California Independent
System Operator Corporation

June 22, 2011

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER11-____- 000

Tariff Revision and Request for Waiver of Sixty Day Notice Requirements

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act[1] and Sections 35.11 and 35.13 of the Commission's regulations,[2] the California Independent System Operator Corporation (ISO) respectfully submits for filing an amendment to the ISO Tariff. This amendment proposes: 1) modifications to the ISO's bid cost recovery rules to remedy the observed exploitative behavior that has resulted in excessive bid cost recovery payments beyond the expected outcome of a competitive market; and 2) to extend mitigation exceptional dispatch energy settlement rules to exceptional dispatches needed to access stranded ancillary services awards and residual unit commitment capacity. The ISO also requests waiver of the sixty-day notice requirement under Section 35.11 of the Commission's Regulations. Waiver is appropriate and necessary to enable the ISO to eliminate immediately incentives for market participants to engage in the identified bidding strategies that, if left unaddressed may cause inappropriately high payments to resources.

Through its bid cost recovery mechanism, the ISO guarantees payment of costs bid into the ISO markets for the services provided by resources to the extent such costs are not covered by ISO market revenue. In March of this year, the ISO made an emergency filing to address similar bidding strategies that had

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[1] 16 U.S.C. § 824d (2006).

[2] 18 C.F.R. §§ 35.11 & 35.13 (2010).

caused bid cost recovery payments to specific resources to reach unjust and unreasonable levels, which the Commission accepted on May 4, 2011.[3] While the market rule changes approved by the Commission were effective in eliminating bid cost recovery payments driven by the previously identified strategy, some resources have now engage in modified bidding practices that cause bid cost recovery payments to increase again for different reasons. Since the early part of April, resources have engaged in a series of complex day-ahead and real-time bidding strategies that maximize bid cost recovery payments during targeted hours of the day-ahead market. The rule changes proposed in this filing address the newly identified bidding strategies through settlement rules that eliminate the potential for excessive bid cost recovery payments.

Additionally, this filing includes certain rule changes to address observed market power issues associated with exceptional dispatches. The general rule for settling incremental exceptional dispatch energy is to pay the higher of the resource's energy bid, the default energy bid or the locational marginal price at the resource's location. Currently the mitigated exceptional dispatch energy settlement rule, which compensates the resource at the higher of the default energy bid or the locational marginal price, applies only to exceptional dispatches to address non-competitive transmission constraints or for seasonal dispatch requirements associated with environmental requirements known as "Delta Dispatch."[4] The same bidding practices used to exploit bid cost recovery payments also resulted in infeasible ancillary services awards and residual unit commitment capacity that the ISO can only access by exceptionally dispatching the resources and paying extremely high bid prices at or near the bid cap of $1,000 per MWh. Accordingly, the ISO is proposing to apply the mitigated exceptional dispatch energy settlement rule to exceptional dispatches to access stranded ancillary services awards and residual commitment capacity.

I. BACKGROUND

A. Recent Filing Addressing Market Behavior Causing the Expansion of Bid Cost Recovery Payments

On March 25, 2011, in Docket ER11-3149, the ISO filed emergency changes to its tariff market rules targeting specific market behavior causing the expansion of bid cost recovery payments above and beyond the appropriate

[3] *See* FERC Docket No. ER11-3149 (*March 25 filing*); *Cal Indep. Sys. Operator Corp.*, 135 FERC ¶ 61,110 (2011) (*May 4 Order*).

[4] The ISO has filed to extend the existing exceptional dispatch mitigated settlement rules that apply to non-competitive transmission constraints and Delta Dispatch beyond April 1, 2011. This matter is pending in ER11-2256. In this filing, the ISO is proposing to apply mitigated exceptional dispatch settlement rules to two different circumstances unrelated to the matters pending in ER11-2256.

outcome of a competitive market. Under the ISO market design, generator resources can submit bids for three cost components: 1) start-up cost; 2) cost to run at a minimum operating level (referred to as "minimum load"); and 3) costs to run at various levels above the minimum load (referred to as the "energy bid curve"). The bid cost recovery mechanism guarantees these costs will be compensated to the extent the resource's costs exceed the resource's total market revenues.

The bidding strategy previously observed, and addressed by the ISO's March tariff changes, involved registering the resource's minimum load costs to the maximum allowable level, submitting negative energy bid prices in the day-ahead market, and subsequently bidding the energy scheduled in the day-ahead back into the real-time market at higher prices.[5] Under this strategy while the minimum load costs are high, the resource's negative day-ahead energy bid renders the effective price for scheduling the resource relatively low. At such low effective prices, the day-ahead market finds it optimal to commit and schedule the resource. Under the market rules prior to the March 25 filing, the resource would recover the high minimum load costs without accounting for the day-ahead market revenue earned from their scheduled energy.[6] The day-ahead market revenue was not accounted for because the resource increased its energy bids in the real-time market at prices that almost always resulted in the market dispatching the resource down to its minimum load level. The prior rules required that in accounting for market revenue associated with energy scheduled in the day-ahead market, the ISO considered the resources "delivered energy" (*i.e.*, what it produced in real-time above minimum load) relative to its day ahead schedule above minimum load. In cases where a resource was dispatched down to its minimum load in the real-time market, the prior rules did not include the resource's day-ahead market revenues in determining the resource's net bid cost payments.[7]

The new market rules adopted in March have removed incentives to engage in the previously identified strategy. However, the ISO continues to observe some variations of the same basic negative bidding strategy by many of the same resources, now exploiting other aspects of the bid cost recovery mechanism. The specific behaviors and proposed market rule changes to correct this behavior are described below.

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5 *See* Docket ER11-3149, Exhibit No. ISO-1 at 11-24; Transmittal Letter at p. 10.

6 *See* Id at 22-23.

7 *See* Id at 23.

B. Exceptional Dispatches Tariff Authority

Under Section 34.9 of the ISO tariff, the ISO can issue exceptional dispatch instructions – *i.e.,* dispatches outside the ISO's markets – for specified purposes.[8]

On June 27, 2008, the ISO filed an amendment to the then pending Market Redesign and Technology Upgrade tariff (also known at the time as the "MRTU tariff") ("June 27 Filing") that would apply mitigated energy settlement rules to resources that are issued exceptional dispatch instructions in circumstances that presented a potential of the exercise of market power.[9] On October 16, 2008, the Commission accepted the ISO's proposed tariff revisions, effective upon implementation of the MRTU tariff, subject to refund and to the outcome of an investigation that the Commission initiated under Section 206 of the Federal Power Act.[10] In the October 16 Order, the Commission also established a technical conference to facilitate the resolution of its investigation and to discuss exceptional dispatch issues

In a February 20, 2009, Order, the Commission found the authority to issue exceptional dispatches to be a just and reasonable mechanism for maintaining grid reliability.[11] The Commission also accepted in part and rejected in part the revised exceptional dispatch proposal that the ISO had filed after the technical conference, effective upon the implementation of MRTU (which occurred March 31, 2009 for the day-ahead market of the April 1, 2009 trading day).

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[8] The purposes for which the ISO may issue an exceptional dispatch include: addressing an existing system emergency; prevention of an imminent system emergency or a situation that threatens system reliability and cannot be addressed by the real-time market optimization and system modeling; avoidance of a market interruption; ancillary services testing pre-commercial operations testing for generating units, avoidance of overgeneration conditions; black start; voltage support; accommodation of transmission ownership rights or existing transmission contracts; self-schedule changes after the close of the hour-ahead scheduling process; to reversal of a commitment instruction issued through the integrated forward market that is no longer optimal as determined through residual unit commitment; addressing transmission related modeling limitations in the full network model; and addressing system conditions for which the timing of the real-time market optimization and system modeling are either too slow or incapable of bringing the ISO controlled grid back to reliable operations in an appropriate time-frame based on the timing and physical characteristics of resources available to the ISO.

[9] The amendment also clarified a number of the existing MRTU Tariff provisions regarding exceptional dispatch.

[10] *Cal. Indep. Sys. Operator Corp.*, 125 FERC ¶ 61,055 (2008) (*October 16 Order*).

[11] *Cal. Indep. Sys. Operator Corp.* 126 FERC ¶ 61,150, *on reh'g* 129 FERC ¶ 61,144 (2009), (*February 20 Order*).

Relevant to this filing, the Commission accepted the ISO's proposal to mitigate exceptional dispatches for the first four months of MRTU and after first four months, to mitigate exceptional dispatches to resolve congestion on non-competitive transmission constraints and for Delta Dispatch (i.e. seasonal dispatch requirements associated with environmental requirements). Under these mitigated settlement rules, a resource that receives an exceptional dispatch would generally be paid the higher of its default energy bid or the locational marginal price. If it is not a resource adequacy unit, the resource would be automatically designated to receive a capacity payment, unless the scheduling coordinator on behalf of the resource has elected to receive supplemental revenues, under which it is eligible to be paid the higher of its energy bid or the locational marginal price, up to the monthly cap.[12]

Although the Commission approved the mitigation proposal, it found that the ISO had not satisfied its burden of justifying its proposed market power mitigation measures in the majority of the types of exceptional dispatch for which it had sought mitigation authority beyond the initial four months of MRTU.[13] As noted above, the Commission approved mitigation in only two situations: exceptional dispatches for the purpose of addressing reliability requirements related to non-competitive constraints; and exceptional dispatches needed to address the Delta Dispatch.[14] These situations for which mitigation may occur are set forth in section 39.10 of the ISO tariff.

The Commission specifically left open the possibility that the ISO might "gather evidence to demonstrate the potential to exercise market power for specific instances of Exceptional Dispatch."[15] Although the Commission was referring in particular to information gathered during the four-month transition period, it did not foreclose the possibility that evidence would appear later. As discussed below, the bidding strategy described in this filing and utilized on behalf of certain resources creates the opportunity for the unilateral exercise of market power requiring the ISO to pay excessive exceptional dispatch energy

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12 The capacity payment was formerly made under the Interim Capacity Procurement Mechanism which, as of April 1, 2011, is now known as the Capacity Procurement Mechanism. The monthly cap is determined by the Interim Capacity Procurement Mechanism or Capacity Procurement Mechanism, as applicable.

13 *Id.* at P 71.

14 *Id.* at P 74. The Commission directed the ISO to submit a compliance filing reflecting the Commission's directives within 30 days, which the ISO filed on March 23, 2009. On September 2, 2009, conditionally accepted, subject to a further compliance filing, the ISO's proposed tariff revisions included in the ISO's March 23 compliance filing. *Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,218 (2009), *clarification granted*, 131 FERC ¶ 61,100 (2010). The ISO made its compliance filing on October 2, 2009, which the Commission accepted on May 4, 2010.

15 *Id.* at P 85.

costs to access market awarded, but stranded, ancillary services and residual unit commitment capacity.[16]

II. EVENTS LEADING TO PROPOSED AMENDMENT AND BIDDING STRATEGIES

Following the ISO's March filing, for a short period of about 10 days, the resources ceased engaging in the identified bidding strategy. That is, for that short period, those resources did not submit bids in the day-ahead market that forced the ISO to schedule the resources at maximum capacity in the day-ahead and, subsequently submit bids in the real-time market that forced the ISO to dispatch such resources down to minimum load.

