions in the reliability commitment process that can make large contributions to the over-commitment on some days:

- The "desired capacity surplus" that operators have the discretion to determine to account for concerns regarding generator availability, load forecast errors, or other factors;[81]
  and
- The assumed level of imports and exports. When evaluating the need for commitments in advance, the ISO generally assumes day-ahead scheduled transactions will flow.[82]

Real-time pricing software can accommodate sub-optimality in the unit commitment and dispatch, whether due to forecast errors, such as weather predictions that are the basis for load forecasts, or errors in operator judgment. ISO/RTO models, to varying degrees, operate consistently with the dispatch-based pricing principle, estimating real-time prices based on the real-time operational quantities of generation injections and load withdrawals, and generally have the objective of avoiding additional uplift due to inconsistency between the prices and the real-time quantities.[83] However, to the extent that there was sub-optimality in the unit commitment and dispatch, such as the commitment of an unneeded generating unit, the real-time prices will reflect this decision, rather than hiding it in uplift. If large quantities of generation are committed after the day-ahead market that are not economic at real-time prices, this will suppress real-time prices.

A number of ISOs are attempting to improve their models of unit commitment and dispatch, so as to eliminate some potential sources of sub-optimal operator intervention. These have the potential to improve price formation, provided that dispatch-based prices are calculated from the dispatch quantities determined with the

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81 The operators have the discretion to commit surplus generation when they believe it is necessary to deal with uncertainty as stated in the System Operating Procedure, Perform Reserve Adequacy Assessment, and Section 5.3.2.3, "The Forecaster may commit additional Generators as needed for reliability (anticipated storms, hurricanes or other conditions that affect Bulk Power System reliability)," (Footnote part of quoted text).

82 Patton et al. 2012 Assessment at 103-104. Note that in 2013, the market monitor found that the quantity of supplemental resource commitments needed to maintain system level reserves rose to 60 percent. Patton et al., 2013 Assessment at 138.

83 These models can estimate prices form dispatch quantities, as in the NYISO, or from actual metered quantities, as in other ISOs. As discussed elsewhere, ISO/RTO pricing software does not include all constraints, especially constraints that may be binding in the unit commitment.

improved models and any changes to the constraint representation flow through into pricing.[84]

Introduction of 30-Minute Reserve Constraint

ISO NE recently added a program for replacement reserves procurement to explicitly account for the additional 30-minute reserves the ISO may require due to concerns about some large contingencies or the reliability of specific generators. This program will be an improvement in price formation *if* it leads to co-optimization and explicit scheduling and pricing of 30-minute reserves – *and the consistent reflection of this price in prices for energy and other ancillary services during the same time step* – in operating conditions in which the ISO would otherwise have performed a supplemental unit commitment that might have suppressed prices. The 30-minute reserve constraint appears to be a step consistent with the principle of dispatch-based pricing; however, this and other efforts (PJM and CAISO) to introduce new reserve constraints will only improve pricing if the constraints are high enough that they will actually supplant supplemental unit commit, bind in price formation when active, and not simply bring extra capacity on-line that suppresses real-time prices.

Representation of Ramping Constraints

The potential for large ramps due to sudden and unpredictable changes in imports and exports is a factor that has contributed to the perceived need for commitment of additional capacity during the operating day. This commitment of additional resources to manage changes in interchange schedules can depress real-time prices and contribute to uplift costs.[85]

A recent evolution in intra-day unit commitment programs has been to try to adapt them for use in managing the variability of intermittent resource output and consequently reduce supplemental unit commitment. Achieving this goal requires evaluating whether there is enough ramp capability and unloaded capacity on line to accommodate potential upward and downward ramp capability requirements associated with unpredictable changes in net load.[86] California implemented such a change in its look-ahead unit commitment program (called the Real-Time Pre-Dispatch, or RTPD) in December 2011, introducing an upward ramp capability target, referred to as the "flexible ramping constraint."[87] While this design has had some success in reducing the

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84 PJM is working on its representation of voltage constraints, and the CAISO is examining minimum on-line capacity constraints.

85 This particular example occurred in MISO.

86 The intra-day unit commitment programs of most ISOs and RTOs are similar in that they evaluate unit commitment decisions on a production cost minimization basis, taking account of start-up costs, minimum load blocks, and minimum run times.

87 California ISO, Opportunity Cost of Flexible Ramping Constraint, Draft Final Proposal, July 20, 2011, http://www.caiso.com/Documents/DraftFinalProposal-FlexibleRampingConstraint.pdf. *See also, California Independent System Operator Corporation*, Docket No. ER12-50-000, 137 FERC ¶ 61,191 (2011). At present, the adequacy of downward ramp capability is not considered in RTPD.

frequency of real-time load balance violations and the associated price spikes, the commitments have been relatively high cost.[88] This is an example of an attempt to improve price formation consistent with the principle of dispatch-based pricing, as it attempts to explicitly price ramping constraints in situations in which these constraints lead to the commitment of additional generation and possibly to price suppression.

Further improvements to unit commitment and dispatch models may be a source of both increased efficiency in the operation of electricity systems and improvements in price formation due to a reduction in surplus on-line capacity. Speaking off-the-record, ISO staff have stated that the primary problem with price formation is not with the actual calculation of prices given the unit commitment and dispatch, but rather with the commitment of too many units through supplemental unit commitments.[89]

Generators evaluated as providing ramp capability in the RTPD evaluation are paid the shadow price of incremental ramp capability in RTPD schedules (determined by opportunity costs or by a penalty value if the target amount of ramp cannot be scheduled). Because the CAISO has not implemented a real-time ramp capability-based dispatch, the ramp capability modeled in RTPD is not necessarily available in real-time.

88 *See, e.g.*, California ISO Department of Market Monitoring, Q3 2012 Report on Market Issues and Performance, November 13, 2012 ("CAISO DMM Q3 2012"), at 41-44, http://www.caiso.com/documents/2012thirdquarterreport-marketissues-performance-nov2012.pdf, and California ISO Department of Market Monitoring, 2013 Annual Report on Market Issues & Performance, April 2014 ("CAISO DMM Annual 2013"), at 91-97. The program has been less effective than hoped in avoiding energy balance violations due to ramp constraints. California ISO Department of Market Monitoring, Q2 2012 Report on Market Issues and Performance, August 14, 2012, at 35-38, http://www.caiso.com/documents/2012secondquarterreport-marketissues-performance-august2012.pdf; CAISO DMM Q3 2012 at 41-45; and Lin Xu and Don Tretheway, California ISO, Flexible Ramping Product, Market Surveillance Committee Meeting, October 19, 2012, at 9-12.

89 Most US ISOs and RTOs have implemented a process for the ISO or RTO to commit non-quick start generating capacity during the operating day to supplement self-commitment decisions by market participants. The commitment criteria include the need to maintain reliability and to minimize production, taking into account: 1) projected transmission congestion; 2) the commitment decisions of other units; and, 3) more up-to-date forecasts for net load. The procedures for performing supplemental unit commitments vary among the ISOs and RTOs.

The NYISO implemented real time commitment (RTC) in 2005. RTC economically evaluates the commitment of resources that can come on line in 30 minutes or less (including gas turbines, combined cycle and pumped storage resources), and schedules net interchange. Significantly, RTC runs every 15 minutes and evaluates operating conditions in 15 minute, rather than hour long, segments. The use of 15 minute time segments in intra-day unit commitment has a number of advantages in terms of efficiency and pricing. First, off-line resources can be committed closer to the period of time in which their capacity is needed, rather than at the start of the hour. Units can be started later to meet increases in load near the end of the hour, which reduces uplift costs and avoids distorting market prices at the beginning of the hour. Second, the use of 4 periods to evaluate hourly imports and resources with one hour minimum run-times results in a more accurate results because in the economic evaluation the peak load can differ from the average load. Third, deferring unit commitment decisions until closer to the time resources are projected to be needed reduces the frequency with which units are committed uneconomically due to load forecast error or changes in intermittent output.

Improvements in unit commitment and dispatch models can help to reduce the sub-optimality of operator interventions, but there will always be new issues creating tension between the strong incentives for the operators on duty to maintain reliability and the pressure not to commit units through out-of-market actions after the close of the day-ahead market.

There continues to be a focus on understanding the reasons for supplemental unit commitments and developing procedures and tools to reduce them where possible through improvements to modeling or other operational procedures. At some point, though, the remaining problems will be infrequent and could be impossible to implement through software solutions, so it will be infeasible and impractical to implement software solutions for *all* causes of supplemental unit commitment. These changes are not part of the "low hanging fruit" for improvements to price formation.

The possible importance of this issue is conveyed by the following table from the ISO NE's Annual Markets Report (copied below), showing the quantity of slow-start generation committed in each month of 2013, by quartiles.

The California ISO implemented a look-ahead unit commitment process similar to RTC in April 2009 as part of its market redesign and technology upgrade (MRTU). Like RTC, this program (referred to as Real-Time Unit Commitment (RTUC) or as Real-Time Pre-dispatch (RTPD)) runs every 15 minutes and evaluates interchange schedules and unit commitment decisions in 15 minute time segments.

The MISO operators used *ad hoc* processes to commit units during the operating day when the ISO started up in 2005. MISO's independent market monitor recommended that it develop a software program to carry out this function for a number of years, and a look-ahead commitment program was implemented on April 1, 2012.

PJM currently uses a program called the Intermediate Security Constrained Economic Dispatch tool (IT SCED) to look forward 1 to 2 hours to aid in committing generation, as well as to apply the three pivotal supplier test and identify reserve shortages.

Table 2[90]
Monthly Minimum, Maximum, and Quarterly Percentiles of Days with Supplemental Commitments for the Peak Hour, January to December 2013 (MW)

Month	Daily Supplemental Commitment MW[(a)]				
	Minimum	25th Percentile	50th Percentile	75th Percentile	Maximum
Jan	54	169	250	709	1,847
Feb	115	262	584	923	2,879
Mar	45	45	115	258	1,475
Apr	47	125	379	535	610
May	26	42	76	498	734
Jun	157	184	270	633	900
Jul	45	95	165	200	707
Aug	95	248	400	400	400
Sep	129	163	327	646	1,320
Oct	150	175	200	225	250
Nov	85	137	269	414	569
Dec	67	94	176	395	733

(a) Supplemental commitments are defined here as the aggregate capacity of non-fast- start generators the ISO committed outside the day-ahead market for the peak hour, dispatched at the generators' economic minimums.

