UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. RM17-3-000**

COMMENTS OF THE DEPARTMENT OF MARKET MONITORING FOR THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

The Department of Market Monitoring (DMM) for the California Independent System Operator (CAISO) files comments in the above-captioned proceeding. In this Notice of Proposed Rulemaking (NOPR) the Federal Energy Regulatory Commission (Commission) is proposing to require all independent system operators to adopt specific rules for how fast-start resources set market prices. DMM opposes requiring CAISO to adopt the proposed modifications to market-wide pricing rules.

Overview

The central issue addressed in the NOPR is not a new. The question of the optimal pricing system to use when discrete or lumpy costs result in decreasing average costs has been discussed in the economic literature for over 70 years. When discrete costs result in average costs that decrease with output, the type of two-part pricing system used by CAISO is just, reasonable and efficient. CAISO sets locational marginal prices based on marginal production costs. CAISO provides bid cost recovery payments made to compensate resources for any discrete commitment costs that are not recovered through marginal cost pricing. The Commission should not undermine marginal cost pricing by requiring CAISO to allow prices to be set by the average cost of fast-start resources.

The NOPR argues that requiring fast-start pricing in ISO spot markets will "improve price signals to support efficient investments in facilities and equipment."[1] CAISO's spot markets are designed to rely on separate capacity payments to support efficient investment in facilities. The amount, location and flexibility of capacity needed is directly incorporated in CAISO's Resource Adequacy program requirements. CAISO's overall market structure for incentivizing efficient long-run investments is just and reasonable without the adjustments proposed in the NOPR. The additional spot market revenues received by some resources because of the pricing rules in the NOPR would not have a significant impact on the decision of whether or not to make a large, long-term capital investment in a facility. However, requiring these changes would undermine the efficiency of the CAISO's spot markets by preventing optimal short-run dispatch.

Moreover, the total bid cost recovery payments associated with fast-start resources is actually very low in the CAISO markets. DMM estimates that total bid cost recovery payments for resources eligible for the pricing rules outlined in the NOPR totaled only about $13 to $22 million in 2016, or just 0.2 to 0.3 percent of total spot market energy costs in the CAISO system. This is less than the

[1] 157 FERC ¶ 61,213, *Notice of Proposed Rulemaking: Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. RM17-3-000, December 15, 2016, ¶ 35, p. 27.

estimated $24 million per year in additional spot market revenues that DMM projects resources providing flexible capacity will now receive through the CAISO's flexible ramping product implemented in November 2016. This innovative market enhancement compensates resources that provide the 15-minute and 5-minute flexibility needed to integrate large amounts of renewable generation into the CAISO market, and incorporates the value of this flexibility into real-time prices for energy.

Implementing the proposed pricing rules in the NOPR would require significant additional market design work and software changes which will be complex and costly. Developing an uninstructed deviation penalty alone represents a major market design issue, and will still be ineffective at preventing the market inefficiencies introduced by the proposed pricing rules. DMM believes the most important cost of complying with the NOPR would be the *opportunity cost* in terms of the market initiatives and software enhancements that would need to be deferred and perhaps never ultimately implemented because of the resources that would be diverted to comply with the NOPR. Delaying these initiatives will prevent significant improvements in market efficiency.

For these reasons, DMM strongly opposes requiring CAISO to adopt the proposed modifications to market-wide pricing rules.

I. CAISO's current pricing system is just, reasonable and efficient.

CAISO uses a two-part pricing structure. CAISO sets locational marginal prices based on marginal production costs. CAISO provides bid cost recovery payments made to compensate resources for any discrete or lumpy commitment costs that are not recovered through marginal cost pricing. The Commission should not undermine marginal cost pricing by requiring CAISO to allow prices to be set by the average cost of fast-start resources. Requiring such an approach for locational marginal pricing would contradict a basic principle of economic theory that has been accepted for over 70 years: a two-part pricing system is efficient when discrete costs cause average costs to decrease as a function of output.

Marginal cost pricing does not cover cost of serving load when discrete commitment costs create decreasing average costs.

The Commission summarizes the goal of the NOPR as follows: "[t]he accurate pricing of fast-start resources can advance price formation goals by more transparently reflecting the marginal cost of serving load, which will reduce uplift costs and thereby improve price signals to support efficient investments in facilities and equipment."[2] When market prices do not cover the commitment costs of the resources needed to meet load in an interval, bid cost recovery payments may need to be paid to these resources. The concern expressed in the NOPR is that electricity spot market prices should directly incorporate all of

[2] NOPR, ¶ 35, p. 27. The rest of section C provides more details that clarify the fundamental concerns the NOPR is designed to address.

the commitment costs of the resources needed to meet load because this will provide better signals for long-term investments to occur.

The NOPR contends that "some current RTO/ISO practices may fail to accurately reflect the marginal cost of serving load."[3] However, the term "marginal cost of serving load" as used in the NOPR is not the standard economist's definition of marginal cost. Under the standard economist's definition of marginal cost, prices would be "set by the offer of the resource that is dispatched up to serve the next additional MW of demand."[4] Fast-start resource commitment costs are not actually marginal costs in this traditional sense of the term because the minimum operating levels of fast-start resources cannot be dispatched to serve the next incremental or decremental MW of demand. Therefore, the commitment costs that would be included in locational prices under the NOPR are not consistent with a standard economic definition of marginal costs.

Instead, the NOPR redefines the term "marginal costs" by stating that "these [fast-start resource] commitment costs should be considered marginal costs."[5] However, a discrete cost ─ such as a commitment cost ─ that must be incurred in order to obtain a discrete quantity of electricity cannot be considered a marginal cost. The NOPR clarifies that the perceived problem with locational marginal pricing systems such as CAISO's – which set prices based on the standard economic definition of marginal cost – is that these pricing systems

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[3] NOPR, ¶ 37, p. 28.
[4] NOPR, ¶ 37, p. 28.
[5] NOPR, ¶ 39, p. 29.

"result in prices that fail to reflect the cost of the marginal resource on the system when that resource is needed to serve load."[6]

Serving the socially optimal amount of load frequently requires that fast-start resources incur large discrete costs in order to produce a discrete block of output. Under standard economic principles, when the marginal cost of an incremental MW from that resource is less than the average cost of the resource's minimum operating level, the average cost of that resource will be decreasing as a function of the resource's output.

If a resource with decreasing average costs is paid its true marginal cost for each MW of output, the resource will not be compensated for its total costs of operating over that time interval. This would be inefficient since a resource with these decreasing average costs would choose not to provide electricity to the market even though consumers value the resource's total output more than the resource's total cost of producing the output. If the market price was instead based on this resource's average cost of producing the socially optimal level of output, the resource would be compensated for its total output through the market prices.