As of April 1, 2011, however, certain of these same resources began engaging in a similar bidding strategy with some modification. Initially, these resources were not accruing significant bid cost recovery payments. Over a period of two months, a number of resources continued to engage in the basic strategy with variations that resulted in excessive payments of bid cost recovery and exceptional dispatch payments.

A. Base Negative Bid Bidding Strategy

Over the past two months, the ISO and its DMM have observed the recurrence of a modified bidding strategy in which certain resources continue to submit negative energy bid prices in the day-ahead market, which causes the resource to be scheduled, and then submit relatively high energy bids in the real-time market so that the resource is dispatched down to its minimum load level. While profitability of this strategy has been greatly reduced by the settlement rule changes that went into effect on March 26, the ISO has identified a residual incentive for participants to continue this practice to either profit from minimum load cost payments or to position the resource to benefit from secondary bidding strategies.

In the March 25 filing, the ISO proposed a rule that specifically targeted a bidding behavior that, combined with the submission of certain bids in the day-ahead and real-time market, resulted in the exploitation of a requirement in the bid cost recovery rules that the ISO calculate market revenues used to offset bid costs based on the resource's <u>delivered</u> portions of the day-ahead scheduled energy. The ISO narrowly tailored its March 25 tariff rule change so that

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[16] The ISO Board of Governors authorized ISO management to file for exceptional dispatch bid mitigation at its May 21-22 meeting. This authority extended bid mitigation for exceptional dispatches to ramp resources from minimum operating levels dispatchable levels. In this filing, the ISO is proposing to apply mitigated exceptional dispatch energy settlement rules to a subset of ramping exceptional dispatches—those necessary to access infeasible ancillary services awards and residual unit commitment capacity.

resources not engaging in this strategy could continue to have the flexibility needed in scheduling in the day-ahead and real-time market in a way that best meets their needs. However, as described by Dr. Hildebrandt, certain resources are now engaging in a modified versions of the bidding strategy previously observed that appear to aid in positioning the resources to exploit other cost recovery mechanisms associated with bid cost recovery in other intervals or with exceptional dispatch payments, as explained further below.[17] But for the opportunity for such windfalls, it would not be rational for parties to engage in this bidding practice. This is because during the market intervals in which the resource bids this way, it would not cover the costs of providing service.[18]

As described by Dr. Hildebrandt, resources are again bidding in the day-ahead market at negative bids at or close to the bid floor and the entity controlling the units have registered minimum load costs at the maximum limited under the registered cost option, i.e., 200% of proxy costs.[19] Such resources are then bid into the day-ahead market with negative bids in several targeted intervals small amounts of energy sufficient to have the unit committed by the ISO integrated forward market software. In all other intervals, the resources will bid all of their other energy at or near the $1,000/MW bid cap. Dr. Hildebrandt demonstrates that the resources bid their available capacity at -$30/MW in hours 12 to 13 and hours 20 to 24, during which the units are not scheduled at their maximum capacity, despite these -$30/MW bids, due to ramping constraints. Dr. Hildebrandt further explains that during these intervals the resources are committed because the relatively high minimum load bid costs are offset by the negative bid cost of the accepted energy bids at the -$30/MW bid floor.[20]

While by itself this bidding strategy does not significantly expand bid cost recovery, the resource then engages in bidding behavior in the real-time that causes the resource to be dispatched below its day-ahead schedule, which expands the resource's bid cost payments and inflates bid cost recovery payments. This similar pattern posed a more significant problem prior to the March 25 filing because under such scenarios the ISO's was discounting market revenues used to offset bid costs in each hour. The ISO's March 25 filing eliminated the bulk of revenues that incentivized this strategy, but as explained by Dr. Hildebrandt, this strategy continues to be viable because the ISO calculates bid costs based on <u>delivered</u> portions of the day-ahead energy schedule as opposed to <u>scheduled</u> portions.

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17 *See* Exhibit No. ISO-1 at 25-26, 42-44.

18 *Id.* at 24.

19 *Id.* at 14-16.

20 *Id.* at 16.

As discussed above, the ISO's rule for using delivered portions to calculate bid costs was in response to the Commission's September 21, 2006 order in which the Commission stipulated that bid cost recovery should not be paid for day-ahead scheduled energy that was not actually delivered.[21] While the ISO continues to believe that this rule is appropriate for the positive portions of the day-ahead energy bid curve, applying this principle to the negative portions is not consistent with the overall payments of bid cost recovery, nor how the optimization considered such negative bids and, moreover, causes an incentive for participants to engage in bidding strategies that are not economic.[22]

In the real-time, these resources raise their bids for the energy scheduled in the day-ahead market, as a result of the negative $30/MW bids, to a bid price level sufficient high enough that is unlikely to clear in the real-time market. Because the ISO calculates bid costs for the resource based on the portions of the day-ahead schedule that are delivered, and the resulting real-time dispatch down to minimum load, the resource's negative bid costs are not fully accounted for to the extent that in the real-time the resource produces below their day-ahead schedule. Resources submit energy bid curves with prices that can range anywhere from negative $30/MWh (the bid floor) to $1000/MWh (the bid cap). In submitting negative bids, resources are essentially indicating a willingness to produce energy at negative prices (*i.e.*, pay the market to produce energy). Applying energy bid costs in the negative portions of the energy bid curve essentially allows for the accounting of negative bid costs that are used to offset the resources overall bid cost recovery payments. Therefore, the exclusion of bid costs in the bid cost recovery process results in the inflation of bid cost recovery payments overall.

Dr. Hildebrandt explains that bid cost payments are maximized under this strategy if the participant submits real-time bid prices that will be consistently just above real-time market cleared locational marginal price.[23] This ensures that the unit will operate at or near its minimum load. As discussed in the March 25 filing, when resources are dispatched to their minimum load, the day-ahead metered energy adjustment factor goes to zero.[24] To determine the delivered portions of the day-ahead schedule to which the energy bid costs are to apply as required by the ISO tariff, the ISO utilizes the day-ahead metered energy adjustment factor. Under this base strategy, when the resource is able to produce a day-ahead

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[21] *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 516 (2006), order on reh'g, 119 FERC ¶ 61,076 (2007) (*September 2006 Order*).

[22] *See* Exhibit No. ISO-1 at 36.

[23] *Id.* at 16-17.

[24] *See* March 25 filing, Transmittal Letter at 11.

metered energy adjustment factor of zero, the resource's negative energy bid costs are completely discounted.[25]

Because the supplier provides decremental real-time energy and incurs negative real-time bid costs recovery,[26] as Dr. Hildebrandt explains, the success of the strategy depends upon increasing day-ahead bid recovery costs in an amount greater than the negative real-time bid recovery costs.[27] The greater the difference between the real-time bid and the real-time price, the lesser the difference between the amount by which the increased day-ahead bid cost exceeds the negative real-time bid recovery.[28]

This bidding strategy results in the unit operating at minimum load during most hours, with resource incurring negative total costs reflecting the fact that the cost paid by the supplier for the decremental energy was lower than the amount the supplier would have been willing to pay for this decremental energy as reflected in its real-time energy bids. As explained by Dr. Hildebrandt, because under the current rules the ISO excludes the negative bid costs for undelivered portions of the day-ahead schedule, the resource still receives a net bid cost recovery payment.[29] Dr. Hildebrandt explains that the inflated bid cost recovery payments due to the ISO's accounting of bid costs on delivered portions and the application of the MEAF to negative day-ahead energy bids may not by itself make it profitable to operate a unit in this manner. However, these inflated bid cost recovery payments appear to be used to enable and "subsidize" other undesirable and uncompetitive bidding practices discussed further below. For example, this basic strategy when combine with other strategies can be highly profitable due to bid cost recovery payments made for energy needed to ramp a unit from its day-ahead schedule at the end of one trade day to its day-ahead schedule at the start of the next trade date.

B. Bidding Strategy Increasing Bid Cost Recovery Payments for Resources in Full Ramp Down Mode in Early Hours of the Day-Ahead Market

1. Inter-Day Ramping Bidding Strategy

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25 *See* Exhibit No. ISO-1 at 16-17.

26 When the resource is decremented in the real-time market, the net-profit, calculated as the difference between the resource's decremented energy bid prices and the applicable LMP multiplied by the decremental dispatched quantity, is used to offset bid cost recovery.

27 *See* Exhibit No. ISO-1 at 17.

28 *Id.* at 17-18.

29 *Id.* at 22.

When the bidding strategy discussed above is employed over two consecutive day-ahead market runs it enables the expansion of bid cost recovery payments for resources in the first few hours of the day when these resources must be scheduled to ramp down to minimum load. This results from a combination of factors. First, most of all of these resources' capacity is bid at -$30/MW in the day-ahead market during the last few hours of each trade day (Hours 20 to 24 in this example).[30] In addition, during the first few hours of the day-ahead market for the next trade day, their full capacity is bid at $1,000/MW.

This bidding practice causes the integrated forward market to schedule the resource at its maximum capacity in the day-ahead market for the last hour of the first trade date and subsequently, because of its high bids in the first hours of the next trade day, the resource is scheduled down to minimum load levels during the first hours of the next trade day.[31] However, because the resource's physical operating limitations submitted to the ISO require that the ISO ramp the resource down gradually at the resources operational ramp-rate, the day-ahead market must ramp these resources down gradually in the first few hours of the day despite the $1000 bids for this ramping energy.

This situation results from the fact that the ISO's day-ahead market optimizes over the twenty-four hour period of each trade day separately and does not look beyond that. Were the ISO market able to look beyond the 24 hour period of each trade day, the market optimization would recognize the high cost of ramping the units down at bid prices of $1000/MWh in the early hours of the next trade day and start ramping these resources down in the last hours of the prior trade day rather than scheduling them to maximum capacity.[32] The lack of a look-ahead period beyond the applicable 24 hours requires the ISO to establish a resource's initial conditions at the start of each day-ahead market. The ISO's practice has been to set the initial conditions based on the day-ahead schedules of the last hour of the prior-day's day-ahead market.[33] Accordingly, the resource is being required to ramp the resource down from their maximum capacity. This results in the need to schedule resources over a full ramp down period over several intervals of the day-ahead market, during which under the existing rules, the resources are earning bid cost recovery for their bid prices submitted for the early hours.[34]

This alone, however, does not maximize the resource's earnings on bid cost recovery. As further explained by Dr. Hildebrandt, the maximization of

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[30] *Id.* at 25.

[31] *Id.*

[32] *Id.* at 29, 53-54.

[33] *Id.* at 26.

[34] *Id.* at 30-31.

profits under this strategy requires a complex set of real-time bidding schemes that ensures that the unit: 1) is operating at minimum load for hours in which it is relying on bid cost recovery under the base strategy during most of the hours of the preceding day in which the strategy is employed, but 2) is operating significantly above minimum load up to its day-ahead schedule for the first few hours of the day when it is receiving bid cost recovery for ramping energy at the $1000 bid prices.