In 2013 there were supplemental commitments in ISO NE on every day, exceeding 1,000 MW on seven days. While further analysis would be required to establish how much of this capacity is "extra," after taking into account events that may have necessitated additional commitments, such as generation that tripped off-line, and the quantity of quick-start generation expected to be available for dispatch in real-time, it is striking that the minimum supplemental commitment is never zero. Analyses by the ISO NE and other ISOs clearly show that market clearing prices are significantly impacted by the quantity of extra capacity available in the real-time market, especially when there is a tight balance between electricity supply and demand and e*ven with dispatch-based pricing,* this extra capacity will suppress prices.[91]

90 ISO New England, 2013 Annual Markets Report, May 6, 2014, at 65, Table 2-23, http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2013/2013_amr_final_050614.pdf.

91 Patton et al. 2012 at 99, Figure 29. See report for an illustration of the relationship between surplus capacity and prices.

As a general matter, increased transparency is a critical part of the effort to improve price formation and reduce uplift and, in particular, understand the reasons for potentially inefficient operator interventions. ISOs and RTOs can provide tremendous assistance by making information about uplift readily available within a short time from the close of a market. This should include reporting on any and all constraints (transmission thermal, voltage and reactive limits, reserve and regulation constraints, minimum on-line and ramping constraints, for example) that are active in their unit commitment and dispatch programs or that led to operator interventions. ISOs and RTOs should report regularly on how much cost recovery actually comes from LMP payments versus uplift, separating the report on uplift into that occurring in each of its market settlements (i.e., DAM, RUC, supplemental commitments, RTM). The availability of more granular information, reported in a standard format on a regular basis, will help stakeholders and experts on market and software design within and outside of the ISOs/RTOs assess the causes of the uplift and possible improvement in price formation.[92] Understanding the magnitude and causes of uplift of different kinds is currently incomplete due to the lack of information.

While transparency of operator actions is critical to price formation and should be visible to market participants, it is not a "solution" to uplift, as some have thought FERC staff implied in their white paper. Market participants will not respond to information about uplift like they respond to energy prices because changes in their behavior will not directly impact the uplift they pay; market response will not cure the problem of uplift. However, regular reporting (e.g., monthly) will provide a strong incentive for system operators to carefully consider out of market actions that may result in significant uplift. NYISO reports on uplift monthly to market participants.[93]

ii. Issues with Price Calculation

The second broad category of price formation issues encompasses those occurring within the process of estimating energy and ancillary services prices, but are not tied to limitations of the unit commitment or dispatch software. In this section, three general categories of issues with the price calculation are described along with the following solutions: pricing of fixed-block fast start units (hybrid pricing); Approximated ELMP; quantity-weighted hourly pricing (5 minute pricing); and, including the reliability unit commitment in day-ahead market scheduling and pricing.

92 There has been much discussion after the fact of PJM operator actions during the Polar Vortex and changes that may be implemented to address these in software models for commitment, dispatch and pricing.

93 *See, e.g.*, New York Independent System Operator, Monthly Report, August 2014. NYISO Monthly Reports are available publicly on the NYISO website at http://www.nyiso.com/public/markets_operations/documents/studies_reports/index.jsp.

Non-Convexities in Price Formation

Challenging problems arise in calculating energy and ancillary services prices because of lumpiness (i.e. non-convexity) in the underlying bids and offers for electricity supply and demand. Generating unit offers include minimum run times, minimum down times, minimum loads, one-time start-up costs, disallowed operating regions, dual-fuel capabilities, and stepped blocks of incremental energy. And most imports, exports and demand response are not dispatchable in real-time but, rather, are scheduled or activated in blocks. In addition, ISO dispatch algorithms incorporate numerous operational constraints, so it can be the case that a resource is dispatched because it is needed for energy, but it may only operate at minimum load, or be committed as block-loaded supply. Because of these non-convexities there is no unique mathematical answer to what the prices are for any hour or any interval from the perspective of the dispatch-based pricing: assumptions are required to estimate the prices. The ISOs and RTOs make these assumptions when they calculate day-ahead and real-time LMPs, and they are not the same everywhere.

For instance, when it started-up, the MISO settled its real-time market with LMPs that were the shadow prices resulting from the linear program it ran to perform its economic dispatch. An implicit assumption underpinning this approach was that the LMPs would be restricted to depend on only the incremental "flexible" cost offers of the marginal generating units in each five minute interval of the dispatch. For many, this is the "pure" notion of LMP, and anything else is a modification or extension of the LMP concept. The same approach has been used at one time or another in all of the ISOs and RTOs other than the NYISO: resources committed to operate at minimum output levels, or whose dispatch is inflexible, are ineligible to set energy or ancillary services market clearing prices. This means that these resources' supply is part of the dispatch, but the resources' costs are not explicitly taken into account when setting market prices. An alternative view is that the original MISO LMPs were calculated based on one extreme of a continuum of possible assumptions to address the lumpiness of bids and offers. There are a number of alternative methods for estimating LMPs, including NYISO's hybrid pricing, which are largely distinguished by their assumptions concerning the treatment of the underlying non-convexities of bids and offers. These alternatives can come closer to achieving the dispatch-compatibility principle of dispatch-based pricing.

The principle of dispatch-based pricing calls for locational clearing prices in electricity markets to be as consistent as possible with the actual operation of the transmission system by a system operator seeking to minimize the offer cost of meeting load while adhering to standards of reliability. Lumpiness and discontinuities in the underlying unit-level supply curves for energy (i.e., non-convexities) have created both conceptual and technical hurdles to correctly forming prices to align with this principle. However, a methodology for price formation taking into account the dispatch of fixed-block fast-start units that are flexible in terms of commitment to meet load but do not operate “flexibly” once committed has been used in the NYISO for almost 15 years, but has not been implemented or only partially implemented in other ISOs and RTOs. A second, and much more difficult, problem is to improve price formation to reflect the minimum load costs of units with significant minimum run times that are started up to serve load or resolve transmission constraints in advance of the hours when they will be needed.

Pricing of Fixed-Block Fast-Start Units

A market design feature impacting the quality of the price signal is the way fixed-block resources such as gas turbines (also called combustion turbines, or CTs) are treated for pricing purposes. Many gas turbines have the property that once they are committed and come on line, they operate at full load and are generally not dispatched down until they are decommitted. While many gas turbines have a small dispatchable range, the incremental dispatch cost for this incremental output is lower than the average cost of their minimum load block so that, for practical purposes, the units are always dispatched at their full load unless the dispatch price falls well below their average full load cost. These cost and operational characteristics of gas turbines have the consequence that other units must be dispatched down to accommodate the full output of the turbines when only part of their fixed-block is needed to meet load in the next dispatch interval. If the fixed-block units are treated as fixed, non-dispatchable resources that cannot set price in real-time, the real-time price will never reflect the offer cost of dispatching these units, even in situations in which the gas turbines are committed repeatedly in real-time over the hours of a day. Rather, the real-time locational prices will be set by the offer costs of lower-cost flexible units that are dispatched down on margin to accommodate the full output of the fixed-block unit.

From the perspective of dispatched-based pricing, the prices are suppressed whenever they are less than the offer costs of a fixed-block fast-start unit that is needed to serve load.[94] Dr. Patton summarizes the adverse consequences of not including these units in price formation in the MISO, for example:

- MISO will generally need to pay Revenue Sufficiency Guarantee payments (RSG) to cover their full as-offered costs;

- The understated real-time prices do not provide efficient incentives to schedule energy in the day-ahead market when lower-cost resources could potentially be scheduled that would reduce or eliminate the need to rely on high-cost peaking resources in real time;

94 The same problem arises when real-time demand response procured in the forward capacity market is not dispatched by the real-time dispatch software, and cannot set real-time energy or reserve prices.

- The market will not provide efficient incentives for participants to schedule exports or imports, which can prevent lower-cost energy from being imported to displace the higher-cost peaking resources.[95]

Since its start-up, the NYISO has had pricing rules to allow fixed-block resources to set day-ahead and real-time prices in hours in which they are required to serve load; this is called "hybrid pricing."[96] The NYISO's real-time pricing algorithm has a step in which locational prices are determined under the assumption that fixed-block units are dispatchable over their full range at their average real-time offer cost.[97] As a result, when gas turbines are dispatched to serve load, the price at their location will be greater than or equal to this offer and the gas turbine will not require make-whole uplift.[98] Also, because of the internal consistency required among locational prices and the underlying generation shift factors, the locational prices at all other locations electrically related to the location of the fixed-block generator are also determined by the hybrid pricing. From an intuitive perspective, this occurs because the price formation recognizes the higher offer cost of the fixed-block generation committed to meet real-time load and the consequently higher value of increased generation at other locations that could (if it were available) avoid the need to commit the high-cost fixed-block unit. By allowing fixed-block units to set market prices, all suppliers in the NYISO receive greater compensation through the energy markets, price responsive demand sees a higher price when gas turbines must run to serve load, there is an increased price incentive to schedule imports to avoid the need to commit the high cost gas turbine supply, and NYISO reduces uplift that would otherwise be paid to the block-loaded resources.[99]

Approximated ELMP

The MISO has recently developed pricing rules similar to the NYISO's hybrid pricing, called Approximated Extended Locational Marginal Pricing or Approximated ELMP. The MISO's new pricing rules were developed after recognizing how deficiencies in pricing of fixed-block units contributed to high uplift costs (Revenue Sufficiency Guarantee costs or RSG in MISO terminology).[100] These rules were filed with FERC in December 2011,

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95 David B. Patton, "Evaluation of ELMP Parallel Operations Results," August 21, 2014 at 1 ("Patton 2014"). https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2014-09-12%20Docket%20No.%20ER14-2566-000.pdf.

96 See New York ISO Market Services Tariff, Attachment B, at 17.1.2.1.2. *See also* NYISO Transmission and Dispatch Operations Manual, Section 5.

97 NYISO Market Services Tariff, at 17, 1.2.1.2.3.

98 However, a constrained-down payment must be made to the flexible generation that is held down out of merit to accommodate the full output of the fixed-block unit.