The NOPR's characterization of this issue as prices "fail(ing) to accurately reflect the marginal cost of serving load" is imprecise and confusing given the standard economic definition of marginal costs. Therefore, in the rest of these comments, DMM uses the term *marginal cost* as it is defined under standard

[6] NOPR, ¶ 37, p. 28.

economics. We will refer to the primary concern expressed in the NOPR as being that marginal cost pricing will not cover the *average cost* of the fast-start resources when discrete or lumpy commitment costs result in decreasing average costs.

Over 70 years of economic theory supports using a two-part pricing system to address the issue identified in the NOPR.

The central issue addressed in the NOPR is not a new issue. The debate over the optimal pricing system to use when discrete costs result in decreasing average costs occurred at the highest levels of the economics establishment over 70 years ago. In 1946, the Nobel prize-winning economist, Ronald H. Coase, wrote a much-cited paper entitled, "*The Marginal Cost Controversy*," that clearly articulates this same issue.[7] Coase's paper clarifies the concept that has become a longstanding principle of standard economics: when discrete costs result in average costs that decrease with output, the "form of pricing which is appropriate is a multi-part pricing system."[8]

Coase's method of framing the issue is particularly useful since he specifically describes the concerns raised in the NOPR as justification for requiring all ISOs to use the average cost of fast-start resources in setting prices. Coase acknowledges that the "the amount paid for a product should be equal to its cost," and then goes on to explain:

> How does this general argument for basing prices on costs apply to the case we are considering – the case of decreasing average costs? The writers whose views I am considering seem to assume that the

[7] Coase, Ronald H., *The Marginal Cost Controversy*, Economica, Vol 13, 1946.
[8] Coase, p. 173.

> alternatives with which one is faced are to charge a price equal to marginal cost (in which case a loss is made) or to charge a price equal to average cost (in which case no loss is made). There is, however, a third possibility – multi-part pricing. In this section, I set out the argument for multi-part pricing when there are conditions of decreasing average costs.[9]

CAISO's method of pricing in cases of decreasing average costs because of the discrete commitment costs of fast-start resources is precisely the method of two-part pricing that Coase — and standard accepted economics theory since that time — explains is efficient. The first part of CAISO's two-part pricing system sets market prices based on the marginal costs of serving an increment or decrement of load. The second part of CAISO's pricing system uses bid cost recovery payments to compensate resources that were necessary for serving the optimal amount of load for any of these discrete costs that the resources did not recover through marginal cost pricing.

The NOPR expresses the view that the existence of bid cost recovery (or *uplift*) payments is problematic and that a goal of electricity market pricing should be to eliminate these payments. The NOPR "preliminarily find(s) that existing RTO/ISO fast-start pricing could create *unnecessary uplift payments* [emphasis added]. For example, when prices do not sufficiently reflect a marginal fast-start resource's commitment cost, the resource must be compensated through out-of-market uplift payments."[10] However, the issue of fast-start resource commitment costs is a textbook example of a situation where decreasing average costs results in marginal cost pricing not fully compensating the total costs of the

[9] Coase, p. 173.
[10] NOPR, ¶ 43, p. 31.

socially optimal production of a good. As Coase (and the papers he cites) make clear, such payments are a necessary component of the appropriate pricing system for this situation. The appropriateness of using bid cost recovery payments for compensation of fast-start resource commitment costs is based on economic principles dating back over 70 years. The CAISO's two-part pricing system is just, reasonable and efficient.

The timing of fast-start commitments does not make start-up and minimum load costs marginal costs.

The NOPR provides a brief justification for why fast-start resource "commitment costs should be considered marginal costs"[11] and should be included in setting market prices. The justification provided in the NOPR is that fast-start resources incur the commitment costs "at short notice to meet some system condition or market need over a short time period." This justification for considering fast-start resource commitment costs as marginal costs rests on the fact that the decision to incur the commitment cost is made at roughly the same time as the decision on how much incremental energy to use to meet the optimal demand in a time period. In other words, the decision to incur these commitment costs is not made years in advance like most other discrete costs incurred to support more than a marginal increment of energy production. The decision to

[11] NOPR, ¶ 39, p. 29.

incur a discrete commitment cost is made contemporaneously with the decision of how much load to consume and how much marginal energy to produce.

However, fast-start resource commitment costs are clearly discrete costs that fit neatly into standard economic justifications for uplift payments. The time period in which the discrete commitment costs occur does not negate the logic that justifies a two-part pricing system as more efficient than average cost pricing in the situation of falling average costs.

In the example Coase uses to discuss the appropriateness of two-part pricing in the situation of falling average costs, he intentionally uses a discrete cost that is incurred in the same time period as the consumption decision is made. The discrete costs being incurred contemporaneously with the consumption and marginal production decisions actually helps to simplify more complicated issues surrounding two-part pricing.[12] Therefore, fast-start resource commitment costs do not represent a special scenario that warrants overturning what has been a standard economic solution to falling average costs for over 70 years. On the contrary, fast-start resource commitment costs are a textbook example of a discrete fixed cost incurred contemporaneously with consumption and marginal production decisions, so it is clearly appropriate to recover these commitment costs through multi-part pricing.

[12] Coase explains that the more complicated issues surrounding two-part pricing systems involve how the costs should be allocated. Much of his paper is devoted to discussing this issue. We discuss the cost allocation issue in a later section of these comments.