To be able to operate significantly above minimum load up to their day-ahead schedule in the first few hours of the day, these resources must be ramped up in the last few hours of the day (hours 23 and 24). This can be accomplished by either submitting relatively low energy bid prices or submitting energy self-schedules in the real-time market during these hours.[35] As such the resource is dispatched at its day-ahead schedule in the real-time. This means that in real-time at the start of the first hour of the next day the resource is operating significantly above minimum load up to its maximum capacity and the ISO is, therefore, required to ramp the resource down in the early hours of the day. This results in a relatively higher day-ahead metered energy adjustment factor up to 1.0 for hour 1, which means that a significant portion or all of the unit's $1,000 bid price for energy in hour 1 needed to ramp the unit down over this hour is included in the bid cost recovery calculations.[36] The bidding strategy is enhanced through the resource's submission of a bid for the early hours of the next day-ahead market at or near that bid cap, which essentially indicate to the ISO market that for those early hours of the day the resource is not willing to operate at anything other than its minimum load unless the ISO pays a high price.

Dr. Hildebrandt explains that the base negative bidding strategy described above ensures that the resource is committed and covers virtually its entire minimum load cost, even on days when they unit may not be economic to be in operation based on its actual costs and sets up the conditions necessary for this second issue to become highly problematic in terms of creating even more excessive BCR payments. While the resources are at times utilizing part of the same bidding strategies employed prior to the March 25 filing, the inter-ramping day bidding strategy was not employed prior to that time. The bidding scenarios described above began to occur around April 16, 2011, and have since caused as significant impact on bid cost recovery payments as described below and in Dr. Hildebrandt's testimony.

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[35] *Id.* at 31-32.

[36] *Id.* at 33.

2. Intra-Day Self-Scheduling Strategy

While the ISO has not yet observed this bidding strategy, in any given day-ahead market intra-day ramping intervals can present the same bid cost recovery problem when the ramping is associated with the need to take a resource to or from a self-schedule.[37] Market participants can submit self-schedules at any part of the day on an hourly basis, which must range between the unit's minimum load and its maximum available capacity. Through the day-ahead market optimization over the 24 hour period, the market software checks whether a self-schedule is at or above its minimum operating level for its minimum operating time and rejects any self-schedule that does not meet this criteria. However, the market software does not check that the hour-to-hour changes in self-schedules submitted by participants are feasible given the unit's actual ramp rate and other operating limitations. To the extent a resource must be dispatched at a higher level during one hour to make its self-schedule in the next hour feasible, the day-ahead software may need to accept energy bids from the unit in addition to the scheduled energy. This is true no matter how high the energy bids submitted by the scheduling coordinator for intervals in between self-schedules because self-schedules are highly protected through penalty prices at the bid cap. Therefore, rather than curtail a self-schedule, the optimization is likely to accept the expensive bid in the intervening ramping periods.[38]

By self-scheduling a unit at different levels in different hours, similarly to the inter-day ramping bidding strategy described above, a market participant could force the ISO day-ahead market to accept extremely high-priced bids for any additional energy needed to make these schedules feasible.[39] Such infeasible schedules can be submitted in multiple intervals of the day-ahead market. Dr. Hildebrandt describes a scenario that results in one such event. However, this is possible in multiple intervals and could result in excessive bid cost recovery payments over the day-ahead market.

Under this bidding strategy, the market participant again would want the unit to operate in the real-time market at or near this day-ahead schedule during hours it was eligible for day-ahead bid cost recovery so that these extremely high bid costs would not be cancelled out of the bid cost recovery calculations due to application of a low day-ahead metered energy adjustment factor.

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[37] *Id.* at 38

[38] *Id.*

[39] *Id.*

C. Bidding Strategy Permits the Exercise of Unilateral Market Power in Context of Exceptional Dispatches

An additional outcome of the base negative bidding strategy in some hours to ensure the resource is committed is related to the need for exceptional dispatch to ensure a resource's awarded ancillary service and or residual unit capacity is not stranded in real-time. One circumstance in which the ISO may need to issue an exceptional dispatch is to ramp a resource to its "dispatchable PMin" to make an ancillary services award or residual unit commitment capacity obligation feasible. Such exceptional dispatches are necessary because the ability to provide ancillary services or meet residual unit commitment obligations depends upon the ability of a resource to increase output, or ramp, within a specified period of time.

As explained in the testimony of Ms. Le Vine, under WECC/NERC requirements, the ISO must maintain a specified level of operating reserve, a type of Ancillary Services. The ISO's operating reserve includes both spinning reserve and non-spinning reserve. Both spinning and non-spinning reserve must be capable of being loaded in 10 minutes (*i.e.,* the unit must be able to produce all of the energy from the specified reserved capacity in 10 minutes). Spinning reserve is operating reserve that is already synchronized to the grid; therefore, units providing spinning reserve must be operating during the period of the award. Thus, if the ISO is relying upon a resource to provide a certain amount of spinning reserve, the resource must be operating at a point where it can ramp up to provide the energy from the amount of capacity awarded within 10 minutes.[40]

Resources provide the ISO with an "operating ramp rate" and an "operating reserve ramp rate." The operating ramp rate is the MW/minute rate at which the unit can increase its energy output, if dispatched from a given operating level. The defined operating reserve ramp rate is a single number – the ramp rate at which the resource is certified to provide operating reserve. The operational ramp rate, in contrast, is dynamic and can be slower (or faster) than the operating reserve ramp rate. For example, a resource may be capable for ramping at of 1.5 MW/minute, when operating between 25 and 125 MW, and 5 MW/minute, when operating at 126-250 MW.[41]

The ISO tariff defines "PMin" as the "minimum normal capability, i.e. the lowest operating level at which the resource can reliably operate. When the ISO commits a generator, but schedules no energy from the unit, the generator is operating at PMin. "Dispatchable PMin" refers to the operating level from which a generating unit can be dispatched at its defined "operating reserve ramp rate." A number of large units have a much lower MW/minute rate at PMin than at

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[40] *See* Exhibit No. ISO-2 at 5-7.

[41] *Id.* at 7-8.

dispatchable PMin. Using the example from the prior paragraph, the dispatchable PMin for the resource would be 126 MW.[42]

The ISO often schedules units to provide both ancillary services and energy in the day-ahead market, as well as residual unit commitment capacity. The energy and ancillary services schedule and award results from the ISO's co-optimization using a resources' bids. A problem may arise when a unit receives *an ancillary services award for operating reserves that is based on an operating* reserve ramp rate that is higher than the operating ramp rate of the resource when it is operating at the output specified in its energy schedule. For example, as described in both Ms. Le Vine's and Dr. Hildebrandt's testimony, a resource might have a PMin of 25 MW, and an operational ramp rate of 1.67 MW/minute when operating between 25 and 125 MW. When the unit is scheduled at PMin, it can provide only about 17 MW of spinning reserve (1.67 MW/minute x 10 minutes). Once operating at 125 MW, it can ramp up at a rate of 6 MW/minute and can provide up to 60 MW of spinning reserve (6 MW/minute x 10 minutes). Currently, the ISO's day-ahead market software considers the amount of spinning reserve available from on-line units based on the fixed operating reserve ramp rate in the ISO master file. This fixed ramp rate represents the maximum amount of spinning reserve the unit is certified to provide, which in this case would reflects the higher 6 MW/minute ramp rate. Thus, even when this unit is scheduled to operate at only 25 MW in the day-ahead market, the unit may be awarded up to 60 MW of spinning reserve.[43]

This can create a situation where the unit is scheduled to provide 60 MW of spinning reserve when it can only provide 17 MW of spinning reserve. In such circumstances, the ISO may need to issue exceptional dispatches to move the resource to its dispatchable PMin.

A similar situation can occur with regard to residual unit commitment capacity obligations. Although the ISO may not need ten minute ramping capacity for resources with residual unit commitment obligations, the ISO may need to issue an exceptional dispatch to a resource so that the energy bids the resource is obligated to submit into the real-time market for the awarded residual unit commitment capacity can be available to the ISO. Dr. Hildebrandt describes an example where less than half of the awarded residual unit commitment capacity would be available unless the ISO issues exceptional dispatches to ramp the resources to an operating level with an operational ramp rate consistent with the resource's residual unit commitment capacity obligation.

This issue is further exacerbated by a resources bidding behavior discussed above where the resource with feasible day-ahead ancillary services awards and

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42 *Id.*

43 *Id.* at 8-10.

residual unit commitment capacity submit bids in real-time to sell back day-ahead energy schedules in such a way to get dispatched down to minimum load. Doing so further positions the resource in real-time such that the awarded ancillary services reserves or residual unit commitment capacity that was feasible in the day-ahead is no longer feasible in the real-time market absent the issuance of an exceptional dispatch

Although the ISO has, since April, generally been able to avoid exceptionally dispatching resources at extremely high prices, it has come at an unacceptable cost and risk to reliability. First, under the tariff the ISO is obligated to procure 100% of its ancillary services requirements in the day-ahead. The ISO made a deliberate decision that day-ahead procurement of 100% of the ISO's forecast ancillary services requirements would best ensure reliable operation of the grid. To this end, the ISO also made a deliberate decision not to permit scheduling coordinators to buy back their ancillary services awards in the hour-ahead scheduling process or the real-time market. Thus, infeasible ancillary services awards puts the ISO in exactly the position that it sought to avoid and undermines the ability of the ISO to operate the grid reliably. Although the ISO has authority to procure additional operating reserves in the hour-ahead scheduling process to supplement or replace any day-ahead operating reserve awards, the operating reserves purchased in the hour-ahead scheduling process are automatically considered as only available in the event of a "contingency." In the day-ahead market, on the other hand, scheduling coordinators must select "contingency only" flag if they desire this status; otherwise the operating reserve will not be reserved for contingencies. Another undesirable outcome of hour-ahead procurement of operating reserve is that if the ISO procures an incremental amount of operating reserve from a resource with a day-ahead award, the total amount of operating reserve will be classified as "contingency only" even though the day-ahead award was not subject to this restriction. As the percentage of operating reserves classified as "contingency only" increases, even less dispatchable capacity is available to ISO operators to manage the grid absent a contingency.