99 Note that the NYISO hybrid pricing software includes steps to ensure that gas turbines only set locational prices when they are needed to serve load. Robert Pike, New York Independent System Operator, NYISO Market Overview: California ISO Pricing Forum, April 22, 2014, at 10, http://www.caiso.com/Documents/3_NewYorkISO_MarketOverview.pdf.

100 MISO 2011 SOM at 35-36, A-68; MISO 2010 SOM at 68-70.

approved by FERC on July 20, 2012, and are currently being tested in parallel operation.[101]

The MISO developed Approximated ELMP after first exploring a comprehensive method for addressing non-convexities due to start-up costs and minimum load costs in the formation of energy market prices known as Extended LMP (ELMP) or, synonymously, Convex Hull Pricing (CHP).[102] MISO's goal was to find new methods for price formation that would minimize or reduce uplift while maintaining consistency between the final locational prices and the underlying shift factors.[103] In addition to minimizing uplift, ELMPs have the property that they will always increase at a location with increases in load. This is a very attractive property for market participants, as it would eliminate some of the price volatility shown in Figure 2.[104]

Because ELMP was untested and difficult to implement in real-time, MISO undertook an internal study to determine near-term changes it could make to its pricing rules to achieve a portion of the uplift reduction possible with ELMP. It also sought changes to the rules that could achieve some of ELMP's reduction in transient price spikes resulting from forecasting problems rather than actual shortages. Since it had estimates of uplift under ELMP and LMP for the same dispatches, it was able to assess the factors driving differences in these prices for their ISO.[105] The resulting Approximated ELMP pricing rules will produce prices reflecting the offer costs of energy supplied by fast-start units, including their start-up/shut down offer costs and no-load offer costs.[106] The methodology proposed is similar to hybrid pricing in the NYISO, which can be viewed as a closely related version of Approximated ELMP. The MISO Approximated ELMP methodology will allow gas turbines to set energy prices, provided that such units have a notification time plus start up time of less than or equal to 10

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[101] *Midwest Independent Transmission System Operator, Inc.*, Docket ER12-668-000, Extended Locational Marginal Pricing Filing, December 22, 2011; *Midwest Independent Transmission System Operator, Inc.*, Docket ER12-668-000, 140 FERC ¶ 61,067 (2012); and *Midwest Independent Transmission System Operator, Inc.*, Docket ER12-668-000, Compliance Filing Regarding ELMP Status Report and Planned Implementation Date, November 19, 2012.

[102] Through this work, MISO made an important theoretical advance with ELMP/CHP, proving that the set of energy prices that would minimize the uplift required for a given unit commitment and dispatch could be identified through the formation of a convex hull of the pricing problem. In simple terms, they proved that a known technique could be used to find uplift-minimizing prices. The relevance of this equivalence -- between uplift-minimizing prices and convex hull prices -- is that it tied understanding of uplift-minimizing prices to a pre-existing body of work in mathematical optimization and, with this, to known approximation techniques. *See* Paul Gribik, William W. Hogan and Susan L. Pope, "Market-Clearing Electricity Prices and Energy Uplift," December 31, 2007; *Midwest Independent Transmission System Operator, Inc.*, Docket ER12-668-000, Direct Testimony of Paul Gribik, December 22, 2011; and Midwest ISO, ELMP Task Team Meeting, March 4, 2011.

[103] The latter is required to maintain economic efficiency and incentives for gaming.

[104] ISO NE Price Formation 2014.

[105] Communication with Paul Gribik, May 2014.

[106] Midwest ISO, Extended Location Marginal Pricing (ELMP) FAQ (MISO ELMP FAQ), at 1, https://www.misoenergy.org/Library/Repository/Communication%20Material/Strategic%20Initiatives/ELMP%20FAQs.pdf.

minutes and a minimum run time of less than or equal to one hour. MISO will "convexify" the offers of these units in their pricing program and represents them as dispatchable over their full dispatch range from zero to maximum. MISO is planning to include the start-up costs and no-load costs of such units, as well as their incremental energy costs, in the convexified offer curve for use in real-time pricing. One difference between Approximated ELMP and hybrid pricing is that the former will include all fast-start resources in pricing, not just block loaded fast-start resources, in order to eliminate the possibility that generators might remove dispatch range from their offers in order to be able to set price.[107] In addition, like the NYISO, the MISO proposes to include off-line fast-start units in the price determination, even if the operators choose not to commit the units, although in the MISO this will occur only under scarcity conditions. [108] Finally, the MISO Approximated ELMP implementation will allow emergency demand response resources to set prices in real-time for both energy and operating reserves.

MISO is continuing to perform parallel testing of Approximated ELMP while responding to concerns raised by its external market monitor about the results of its testing this summer. In the first set of results, Dr. Patton observed instances in which the real-time price fell for a short period of time as off-line units set prices during transmission or energy scarcity conditions, rather than having prices set by reserve shortage pricing or demand response. This phenomenon is related to several elements of MISO's Approximated ELMP methodology, including the heuristic employed to include start-up and minimum load offers in the convexified offer curves of off-line units that are used in the Approximated ELMP price determination, and rules about which off-line units should be considered (i.e., the magnitude of their shift factor on the binding constraint) in the price formation.[109] MISO is supportive of the market monitor's recommendation that real-time prices should be at the cap when demand response is activated.

Like the NYISO's hybrid pricing, MISO's Approximated ELMP will apply to both day-ahead and real-time pricing. As a general matter, though, the modification of day-ahead price formation to include fixed-block resources is less of an issue than for real-time, because of the presence of virtual bidding and price-capped load bids in the day-ahead markets. The MISO studies found that ELMP had little effect on prices in the day-ahead market

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[107] Communication with Paul Gribik, May 2014.

[108] "Offline Fast Start Resources set prices when the real time SCED dispatch experiences reserve deficit, or when transmission constraint violation conditions occur where Fast Start Resources could have been called on to mitigate the conditions. During real time operation, these conditions may or may not result in the actual call-on of the Fast Start Resources depending on the transient nature of the conditions. Persisting reserve deficits or transmission constraint violations would lead to commitment of the Fast Start Resources for mitigation." MISO ELMP FAQ at 4.

[109] Patton, August 2014 and MISO, "ELMP Parallel Operations Update", September 2, 2014. https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2014/20140902/20140902%20MSC%20Item%2005a%20ELMP%20Parallel%20Operations%20Update.pdf. Unlike the NYISO, MISO does not have a software tool to evaluate the economics of fast-start units looking forward over multiple real-time intervals.

because virtual bids had the effect of removing lumpiness from the price determination, i.e., they convexified the day-ahead offers. However, there appear to be material issues in the day-ahead market in PJM, which does not include CTs in day-ahead price formation, and also has experienced a reduction in virtual bidding due to the allocation rules for its real-time uplift.

There has been renewed interest in ELMP in addressing price formation when minimum load costs are incurred to commit units with significant minimum run times or start-up times that are needed to serve load or resolve transmission constraints. The commitment of such units has a role in the prices seen in California in the "belly of the duck" when units must be started in advance to meet the evening ramp and in price formation in New England, when the ISO states that units with longer run times must be started because additional quick-start capacity is not available.[110] While it is useful to investigate how ELMP pricing would work in these situations, it is not apparent that it would accomplish what some wish that it would, which is to lift prices when they are low due to excess on-line capacity, possibly because of larger units with long minimum run times. When excess capacity is on-line, it is efficient for prices to be low to signal the availability of cheap exports and to discourage imports; ELMP is not likely to significantly change this. *A first course of action could be to make other changes to improve the quality of real-time price signals in these regions to encourage investment in existing or new generation that can respond more quickly in response to real-time price changes.*

Pricing approaches for fast-start block-loaded units are varied and incomplete within ISO NE, PJM and the CAISO. For a number of years, ISO NE's external market monitor has recommend that it investigate changes to its pricing to allow the deployment costs of fast-start generators to be more fully reflected in the real-time market prices. He found that "real-time prices often do not fully reflect the cost of satisfying demand and maintaining reliability during tight market conditions, particularly when fast-start resources or demand response resources are deployed in the real-time market."[111] Under ISO NE's current pricing rules, fast-start resources are only included in price formation in the single interval in which they are synchronized to the transmission system, which is before they start to produce energy.[112]

PJM's software allows CTs to set real-time prices to a limited extent when they are on-line to solve a transmission constraint in real-time, but does not allow CTs to set day-ahead prices. The PJM manuals state that a CT can set LMP if "[t]he CT is logged on for

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[110] Compared with other regions, New England has fewer quick-start units that can ramp up in a matter of minutes. Instead, its operators rely more on inflexible units with long minimum run times, including oil-fired units that take many hours to ramp up. It is possible that some of the dearth of quick-start capacity in the New England is occurring because units are bid inflexibly due to the lack of price incentive when quick response is needed.

[111] Patton, et al. 2012 Assessment at iii.

[112] Dane Schiro and Matthew White, Real-Time Price Formation: Technical Session #6, ISO New England, September 22, 2014, at 23-28, http://www.iso-ne.com/static-assets/documents/2014/09/price_information_technical_session6.pdf.

transmission and a transmission constraint is logged (CTs logged as on for transmission when a constraint is not logged are treated as economic), the CT bid price is less than or equal to the dispatch rate, and the state estimator MW output of the CT is greater than zero."[113] However, there is no description of the rules PJM uses to determine when a CT is logged on or not for transmission. Moreover, even when CT pricing occurs the PJM software does not necessarily treat the CT as dispatchable for its full output. Instead, there is a parameter in the PJM software to adjust the percentage of the capacity of the CT that will be modeled as dispatchable for pricing purposes.[114] If this is only set for a small portion of the CT's capacity – it has been reported to be 10% -- the CT will still typically remain pinned at its minimum load and therefore not included in price formation.[115] Additional information is required to evaluate how often and how effectively PJM is allowing block-loaded CTs to set price.[116]

The NYISO approach to hybrid pricing has been in use for many years, and it is not apparent why the other ISOs/RTOs cannot follow its lead in this area. There may be impediments, having to do with the characteristics and quantity of fast-start in different regions, software design, and interactions with other market rules, such as whether or not uplift is paid to constrained-down supply. The MISO's current efforts with Approximated ELMP also have revealed that the look-ahead capability of the NYISO real-time dispatch could be an important aspect of the performance of their present implementation of hybrid pricing. However, hybrid pricing was used successfully in the NYISO before it developed its real-time look-ahead dispatch software. Whether and how look-ahead software is used for these implementations may depend on the characteristics of the intermittent generation and real-time demand response in different regions, as these will affect the ability to reasonably forecast the economics of the commitment of a fast-start unit in future intervals.