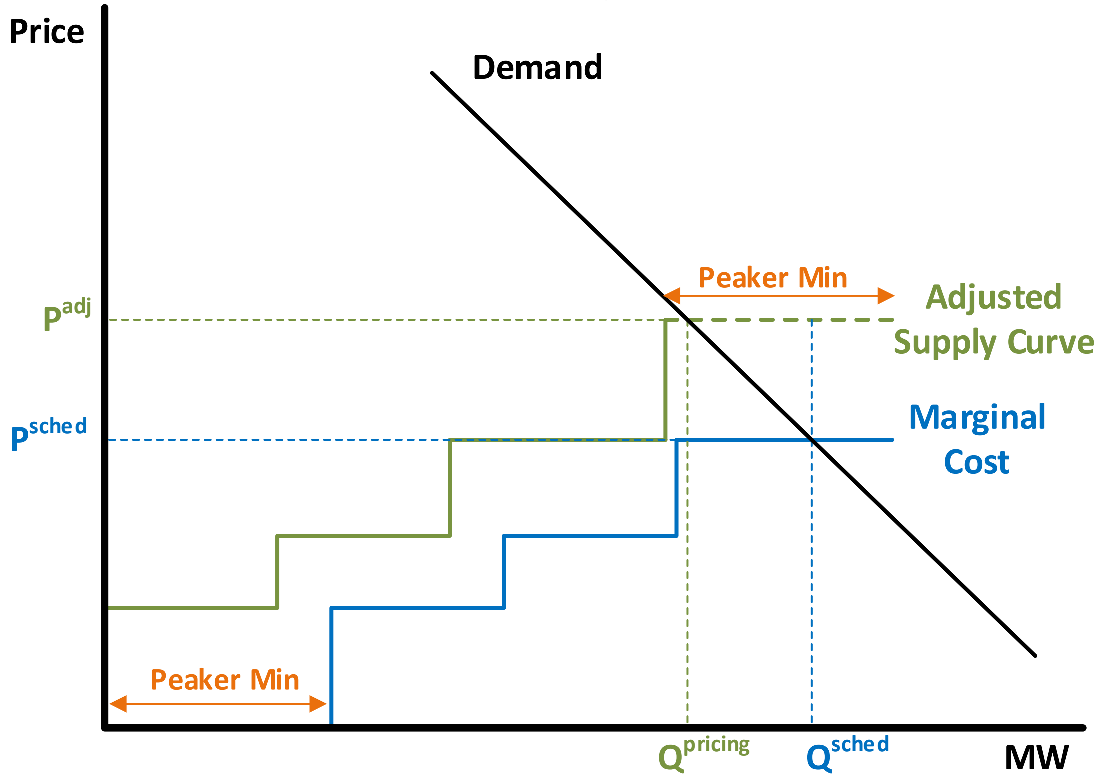
Allowing the average cost of fast-start resources to set price will create inefficiencies.

Requiring CAISO to directly incorporate commitment costs in locational marginal prices for energy would undermine the efficiency of CAISO's spot markets in several ways.

Figure 1 illustrates an example of schedules and prices in the scheduling and pricing runs that would occur under the pricing rules outlined in the NOPR. The blue stepwise curve in Figure 1 shows the supply curve that is used in the scheduling run. It is composed of the marginal costs of resources. The market optimization dispatches a fast-start peaking unit to its minimum output level. The green curve illustrates the adjusted supply curve that would be used in the pricing run under the NOPR's preliminary fast-start resource pricing proposal. The supply curve used in the pricing run has been adjusted so that the minimum output range of the fast-start peaking unit has a price equal to the average cost of the resource's commitment costs over the minimum output range. The black line represents the demand curve.

In the scheduling run, the unit's commitment costs are discrete sums that are considered by the optimization when deciding whether or not to commit the resource. These commitment costs therefore cannot be represented as marginal costs. Under the assumption that suppliers and consumers bid their true marginal cost and marginal value into the market, the scheduling run produces energy supply and demand schedules that maximize market surplus for consumers and suppliers.

Figure 1. Example of supply and demand curves under NOPR fast-start pricing proposal



The total area in Figure 1 above marginal cost (the blue line) and below marginal value (the black line) is maximized. The total quantity demanded is Q^{sched} where surplus is maximized.

The scheduling run price is the price at which marginal cost equals marginal value. The scheduling run price is incentive compatible. This means that no generator or participating load has an incentive to deviate from its dispatch at the scheduling run price. No uninstructed deviation penalty is needed to incentivize generation and participating load to follow its dispatch. The scheduling run price is the marginal cost of supplying the optimal dispatch and the marginal value that the final increment of load receives from consuming the optimal dispatch.

The NOPR proposes to require CAISO to implement a pricing run that uses adjusted bids for fast-start resources. The true marginal costs of fast-start resources would be changed to average costs. Also, the minimum output range of these resources will be modeled as being fully dispatchable as opposed to being treated as a discrete commitment decision. The pricing run price is the price where the demand curve intersects this adjusted supply curve. Individual resource dispatches and the total quantity demanded will be different in the pricing run than in the scheduling run. However, pricing run dispatches will not be the binding schedules sent to resources. The scheduling run dispatches will be the binding schedules. These binding scheduling run dispatches will be settled using the adjusted prices from the pricing run.

The adjusted price from the pricing run is not consistent with the scheduling run dispatches and quantity demanded. At the adjusted prices from the pricing run, the generator with marginal cost P^{sched} would want to produce at its full output rather than at the socially optimal dispatch level the generator receives from the scheduling run. Similarly, electricity consumers would want to consume less power than the socially optimal quantity determined in the scheduling run. This is because the adjusted price from the pricing run that consumers have to pay is greater than their marginal willingness to pay at the socially optimal consumption level determined in the scheduling run (Q^{sched}). The adjusted price from the pricing run is not incentive compatible with the binding schedules determined in the scheduling run.

Uninstructed deviation penalties will not solve the incentive problems caused by average cost pricing.

The NOPR acknowledges that inefficient incentives will be created for resources to deviate from their dispatch instructions by the preliminary fast-start pricing proposal. The NOPR assumes that these inefficiencies can be remedied by "market rules that address the potential for over-generation due to deviations from dispatch instructions."[13] However, a successful uninstructed deviation penalty that deters generation resources and participating load from deviating from dispatch instructions will instead undermine the incentives for generators to bid their true marginal cost and for load to bid its true marginal value.

Specifically, under the NOPR proposal, a supply resource dispatched to produce at a level where its marginal costs are below the adjusted price it receives from the pricing run will have the incentive to bid below its true marginal cost. This would allow the supply resource to receive a higher dispatch in the scheduling run and earn a greater profit than if the resource bid its true marginal cost. Similarly, a participating load resource would have the incentive to bid below its true marginal value in order to avoid getting dispatched to consume power at a price above its willingness to pay for that power.

Therefore, the NOPR proposal to create dispatches that are not incentive compatible with settlement prices and to force resources to follow those dispatches through an uninstructed deviation penalty will undermine the incentive for supply resources to bid their true marginal cost and for load resources to bid their true marginal value. If resources do not have the incentive to bid their true

[13] NOPR, ¶ 54, p. 39.

marginal costs and marginal values, the optimization will not know entities' true costs and values. As a result, the scheduling run dispatch will not be the dispatch that maximizes consumer and supplier surplus. The NOPR's preliminary proposal will therefore undermine the Commission's number one goal for price formation — it will undermine the efficiency of the spot market dispatch.