Moreover, when compounded by the bidding strategy explained in Dr. Hildebrandt's testimony, the alternatives may be ineffective in avoiding the need for exceptional dispatches. In brief summary, the bidding strategy forces the ISO market software to commit resources at PMin and then to keep the resource at PMin when the ISO has the most need for ramping capacity to meet peak load as well as the awarded ancillary services and residual unit commitment capacity. This bidding strategy also has the consequence of preventing other resources that have bidding profiles more reflective of actual costs from getting committed and scheduled in the market, thus depriving the ISO of alternative dispatchable capacity from resources that are willing to provide it. The net result of these factors is that the ISO has less dispatchable capacity and more operating reserve capacity that is only available in the event of a contingency, increasing the likelihood that exceptional dispatches may be necessary. In addition, the ISO may also be forced to, and has issued exceptional dispatches to off-line resources to ensure sufficient dispatchable capacity is available to operate the grid reliability when it is less costly to issue exceptional dispatches to off-line units than to units that are already on-line. Thus, the bidding scenario described both in Ms. Le Vine's and in Dr. Hildebrandt's testimony not only causes increased infeasible operating reserve awards and residual unit commitment awards, it may also require the ISO to commit additional resources through its exceptional dispatch authority to ensure that sufficient ramping capacity is available.[44]

D. Financial Impact of Bidding Strategies

Bid Cost Recovery

The bidding strategies which artificially inflate bid cost recovery payments commenced in early April 2011. Figure 1 below illustrates the impact of the base negative bidding strategy in blue and the inter-day ramping bidding strategy in red. As illustrated by the green trending line, bid cost recovery payments increased significantly from April 1 to the week prior to this filing. The blue bars also indicate that the base bidding strategy started having a small impact on the bid cost recovery payments in early April. It was not until about April 19 that the inter-day ramping bidding strategy began to appear in the ISO markets. As is illustrated by the red bars, once that bidding strategy started, however, bid cost recovery attributed to the inter-day ramping bidding strategy began to spike on certain days and as of May 31, it spiked the highest and remained at that high level on most weeks thereafter. In the last two weeks, as illustrated by Figure 1 below, the bidding strategy has been further refined to more consistently maximize a profitable return.

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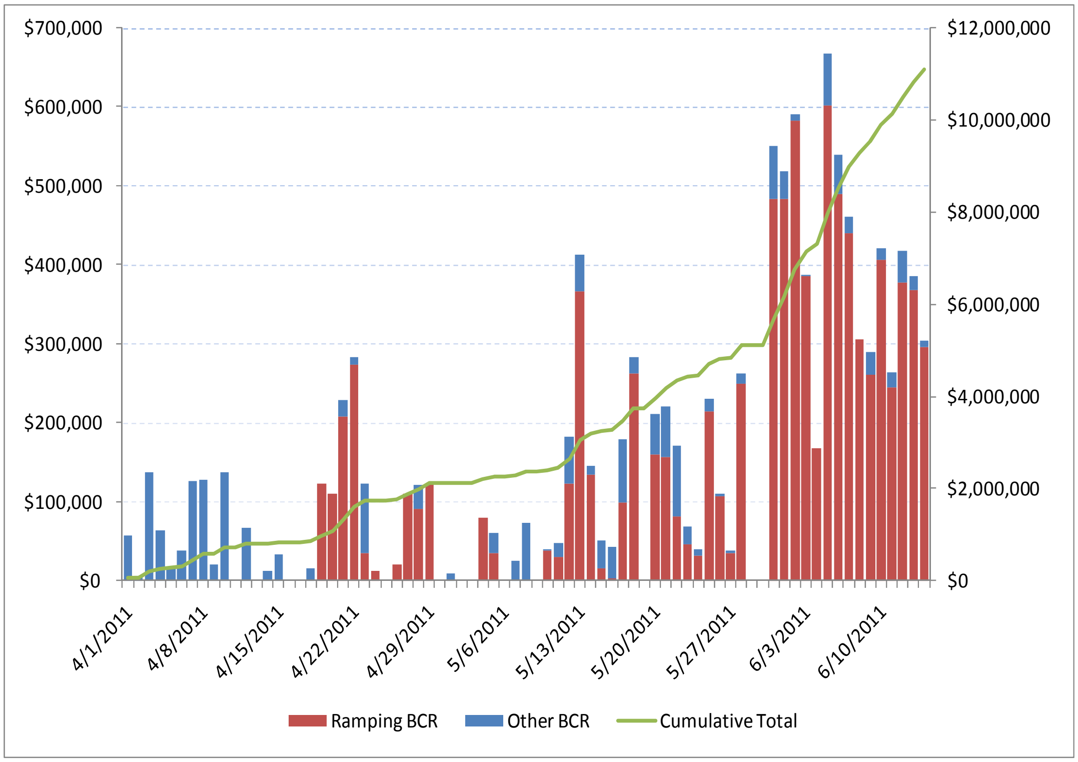
[44] *Id.* at 16.

Figure 1: Financial Impact of Identified Bid Cost Recovery Related bidding strategies



Exceptional Dispatch

In April the ISO needed to exceptionally dispatch several units that had infeasible ancillary services awards and residual unit commitment capacity obligations. These units had pursued the bidding strategies discussed above and were scheduled to operate at minimum load over the most critical morning and evening hours when market energy prices and reliability concerns are generally highest. The units had ancillary services awards or residual unit commitment awards for many hours of the days involved that would have been infeasible and unavailable unless the ISO issued exceptional dispatches. Through the bidding strategy discussed above of submitting negative bids in day-ahead to get the resource committed and then submitting real-time energy bids to dispatch the resource to minimum load in real-time, the resource was able to position the resource in real-time to create the condition that the awarded ancillary service or residual unit commitment capacity was stranded. This required the ISO operators to make an exceptional dispatch forcing the ISO to pay the high energy bid price to position the resource in real-time such that that the capacity was operational useable. The scheduling coordinators for these units submitted all of the energy above minimum load at bid prices just below the $1,000/MW bid cap. As a result, in just five days, during a total of 24 hours, almost $5.3 million in exceptional dispatch payments were incurred for energy bids at prices approximately equal to the $1,000/MW bid cap. About $3.6 million of these exceptional dispatches payments were incurred when units with infeasible ancillary service awards and residual unit commitment capacity were dispatched above minimum load to a level at which they had a much higher ramp rate that would make these awards feasible.[45]

III. PROPOSED SOLUTIONS AND TARIFF AMENDMENTS

A. Proposed Changes to Integrated Forward Market Bid Cost Accounting Rule to Address Base Strategy

To eliminate the base-strategy subsidy that appears to enable alternative bidding strategies to expand bid cost recovery payments, the ISO proposes a simple rule change. Instead of accounting for energy bid costs for negative bids on the basis of delivered portions and applying the day-ahead metered energy adjustment factor, the ISO proposes to base these costs on the energy scheduled in the day-ahead market and not apply the metered energy adjustment factor to negatively-priced bids when calculating bid costs for energy. As discussed by Dr. Hildebrandt, this modification will effectively target the bidding strategies that have been using negative day-ahead energy bids to get units committed and then inflate bid cost recovery payments by eliminating over-recovery for the resource's minimum load costs.[46]

This change is not expected to have an adverse impact on market participants because, as discussed by Dr. Hildebrandt, other than the resources engaged in the bidding strategies described in the March 25 filing and in this filing, a very limited number of negatively priced bids have been submitted into the day-ahead market by generating units since the ISO's new market began in April 2009. All other negatively priced bids have all been submitted by either hydro or renewable energy resources units and are likely to reflect operating constraints that essentially required these units to generate during some hours. Moreover, virtually all of these negatively priced bids were above -$7/MW and, more importantly, virtually all of the day-ahead energy with these negatively priced bids was actually delivered in the real-time market.[47] Therefore, the proposed modification would have no significant financial impact on resources submitting negative bids and operating appropriately in this manner.

The ISO proposed the following change to Section 11.8.2.1.5 IFM Energy Bid Cost, to enable this rule change.

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[45] *Id.* at 14.

[46] *See* Exhibit No. ISO-1 at 52.

[47] *Id.* at 52-53.

11.8.2.1.5 IFM Energy Bid Cost

For any Settlement Interval, the IFM Energy Bid Cost for Bid Cost Recovery Eligible Resources, except Participating Loads, shall be the integral of the relevant Energy Bid submitted to the IFM, if any, from the higher of the registered Bid Cost Recovery Eligible Resource's Minimum Load and the Day-Ahead Total Self-Schedule up to the relevant MWh scheduled in the Day-Ahead Schedule, divided by the number of Settlement Intervals in a Trading Hour. The IFM Energy Bid Cost for Bid Cost Recovery Eligible Resources, except Participating Loads, <u>and except for any portion of the Day-Ahead Schedule associated with an Energy Bid less than zero,</u> for any Settlement Interval is set to zero for any portion of the Day-Ahead Schedule that is not delivered from the otherwise Bid Cost Recovery Eligible Resource that has metered Generation below its Day-Ahead Schedule; any portion of the Day-Ahead Schedule that is actually delivered remains eligible for IFM Energy Bid Cost Recovery. The delivered portions of the Day-Ahead Schedule for this calculation are determined using the Day-Ahead Metered Energy Adjustment Factor. <u>The Day-Ahead Metered Energy Adjustment Factor is not applied to IFM Energy Bid Costs that associate with Energy Bids that are less than zero.</u> The CAISO will determine the IFM Energy Bid Cost for a Multi-Stage Generating Resource at the Generating Unit or Dynamic Resource-Specific System Resource level. <u>The CAISO will determine the applicable net IFM Energy Bid Cost surplus or net IFM Energy Bid Cost shortfalls as described in Section 11.8.2.4.</u>

B. Proposed Tariff Amendments to Address Bidding Practices Expanding Bid Cost Recovery for Resources During Ramping Periods

To address both the inter-day and intra-day ramping energy bid cost recovery issue the ISO proposes to add a new rule to its bid cost recovery rules that will enable the ISO to exclude day-ahead energy bid costs from the daily bid cost recovery calculation in cases where, because of the ramping conditions associated with either an initial condition or self-schedule as described above, the resource should not obtain bid cost recovery for ramping energy. Under the proposed new rule, for each day the ISO will first identify the hours scheduled as full ramp periods. A full ramp-up period will be identified as of the first hour where the resource is ramping up at full ramp until the last hour where the resource is ramping up at full ramp. Likewise, a full ramp down period will be identified as of first hour where the resource is ramping down at full ramp until the last hour that the resource is ramping down at full ramp.

For such full ramp down periods that are triggered by an initial condition setting from the previous day or ramp up or down periods associated with a self-schedule within the day, the ISO will identify and calculate net energy bid cost recovery surpluses and shortfalls. For the ramp periods with a net energy bid cost shortfall, the energy bid cost recovery shortfall will not be included in bid cost recovery, which means that the shortfalls for the resource will not be funded through the rest of bid cost recovery calculated for the day. Conversely, for the ramp periods with a net surplus, the surplus will be included in bid cost recovery, which means that the surplus will be used to offset bid cost recovery shortfalls over the day.

This rule will eliminate the incentive for resources to bid to create initial conditions or self-schedule in the day-ahead market to create ramp periods for the sole purpose of obtaining bid cost recovery. In the vast majority of cases, this rule will not have any unintended consequences for units that are subject to shortfalls and that should legitimately receive bid cost recovery. As discussed by Dr. Hildebrandt, the ISO conducted an analysis to determine the impact of the rule had the proposed rule been in effect during the 2010 calendar year, during which the ramping bidding strategy was not employed by any market participant. The analysis reveals that only a total of 9 units would have had bid cost recovery payments reduced and only by a total of about $88,000 for all the 9 resources. The ISO proposes to monitor for potential adverse outcomes and to propose rule changes should they occur.