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[113] PJM Manual 11: Energy & Ancillary Services Market Operations, Revision 64, January 6, 2014, at 40, http://www.pjm.com/~/media/committees-groups/committees/mrc/20140227/20140227-item-11b-m11-energy-and-ancillary-services-market-operations.ashx.

[114] Communication with Adam Keech, August 2014.

[115] If CTs could be offered with lower minimums it could make them eligible to set price.

[116] Unlike the NYISO and MISO, PJM sends a price signal to generators as the basis for its real-time dispatch, rather than a dispatch base point. This has raised a hurdle to the full implementation of hybrid pricing out of concern that units will increase their generation in response to a (higher) hybrid price signal, when the units actually need to be held at a lower dispatch point when a CT is block-loaded. This could cause the ISO to have difficulty maintaining reliability because, at present, neither PJM nor ISO NE make constrained-down payments to generators when the price is higher than their offer at the dispatch point resulting from least-cost security constrained dispatch. PJM and ISO NE may not have the settlement rules at present to prevent over-generation from occurring under hybrid pricing; their choices are to limit the application of hybrid pricing and suppress LMPs, or pay constrained-down payments, which will have the appearance of increasing uplift. Other ISOs, such as the NYISO and MISO, make these constrained-down payments in order to provide a price incentive for generators to dispatch at their base point, rather than over-generate in these situations. It bears repeating that under hybrid pricing the price signal will immediately fall when the CT is no longer needed to serve load, even if it has not satisfied its minimum run time.

Averaging of Settlement Prices

A second type of price formation issue arises if the prices used for settlements for energy and ancillary services do not include the full granularity of the dispatch-based prices calculated by the pricing software, or capable of being calculated by the pricing software, and that correspond to dispatch intervals. The chief example here is paying suppliers the real-time dispatch based on a simple average of the prices in each interval of the dispatch hour at the supplier's location, rather than based on a quantity-weighted average of the interval prices at the supplier's location. The latter is equivalent to settling the supplier's injection in each interval at the interval price at its location. This is often called "5 minute pricing," although dispatch intervals are not always exactly five minutes in length. When prices rise during an interval because the system operator needs increased supply from generation able to ramp up, available generation will be motivated to respond more quickly when it is paid the interval price for its output in the interval, rather than the (lower) time-weighted average hourly price. Payment of the high interval price for supply during the interval is a direct application of the principle of dispatch-based pricing. A second example of this type of departure from dispatch-based pricing is the averaging of prices prior to settlements in charging zonal average prices to loads. Zonal pricing for loads will become problematic as states seek to include more price responsive demand response in their markets.

Quantity-Weighted Hourly Pricing

Supplier settlements based on hourly generation and on hourly average LMPs fail to compensate generation for ramping to meet changes in five minute generation and loads, and also tend to incent behaviors detrimental to reliability. For instance, there can be relatively large movements in prices at the top of the hour, when hourly interchange schedules are adjusted. If this causes a spike in prices, and payments to generators are based on hourly average LMPs, there can be an incentive for generators to exceed their dispatch instructions during the remainder of the hour because they will be paid the relatively high hourly average price even when the actual value of their injections is much lower during many five minute intervals. Conversely, if a generator has the ability to respond to a rapidly increasing price signal occurring for only some of the intervals of an hour, its financial incentive to respond will be suppressed by the possibility that the average price paid for the hour could be less than its actual costs for the intervals when it is dispatched.[117] In addition, the use of hourly average prices, rather than quantity-weighted hourly prices, will dampen price signals to dispatchable loads, wasting the most potent cost savings potential of investments in metering. Finally, inaccurate real-time settlements will tend to undermine import supply in regions with price-taking imports forgoing the full potential of 15 minute scheduling.

[117] This unit would, of course, receive make-whole uplift; however, the form of make-whole mechanism can still be punitive. Under current ISO-NE rules, which consider daily revenues against daily as-bid costs, such an outcome could require a fast-start resource to fund its own make whole uplift from another hour where it earned an energy margin (LMP > cost).

Quantity-weighted hourly pricing is extremely important in regions in which flexible generation is needed to accommodate intermittent generation. Quantity-weighted prices should be charged to generators for schedule deviations, and paid to flexible generators for providing energy that may be essential for maintaining reliability. This will compensate supply that is available when interval prices are high due to a sudden dip in energy supply. There are both reliability and cost-shifting consequences of pricing based on straight time-weighed hourly averages of interval prices. The best incentive for investments in generation that can ramp quickly is for ISOs and RTOs to provide a meaningful price signal and appropriate compensation through quantity-weighted hourly prices.

The NYISO has employed quantity-weighted hourly settlements since start-up; both the CAISO and SPP also have it in place; and, the ISO NE is planning to move to five-minute quantity-weighted pricing this year. In addition, five-minute pricing is currently a part of the plans for the possible implementation of a real-time security-constrained economic dispatch (SCED) for most of the Northwest Power Pool entities outside of California.

Pricing Model Inputs Inconsistent with Unit Commitment and Dispatch

A third problem arising in the calculation of energy and ancillary services prices arises if the software model used for pricing is not based on actual dispatch quantities, on the physical transmission model used for the dispatch, or on all of the constraints the dispatch software and system operator observe to maintain reliability. As previously mentioned, the concept of system constraints should include all constraints imposed on the unit commitment and dispatch in order to maintain reliability, including voltage limits, minimum on-line capacity constraints and requirements for reserve, regulating and ramping capacity, as well as thermal and interface transmission limits. Price suppression can occur when fast-start units are committed in supplemental commitments close to real time (or demand response is activated or exports are cut), and the supply from these units is included in real-time price formation, but the constraints that led to operator action are not included in the pricing model, are not fully included, or cannot be included because they bind in the commitment model rather than the dispatch. This can occur, for example, when the penalty factor for the constraint is inconsistent with the cost of operator actions.

It may be possible to include constraints or other system conditions that led to operator actions in models used for price formation even if they cannot be represented in the unit commitment and dispatch model. For example, the same technique discussed for binding voltage constraints might be employed to develop a representation of other constraints that lead to other operator actions occurring outside of the dispatch, such as the activation of emergency demand response that is dispatchable. Once emergency demand response is called, if the constraint leading to this operator action could be represented in real-time price formation and binds during the price formation step, it will be reflected in energy and ancillary services prices (assuming that energy and reserve prices are systematically related in real-time).

This approach for improving price formation will generally not be effective, however, when operators bring blocks of non-dispatchable supply on-line through supplemental commitments. If the minimum load of a unit constrained-on is large or the unit or other supply resource (e.g., demand response or an export that has been cut) is block-loaded, the constraint leading to the supplemental operator action might not bind in price formation, even if it is included in the pricing model. This occurs because the additional block of supply is greater than the quantity needed to remove the constraint in the pricing model, so the constraint binding in the unit commitment does not bind in either the dispatch or pricing models. The problem is compounded when the supplemental supply has a minimum run time and cannot be turned off when it is no longer needed. Price formation in this situation is problematic, as forming prices based on the average offer of the constrained-on supply block could lead to enormous uplift due to the need for constrained-down payments.[118] The only apparent near-term approach to addressing this issue is to increase quantities of dispatchable demand response; in the longer run it might be addressed through the implementation of ELMP.

Including RUC in DAM Schedules and Prices

A long-standing problem of omission of information from the pricing calculation is the decision not to include supply committed in the Residual Unit Commitment (RUC, or Reserve Adequacy Assessment (RAA), in the case of New England) in the determination of day-ahead schedules and day-ahead prices in most ISOs and RTOs. Because ISOs and RTOs must ensure that sufficient resources are scheduled day-ahead to meet their forecast of demand, they carry out unit commitment reliability checks and may commit additional resources immediately after the close of the day-ahead market in the RUC and also closer to real-time. Resources are committed in the RUC due to the software modeling limitations discussed above (e.g., voltage and minimum on-line operating constraints); because the supply clearing in the day-ahead market is insufficient based on the ISO's forecasts of real-time load; or for other reasons, such as advance knowledge of a possible generator outage.

Price formation will be improved if day-ahead schedules and prices are determined in models including the RUC commitments, since this is the same unit commitment that is expected to underpin real-time schedules and prices, notwithstanding the fact that ISOs and RTOs will still commit generation after the RUC to compensate for outages, deratings and import curtailments. At present, only NYISO calculates its day-ahead prices including generation scheduled in its RUC. This design feature dates back to the beginning of the NYISO in the late 1990s.

[118] A further problem is to determine how to represent constraints that bind in the unit commitment, such as the minimum on-line capacity constraint, in the pricing algorithm in the absence of ELMP.

If the ISO/RTO commits generators with significant minimum loads for reliability in the RUC and this generation commitment is not taken into account in the schedules used for calculating day-ahead LMPs, it means that schedules and LMPs in the day-ahead and real-time markets will be formed based on different unit commitments even when real-time conditions conform to the ISO's forecasts at the time of the RUC. This practice will tend to decrease real-time prices relative to day-ahead prices, and can distort bidding incentives for generation and loads. In particular, if the RUC is systematically scheduling units that must be started up and operated at least at their minimum load rather than relying on quick start resources to meet under-bid load, LSEs can have an incentive to schedule less than 100% of their forecast real-time demand in the day-ahead market because they may decrease their costs by doing so.[119]

The exclusion of RUC commitments from day-ahead price formation is one of the underlying causes of a cycle of real-time price suppression observed in a number of ISOs.[120] Bids and offers for virtual supply and demand should, in principle, respond to the potential for a systematic difference in day-ahead and real-time prices. A systematic price difference should, in principle, lead to sufficient virtual demand bids in the day-ahead market to proxy for any missing bids from physical loads to enable a commitment in the day-ahead market minimizing the cost of serving expected physical load, and convergence of day-ahead and real-time prices. There are transaction costs and risks for virtual trading, however, such as collateral costs, charges per bid, and allocations of uplift, so that virtual trading will reduce but not eliminate the systematic difference between day-ahead and real-time prices resulting from the exclusion of RUC commitments from day-ahead price formation. The biggest problem in a number of ISOs/RTOs is that virtual demand bids in the day-ahead market are penalized by the allocation of the uplift costs occurring in the real-time market. Allocations of uplift costs to virtual deviations that do not cause the uplift has led to a huge decrease in virtual bidding in regions such as PJM and the CAISO, and squelched the important role of virtual supply and demand bidding in driving convergence of the day-ahead market to the expectation of real-time prices and quantities.[121] Exclusion of the RUC commitments from day-ahead price formation thus contributes to the perpetuation of a cycle of real-time price suppression and uplift: a gap between day-ahead and real-time prices leads to underbidding of physical load in the day-ahead market, the consequent need for RUC commitments, the suppression of real-time prices and need for uplift, and a continuing incentive for underscheduling of load in the day-ahead market.