In addition to being ineffective at preventing market inefficiencies, developing an uninstructed deviation penalty represents a major market design issue in and of itself. Development of such penalties have proven problematic in the past for the CAISO because of the concern that generators may in some cases be unfairly charged for deviations beyond their control. This alone represents a major implementation challenge and cost associated with the NOPR in the CAISO market. As discussed later in these comments, DMM is particularly concerned about the *opportunity cost* of the foregone savings and market efficiencies from other initiatives that would need to be deferred or eliminated in order to implement the NOPR and an uninstructed deviation penalty.

Bid cost recovery allocation issues can be addressed without undermining marginal cost pricing.

As explained above, mainstream economic literature and thought resolved long ago that a multi-part pricing system is the appropriate pricing structure in the situation of decreasing average costs. The marginal production cost should set the price of goods, and other payments should be used to compensate suppliers for any discrete costs not recovered through the marginal cost pricing. However, there is not a universally accepted answer to the issue of how to allocate the costs of these additional payments among consumers.

As Coase explains, the allocation of the uplift cost is straightforward in situations when the discrete costs are attributable to individual consumers. When discrete costs cannot be attributed to individual consumers, as is the case with fast-start resource commitment costs, the issue of how to allocate the uplift costs is more complicated. Therefore, CAISO's general pricing system of using marginal costs to set prices and bid cost recovery to compensate fast-start resources for commitment costs they did not recover through market prices is without question just and reasonable.

However, CAISO's current method of allocating bid cost recovery payments to load based on the volume of energy consumed each hour may indeed create some inefficiencies. But inefficiencies in the CAISO's method of allocating the bid cost recovery payments is a separate issue from the question of whether or not a two-part pricing system is appropriate for compensating resources for unrecovered commitment costs. Potential improvements to CAISO's method of allocating bid cost recovery payments can be addressed outside the context of the fast-start pricing NOPR proceedings and without undermining CAISO's efficient marginal cost pricing paradigm.

Moreover, the total bid cost recovery payments associated with fast-start resources are actually very low in the CAISO markets. As explained later in these comments, DMM estimates that total bid cost recovery payments for resources that might be eligible for the pricing rules outlined in the NOPR totaled only about $13 to $22 million in 2016, or just 0.2 to 0.3 percent of total spot market energy costs in the CAISO system.

II. CAISO's market design for incentivizing investment is just and reasonable.

CAISO's markets are designed to have a spot market to create the most efficient scheduling and dispatch of resources, and to rely on separate capacity payments to support efficient investment in facilities. This section explains how this market design structure is just and reasonable. It would be inappropriate to undermine the efficiency of CAISO's spot markets in an attempt to try to utilize spot market prices to drive long term investment decisions. The "enhancements" to spot market prices that would result from the NOPR would have little impact on investment decisions. Attempts to improve efficient investment in facilities in CAISO need to be done through the design of the capacity procurement programs, not the spot market.

The efficiency of CAISIO's spot markets should not be undermined in an attempt to improve investment in facilities and equipment.

The NOPR argues that requiring fast-start pricing in ISO spot markets will "improve price signals to support efficient investments in facilities and equipment."[14] The CAISO's market structure is not designed to rely on spot market revenues to support efficient investments in facilities.

CAISO runs a spot market to create the most efficient dispatch over the time horizon of the particular spot market run given current system resources, conditions, and reliability constraints. Spot market prices are a mechanism for incentivizing the facilities that currently exist to participate in the market and to perform in the way that maximizes consumer and supplier (total) surplus while

[14] NOPR, ¶ 35, p. 27.

maintaining grid reliability. The two-part pricing structure of CAISO's spot markets is designed to ensure that all resources receive payments to at least cover the costs they incur over the spot market's time horizon. Resources whose costs over the spot market time horizon are less than their spot market revenues will earn a short-run profit. This profit is the resource's share of the maximized short-run total surplus.

The CAISO spot market is not designed to ensure that resources critical to short-run efficiency and reliability recover their long-run capital costs. CAISO's spot markets have design elements — such as bid caps and local market power mitigation — to explicitly limit spot market clearing prices so that these prices remain close to the short-run marginal cost of serving electricity demand. The CAISO spot market's two-part pricing system is designed to compensate resources for their commitment costs and incremental energy production costs. These short-run costs have nothing to do with the long-run capital investment costs needed to support the construction of the facilities that are socially optimal in the long-run. The short-run profits earned in the spot markets by resources whose short-run costs are less than spot market prices cannot be relied upon to incentivize the efficient long-run investment in facilities and equipment.

Instead, CAISO's spot markets are designed to rely on separate capacity payments to support efficient investment in facilities. Currently, CAISO markets are designed to rely on capacity procurement programs administered by Local Regulatory Authorities, such as the CPUC's Long-term Procurement and Resource Adequacy programs. Attempts to improve efficient investment in facilities in CAISO can be achieved through enhancements to these capacity procurement programs. Resource Adequacy program requirements are set to ensure that the total amount, location and flexibility of capacity that is built and procured is sufficient to meet CAISO system needs.

CAISO's overall market structure is composed of a spot market to create the most efficient short run dispatch and a separate market for the capacity payments that support efficient investment in facilities. Given this overall market structure, it would be inappropriate to undermine the efficiency of CAISO's spot markets by forcing the creation of spot market price signals that are intended to support efficient investment in facilities but that will actually prevent the spot market from achieving the most efficient current dispatch. Changes to the spot market design should continue to focus on modeling and pricing enhancements that will increase the efficiency of the current dispatch in meeting the reliability constraints that will become increasingly more complex with increased penetration of variable renewable and demand-side resources.

The NOPR proposal will be ineffective in improving investment in facilities and equipment.

The NOPR proposal would be unlikely to significantly impact capital investment decisions. Resources in CAISO only recover a portion of their total long-run fixed costs through spot market profits. A new resource in CAISO would need to rely on capacity payments in order to recover most of its investment costs in facilities and equipment. For example, each year DMM analyzes the extent to which revenues from spot markets would contribute to the annualized fixed costs of typical new gas-fired generating resources. For a new combustion turbine unit, net operating revenues earned from CAISO spot markets in 2015 were only an estimated $40/kW-year in Southern California, compared to potential annualized fixed costs of $176/kW-year.[15]

With resources receiving only 20 to 25 percent of investment costs from spot market profits, small and unpredictable changes in spot market prices such as those proposed in the NOPR would be unlikely to significantly impact the decision of whether or not to make a large, long-term capital investment in a facility. Regardless of whether or not the NOPR proposal is implemented in CAISO, resources will continue to make their long-term capital investment decisions based on capacity payments they may receive in capacity markets, not spot market revenues. Small potential increases in spot market revenues may decrease the size of the capacity contract a resource would require before making a long-term investment decision, but they would not likely be pivotal in the decision of whether or not to make the investment.