Accordingly, the ISO proposes to add new Section 11.8.2.4 to include the above rule as follows:

11.8.2.4 Ramping for IFM Initial Conditions or Self-Schedules

The CAISO shall determine the net IFM Bid Cost Surplus or net IFM Bid Cost shortage across all full ramp down periods that start with an initial condition at the start of the IFM or a full ramp period within a 24 hour day-ahead market associated with a Self-Schedule any time within the full ramp period. For such full ramp periods associated with an initial condition or Self-Schedule with a net IFM Bid Cost shortfall, the net IFM Energy Bid Cost shortfall will not be included in IFM Bid Cost calculations. For the full ramp periods with a net IFM Bid Cost Surplus, the surplus will be included in IFM Bid Cost calculations. For full other ramp periods not associated with an initial condition or Self-Schedule with IFM Energy Bid Cost shortfall, the shortfall with be included in IFM Bid Cost calculations. The CAISO will identify the Trading Hours scheduled as full ramp up periods as of the first hour where the resource is ramping up at full ramp until the last hour where the resource is ramping up at full ramp. Likewise, a full ramp down period will be identified as of first hour where the resource is ramping down at full ramp until the last hour that the resource is ramping down at full ramp.

C. Proposed Tariff Amendments to Address Expansion of Exceptional Dispatch Payments

The ISO also proposes to amend section 39.10 to permit bid mitigation when the ISO issues an exceptional dispatch to ramp a resource up to its dispatchable PMin in order to make any stranded ancillary services awards or residual unit commitment capacity obligations feasible. Specifically, the ISO proposes the following amendments to Section 39.10:

> The CAISO shall apply Mitigation Measures to Exceptional Dispatches of resources when such resources are committed or dispatched under Exceptional Dispatch for purposes of: (1) addressing reliability requirements related to non-competitive Transmission Constraints; ~~and~~ (2) ramping resources with Ancillary Services Awards or RUC Capacity to a dispatch level that ensures their availability in real-time; and (3) addressing unit-specific environmental constraints not incorporated into the Full Network Model or the CAISO's market software that affect the dispatch of Generating Units in the Sacramento Delta and are commonly known as "Delta Dispatch".

The ISO recognizes that operational and market enhancements are also needed. In the near term, by approximately July 5, the ISO will implement a software enhancement – referred to as dynamic ancillary services procurement – that will incorporate the unit's operational ramp rate at different operating levels into the day-ahead software optimization. This would ensure that a unit is not awarded more ancillary service capacity than it could provide based on its operational ramp rate at its day-ahead energy schedule. Since the software co-optimizes energy and ancillary services, this enhancement allow the software to determine the optimal level at which to schedule the unit for energy. The ISO believes this software modification and the related tariff modifications can be completed on a schedule that would allow implementation within the next few months. This enhancement will reduce the incidence of day-ahead infeasible ancillary services awards but would not reduce the incidence of infeasible residual unit commitment capacity.[48] Nor would it prevent feasible day-ahead ancillary services and residual unit commitment capacity from becoming infeasible due to the bidding strategy described in this filing of buying back day-ahead energy schedules to PMin in the real-time market.

Accordingly, it is necessary to apply the mitigated exceptional dispatch energy settlement rule to exceptional dispatches issues to access stranded ancillary services awards and residual unit commitment capacity for reliability reasons and to mitigate the unilateral exercise or market power. As Dr.

[48] *Id.* at 47-48.

Hildebrant explains, limiting the amount of ancillary service capacity that can be bid in to the amount the unit could provide while operating at minimum load would artificially restrict the amount of ancillary services actually available to the market. This could also provide a way for suppliers to withhold capacity from the ancillary service market. The ISO tariff includes a key provision designed to specifically prevent this by requiring that resource adequacy units make their full ancillary service capacity available in the market.[49] As discussed above, other alternatives such as forced ancillary services buy-back and exceptionally dispatching off-line resources involve unacceptable costs and risks to reliability.

Mitigation is an appropriate remedy because as Dr. Hildebrandt has concluded, the bidding behavior constitutes an exercise of market power. Market power is broadly defined as the ability of a supplier to unilaterally set prices significantly in excess of levels that would result in a competitive market. For example, a generator has market power if they can effectively demand any price for their energy as a result of a lack of other supply alternatives or demand elasticity. As described in Ms. Le Vine's testimony, when the supply of replacement ancillary service capacity is limited in this real-time market, the ISO may determine it has no choice but to issue an exceptional energy dispatch to ramp the unit up to a level at which the unit would be able to provide its day-ahead ancillary service schedule, even though this energy is bid at an extremely high and uncompetitive price. This represents the equivalent of unilateral market power by the supplier. Moreover, the day-ahead bidding scheme discussed above has been employed to specifically create the conditions that dramatically increase the likelihood that this unilateral market power will exist.[50] This market power has been exercised to generate payments of over $1 million per day at a price of about $1,000/MW. As noted above, the Commission has previously recognized the possibility that the ISO's experience with its new market structure would reveal evidence of an exercise of market power that would require expansion of the types of exceptional dispatches that are to be settled under the mitigation rules. The ISO has with this filing provided actual evidence of the existence and exercise of market power when the ISO must exceptionally dispatch resources in order to make ancillary services wards and residual unit commitment capacity feasible.

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[49] *Id.* at 47.

[50] *Id.* at 51.

IV. EFFECTIVE DATE

Pursuant to Section 35.11 of the Commission's regulations,[51] the ISO requests that the Commission waive its notice requirements for the proposed amendment, accept it for filing, and permit it to become effective on June 23, 2011.[52] Good cause exists for granting this waiver.

The proposed tariff amendment eliminates the potential for continued unexpected market outcomes resulting from a bidding practice and existing market rule deficiency that result in exaggerated payments to resources for bid cost recovery uplift. The ISO normally follows a robust stakeholder process to develop such market rule changes. In this case, however, because the described unexpected market outcome can be exacerbated if engaged in by multiple scheduling coordinators, it is necessary to immediately eliminate any incentive to engage in such activity. The proposed amendments immediately put in place a tariff rule that eliminates the opportunity for excessive bid cost recovery amounts that would incentivize the bidding practice.

The proposed amendment consists of settlement rules that are narrowly tailored to eliminate the opportunity for excessive bid cost recovery amounts associated with the observed bidding practice.

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[51] 18 C.F.R. § 35.11 (2010).

[52] The ISO requests an effective date of June 23, 2011, but notes that the requested rule changes in Sections 11.8.2.4 and 11.8.2.1.5 will be implemented in upcoming settlement statements (currently targeted for 76 business days after the applicable trade date) due to the need to modify the ISO settlement charge codes and upstream systems in order to implement the requested rules.

V. COMMUNICATIONS

The ISO requests that all correspondence, pleadings and other communications concerning this filing be served upon the following:

Nancy Saracino
General Counsel
Sidney Davies
Assistant General Counsel
*Anna A. McKenna
Senior Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7222
amckenna@caiso.com

*Individual designated for service pursuant to 18 C.F.R. § 203(b)(3).

VI. SERVICE

The ISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, and all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO Website.

VII. ATTACHMENTS

The following documents, in addition to this transmittal letter, support the instant filing:

Attachment A	Revised ISO Tariff sheets that incorporate the proposed changes described above
Attachment B	The proposed changes to the ISO Tariff shown in black-line format
Attachment C	Exhibit ISO-1: Prepared Direct Testimony of Dr. Eric Hildebrandt

Attachment D	Exhibit ISO-2: Prepared Direct Testimony of Ms. Debi Le Vine
Attachment E	Description of Bid Cost Recovery Mechanism

VIII. CONCLUSION

For all the foregoing reasons, the Commission should accept the proposed amendments to become effective on June 23, 2011. Please contact the undersigned if you have any questions concerning this matter.

Respectfully submitted,

By: /s/ Anna McKenna

Nancy Saracino
General Counsel
Sidney Davies
Assistant General Counsel
Anna A. McKenna
Senior Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7222
amckenna@caiso.com

Attorneys for the California Independent
System Operator Corporation

Attachment A – Clean Tariff

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

June 22, 2011

* * *

11.8.2.1.5 IFM Energy Bid Cost

For any Settlement Interval, the IFM Energy Bid Cost for Bid Cost Recovery Eligible Resources, except Participating Loads, shall be the integral of the relevant Energy Bid submitted to the IFM, if any, from the higher of the registered Bid Cost Recovery Eligible Resource's Minimum Load and the Day-Ahead Total Self-Schedule up to the relevant MWh scheduled in the Day-Ahead Schedule, divided by the number of Settlement Intervals in a Trading Hour. The IFM Energy Bid Cost for Bid Cost Recovery Eligible Resources, except Participating Loads, and except for any portion of the Day-Ahead Schedule associated with an Energy Bid less than zero, for any Settlement Interval is set to zero for any portion of the Day-Ahead Schedule that is not delivered from the otherwise Bid Cost Recovery Eligible Resource that has metered Generation below its Day-Ahead Schedule; any portion of the Day-Ahead Schedule that is actually delivered remains eligible for IFM Energy Bid Cost Recovery. The delivered portions of the Day-Ahead Schedule for this calculation are determined using the Day-Ahead Metered Energy Adjustment Factor. The Day-Ahead Metered Energy Adjustment Factor is not applied to IFM Energy Bid Costs that associate with Energy Bids that are less than zero. The CAISO will determine the IFM Energy Bid Cost for a Multi-Stage Generating Resource at the Generating Unit or Dynamic Resource-Specific System Resource level. The CAISO will determine the applicable net IFM Energy Bid Cost surplus or net IFM Energy Bid Cost shortfalls as described in Section 11.8.2.4.

* * *

11.8.2.4 Ramping for IFM Initial Conditions or Self-Schedules

The CAISO shall determine the net IFM Bid Cost surplus or net IFM Bid Cost shortage across all full ramp down periods that start with an initial condition at the start of the IFM or a full ramp period within a 24 hour day-ahead market associated with a Self-Schedule any time within the full ramp period. For such full ramp periods associated with an initial condition or Self-Schedule with a net IFM Bid Cost shortfall, the net IFM Energy Bid Cost shortfall will not be included in IFM Bid Cost calculations. For the full ramp periods with a net IFM Bid Cost surplus, the surplus will be included in IFM Bid Cost calculations. For full other ramp periods not associated with an initial condition or Self-Schedule with IFM Energy Bid Cost shortfall, the shortfall with be included in IFM Bid Cost calculations. The CAISO will identify the Trading Hours scheduled as full ramp up periods as of the first hour where the resource is ramping up at full ramp until the last hour where the resource is ramping up at full ramp. Likewise, a full ramp down period will be identified as of first hour where the resource is ramping down at full ramp until the last hour that the resource is ramping down at full ramp.

* * *

39.10 Mitigation Of Exceptional Dispatches Of Resources

The CAISO shall apply Mitigation Measures to Exceptional Dispatches of resources when such resources are committed or dispatched under Exceptional Dispatch for purposes of: (1) addressing reliability requirements related to non-competitive Transmission Constraints; (2) ramping resources with Ancillary Services Awards or RUC Capacity to a dispatch level that ensures their availability in Real-Time; and (3) addressing unit-specific environmental constraints not incorporated into the Full Network Model or the CAISO's market software that affect the dispatch of Generating Units in the Sacramento Delta and are commonly known as "Delta Dispatch".