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119 Note that under-bidding of load in the day-ahead market, like uplift, is a *symptom* not a *cause* of problems with price formation.

120 Osipovich 2013.

121 *See, e.g.*, PJM Interconnection, Docket No. ER13-1654, Attachment I: Report on the Impacts of Virtual Transactions, February 7, 2014, http://www.pjm.com/~/media/documents/ferc/2014-filings/20140207-er13-1654-000.ashx.

Although RUC commitments are not large in most ISOs/RTOs, the quantity of generation committed in the ISO NE's Reserve Adequacy Assessment (RAA, i.e., the RUC) and the associated impacts on real-time prices and uplift have been a source of concern for many years. If the RAA is consistently scheduling thousands of megawatts of capacity, it is a signal of a problem with the day-ahead and real-time markets. Day-ahead market schedules should provide gas-fired generators with a reasonable basis for purchasing and scheduling gas. If day-ahead market schedules cannot serve this function because they are not sufficient to cover real-time load, this is one element of the reliability issues occurring when the gas pipeline system is constrained and the supply of gas for generation is less elastic than normal.

iii. Issues with Rules Defining Electricity Markets and Bidding Rules

A third broad category of price formation problems arises from issues with the rules defining electricity market products and bidding rules. This section discusses three important enhancements that need to be implemented in some regions and further developed in others: co-optimization of operating reserve and energy schedules and prices in the day-ahead market; enabling suppliers to submit intra-day changes to their offers and to submit day-ahead offers that differ by hour; and enhancements to shortage pricing, such as improved estimates of reserve penalty factors and implementation of shortage pricing in the real-time physical dispatch.

Absence of Operating Reserve Schedules and Prices in DAM

ISO NE lacks a day-ahead market for reserves and day-ahead co-optimization of the unit commitment for reserves and energy.[122] The ISO NE does not procure generation to provide reserves day-ahead. While it utilizes a forward reserve market to purchase the bulk of operating reserve, *incremental* reserves are scheduled (but not priced) through the unit commitment. ISO-NE also does not co-optimize the scheduling of regulation with reserves and energy.

The ISO NE design has impacts on reliability, efficiency and pricing. Inefficiency and possible reliability impacts occur because long-start generators need to be on-line in order to provide reserves (or unload other obligations in order to provide reserves), but the identity of which long-start generators will be economic sources of reserve varies from day to day with market conditions. Long-start generators cannot predict in advance whether they will be scheduled to provide incremental reserves in real-time in order to arrange for fuel supplies in advance, so they need a day-ahead financial settlement at the time that they receive their day-ahead reserve schedules. The day-ahead settlement provides the financial assurance that they will cover their costs when they start-up (if necessary) and obtain any additional fuel they may need to meet their

[122] Patton et al., 2013 Assessment at 20.

reserve schedules. The lack of co-optimization of energy and reserve prices in the day-ahead market means that clearing prices in the day-ahead market do not reflect the costs of meeting requirements for operating reserves, so are suppressed when these requirements are binding.

Co-Optimization of Operating Reserves and Energy in the DAM

Software and market rules for co-optimization of energy and reserves (including regulation) have been in place and working for many years in a number of ISOs/RTOs. NYISO and MISO employ a full two-settlement system for energy and reserves, co-optimizing the scheduling and pricing in both their day-ahead and real-time markets, and settling the real-time market based on differences between day-ahead and real-time schedules.[123] The CAISO also co-optimizes energy and reserves in its day-ahead market. Implementation of co-optimized energy and reserve markets in the day-ahead market, along with a two-settlement system for reserves and energy, is becoming standard practice to improve both reliability and price formation.

Inefficient Electricity Market Bidding Rules

As electricity markets have evolved over the last 15 years, many changes have been made to better align the definition of electricity market products and bidding rules with the actual engineering-economic operation of generation and transmission and with the structure of related markets, such as gas supply. Several issues fall into this category: the need to accommodate intra-day changes to offers in order to reflect underlying changes in the cost of electricity supply; the possible lack of an explicitly priced ramping product; and the problems arising from offer caps that are too low during periods of tight gas supply. Issues arise because the time step of energy and ancillary services markets or the rules governing the components of bids and offers for a product do not align with the system operator's need to manage reliability or suppliers' needs to manage business risk. In considering changes to product definitions or bidding rules, it is essential to tightly tie the payment for the product to provision of the specific electrical capability and performance that the system operator needs to purchase.

Intra-day Changes in Supply Offers

Many ISOs and RTOs are beginning to recognize the importance of allowing generation suppliers to adjust their offer prices during the operating day to reflect changing conditions, as well as allowing day-ahead offers to vary between hours. This issue was apparent when gas pipelines were constrained during the last winter in New York, New England and PJM. The inability of generators to adjust their offer prices during the operating day can compromise energy- or fuel-limited suppliers' ability to cover their day-ahead market schedules, or worse yet, to cover their intraday commitment schedules. This can occur if suppliers do not raise their offer prices in the reoffer period

[123] Shaun Johnson, June 28-29, 2010 at 2 and 4, http://www.ferc.gov/CalendarFiles/20110628072825-Jun28-SesA1-Johnson-NYISO.pdf.

the day before, and as a consequence are dispatched above their day-ahead schedules at offer prices that are less than the cost of generating in real-time.

While the NYISO, MISO and CAISO have rules allowing suppliers to adjust their incremental energy offer prices from hour to hour through the day, this is not the case in PJM, and is in the process of implementation in ISO NE. NYISO has allowed within-day offer changes since 1999 to maintain reliability during the winter on a gas dependent transmission system. Moreover, in 2010 NYISO added the flexibility for generators with day-ahead market schedules to raise their offer prices and has been working to apply market power mitigation in a manner that recognizes the need for offer price flexibility when costs are changing. The NYISO has allowed generators to vary their day-ahead offers between hours since its start-up.[124]

It is crucial to allow gas suppliers to adjust their intra-day offer prices when gas pipelines are constrained so that they can be sure that when intra-day gas prices rise they will not lose money when procuring gas needed to cover day-ahead schedules or intra-day commitments. If they are dispatched uneconomically at an offer price that is less than their actual cost of gas supply, they may draw down their gas storage, and then have too little gas to cover their day-ahead market obligations later in the day. Rules limiting adjustments to offer prices during the operating day can impact the system operator's ability to maintain reliability during periods in which real-time prices fall below intra-day gas prices.

The inability of suppliers to make within-day adjustments to their offers also has negative consequences for efficiency: the cheapest generation may not be running to serve load or to solve transmission constraints. This can occur because even more expensive generation has to be run than otherwise possible or because suppliers may overestimate the price of intra-day fuel in their significantly advanced offer. The cheapest generators do not run to serve load and the more expensive fuel may be burned simply because generators cannot submit offers to match their costs.

In addition to reliability and efficiency impacts, limitations on within day adjustments to offers can distort real-time price formation when prices change significantly within a day. In ISO NE last winter there was price suppression during periods of limited gas availability because real-time offer prices do not reflect the price of intra-day gas. Suppression of energy and ancillary services prices creates a list of problems that have already been discussed: load has less incentive to reduce consumption so as to relieve the shortage; imports that could relieve the shortage see a lower price signal and thus have less incentive to respond; gas-fired generators have less incentive to invest in

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124 NYISO Market Services Tariff at 4.2.1.3. It is very important to allow generators to vary their day-ahead offers over the hours of the day because units may be committed within a day based on a software tool minimizing offer cost. ISO NE also plans to allow day-ahead offers to vary between hours, effective December 3, 2014. ISO New England Inc. and New England Power Pool, Docket No. ER13-1877, 145 FERC ¶ 61,014 (2013). This important improvement needs to be discussed in PJM.

dual-fuel capability, storage, pipelines, or efficiency enhancements; and suppliers as a whole will receive less compensation from the energy and ancillary services markets, which may increase uplift and place a greater burden on capacity payments.

ISO NE is changing the market rule that through last winter prevented suppliers of gas-fired generation from adjusting their offer prices over the course of the operating day to reflect the level of intra-day gas prices. It has a target date of December 2014 to implement a number of changes to increase the flexibility of energy offers, including allowing suppliers to vary day-ahead supply offer values hourly, update offers in real-time (30 minutes in advance of the hour) and submit negative offers down to ($150).[125] The ability of suppliers to adjust offer prices during the operating day to reflect the level of intra-day gas and other costs will contribute to better aligning real-time electric prices with market conditions, resulting in higher real-time prices when intra-day gas prices are higher than expected or when the electric system is stressed, and lower prices when intra-day gas prices fall or there is a variety of supply available to meet needs. This change in real-time pricing will also provide incentives for load to schedule adequate generation through the day-ahead market.

Evolving Implementation of Shortage Pricing

A number of price formation issues arise because of the lack of development of the demand-side of electricity markets.[126] Dispatchable demand can respond to real-time prices and contribute to reliable system operation even when all generation resources have been committed and dispatched to provide energy or ancillary services. Under these conditions, it is expected that prices would rise sharply to reflect the value of the unserved load of customers who are willing to curtail their consumption. In practice, though, price-responsive demand is generally not dispatchable so that when it is activated it does not set price; the NYISO is an exception to this.