The adjusted price signals in the NOPR may not even go to the intended resources or at the appropriate times in CAISO.

The adjusted price signals proposed in the NOPR may not go to the intended resources or at the appropriate times in CAISO. This is because the CAISO's short-term unit commitment (STUC) software optimizes over a multi-hour time horizon. Under the NOPR proposal, situations will arise in which fast-

[15] *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2016, p. 55: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

start resource commitment costs will be allowed to set prices in the wrong time intervals and grid locations.

For example, assume a fast start resource will be necessary to relieve congestion on a local area constraint in hour 10. The need to commit this unit is first identified by the STUC software in the four-hour unit commitment period that starts with hour 8 and ends with hour 11. If the resource has a relatively high start-up cost, once the need to commit the unit is identified the discrete start-up cost becomes a *sunk* cost. The optimal solution may then be for the resource to be committed before hour 10.

The need to commit the resource in hour 10 for a local constraint may make it economic to also commit the unit in hour 9. This is because the start-up cost of the local resource in hour 9 is effectively $0, so minimum load cost and incremental energy costs of the local resource may appear less expensive relative to the full start-up, minimum load, and incremental energy costs of system resources. The commitment of this local resource in hour 9 results in other system resources, outside of the local area in which this resource is needed, not being committed.

Under this scenario, the NOPR would allow the commitment costs of the local resource to set a high system price during hour 9. The local resource will set a high system price even though it has only become “necessary for meeting load” in hour 9 because its commitment for hour 10 caused other resources to not be committed in hour 9.

Moreover, since the proposed pricing rules in the NOPR would not allow the local unit's commitment costs to set prices beyond the resource's one-hour minimum run time, the unit's commitment costs will not contribute to elevating the price in the local constrained area in hour 10. As a result, the price in the local constrained area where the local resource is actually needed in hour 10 — and where the NOPR proposal contends that higher price signals may be beneficial — is never higher than the price in the wider CAISO system. In other words, the locational price signal that the NOPR proposal wishes to apply to one specific area during hour 10 would instead be applied to a larger area during hour 9.

Spot market adjustments proposed in the NOPR will have little impact on the efficiency of investments in facilities in CAISO. CAISO's spot markets are designed to achieve the optimal short-run dispatch. Improvements in the efficiency of investments in CAISO facilities and equipment can be accomplished by redesigning CAISO's capacity market structure. Therefore, CAISO's overall market structure for incentivizing efficient long-run investments is just and reasonable without the adjustments proposed in the NOPR. It would be inappropriate to force changes to CAISO's spot markets that would interfere with the ability of CAISO's spot markets to achieve the optimal short-run dispatch.

III. Bid cost recovery payments

The Commission seeks to support the fast-start pricing rules in the NOPR based on a "preliminary finding that existing RTO/ISO fast-start pricing could create unnecessary uplift payments." The NOPR contends that uplift payments are less transparent than compensating units through market prices and that since the cost of uplift payments are allocated more broadly [to other participants] this can "mute the investment signals provided by prices over time."[16]

As previously explained in these comments, the uplift payments referenced in the NOPR are actually *bid cost recovery* payments made to fast-start resources as part of a two-part tariff that is efficient in energy markets with declining average costs. Under the Commission's proposal, fast-start resource commitments would still be made by the market software based on the objective of minimizing the sum of accepted commitment cost bids plus accepted energy bids, taking into consideration each resource's minimum operating time. The "enhanced energy offer" described in the NOPR essentially rolls these same bid costs into a single average cost bid used in the proposed pricing run. Fast-start resources whose "enhanced energy offer" sets the price in the pricing run would not be compensated any more than under the current marginal cost pricing approach. Rather, the source of the payment would simply shift from bid cost recovery to energy market payments.

[16] NOPR, ¶ 43, p.31.

Since the NOPR suggests that the Commission views bid cost recovery payments for fast-start resources as an undesirable result of the current marginal cost pricing approach, DMM is providing the following summary of the actual magnitude of bid cost recovery payments to fast-start resources in the CAISO markets. Results of this analysis show that in the CAISO's markets, bid cost recovery payments to fast-start gas-fired resources are actually quite low.

In the day-ahead market, fast-start resources received about $0.6 million in uplift payments in 2016, or about 5 percent of the total day-ahead bid cost recovery payments for the year. In the real-time market, fast-start resources received about $12.7 million or 22 percent of total real-time bid cost recovery payments.[17] Approximately $3 million of this amount is allocated to a single resource with a limitation of one daily start per day. Our analysis has shown that much of this resource's bid cost recovery payments were related to the daily start-limitation, rather than its fast-start characteristics. Based on this analysis, DMM estimates total uplift related to fast-start resources was $13.3 million or about 18 percent of total bid cost recovery payments.[18] This represents about 0.2 percent of the total wholesale costs within the ISO.

DMM also examined bid cost recovery payments received by multi-stage resources (e.g. combined cycle resources) which have one or more configuration

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[17] This analysis includes gas resources that can start-up within 10 minutes and have minimum run times of an hour or less.

[18] It is difficult to parse this out in the data, so the $12.7 million should be considered the upper estimate of bid cost recovery payments due to fast-start unit commitment costs.

that can transition from a lower configuration to higher configuration in 10 minutes or less and also have minimum run times of one hour or less. The NOPR on fast-start resources does not explicitly indicate that resources with transitions would be included in the Commission proposed fast-start pricing rules. Including all bid cost recovery payments to these units overstates the amount that might be associated with ”fast-transition” configuration since the ISO allocates the bid cost recovery for multi-stage generating units at the resource level (rather than for each different configuration of the resource). In some cases, configurations of the resource that are not fast-start are the source of the bid cost recovery payments and that these payments are not associated with a fast-start transition configuration of the resource.

Including bid cost recovery payments for this type of multi-stage resource increased the day-ahead uplift payments from $0.6 million to about $3 million (24 percent) of total day-ahead uplifts and from $12.7 million to $19.6 million (33 percent) of total real-time uplifts. This increases the potential total bid cost recovery payments in 2016 from $13.3 million to $22.6 million or about 31 percent of total uplift payments. This represents about 0.3 percent of the total wholesale costs within the ISO. Thus, DMM believes that the amount of bid cost recovery payments for fast-start resources provides further evidence that the pricing issue the NOPR is intended to address is not a significant source of inefficiency or problem in the CAISO markets.[19]

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[19] Total uplift payments in general have declined over the last few years, dropping from $92 million in 2015 to $72 million in 2016. These uplifts were the lowest since 2010.