Attachment B – Marked Tariff

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

June 22, 2011

* * *

11.8.2.1.5 IFM Energy Bid Cost

For any Settlement Interval, the IFM Energy Bid Cost for Bid Cost Recovery Eligible Resources, except Participating Loads, shall be the integral of the relevant Energy Bid submitted to the IFM, if any, from the higher of the registered Bid Cost Recovery Eligible Resource's Minimum Load and the Day-Ahead Total Self-Schedule up to the relevant MWh scheduled in the Day-Ahead Schedule, divided by the number of Settlement Intervals in a Trading Hour. The IFM Energy Bid Cost for Bid Cost Recovery Eligible Resources, except Participating Loads, and except for any portion of the Day-Ahead Schedule associated with an Energy Bid less than zero, for any Settlement Interval is set to zero for any portion of the Day-Ahead Schedule that is not delivered from the otherwise Bid Cost Recovery Eligible Resource that has metered Generation below its Day-Ahead Schedule; any portion of the Day-Ahead Schedule that is actually delivered remains eligible for IFM Energy Bid Cost Recovery. The delivered portions of the Day-Ahead Schedule for this calculation are determined using the Day-Ahead Metered Energy Adjustment Factor. The Day-Ahead Metered Energy Adjustment Factor is not applied to IFM Energy Bid Costs that associate with Energy Bids that are less than zero. The CAISO will determine the IFM Energy Bid Cost for a Multi-Stage Generating Resource at the Generating Unit or Dynamic Resource-Specific System Resource level. The CAISO will determine the applicable net IFM Energy Bid Cost surplus or net IFM Energy Bid Cost shortfalls as described in Section 11.8.2.4.

* * *

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* * *

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System)
Operator Corporation)

Docket Nos. ER11-____

ATTACHMENT C

PREPARED DIRECT TESTIMONY
OF
DR. ERIC HILDEBRANDT

ON BEHALF OF

THE CALIFORNIA INDEPENDENT SYSTEM

OPERATOR CORPORATION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System) Docket No. ER11-____-___
Operator Corporation)

PREPARED DIRECT TESTIMONY
OF
DR. ERIC HILDEBRANDT ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Eric Hildebrandt. My business address is 250 Outcropping Way, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am the Director of the Department of Market Monitoring (DMM) of the California Independent System Operator (ISO). I oversee the independent market monitoring unit charged with monitoring of ISO market performance and behavior. In this capacity, I am responsible for analyzing performance of the ISO markets, assessing the impact of market rules and behavior of market participants on market performance, investigating potential non-compliance with ISO and Federal Energy Regulatory Commission (FERC or Commission) market rules, and helping to design market rules that promote overall market efficiency, mitigate market power and deter detrimental market behavior. I have previously served in several managerial positions in the Department of Market Monitoring which involved similar responsibilities.

Q. Please describe your professional and educational background.

A. I have twenty-two years of experience in the electric utility industry, along with a B.S. degree in Political Economy from Colorado College, and a M.S. and Ph.D. in Energy Management and Policy from the University of Pennsylvania. I worked over six years as an economic consultant to the electric utility industry with the consulting firms of Xenergy Inc. and Hagler Bailly. I then worked over three years at the Sacramento Municipal Utility District as Supervisor of Monitoring and Evaluation. Since joining the ISO's Department of Market Monitoring in 1998, I have worked extensively on a wide range of issues involving analysis of market performance, market participant behavior, and design of market rules that promote market efficiency and deter potential detrimental market behavior. Following California's energy crisis of 2000-2001, I was the ISO's lead investigator on a wide range of investigations and other regulatory proceedings relating to market behavior of individual participants in California's wholesale energy markets. In this capacity, I performed extensive analysis to identify scheduling and trading practices involving abuse of market power, manipulation, gaming, and other anomalous market behavior inconsistent with ISO market rules or competitive efficient markets. Over the last six years, I have played a lead role in developing and implementing new FERC and ISO market rules to prevent or address such detrimental market behavior in the future. During this period, I have also led the ISO's efforts to monitor and investigate potential non-compliance with current ISO and FERC behavioral market rules, and to refer potential violations of these rules to the Commission's Office of Enforcement.

Q. Have you previously testified before the Commission?

A. Yes. I have previously testified in the following matters. In Docket ER08-1113, I testified on how the ISO's proposal for treatment of Integrated Balancing Authority Areas would mitigate potential market inefficiencies and gaming. I have provided testimony on behalf of the ISO in the Commission's proceedings concerning gaming and market manipulation in the California wholesale electric markets (Docket No. EL03-137-000, et al), and in the so-called "100 Days Evidence" proceeding (Docket Nos. EL05-05-069 and EL00-98-042). I also provided testimony on behalf of the ISO in the proceeding concerning refunds for transactions in the California wholesale electric markets (Docket Nos. EL00-95-000, et. al), as well as affidavits and analysis in support of the ISO's efforts to mitigate the market failures during the California energy crisis of 2000-01. During 1999, I provided testimony in proceedings related to RMR contracts in California (Docket Nos. ER98-496-000, ER98-18 1614-000, ER2145-000 and ER99-3603). While working at the ISO, I have also submitted numerous affidavits and analyses to the Commission in conjunction with confidential investigations of market behavior.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to explain three issues related to a general bidding strategy that has resulted in economic and operational outcomes that are inefficient and inconsistent with those expected under a competitive market. I also identify a fourth potential bidding strategy that has not been observed yet, but because of the similarity to the identified practices, can also lead to similar adverse market outcomes if parties were to engage in such a bidding strategy and it were left unmitigated. Finally, I discuss three market rule changes the ISO is proposing in this proceeding that will address these issues:

1) The first of these rule changes involves a modification to the accounting of energy bid costs to ensure that negative energy bids accepted in the day-ahead market are included in bid cost recovery calculations. The modification to the bid cost recovery rules made in the ISO's March 25, 2011 filing in Docket No. ER11-3149 was effective at mitigating the behavior and high bid cost recovery payments associated with the behavior identified and discussed in that filing. However, this additional rule change is necessary to ensure that the newly identified bidding practices cannot be employed to create inefficient and uncompetitive market outcomes.

2) The second of these changes involves a modification of the settlement provisions for any energy needed to ramp a unit from its day-ahead schedule at the end of one trading day to its day-ahead feasible

schedule at the start of the next trading day. This modification is necessary to eliminate the incentive to exploit bid cost recovery for ramping energy that may be needed for a unit to transition from its day-ahead schedule at the end of one trade day to its day-ahead schedule in the first hours of the next trade day. This same rule would apply to any ramping energy needed to make a unit's day-ahead market self-schedules feasible. This is necessary to ensure that a supplier could not self-schedule in a way to create bid cost recovery payments for any ramping energy awarded by the day-ahead market software to make a unit's day-ahead market self-schedules feasible.

3) The third change is to implement mitigation for uncompetitively priced bids that must periodically be exceptionally dispatched to make market awarded ancillary service or residual unit commitment capacity available in the real-time market. This measure addresses the fact that the certain bidding behavior combined with some features of the current market design features can cause capacity scheduled in the day-ahead market to provide ancillary services or residual unit commitment capacity can be *stranded*, or unavailable in real-time because of a unit's real-time dispatch level. The ISO is seeking to reduce the need to rely on exceptional dispatch to access stranded market awarded capacity through modifications to its day-ahead market rules and software. However, until these issues can be resolved through a combination of operational and market rules and software changes, the ISO is

proposing that exceptional dispatches issued to access infeasible ancillary services awards and residual commitment capacity be subject to mitigation in the settlement process. Under these provisions, any additional energy needed to make ancillary service or residual unit commitment capacity feasible would be paid the higher of the locational marginal price or the resource's default energy bid and would be ineligible to be paid as bid.

Q. Are these three issues and market rule changes related?

A. Yes. The three issues are related in that they have all been exploited as part of a overall bidding scheme that appears to be specifically designed to create excessive bid cost recovery payments and, periodically, excessive payments from exceptional dispatches. The first issue – negative day-ahead bid prices that are subsequently canceled out of bid cost recovery calculations when this energy is not delivered in the real-time market – allows a supplier to bid in a way that gets a unit committed in the day-ahead market and to then receive inflated bid cost recovery payments by raising bid prices in the real-time market to ensure that units are dispatched below their day-ahead schedules. These bid cost recovery payments and the resulting schedules can be used to enable and subsidize other undesirable and uncompetitive bidding practices. For example, this fundamental bidding scheme has been employed to ensure that resources are scheduled at their minimum load during all of the peak hours of the day and schedule at or near maximum load during the last few hours of day. This sets up the conditions necessary for the second and third issues to become more problematic. These other issues have only recently become problematic due to anomalous bidding behavior associated the first issue. Thus, the ISO's filing includes a series of market rules changes that address these three issues separately, but together will to deter undesirable and uncompetitive bidding practices.

II. DESCRIPTION OF THE ISO'S BID COST RECOVERY MECHANISM

Q. What is the bid cost recovery mechanism?

A. The bid cost recovery mechanism is a series of market rules and calculations that together serve as the mechanism for ensuring that resources dispatched or scheduled by the ISO receive their unrecovered energy bid costs and that resources committed by the ISO receive in addition their unrecovered start-up and minimum load bid costs. The bid cost recovery mechanism performs four main functions: 1) calculates the applicable bid costs to be paid if a resource is dispatched or scheduled by the ISO; 2) determines the applicable market revenues earned by that resource; 3) offsets the calculated bid costs by the market revenue to determine bid cost recovery uplift to be paid to the resource; and 4) allocates to ISO load and exports the total cost of the bid cost recovery uplift paid to resources.

Q. How does the ISO calculate the applicable bid costs to be paid to a resource?

A. Bid costs include a resource's start-up and minimum load costs and its energy or ancillary services bid costs. The ISO pays a resource's unrecovered start-up and minimum load bid costs only for time periods in which the ISO committed the resource. The unrecovered energy or ancillary services bid costs are calculated and paid if, for a given time period (24 hours), the resource is scheduled at prices below the bid price included in its bid for the relevant time period. This ensures that the resource is not paid lower than its submitted bid price over the relevant time period.

Q. Please describe how start-up and minimum load bid costs are determined for each resource.

A. Pursuant to section 30.4 and 39.6.1.6 of the tariff, start-up costs can either be based on a proxy cost, which is cost-based, or registered cost, which is a value registered by the scheduling coordinator subject to a cap. Scheduling coordinators are allowed to register up to 200% of the proxy-based minimum load costs to account for costs that are not directly incorporated into the proxy based cost calculation.