Reserve and regulation penalty factors and shortage pricing serve as a proxy for the effect dispatchable demand would have on the real-time dispatch and pricing for energy and reserves. The methodology assigns value to operating reserves and regulation when they are in short supply in the real-time dispatch. These market design features allow prices to rise in a pre-determined way when reserve or regulation constraints cannot be met because the system is short of capacity or ramping capability and, because these features allow constraints to be relaxed, enable the dispatch to solve. In most ISOs/RTOs, the impact of shortage pricing on energy and ancillary services prices is intended to cover the cost of the increased probability of a loss of load from relaxing the reserve or regulation constraint. Reflecting reserve shortage conditions in energy and ancillary services market prices provides an improved price signal for consumer load response and stronger performance incentives for on-dispatch suppliers during

125 *ISO New England Inc. and New England Power Pool*, Docket ER13-1877-000, Energy Market Offer Flexibility Changes, July 1, 2013.

126 The quantity of price-responsive demand will depend on the level and variability of real-time prices.

reserve shortage conditions. Implementation of reserve and regulation penalty factors and shortage pricing in real-time sits within the framework of dispatch-based pricing as the objective is to calculate prices consistent with the real-time dispatch.

Shortage pricing assigns additional value to operating reserves and regulation in the real-time dispatch under certain conditions, which vary by ISO/RTO. In general, if the ISO must re-dispatch resources to meet the requirement for operating reserves plus load, the real-time reserve price will be determined by the estimated opportunity cost of the redispatch to supply reserves,[127] or an administratively set demand curve that is a measure of the marginal reliability value of reserves or regulation. Since, at the margin, a unit of generating capacity can be used to supply energy, reserves or regulation in real-time, the LMP for energy will generally rise whenever the shortage price of reserves or regulation rises. When reserves and/or regulation have an increased value in real-time, this will flow through into energy prices.

There are differences among the ISOs/RTOs in the operating reserve products to which they apply penalty factors, the level of the penalty factors, and whether the shortage pricing flows through into energy pricing through co-optimized dispatch of energy and reserves or through a separate settlement mechanism. NYISO, MISO and ISO NE have had versions of reserve shortage pricing in place for some time.

PJM implemented reserve shortage pricing on October 1, 2012, following delayed FERC approval of its design.[128] In PJM there is an $850 shortage value for shortages of non-synchronous reserves and synchronous reserves, and two nested reserve zones, with an overall cap of $2,700 on energy prices.[129]

The Electric Reliability Council of Texas (ERCOT) has recently implemented an advanced form of shortage pricing based on operating reserve demand curves. [130] This approach is conceptually straightforward: the shortage values rise sharply when reserves fall below target levels, but also do not fall immediately to zero when there are extra reserves, because the extra reserves have a value greater than zero to the dispatch. The primary challenge is to estimate the shape and height of each reserve demand curve to appropriately reflect the marginal value of reserves. The shortage values are intentionally higher than in other regions because of the decision not to implement capacity market and capacity pricing in Texas at this time. ERCOT originally had a design in which ancillary service schedules were determined prior to the real-time

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[127] ISO New England Internal Market Monitor, Overview of New England's Wholesale Electricity Markets and Market Oversight, May 15, 2012, at 15, http://www.iso-ne.com/pubs/spcl_rpts/2012/markets_overview_final_051512.pdf.

[128] *PJM Interconnection, L.L.C.*, Docket No. ER09-1063-004, Compliance Filing, June 18, 2010 (PJM Compliance Filing 2010). *See also PJM Interconnection, L.L.C.* Docket No. ER09-1063-004, 139 FERC ¶61,057 (2012).

[129] PJM Compliance Filing 2010 at 3.2.3A and 3.2.3.001.

[130] William W. Hogan, "Electricity Scarcity Pricing through Operating Reserves: An ERCOT Window of Opportunity," November 1, 2012.

dispatch, with the consequence that energy and ancillary services were not simultaneously optimized in real-time.

Increases in Level of Penalty Factors

U.S. ISOs and RTOs have been fine tuning the penalty values used to set prices when they are short of reserves or regulation, so as to provide appropriate real-time price incentives for demand reduction, additional supply (e.g., imports), and the development and offering of increased ramp capability. ISOs and RTOs such as NYISO and MISO have been adjusting the values over time to provide a price signal consistent with operating conditions. It is not desirable to send out a zero or low- priced shortage signal when the system is seriously short of reserves, but it is also not desirable to send out a $1,000 price signal when the system is temporarily ramp constrained in a region in which reserves are scheduled and available. Enhanced implementations allow shortage prices to increase gradually as the dispatch approaches a constraint limit.

NYISO was the first U.S. ISO to use penalty or shortage prices to set real-time energy and ancillary services prices in its Real-Time Commitment market design, which was implemented in February 2005. In 2011, the NYISO adjusted its penalty values, raising the shortage value for total New York control area 10-minute reserves and reducing the shortage value for Long Island 30-minute -reserves. The current values are shown in Table 3 below.

Table 3

NYISO Reserve Shortage Values - April 2011

Total Spinning Reserves	$500/MW
Eastern 10-Minute Reserves	$500/MW
Total 10-Minute Reserves	$450/MW
Total 30-Minute Reserves	$200/100/50/MW
Eastern Spinning Reserves	$25/MW
Eastern 30-Minute Reserves	$25/MW
Long Island Spinning Reserves	$25/MW
Long Island 10-Minute Reserves	$25/MW
Long Island 30-Minute Reserves	$25/MW

Since NYISO co-optimizes the dispatch of energy and reserves, the price of reserves will set a floor on the price of energy.[131] NYISO's reserve penalty factors also are additive,

[131] There are some situations in which reserve shortage prices would be reflected differently in energy prices in different sub-regions. If there is transmission congestion within the region to which a given

so that if NYISO were short of both 10-minute and 30-minute reserves, energy prices would exceed the energy offer of the incremental resource by $350 ($200 plus $150). In addition, the New York real-time dispatch will go short on regulating capacity when ramp constraints otherwise prevent the NYISO from balancing real-time load and generation. The current regulating capacity shortage values are: 0-25 MW ($80), 26-80 MW ($180), over 80 MW ($400). In NYISO, the shortage pricing is implemented by including the reserve and regulation shortage penalty factors in the real-time dispatch.

ISO NE implemented reserve shortage pricing on October 1, 2006, for total reserves and for 30-minute reserves within load pockets for which it sought to commit enough capacity to maintain reliability following a second contingency. When one of these constraints binds in the ISO NE dispatch, the applicable penalty factor is added to the marginal energy component of the LMP. ISO NE's shortage values (called Reserve Constraint Penalty Factors) are additive, so a shortage in two or more would result in adding all of the applicable penalty factors to set a minimum value for the marginal energy component of the LMP.

The experience with reserve penalty factors in New England illustrates the importance of setting these factors so as to lead to the formation of energy and ancillary services prices that are consistent with the real-time dispatch. Prior to June 1, 2012, the ISO NE used a $100 penalty factor for system-level 30-minute reserves, which led to inefficiently low real-time prices that did not reflect the cost of maintaining reliability. As a result, ISO NE had to curtail exports and employ other manual interventions in order to maintain adequate reserves. The external market monitor supported the increase in the system-level 30-minute reserve penalty factor to $500/MW, stating that it "provides market participants better incentives to schedule in the day-ahead market and schedule net imports from external areas that will lower the costs of maintaining reliability."[132] Recently, FERC has directed ISO NE to increase the system-wide Reserve Constraint Penalty Factor for 10- and 30- minute operating reserves to $1,500 and $1,000, respectively.[133]

MISO implemented real-time reserve shortage pricing for operating reserves in January 2009 with implementation of the MISO co-optimized ancillary services market. This design initially included penalty values limiting the dispatch of capacity providing spinning reserves or regulation, but the dispatch of this capacity did not explicitly set

reserve requirement applies, it is possible for there to be a tradeoff between reserves and energy that differs between locations.

132 Patten et al. 2012 Assessment at xvi.

133 Docket No. ER14-1050; ISO NE also has shortage value of $50/MW for 10-minute spinning reserves and $250/MW for local 30-minute operating reserves. In addition, as discussed in an earlier section, ISO NE has implemented a reserve constraint penalty factor of $250/MWh for Replacement Reserves, with the objective of incorporating at least some of its supplemental unit commitment capacity into a reserve market so as to price scarcity consistently with the actions of the system operators. Currently, the replacement reserve MW level is set to 180 MWs for winter and 160 MW for non-winter, but can be increased to approximately 300 MW at the ISO NE's discretion.

real-time energy prices. This had the consequence that real-time energy prices could fall when ramp constraints caused capacity providing spinning reserves to be dispatched for energy.[134] The MISO for a period used *ad hoc* methods to send an appropriate price signal during these conditions but implemented explicit real-time shortage pricing for spinning reserves on May 1, 2012.[135] The current MISO shortage values set a price of $65 per megawatt for spinning reserves shortages of 150 megawatts or less and a shortage price of $98 for shortages of more than 150 megawatts.

CAISO uses penalty values to relax its spinning reserve and regulation constraints in the Real-Time Pre-Dispatch (RTPD) program, which schedules ancillary services across units and commits generation to provide ramp capability prior to the real-time dispatch. The imposition of reserve and regulation constraints in the RTPD, rather than in the real-time dispatch, has distorted the real-time price signals in CAISO because the ancillary service schedules set in RTPD are treated as fixed in the real-time dispatch. This inflexibility contributes to $1,000 price spikes in real-time when ramp constraints prevent CAISO from meeting the energy balance constraint using the resources that are available for dispatch,[136] because capacity scheduled in RTPD to provide spinning reserves and regulation cannot be dispatched to meet load. CAISO's fixed real-time ancillary service schedules can be particularly problematic when transmission constraints are binding in real-time, and there is more than enough capacity to balance load and generation and meet reserve requirements, but the reserves are scheduled by RTPD in transmission-constrained regions where additional ramping capability is needed in real-time. These problems lead sporadically to very high real-time prices and contribute to the differences between the prices in the Hour-Ahead Scheduling Process (HASP) evaluation that schedules net interchange, but tends not to foresee ramp constraints, and the prices in real-time when ramp constraints up or down are binding and prices are set by the power balance penalty value.