IV. CAISO markets incent flexibility needed to integrate renewables

Under the fast-start pricing rules, fast-start resources would not be compensated any more than under the current pricing rules. Rather, the source of the payment would simply shift from bid cost recovery to energy market payments. However, resources that are less expensive than the market clearing price would be paid substantially more through a higher market clearing price. This transfer of spot market surplus from consumers to producers would likely be substantially larger than the size of current bid cost recovery payments to fast-start resources. Thus, we do not view this proposal as necessarily increasing revenues for fast-start resources, but rather as a modification that would increase spot market revenues for less expensive resources including resources that may be base load or slower ramping.

As explained in a prior section of these comments, these additional payments to lower cost and slower ramping resources would not be significant enough to actually drive investment, as suggested in the NOPR. Nor are the resources that may receive these increased spot market revenues the kind of resources that can provide the kind of flexibility needed to integrate the increasing amount of renewable generation being added to the CAISO system.

To address the need for flexibility, the CAISO continues to refine resource adequacy requirements to ensure that the total amount, location and flexibility of capacity that is built and procured is sufficient to meet CAISO system needs.

The CAISO has also implemented an innovative flexible ramping product that directly compensates resources that provide the 15-minute and 5-minute flexibility needed by the CAISO system. This innovative market also incorporates the trade-off between providing this flexibility versus energy directly in locational marginal prices. To the extent short-start resources can provide the 15-minute and 5-minute flexibility needed by the CAISO system, these short-start units will receive additional spot market revenues through flexible ramping product payments and higher locational marginal process.

DMM projects that resources providing flexible capacity will receive about $24 million in direct payments through the CAISO's flexible ramping product implemented in November 2016.[20] Interestingly, this exceeds the $13 million to $22 million in bid cost recovery payments that might be "eliminated" by the pricing rules proposed in the NOPR. CAISO's new flexible ramping product may reduce bid cost recovery payments for fast-start resources. This is because fast-start resources can receive flexible ramping product payments even when not dispatched and can earn higher prices when dispatched during intervals when the market prices are increased due to the opportunity cost of providing flexible ramping product.[21]

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[20] DMM projects total flexible ramping product payments of $24 million based on a simple extrapolation of payments made over the first four months since the flexible ramping product was implemented in November 2016.

[21] The flexible ramping product can also reduce bid cost recovery payments by pricing flexibility in the binding market interval. This will reduce bid cost recovery payments because this flexibility was previously only "priced" in a non-settled advisory interval. Therefore, constraints that were not settled is CAISO markets this type of bid cost recovery, not decreasing average costs.

V. Market power mitigation

The NOPR seeks comment on whether allowing fast-start resources to set prices (based on average costs including commitment cost) could result in the exercise of market power.[22] Addressing implementation challenges that involve market power mitigation is an important part of the design of any changes to price setting procedures in the ISO markets. Changes to mitigation that may be needed will depend on the exact implementation plan for any pricing changes. At this time, DMM has identified a variety of issues that will need to be addressed by modifying the market power mitigation rules and software. The need to further analyze and address issues related to market power mitigation represents another significant implementation issue associated with the NOPR.

The biggest design and implementation challenge related to market power mitigation may stem from using average costs in the mitigation procedures. The *enhanced bid* described in the NOPR is composed of three parts: energy bids, start-up bids, and minimum load bids. A key question is exactly when and how each of these bid components would be subject to mitigation in order to retain the integrity of the CAISO's current market power mitigation procedures.

Regardless of how different bid components are mitigated, the market power mitigation procedures will need to calculate and retain much more information than before to effectively mitigate market power. In addition to adding in commitment costs for some resources, the software would need to track commitment times and minimum operating times for these resources in order to determine when to revert to

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[22] NOPR, ¶ 64, p. 46.

using actual marginal energy bid costs for these resources. Any future changes to commitment cost bids or mitigation will also need to work within the more complex framework designed for fast-start pricing.

Although it may be possible to address all these issues through software enhancements, this clearly adds to even more complexity to the overall market design and software effort needed to implement the NOPR. As discussed later in these comments, DMM is particularly concerned about the *opportunity cost* of the foregone savings and market efficiencies from other initiatives that would need to be deferred or eliminated in order to implement the NOPR and an uninstructed deviation penalty.

VI. Definition of fast-start resources

The Commission is seeking comments on the proposed definition of fast-start resources.[23] As previously explained in these comments, the fast-start pricing approach described in the NOPR would decrease market efficiency if implemented in the CAISO's markets. Therefore, if the CAISO is required to implement the Commission's fast-start pricing proposal, the detrimental impacts on efficiency would be increased if the definition of fast-start resources in the NOPR was expanded in any way.

Different resource types present many different implementation issues.

In the event the Commission requires the CAISO to implement the NOPR, DMM has identified a number of issues that would need to be addressed before

[23] NOPR, ¶ 48, p. 35.

implementing fast-start pricing rules. These issues are based on DMM's review of data on resource characteristics currently registered in the CAISO's Master File.

First, there are a series of different fuel and technology types in addition to natural gas that have submitted start-up times of 10 minutes or less and minimum run times of an hour or less to the ISO Master File. Many wind, solar, storage (including battery), and demand response resources may potentially qualify based on their reported start-up and minimum run time characteristics. If the CAISO is required to implement the fast-start pricing rules in the NOPR, it will be important to more carefully explore how these other types of resources differ from natural gas-fired generation.

CAISO start-up and minimum load characteristics of non-gas resources, including demand-side resources, may be very difficult to verify empirically, and may be determined by the scheduling coordinator more as a matter of preference than as an actual physical constraint. Demand response resources are currently excluded from local market power mitigation, but are often located in load pockets. More detailed consideration would be needed to assess what additional restrictions or provisions would be needed if demand response resources are eligible for treatment as fast-start resources ─ as proposed by the NOPR ─ that can cause local prices to be set at a bid that cannot be mitigated.

Second, unlike many other ISO and RTO markets, the California ISO has the capability to explicitly optimize the dispatch of multi-stage generating units, which are units that have different sets of configurations ─ such as combined cycle resources. As part of the market optimization, some multi-stage resources can transition from one configuration to another configuration within 10 minutes and also have a reported minimum run time in that configuration of less than an hour. While technically not start-up costs, transition costs can sometimes be considered analogous to start-up costs. Configurations of multi-stage generating units can also have very high minimum load levels and costs (e.g. the minimum operating level of a large combined cycle unit in a 2x1 configuration can be equal or above the unit's output in a 1x1 configuration). Thus, DMM believes treatment of such multi-stage generating units would need to be further considered and clarified.