Q. Are the bid costs paid if market revenues earned by the resource exceed the bid costs?

A. No. The ISO's market is designed to guarantee recovery only of the resource's *unrecovered* bid costs – that is, only to the extent their market revenues do not cover these costs over a 24 hour period. Resources scheduled in the day-ahead market are settled at the locational marginal price (LMP) cleared in the day-ahead integrated forward market for all the energy scheduled, regardless of whether the energy is delivered in real-time. Similarly, resources dispatched in the real-time market are settled at the applicable LMP in that market. To the extent these market revenues meet or exceed the bid costs, there are no unrecovered bid costs and therefore no need to provide additional compensation through the bid cost recovery mechanism. Accordingly, under the bid cost recovery mechanism, the ISO offsets the calculated bid costs by the market revenue costs, first at the interval level and ultimately based on all market revenues earned by the resource across all of the ISO markets over the 24 hour period of a trade day.

Q. With respect to IFM bid costs, does the ISO pay these bid costs associated with all energy scheduled in the IFM?

A. No. The ISO only pays for the bid costs associated with portions of the day-ahead scheduled energy that are actually delivered. The ISO does not guarantee recovery of bids costs for the resource for energy that is not delivered as measured by the metered data. This requirement is consistent with the Commission's prior directive specified in the September 21, 2006 order in Docket ER06-615, specifying that the ISO should not pay bid costs for scheduled energy not actually delivered. Minimum load costs are paid only to the extent that the resource is actually on-line in the applicable trading hour, subject to a tolerance band. Similarly, start-up costs are only paid to the extent the resource actually starts up within the applicable commitment period.

Q. Under what circumstances may a resource deliver less energy than is scheduled day-ahead?

A. A resource's day-ahead schedule is financial binding, but does not necessarily cause the ISO to dispatch the resource in real-time through the real-time market dispatch. For the hour-ahead scheduling process and real-time market, the scheduling coordinator may increase or decrease the bid for any energy that was scheduled day-ahead (re-bid), as well as submit bids for any energy that was not scheduled day-ahead. Actual dispatch is based upon bids in the real-time market. Thus, a unit that is scheduled day-ahead, but submits real-time bids greater than the expected real-time price, may be dispatched at a level less than its day-ahead schedule. It is also possible that a resource may simply fail to deliver energy that was dispatched. However, resources remain financially responsible for their day-ahead schedules, and must pay the real-time price any energy that was scheduled day-ahead but which the ISO did not dispatch. This is sometime referred to as *buying back* day-ahead energy schedule in the real-time market.

Q. How does the ISO determine the portion of the day-ahead scheduled energy that was delivered and for which the resource will receive energy bid cost recovery?

A. The ISO compares the metered energy for a given resource to its day-ahead schedule. A formula known as the day-ahead metered energy adjustment factor (MEAF) is used to determine the portion of day-ahead schedule issued by the ISO for a specific resource that is actually delivered. A detailed description of the MEAF calculation was provided with the ISO's March 25 filing. When a generator is scheduled above minimum load in the day-ahead market, but then operates below this day-ahead energy schedule in real-time, the MEAF is essentially calculated as follows:

(Metered Energy – Minimum Load) ÷

(Day-Ahead Scheduled Energy - Minimum Load)

Thus, the MEAF reflects the portion of the energy curve above its minimum load dispatched in the day-ahead market based on the unit's day-ahead bid curve that was delivered in the real-time market. For example, if only 80 percent of the energy scheduled above minimum load in the day-ahead schedule is ultimately delivered in real-time, the ISO pays energy bid cost recovery to 80 percent of the scheduled energy. In other words, the ISO determines the energy bid cost recovery amounts that would apply for the energy scheduled in the day-ahead schedule and applies the day-ahead MEAF. In his testimony accompanying the March 25 filing, Mr. Mark Rothleder provided numerical examples of the mechanics of the day-ahead MEAF in determining the delivered portions of the day-ahead schedule.

Q. How does the ISO determine the IFM market revenue used to offset the IFM calculated bid costs for a given hour?

A. Prior to the March 25 tariff amendment, the ISO based the market revenue calculation on the delivered portions of the day-ahead schedule. As explained in the March 25 filing, this allowed a bidding strategy that resulted in a significant overpayment of bid cost recovery in some cases. In cases where the resource is dispatched down from its day-ahead schedule, the resource's the ISO now calculates day-ahead market energy revenues earned by the resource for a given trading hour as the product of the resource's total MWhs scheduled in the day-ahead market (including minimum load energy) and the applicable LMP. In such cases, the ISO no longer applies the day-ahead MEAF to the calculation of revenues for energy above minimum load scheduled in the day-ahead market. As explained in the March 25 filing, this specific change was adopted because prior to that time, resources were engaging in a specific bidding strategy that resulted in the ISO dispatching the resource down to or close to minimum load, which was resulting in the lack of consideration of the resource's IFM market revenue given that in such cases the day-ahead MEAF tended towards zero.

III. ISSUE 1: USE OF METERED ENERGY ADJUSTMENT FACTOR IN CALCULATING DAY-AHEAD MARKET BID COSTS

Q. How effective is the day-ahead MEAF in determining bid costs for the delivered portions of a resource's day-ahead schedule?

A. Generally, the day-ahead MEAF is effective in determining the energy bid costs for portions of the day-ahead schedule that are actually delivered in real-time. However, application of the MEAF to energy scheduled as a result of negative day-ahead bids which are not delivered in real-time provide market participants with a continuing opportunity to artificially inflate bid cost recovery payments through a particular bidding strategy. Such artificially inflated bid cost recovery payments "subsidize" or facilitate several other bidding strategies that hinder the efficiency of the ISO market and create other unnecessary market costs.

Q. Can you provide an example?

A. Yes. Let me provide an example, to use throughout my discussion of these issues. Consider a gas-fired generating unit with a maximum capacity (*i.e.*, PMax) of 300 MW. The resource has registered its minimum load (*i.e.*, PMin) of 25 MW. The unit can increase its operation, or *ramp up*, from its 25 MW minimum load up to 125 MW in one hour and, from there, can ramp up to its maximum capacity of 300 MW in the second hour. It can ramp down from 300 MW to 125 MW in one hour and then down to its minimum operating level of 25 MW in the next hour. The unit is relatively inefficient to operate at minimum load and has an operating cost of about $73/MW at minimum load. However, the entity controlling the units has submitted a minimum load bid cost at the maximum limited under the registered cost option, *i.e.*, 200% of proxy costs. The unit's proxy bid cost is $80/MW – its estimated operating cost at minimum load ($73/MW) plus a 10% adder. Thus its minimum load bid is $160/MW, or $4,000 for its 25 MW minimum load. The units incremental operating cost for energy above minimum load is $40/MW.

Q. Is this a realistic example?

A. Yes. The unit characteristics and bidding patterns depicted in the examples provided in this testimony are representative of the actual conditions that market rule changes proposed in this filing are designed to mitigate. All of the specific scenarios described in my testimony realistically reflect situations that occurred during April to June 2011. The specific hours and bid prices used in the examples are based on extensive quantitative analysis of market activity during April to May 2011 and are highly representative of the behavior targeted by the proposed rules changes. In my discussion of this example, I will also use hourly market prices that are approximately equal to the actual average hourly prices in the ISO markets during April to May 2011.

Q. Please provide an example of the use of this bidding strategy in the day-ahead market.

A. Under this strategy, the supplier will bid a small amount of energy at ISO's -$30/MW bid floor that is sufficient to get the unit committed by the ISO market software. The supplier bids all other energy at or near the $1,000/MW bid cap. As shown in Table 1, this is done by bidding the unit's available capacity at -$30/MW in hours 12 to 13 and hours 20 to 24. During some of these hours, the unit is not scheduled at its maximum 300 MW capacity despite these -$30/MW bids due to ramping constraints. As shown in Table 1, the market revenues from its total accepted bids ($60,624) exceed the bid costs for these bids ($57,000). Therefore, the

ISO software will commit and schedule the unit in the day-ahead market. It is important to note that the reason the unit is committed is that the unit's relatively high minimum load bid costs ($96,000) are offset by the negative bid cost of the accepted energy bids at the -$30/MW bid floor (-$39,000). Thus, by itself, this day-ahead bidding strategy does not cause excessive bid cost recovery. However, when combined with a real-time bidding strategy that causes the resource to be dispatched below its day-ahead schedule, this bidding strategy can artificially trigger and inflate bid cost recovery payments.

Q. What is this real-time bidding strategy?

A. In the real-time market, the supplier raises the bid for the energy that was scheduled in the day-ahead market (as a result of -$30/MW bids) to a bid price that is unlikely to clear in the real-time market. The optimal strategy for inflating the bid cost recovery payments is to submit real-time bid prices that will be consistently just above real-time prices. This ensures the unit usually operates at or near minimum loads when it was scheduled at higher levels in the day-ahead market, while maximizing bid cost recovery payments. Our analysis indicates that, under this scheme, energy that was bid at -$30/MW in the day-ahead market was generally re-bid in the real-time market at price equal to about 120% of the day-ahead LMP for that hour. This appears to be a *rule of thumb* for re-bidding this energy in real-time market, with occasional adjustments to account for expectations of higher or lower real-time prices. The dynamic nature of these real-time bids from hour to hour shows that the supplier is maximizing bid cost recovery payments by submitting real-time bid prices that are consistently above real-time prices – but only by the minimum amount necessary to ensure these bids do not clear in real-time.

Q. If the objective of the strategy is to be dispatched at minimum load, why wouldn't a supplier just submit an extremely high bid price in the real-time market?

A. This would decrease the overall bid cost recovery payments that can be achieved by this scheme. Under this scheme, because the unit is dispatched at a level below its day-ahead schedule, the unit provides decremental real-time energy and incurs negative real-time bid recovery costs since its bid costs for this decremental energy are higher than the market price of the decremental energy that the unit "buys back." To trigger and inflate bid cost recovery payments, the negative day-ahead energy bid costs that are "cancelled out" by operating below the unit's day-ahead schedule must be greater than net negative real-time bid recovery costs (or real-time revenues) that are created by bidding in the real-time market to ensure the unit is dispatched below the unit's day-ahead schedule. The greater the difference between the real-time bid and the real-time price, the lesser the difference between the amount by which the increased day-ahead bid cost exceeds the negative real-time bid recovery.

Q. Can you provide an example of how a supplier can successfully bid in the real-time market to inflate bid cost recovery payments?

A. Sure. For instance, assume a unit bids $1,000/MW in the real-time market when the market price is $50/MW, and as a result is dispatched below its day-ahead schedule by 100 MW. This would represent a decremental energy bid cost of -$100,000 (-100 MW x $1,000/MW bid price). The revenues for this decremental real-time energy would be only -$5,000 (100 MW x $50/MW), *i.e.*, the scheduling coordinator would pay $5,000. This would reduce the total bid cost recovery (day-ahead and real-time) by $95,000. Instead, assume a unit's bid is $60/MW in the real-time market when the market price is $50/MW. This example is consistent with the previously mentioned rule of thumb of submitting real-time bids equal to about 120% of the day-ahead price. Under this scenario, the unit is also dispatched below its day-ahead schedule by 100 MW. However, this would represent a decremental energy bid cost of only -$6,000 (-100 MW x $60/MW bid price). The negative revenues paid by the supplier for his decremental real-time energy would be only $5,000 (100 MW x $50/MW). Thus, this would reduce the total bid cost recovery by only $1,000.