Because CAISO does not co-optimize reserves and energy in real-time and apply shortage pricing for reserves within this co-optimization, CAISO's reserve prices do not reflect the impact of real-time price volatility. This is because they are set in RTPD rather than in real-time, and RTPD cannot foresee actual real-time conditions leading to

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[134] Potomac Economics, 2010 State of the Market Report for the MISO Electricity Markets, June 2011, at 57-58, https://www.potomaceconomics.com/uploads/midwest_reports/2010_State_of_the_Market_Report_Final.pdf, *See also* Potomac Economics, 2009 State of the Market Report for the Midwest ISO, at 54-55, https://www.misoenergy.org/Library/Repository/Report/IMM/2009%20State%20of%20the%20Market%20Report.pdf.

[135] *Midwest Independent System Operator Inc.,*, Docket No. ER12-1185-000, Section 205 Filing Regarding Regulating and Spinning Reserve Demand Curves, March 1, 2012; *Midwest Independent System Operator Inc.,*, Docket No. ER12-1185-000, 139 FERC ¶61,081 (2012); and MISO 2011 SOM at 71.

[136] CAISO DMM Q3 2012 at 10-13.

volatility. Real-time volatility is increasing in CAISO due to the growth of intermittent resources, and impacts the cost of meeting load in each dispatch. By pricing reserves and regulation in RTPD, and imposing the penalty factors estimated in RTPD rather than in real-time, the CAISO is not sending a real-time dispatch-based price to suppliers who could potentially respond to the real-time volatility.

IV. Conclusions

Assessment of concerns about price formation and prompt action to address the underlying problems identified should be an urgent priority for regulators and ISOs/RTOs in order to preserve and strengthen competitive electricity markets.

Very few ideas in this paper are new. The objective has been to describe the issues and a set of improvements that have been proved in practice or are under development and, from this, distill a set of suggestions and recommendations to support attempts to move forward as quickly as possible to improve price formation. The topic of price formation has many related sub-topics and it can be difficult to identify the right points of entry for productive discussion without becoming encumbered by details. The author is solely responsible for the following substantive recommendations and practical suggestions.

Substantive Recommendations

Five improvements to price formation stand out as possibilities for near-term change. The methodologies summarized below have been worked through and proved in operation in one or more ISOs/RTOs. Where they are in use there are generally differences in the implementation, a number of which could be significantly improved. Other ISOs/RTOs are in the process of working on similar changes. The benefits and challenges of implementing the recommendations below will differ somewhat across ISOs and RTOs depending on the circumstances in each, such as the underlying asset mix and the ISO's/RTO's existing software. However, examination of the details of the market systems already in use -- in some cases for a decade or more -- provides a way to move forward to progressively improve price formation in ISOs/RTOs.

1. Include All Active Constraints in Price Formation, Including Those Leading to Operator Actions

Price formation problems arise when the software used for the price calculation does not explicitly represent all constraints affecting the dispatch and/or commitment. Problems occur when the omitted constraints resulted in modifications to generator instructions, activation of emergency demand response, the cutting of exports or scheduling of extra imports or the scheduling of additional reserves.

The dispatch-based pricing principle described in the paper starts with the assumption that the dispatch, whatever it is, is the best that the system operator can do during an interval, using all of its software tools and making manual adjustments based on these tools if necessary; this is the least-cost dispatch that maintains reliability. The price formation problem arises because the pricing software sees all of the supply and demand in the actual physical dispatch, but does not model all of the constraints that have led to this result. This can mask differences in prices between locations and suppress prices because the pricing software does not calculate a congestion value for one or more active constraints and include this in locational prices.

This paper presents a number of examples of how price formation has been and could be improved by explicitly representing active constraints in ISO/RTO pricing software.

- ISOs/RTOs should be using “soft constraints” in their dispatch and pricing in order to avoid taking unnecessarily costly actions to avoid violating transmission constraints. This approach is an improvement to the efficiency of the dispatch that also includes a congestion component in LMPs for transmission constraints that are violated in the dispatch. Alternative approaches, which have been abandoned by many ISOs and RTOs, relax transmission constraints that cannot be solved by the dispatch software, which often results in the failure of the constraint to be active in price formation and leads to suppressed and inaccurate prices. Soft constraints are in use in many ISOs/RTOs, but are not universally applied.

- When the need for specific types of reserves repeatedly leads to supplemental unit commitments or other out of market actions, ISOs/RTOs should develop requirements for those reserve products and impose them in the pricing software and possibly also in the software used for unit commitment and dispatch. This can improve price formation if it leads to explicit scheduling and pricing of the reserves and the consistent reflection of this price in prices for energy and other ancillary services during the operating conditions in which the ISO would otherwise have performed a supplemental unit commitment that might have suppressed prices.

- Where possible, ISOs/RTOs should develop methodologies for representing voltage constraints in their pricing software, even when these cannot be modeled in the unit commitment and dispatch software. The methodology for implementing this is under development. Improvements in pricing through the modeling of voltage constraints in the pricing software may not be possible in all instances because of problems with non-convexity arising from the minimum loads of units within load pockets, but is nevertheless an approach with substantial potential to reduce price suppression.

2. Enable Intra-Day Offer Changes

ISO/RTO bidding rules should allow generation suppliers to adjust their offer prices during the operating day to reflect changing conditions, as well as to allow day-ahead offers to vary between hours. The inability of generators to adjust their offer prices during the operating day can compromise their ability to cover their day-ahead market schedules, or worse yet, to cover intraday commitment schedules. In addition, if suppliers do not anticipate increases in intraday gas prices and do not raise their offer prices in the reoffer period the day before, they can be dispatched above their day-ahead schedules at offer prices less than their cost of generating electricity in real-time.

In addition to these reliability and efficiency impacts, limitations on within-day adjustments to offers can distort real-time price formation when gas prices change significantly from day to day or within a day. In ISO NE last winter there was price suppression of energy and reserve prices during periods of limited gas availability because real-time offer prices did not reflect the price of intra-day gas.[137] This price suppression creates the usual list of problems: load has less incentive to reduce consumption so as to relieve the shortage; imports that could relieve the shortage see a lower price signal and thus have less incentive to respond; and gas-fired generators have less incentive to invest in dual-fuel capability, storage, pipelines, and efficiency enhancements. Supplies as a whole receive less compensation from the energy and ancillary services markets, increasing uplift and placing a greater burden on capacity payments.

NYISO has allowed within-day offer changes since 1999 and in 2010 added the flexibility for generators with day-ahead market schedules to raise their offer prices. It also has allowed generators to vary their day-ahead offers between hours since its start-up in 1999 and has been working to apply market power mitigation in a manner that recognizes the need for offer price flexibility when costs are changing. MISO also allows intra-day changes in offer prices and since April 2009 CAISO has allowed intra-day changes in incremental energy offers. ISO NE is in the process of changing the market rule that has prevented suppliers of gas-fired generation from adjusting their offer prices when interstate pipelines are constrained and day-ahead gas prices may not accurately reflect the cost of buying gas during the operating day. This change should also be considered in regions such as PJM that presently do not allow this offer price flexibility.

3. Include Block-Loaded Fast-Start Resources in Prices

Real-time price formation is significantly impacted by the methodology for addressing fixed-block fast-start resources such as gas turbines. When gas turbines are committed to meet incremental load, other units may need to be dispatched down to accommodate their fixed-block even when only part of the block is needed to meet load. If these gas turbines are treated as fixed resources that cannot set price, the price will never reflect their offers, even in situations when multiple units are committed to meet load over the hours of a day. Rather, the LMPs will be set by the offer costs of lower-cost flexible units that are dispatched down to accommodate the full output of the fixed-block unit. Prices are suppressed whenever they are less than the offer costs of a fixed-block fast-start unit that is needed to serve load.

NYISO uses hybrid pricing to allow fixed-block resources to set day-ahead prices in

[137] This price suppression also arises when price caps are too low.

hours in which they are required to serve load. In the NYISO pricing software, LMPs are determined under the assumption that fixed-block units are dispatchable over their full range at their average real-time offer cost. As a result, when gas turbines are dispatched to serve load, the LMP at their location will be greater than or equal to their offer and the unit will not need to be made-whole with uplift. Also, because of the internal consistency required among LMPs, the LMPs at all locations electrically related to the location of the fixed-block generator are also consistent with the hybrid pricing. MISO is in the process of refining and implementing an Approximated ELMP methodology, which is similar to NYISO's hybrid pricing approach.

In the absence of something like hybrid pricing, fixed-block fast-start units will receive uplift if needed to cover the difference between their offer and their LMP revenue. However, the associated price suppression reduces incentives to invest in additional fixed-block fast-start units because even if the units respond quickly when needed, prices may not rise when they are infra-marginal to compensate them for the high value of their energy at that time. In New England the External Market Monitor has estimated that "if the average total offers of these units were fully reflected in the energy price, the average real-time LMP would increase approximately $3.34 per MWh in 2013. If these price increases were reflected in the calculation of NCPC uplift charges, we estimate that they would have been $9.3 million lower in 2013."[138]

Pricing approaches for fast-start block-loaded units are varied and incomplete in ISO NE, PJM and CAISO. Under ISO NE's current pricing rules, fast-start resources are only included in price formation in the interval in which they are synchronized to the transmission system. In PJM, CTs cannot set the price in the day-ahead market, and when CT Pricing occurs in real-time, the PJM software does not treat CTs as dispatchable over their full output so they almost never set the dispatch signal that caps the ex post price.

4. Use Quantity-Weighted Hourly Prices (5 Minute Prices)

Until recently, in all FERC jurisdictional regions except for NYISO and CAISO, suppliers to the real-time dispatch were paid based on a simple average of the prices in each interval of the dispatch hour at the supplier's location, rather than based on a quantity-weighted average of the interval prices at the supplier's location. The latter approach, called 5 minute pricing, pays suppliers for their injections in each interval at the interval price at their location. Supplier settlements based on hourly generation and on hourly average LMPs fail to pay generation higher prices for ramping up to meet changes in five minute generation, and load over-pays for power supplied in intervals when prices are lower.