Third, there are currently some resources in the California ISO markets that have minimum run times less than 15 minutes, with some even having reported minimum run times of zero minutes. Given that the CAISO currently commits real-time resources in its 15-minute market, it is unclear to DMM how the "amortization" of commitment costs would be done for resources that have minimum run times that are less than the 15-minute commitment interval if the Commission requires the CAISO to implement fast-start pricing. In these cases, it seems that the period over which commitment costs are "amortized" for inclusion into bid prices would need to be no less than the period covered by the commitment interval. For instance, for a 15-minute commitment interval, fast-start resources with minimum run times less than 15 minutes would recover costs over 15 minutes.

Fourth, in reviewing actual minimum load, start-up and incremental energy bids, DMM notes that there are cases where bids associated with fast-start pricing as proposed by the Commission could exceed the current price cap of $1,000/MWh. With FERC Order No. 831, the price cap shifts to a soft cap at $1,000/MWh and a hard cap of $2,000/MWh.[24] DMM believes that in no case should the fast-start pricing exceed the hard price cap. Moreover, we believe that justification would need to be presented and reviewed in order to exceed the soft cap under these pricing rules to be compliant with FERC Order No. 831. We believe that this issue requires further consideration and clarification.

CAISO would need to establish better verification of resource characteristics.

DMM also notes that there are a significant volume of resources that currently would not qualify as fast-start resources as it is defined in the NOPR, but might be classified as a fast-start resource if these criteria are changed or the units' operating characteristics are changed. For example, this incudes resources that can start-up in less than 15 minutes and have minimum run times of an hour, or resources that can start-up in less than 10 minutes but have run times of two hours. Given the significant differences in pricing afforded to fast-start resources, participants would have a strong incentive to seek to reclassify their resources in ways that they may not be capable of performing.

[24] 157 FERC ¶ 61,115, *FERC Order No. 831: Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. RM16-5-000, November 17, 2016: https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-2.pdf.

Thus, if the Commission requires the CAISO to implement the fast-start pricing rules in the NOPR, DMM notes that the CAISO would need to carefully scrutinize and verify any changes that are made in these resource characteristics. Current CAISO market rules require that unit constraints registered in the Master File reflect the actual physical characteristics of each resource.[25] Resource constraints such as minimum start times and minimum operating times should be very static and not subject to change unless there is an actual change to the resource that changes these operating constraints. The NOPR would increase the importance of ensuring that the CAISO establishes a process for scrutinizing and verifying any such changes.

VII. Potential market inefficiencies associated with virtual bidding

In the CAISO markets, fast-start resources are often committed to address very short-term ramping needs in the real-time market rather than capacity needs. This ramping need is anticipated to grow as more renewable generation is added to meet California's 50 percent renewable goal by 2030. However, when hourly virtual bids clear in the day-ahead market, these virtual bids cannot directly affect the same ramping constraints that occur in the real-time market. This is because the day-ahead market optimizes on an hourly and not a 15-minute interval basis. The day-ahead market has more flexibility to alter dispatch levels and commitments simultaneously over a 24-hour time horizon as it has

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[25] Section 4.6.4 of the CAISO tariff contains a general rule requiring that "[a]ll information provided to the CAISO regarding the operational and technical constraints in the Master File shall be accurate and actually based on physical characteristics of the resources . . . ."

more resources available to start than the real-time market, which greatly reduces the effects of ramping constraints on day-ahead prices. In the California ISO markets, virtual bids accepted in the day-head market on an hourly basis are settled based on an hourly average of 15-minute real-time market prices that can be affected by short-term ramping limitations.

When short-term ramping constraints bind and cause high prices in the real-time market, clearing virtual bids may only result in wealth transfers rather than increased efficiency. For instance, short-term ramping constraints in real-time can cause real-time prices to be higher, which in turn makes virtual demand more likely to bid into and clear in the day-ahead market. While this virtual demand may increase day-ahead prices, Commission staff from the Division of Analytics and Surveillance and an MIT researcher found that it is often the case that "…this isn't actually doing anything productive in terms of improving the efficiency of Day-Ahead scheduling. The extra generation that is receiving [sic] Day-Ahead award is generation that cannot actually provide any fast ramp capability. So this extra generation is not going to reduce any costs to the system."[26]

DMM believes that similar conditions would likely arise if fast-start resources were to set higher prices based on the proposed pricing rules for the

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[26] Parsons, John E., Cathleen Colbert, Jeremy Larrieu, Taylor Martin and Erin Mastrangelo, *Financial Arbitrage and Efficient Dispatch in Wholesale Electricity Markets*, MIT Center for Energy and Environmental Policy Research, Working Paper, February 2015, p. 44: http://www.mit.edu/~jparsons/publications/20150300_Financial_Arbitrage_and_Efficient_Dispatch.pdf.

periods of their minimum run time. If fast-start resources set high prices, the real-time pricing signal to virtual bids would be to increase virtual demand in the day-ahead market and potentially increase physical supply commitment. However, additional capacity may not be in fact needed for the entire hour and that this added capacity may not be capable of providing needed ramping services in the real-time market. This could then lead to significant market inefficiencies and unjust transfers to virtual bidders without converging prices.

For example, in our 2012 Annual Report, DMM found that most virtual bidding net revenues were on virtual demand positions, which anticipate lower prices in the day-ahead market and higher prices in the real-time market. These virtual demand positions benefited from short-term ramping limitations on a system or regional basis. We noted that "although upward ramping capacity was insufficient during less than 1 percent of hours each quarter, these hours accounted for all net revenues for virtual demand."[27] Moreover, the value captured during these periods were sufficient to exceed losses when day-ahead prices were higher than real-time prices and that "during the other 99 percent of hours when sufficient ramping capacity was available, virtual demand bids were highly unprofitable."[28]

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[27] *2012 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2013, p. 110: http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

[28] *2012 Annual Report on Market Issues and Performance*, p. 111.

Based on our analysis of fast-start resources and historic bid patterns, DMM would anticipate that the Commission's proposed fast-start pricing rules could significantly increase in the frequency of higher real-time prices related to ramping limitations. This would give virtual bidders the incentive to place virtual demand positions that may not result in improving commitment, but may result in inefficient prices in many hours.

VIII. Implementation costs

The NOPR recognizes that the proposed changes will require significant software changes, which can be complex and costly, and seeks comment on the cost, time and any additional considerations relating to the implementation of the proposed changes.[29] DMM has highlighted numerous design issues in these comments that would need to be addressed concerning virtually every aspect of the proposed fast-start pricing rules prior to even beginning the software and process changes needed for implementation.

The NOPR estimates the cost of complying with a Final Rule at $291,042 per respondent.[30] DMM believes this is ridiculously low for the CAISO market. DMM has requested that the CAISO also address the issue of implementation cost, complexity and resources it its comments on the NOPR.

DMM believes the most important cost of complying with the NOPR would be the *opportunity cost* in terms of the market initiatives and software enhancements that would need to be deferred and perhaps never ultimately

[29] NOPR, ¶ 65, p. 46.

[30] NOPR, ¶ 72, p. 51.

implemented due to the resources that would need to be diverted to complying with the NOPR. Delaying these initiatives will prevent significant improvements in market efficiency.

As part of the CAISO's stakeholder initiative ranking process, the CAISO prioritizes a wide range of initiatives that can improve market efficiency and are desired by stakeholders. The CAISO then selects a very limited number of these initiatives which the CAISO can add to its existing schedule of potential market enhancements. This year the CAISO could only select six new initiatives that it could seek to begin in 2017.[31] DMM fears that implementing the fast start pricing NOPR could delay one of more of these very valuable initiatives.

In addition to the initiatives considered in the CAISO's most recent stakeholder initiatives ranking process, the CAISO is also facing the need to implement provisions in Order 831 regarding price caps and cost verification of bids in excess of the $1,000/MWh.[32] DMM expects Order 831 to have minimal or no direct impact or benefits in the CAISO markets, since gas cost have never reached levels that could justify $1,000/MWh bid prices. However, complying with Order 831 will take a substantial effort in terms of a stakeholder process,

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[31] Cook, Greg, *2017 Policy Initiatives Roadmap*, Presentation at Board of Governors Meeting, February 16, 2017, p. 6: http://www.caiso.com/Documents/Briefing_PolicyInitiativesRoadmap-Presentation-Feb2017.pdf.

[32] 157 FERC ¶ 61,115, *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. RM16-5-000, Order No. 831, November 17, 2016: https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-2.pdf.

policy development and software implementation. In addition, the Commission is also proposing to mandate potential changes in uplift allocation.[33]

One key initiative DMM fears will be delayed by the additional rules being mandated by the Commission is the CAISO's recommendations for reform of the congestion revenues rights auction. This issue cost transmission ratepayers another $47 million in 2016 and over $560 million since 2012.[34] As part of the CAISO's 2017 roadmap, the ISO planned to begin to assess this issue in the second half of 2017.[35] Any further delay addressing this issue will just continue to cost transmission ratepayers tens or hundreds of millions of dollars.

Another key initiative DMM fears will be delayed significantly by the various market design changes being mandated by the Commission is the CAISO's efforts to modify the market software and processes to enhance the efficiency and flexibility for commitment costs and energy bids.[36] DMM believes a very important enhancement needed as part of this initiative is to modify the market software and processes to update gas price indices used to calculate

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[33] 158 FERC ¶ 61,047, *Notice of Proposed Rulemaking: Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. RM17-2-000, January 19, 2017: https://www.ferc.gov/whats-new/comm-meet/2017/011917/E-1.pdf

[34] Eric Hildebrandt, Director, Market Monitoring, *Memorandum to ISO Board of Governors, Re: Department of Market Monitoring update*, February 9, 2017, pp. 4-5. http://www.caiso.com/Documents/Department_MarketMonitoringUpdate-Feb2017.pdf.

[35] 2017 Policy Initiatives Roadmap Presentation, p. 6: http://www.caiso.com/Documents/Briefing_PolicyInitiativesRoadmap-Presentation-Feb2017.pdf.

[36] 2017 Policy Initiatives Roadmap Presentation, p. 6: http://www.caiso.com/Documents/Briefing_PolicyInitiativesRoadmap-Presentation-Feb2017.pdf.

real-time market bid caps at the start of each operating day based on observed same day gas prices. Currently, commitment cost and energy bid caps for the real-time market used in local market power mitigation are based on next day prices.[37] This represents a very important enhancement to the CAISO real-time market.

DMM believes it is highly likely that one or more of the very limited number of "discretionary" initiatives the CAISO hopes to address over the next few years will certainly need to be delayed or deferred indefinitely if the CAISO needs to divert resources to implement the NOPR. The resulting opportunity cost in terms of market efficiency and savings will be significant. Meanwhile, as explained previously in these comments, implementing the NOPR will not result in any efficiency benefits – and will instead actually reduce the efficiency of the real-time dispatch. Thus, the Commission should not require the CAISO to implement the changes outlined in the NOPR.

IV. Conclusions

When discrete costs – such as commitment costs for fast-start resources – result in average costs that decrease with output, the type of two-part pricing system used by CAISO is just, reasonable and efficient. CAISO sets locational marginal prices based on marginal production costs. CAISO provides bid cost recovery payments made to compensate resources for any discrete commitment

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[37] *Comments on the Commitment Costs and Default Energy Bid Enhancements – Issue Paper,* Department of Market Monitoring, November 29, 2016: http://www.caiso.com/Documents/DMMComments-CommitmentCostsandDefaultEnergyBidEnhancementsIssuePaper.pdf.

costs that are not recovered through marginal cost pricing. The Commission should not undermine marginal cost pricing by requiring CAISO to allow prices to be set by the average cost of fast-start resources.

CAISO's overall market structure for incentivizing efficient long-run investments is just and reasonable without the adjustments proposed in the NOPR. The additional spot market revenues received by some resources because of the pricing rules in the NOPR would not have a significant impact on the decision of whether or not to make a large, long-term capital investment in a facility. Requiring the average cost pricing for fast-start resources as outlined in the NOPR would undermine the efficiency of the CAISO's spot markets by preventing optimal short-run dispatch.

Implementing the proposed pricing rules in the NOPR would require significant additional market design work and software changes which will be complex and costly. Diverting the CAISO's limited resources to implement these changes would have a very high *opportunity cost* in terms of the market initiatives and software enhancements that would need to be deferred and perhaps never ultimately implemented. Delaying these other initiatives will prevent significant improvements in market efficiency.

For these reasons, DMM strongly opposes requiring CAISO to adopt the proposed modifications to market-wide pricing rules in the NOPR.

Respectfully submitted,

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Dated: February 28, 2017

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties listed on the official service lists in the above-referenced proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 28th day of February, 2017.

/s/ Anna Pascuzzo
Anna Pascuzzo