When the system operator needs increased supply, available generation will be motivated to respond more quickly when it is paid the high interval price for its output in

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[138] Patton et al. 2013 Assessment at 22.

the interval, rather than the (lower) time-weighted average hourly price. In addition, the use of hourly average prices, rather than quantity-weighted hourly prices, will dampen price signals to dispatchable loads, wasting the most potent cost savings potential of investments in metering. And inaccurate real-time settlements will tend to undermine import supply in regions with price-taking imports, forgoing the full potential of 15 minute scheduling. Generation is not going to be built that will be available to ramp quickly unless ISOs and RTOs provide a meaningful price signal and appropriate compensation through quantity-weighted hourly prices.

Quantity-weighted hourly pricing is extremely important in regions that need flexible generation to adjust to changes in intermittent generation. 5 minute prices should be charged to generators for schedule deviations, and paid to flexible generators for providing energy that may be essential for maintaining reliability. SPP has recently implemented 5 minute pricing and ISO NE is planning to shift to 5 minute pricing this year.

5. Continue to Improve Shortage Pricing

Shortage pricing is an established methodology for assigning value to capacity that can provide operating reserves, regulation, energy or ramping, when such capacity is in short supply in the real-time dispatch. Reserve and regulation penalty factors and shortage pricing allow prices to rise in a pre-determined way when reserve or regulation constraints cannot be met in real-time because the system is short of capacity or ramping capability. Shortage pricing will affect real-time energy and reserves prices in fewer days of the year than other changes recommended here, but when it occurs, the shortage prices will provide compensation to suppliers of all kinds who are available to produce at times when on-line capacity and/or ramping capability are minimally adequate to meet load.

The effect of shortage pricing on energy and ancillary services prices is intended to reflect the cost of the increased probability of a loss of load from relaxing reserve or regulation constraints.

If the ISO must redispatch resources to meet the requirement for load and operating reserves, the real-time price will rise: it will be determined by the estimated opportunity cost of the redispatch to supply reserves, or an administratively set demand curve that is a measure of the marginal reliability value of reserves or regulation. Since a unit of generating capacity can be used interchangeably to supply energy, reserves or regulation in real-time, the LMP for energy should rise whenever the shortage price of reserves or regulation rises. The inclusion of shortage values in energy and ancillary services market prices provides an appropriate price signal for consumer load response and potentially stronger performance incentives for on-dispatch suppliers during reserve shortage conditions.

U.S. ISOs and RTOs have been fine tuning the penalty values used to set prices when they are short of reserves or regulation and the definition of the reserve and regulation constraints to which the penalty factors apply, so as to provide appropriate incentives for additional supply during periods of shortages, such as demand reduction, imports, and increased supply from units that develop the capability to ramp more quickly. ISOs and RTOs such as NYISO, ISO NE and MISO have been adjusting the values over time to provide a price signal consistent with operating conditions. CAISO could improve its real-time price formation by making the changes needed to implement co-optimization of energy and reserves in their real-time dispatch, along with shortage pricing, rather than in a look-ahead optimization occurring prior to the real-time dispatch.

Practical Suggestions

The following practical suggestions are directed to the process for identifying and implementing improvements to price formation.

Observe the Principle of Dispatch-Based Pricing

The principle of dispatch-based pricing should be employed to guide the direction of efforts to improve price formation. The principle of dispatch-based pricing calls for the determination of clearing prices in electricity markets that are as consistent as possible with the actual operation of the transmission system by a system operator seeking to minimize the offer cost of meeting load while adhering to all standards of reliability. In the words of a market participant, dispatch-based pricing translates to the goal, "if the system operator did it [e.g., dispatched a unit or cut an export], it should be included in the pricing." The principle should be applied in day-ahead markets, real-time markets, to energy pricing, and to the pricing of market-based ancillary services.

Focus on Real-Time Pricing

In real-time, prices are determined by the dispatch decisions necessary for actual physical delivery of energy to load. As long as market participants have choices about the markets in which they are permitted to transact, they will not engage in forward market transactions that would yield a worse financial result (on an expected value basis) than simply buying or selling in the real-time market. Offers and prices in the day-ahead market and forward markets will follow and respond to those in real-time, especially where day-ahead virtual bidding is able to drive convergence. Systematic differences between day-ahead and real-time prices, like uplift, are a flag for possible problems with price formation.[139] Day-ahead and real-time markets should be based on

[139] It is not expected that day-ahead and real-time prices will converge every day; differences will occur whenever the day-ahead forecast of a real-time parameter is different from what actually happens in real-time. Also, allocation of high uplift changes to virtual supply and demand may impede the

the same models (e.g., transmission model, constraint representation and reserve and regulation constraints), except to the extent that there are differences between real-time forecasts and conditions and those expected at the time of the day-ahead market.

This is not to say that efforts to improve price formation should ignore the day-ahead market, as aspects of the day-ahead market design can affect real-time prices, such as practices that can lead to supplemental unit commitments. The suggestion is to begin with the goal of improving real-time pricing, with the expectation that this will lead to corresponding improvements in forward market pricing, rather than following the opposite approach and starting with the question of how to improve day-ahead or forward pricing.

Focus on Improving Prices, Rather than on Reducing Uplift

Excessive levels of make-whole uplift are a symptom of a problem with price formation. The only way to reduce this uplift, other than simply shifting the allocation, is to improve the underlying prices.[140] While there are changes that probably need to be made to the allocation of uplift in some ISOs, this issue will diminish in importance if uplift can be reduced through improvements to price formation.

The pricing rules for uplift and capacity should compensate for the incentives provided by real-time and day-ahead pricing of energy and ancillary services, and should be designed so as to disrupt the incentives provided by real-time and day-ahead pricing as little as possible. A goal should be to reduce the importance of uplift and capacity payments by improving the performance of the basic energy markets in all hours. Ideally, uplift and capacity payments should address only the pricing issues that remain after pursuing all possible improvements to real-time pricing.

Adopt Decision Criteria that Do Not Hinge on Quantification of Costs and Benefits

ISOs, RTOs, regulators and market participants should be wary of becoming bogged down in efforts to quantify the benefits of improvements in price formation, although it goes without saying that this is an important point for market participants: parties want estimates of how much a given change to pricing will affect their revenues or costs, and decrease uplift. Unfortunately, both the social benefits of a change in price formation and the impacts on individual market participants will often be extremely difficult to quantify.

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convergence of day-ahead and real-time prices. This is a separate problem that needs to be addressed, but does not alter the suggestion to focus on real-time prices.

140 Make-whole uplift could be hidden through changes in accounting or by the imposition of administratively penalties that impede market responses.

First, costs and benefits typically cannot be estimated in a model that simply applies new proposed pricing rules and recalculates prices for a set of bids and offers submitted for a historical dispatch. This static modeling approach is incorrect. The implementation of new pricing rules will change the bids and offers of market participants and, more importantly, will also change long run decisions about the timing, location and quantity of investments in new plants and technologies (e.g., energy storage), upgrades to existing plants (e.g. dual-fuel capability or increased ramp speed) and retirement decisions to name a few. It is very difficult to create proxies to represent market participant investment decisions in economic models. These dynamic changes to long-run market efficiency are the primary goal of improved pricing.

A second problem with studies of costs and benefits is that the results may be difficult to interpret because of subtle differences between the base and the "but for" analysis. For example, in the ISO NE it has been observed that including fast-start units in real-time price formation would likely entail paying a new form of uplift (i.e., to constrained-down units) that is currently not paid but is, instead, addressed through a series of other rules so that the costs are dispersed through other price effects and settlement accounts. Thus, a calculation of uplift after including fast-start units in real-time pricing might show an increase in uplift due to a change in the uplift calculation, but this is not really the end of the story.

ISOs, RTOs and their market participants should adopt a decision process to move forward with improvements to price formation in the absence of a precise quantification of benefits. A suggestion would be to, first, identify changes to price formation that are directionally correct, in the sense that they clearly align with the principle of dispatch-based pricing and will tend to result in prices that better reflect the actions of the system operator. Secondly, ask "why not?" and develop a concrete list of concerns about implementing the possible change. The stakeholder group tasked with evaluating the proposed change should then focus on stepping through the list of concerns to determine which are valid and whether any are insurmountable. *Thus, the suggestion is to presume that a pricing change in pursuit of dispatch-based pricing is efficient, and require a concrete and focused discussion of concerns about costs, changes to software, changes to related market rules, and impacts on market participants.*

Don't Underestimate the Value of Small Improvements

There is pressure to find quick fixes to real and perceived problems with price formation and, parties have expressed frustration that a proposed change only addresses a small part of the "problem." In evaluating the merit of these statements, it's important to consider whether they take into account the dynamic impact of changes in bids, offers and long-term investment decisions that may result over time from incremental changes to the rules governing price formation.

In some regions, the “problem” has to do with uplift paid to units with both long minimum run times and substantial minimum load costs, and is coupled with the claim that improved pricing of fast-start units will not address this problem. This may be true in the very short run, but in the long run, addressing the price suppression arising from a number of sources will create incentives for investments in existing and new capacity, as well as changes to offers, so as to reduce the frequency with which the system operator must supplementally commit units with long minimum run times. This is when an additional reduction in uplift may occur.

Monitor Uplift, But Transparency is Not a Substitute for Changes to Pricing Rules

Increased transparency is a critical part of the effort to improve price formation and reduce uplift. ISOs and RTOs can aid informed decision-making by providing information about uplift within a short time from the close of a market. Reports should contain information about any and all constraints (transmission thermal, voltage and reactive limits, reserve and regulation constraints, minimum on-line and ramping constraints, for example) that are active in the dispatch programs or that result in supplemental unit commitments or other operator interventions. ISOs and RTOs should report regularly on how much cost recovery actually comes from LMP payments versus uplift, separately identifying uplift occurring in each of its market settlements (i.e., DAM, RUC, supplemental commitments, RTM). Granular information, reported in a standard format on a regular basis, will help with assessment of the causes of the uplift and possible improvement in price formation.

While information about operator actions is critical to price formation and should be visible to market participants, transparency is not a “solution” to uplift. Market participants will not respond to information about uplift like they respond to energy prices, because changes in their behavior will not directly impact the uplift they pay; market response will not cure the problem of uplift. However, regular reporting will provide a strong incentive for system operators to carefully consider out of market actions that may result in significant uplift.