Q. How would this real-time bidding strategy work given the day-ahead market example illustrated in Table 1?

A. Table 2 shows the impact of this bidding strategy in the real-time market given the same day-ahead example depicted in Table 1. In Table 2, all energy that was scheduled in the day-ahead market as a result of -$30/MW bids is re-bid in the real-time market at a price equal to 120% of the day-ahead price. During all other hours, when the unit is scheduled at minimum load, all of the unit's capacity is bid at the price cap of $1,000/MW. As previously noted, hourly day-ahead and real-time market prices used in this example are approximately equal to the actual average hourly prices in these markets April to May 2011. As shown in Table 2, this bidding strategy results in the unit operating at minimum load during all hours. The unit will be charged a total of $45,525/MW (representing negative revenues) for 1,300 MW of decremental real–time energy, representing an average real-time price of $35/MW. The total real-time bid cost of this 1,300 MW of decremental energy is just over $56,000 (-1,300 MW at an average bid price of about $43/MW). This results in a net real-time bid cost recovery total of -$10,958 for the day. This negative total reflects the fact the cost paid by the supplier for this decremental energy was lower than the amount the supplier would have been willing to pay for this decremental energy as reflecedt in its real-time energy bids.

Table 1. Day-ahead Market Bidding and Results (Base Case)

				Day-ahead revenues		Day-ahead bid costs	
Hour	**Day-ahead energy bid price**	**Day-ahead LMP**	**Day-ahead schedule (MW)**	**Minimum load energy**	**Energy above minimum load**	**Minimum load bid cost**	**Energy above minimum load**
1	$1,000	$18	25	$450	$0	$4,000	$0
2	$1,000	$12	25	$300	$0	$4,000	$0
3	$1,000	$5	25	$125	$0	$4,000	$0
4	$1,000	$4	25	$100	$0	$4,000	$0
5	$1,000	$6	25	$150	$0	$4,000	$0
6	$1,000	$13	25	$325	$0	$4,000	$0
7	$1,000	$24	25	$600	$0	$4,000	$0
8	$1,000	$34	25	$850	$0	$4,000	$0
9	$1,000	$35	25	$875	$0	$4,000	$0
10	$1,000	$34	25	$850	$0	$4,000	$0
11	$1,000	$37	25	$925	$0	$4,000	$0
12	-$30	$38	125	$950	$3,800	$4,000	-$3,000
13	-$30	$37	125	$925	$3,700	$4,000	-$3,000
14	$1,000	$37	25	$925	$0	$4,000	$0
15	$1,000	$35	25	$875	$0	$4,000	$0
16	$1,000	$35	25	$875	$0	$4,000	$0
17	$1,000	$31	25	$775	$0	$4,000	$0
18	$1,000	$29	25	$725	$0	$4,000	$0
19	$1,000	$27	25	$675	$0	$4,000	$0
20	-$30	$38	125	$950	$3,800	$4,000	-$3,000
21	-$30	$47	200	$1,175	$8,225	$4,000	-$5,250
22	-$30	$37	300	$925	$10,175	$4,000	-$8,250
23	-$30	$29	300	$725	$7,975	$4,000	-$8,250
24	-$30	$23	300	$575	$6,325	$4,000	-$8,250
		Daily totals	**1,900**	**$16,625**	**$44,000**	**$96,000**	**-$39,000**

	Revenues	Bid costs
Minimum load	$16,625	$96,000
Energy	$44,000	-$39,000
Total	$60,625	$57,000

Table 2. Real-time Market Bidding and Results (Base Case)

Hour	Day-ahead schedule (MW)	Real-time energy bid price	Real-time LMP	Real-time dispatch (MW)	Real-time energy (MW)	Real-time energy revenue	Real-time energy bid cost	MEAF for day-ahead bid costs
1	25	$1,000	$27	25	0	$0	$0	--
2	25	$1,000	$24	25	0	$0	$0	--
3	25	$1,000	$8	25	0	$0	$0	--
4	25	$1,000	$10	25	0	$0	$0	--
5	25	$1,000	$8	25	0	$0	$0	--
6	25	$1,000	$13	25	0	$0	$0	--
7	25	$1,000	$15	25	0	$0	$0	--
8	25	$1,000	$36	25	0	$0	$0	--
9	25	$1,000	$34	25	0	$0	$0	--
10	25	$1,000	$34	25	0	$0	$0	--
11	25	$1,000	$29	25	0	$0	$0	--
12	125	$62	$33	25	-100	-$3,300	-$6,217	0.00
13	125	$65	$37	25	-100	-$3,700	-$6,466	0.00
14	25	$1,000	$30	25	0	$0	$0	--
15	25	$1,000	$33	25	0	$0	$0	--
16	25	$1,000	$32	25	0	$0	$0	--
17	25	$1,000	$32	25	0	$0	$0	--
18	25	$1,000	$25	25	0	$0	$0	--
19	25	$1,000	$23	25	0	$0	$0	--
20	125	$46	$35	25	-100	-$3,500	-$4,560	0.00
21	200	$56	$43	25	-175	-$7,525	-$9,870	0.00
22	300	$44	$40	25	-275	-$11,000	-$12,210	0.00
23	300	$35	$34	25	-275	-$9,350	-$9,570	0.00
24	300	$28	$26	25	-275	-$7,150	-$7,590	0.00
Total	**1,900**			**600**	**-1,300**	**-$45,525**	**-$56,483**	

	Revenues	Bid costs
Real-time energy	-$45,525	-$56,483
	Real-time BCR =	-$10,958

Q. How would this unit end up receiving any bid cost recovery?

A. This is because under the current tariff the MEAF is applied to the unit's negatively priced bids that cleared in the day-ahead market. As shown in the last column of Table 2, the MEAF is 0 for hours when the unit was scheduled in the day-ahead market since the unit ran at its minimum load each of these hours. Table 3 shows how the total bid cost recovery payments are calculated after the MEAF is applied to the unit's negatively priced bids that cleared in the day-ahead market. As shown in Table 3, application of the MEAF to the unit's -$30/MW day-ahead energy bids eliminates the -$39,000 day-ahead energy bid costs. As shown below Table 3, this results in day-ahead bid costs of $35,375 more than the unit's day-ahead revenues. After that amount is reduced by the -$10,958 negative net bid cost recovery total from the real-time market, the unit receives a net bid cost recovery payment $24,417.

Table 3. Bid Cost Recovery Results (Base Case)

				Day-ahead revenues		Day-ahead bid costs			
Hour	Day-ahead energy bid price	Day-ahead LMP	Day-ahead schedule (MW)	Minimum load energy	Energy above minimum load	Minimum load bid cost	MEAF	Energy above min load	Energy above min load (MEAF adjusted)
1	$1,000	$18	25	$450	$0	$4,000	--	$0	$0
2	$1,000	$12	25	$300	$0	$4,000	--	$0	$0
3	$1,000	$5	25	$125	$0	$4,000	--	$0	$0
4	$1,000	$4	25	$100	$0	$4,000	--	$0	$0
5	$1,000	$6	25	$150	$0	$4,000	--	$0	$0
6	$1,000	$13	25	$325	$0	$4,000	--	$0	$0
7	$1,000	$24	25	$600	$0	$4,000	--	$0	$0
8	$1,000	$34	25	$850	$0	$4,000	--	$0	$0
9	$1,000	$35	25	$875	$0	$4,000	--	$0	$0
10	$1,000	$34	25	$850	$0	$4,000	--	$0	$0
11	$1,000	$37	25	$925	$0	$4,000	--	$0	$0
12	-$30	$38	125	$950	$3,800	$4,000	0.00	-$3,000	$0
13	-$30	$37	125	$925	$3,700	$4,000	0.00	-$3,000	$0
14	$1,000	$37	25	$925	$0	$4,000	--	$0	$0
15	$1,000	$35	25	$875	$0	$4,000	--	$0	$0
16	$1,000	$35	25	$875	$0	$4,000	--	$0	$0
17	$1,000	$31	25	$775	$0	$4,000	--	$0	$0
18	$1,000	$29	25	$725	$0	$4,000	--	$0	$0
19	$1,000	$27	25	$675	$0	$4,000	--	$0	$0
20	-$30	$38	125	$950	$3,800	$4,000	0.00	-$3,000	$0
21	-$30	$47	200	$1,175	$8,225	$4,000	0.00	-$5,250	$0
22	-$30	$37	300	$925	$10,175	$4,000	0.00	-$8,250	$0
23	-$30	$29	300	$725	$7,975	$4,000	0.00	-$8,250	$0
24	-$30	$23	300	$575	$6,325	$4,000	0.00	-$8,250	$0
		Daily totals	**1,900**	**$16,625**	**$44,000**	**$96,000**		**-$39,000**	**$0**

Day-ahead (after MEAF)	Revenues	Bid costs
Minimum load	$16,625	$96,000
Energy	$44,000	$0
Total	$60,625	$96,000
	Day-ahead BCR =	$35,375

Real-time	Revenues	Bid costs
Energy	-45,525	-56,483
	Real-time BCR =	-$10,958

	Total BCR	$24,417

Q. Is this strategy profitable if the resource deviates from its day-ahead schedule in the real-time?

A. By itself, this bid cost recovery payment may not make it profitable to operate a unit in this manner. In this example, the unit would receive $60,625 in revenues from its day-ahead minimum load and energy schedules. It would pay $45,525 for real-time decremental energy. This represents net market revenue of only $15,100. The bid cost recovery payment of $24,417 would bring the unit's total revenues to just under $40,000. In this example, the unit's actual operating costs would be about $43,000 (600 MWh (24 hours x 25MW) of minimum load energy @ $73/MW). Thus, the inflated bid cost recovery payments due to application of the MEAF to negative day-ahead energy bids may not by itself make it profitable to operate a unit in this manner. However, these inflated bid cost recovery payments appear to be used to enable and "subsidize" other undesirable and uncompetitive bidding practices. For example, this basic strategy can be highly profitable due to bid cost recovery payments made for energy needed to ramp a unit from its day-ahead schedule at the end of one trade day to its day-ahead schedule at the start of the next trade date.

IV. ISSUE 2: BID COST RECOVERY FOR RAMPING ENERGY

A. INTER-DAY RAMPING ENERGY

Q. How can the bidding strategy you just discussed be used with a strategy to increase bid cost recovery payments for energy needed to ramp a unit from its day-ahead schedule at the end of one trade day to its day-ahead schedule at the start of the next trade date?

A. I will illustrate this issue by building on the example I provided previously. As shown in Table 1, the bidding pattern used in this example involves bidding all capacity at -$30/MW in the day-ahead market during the last few hours of each trade day (Hours 20 to 24 in this example). All capacity during the first few hours of the trade day is bid at $1,000/MW. When this bidding pattern is employed for two consecutive trade days, this causes the unit to be scheduled at its maximum capacity in the day-ahead market for the last hour of the first trade date (300 MW) and at its minimum load level during the first hours of the next trade day (25 MW). Figure 1 provides a graphic illustration of this. As shown in Figure 1, in practice, the unit would need to gradually ramp down from its day-ahead schedule for the last hour of this first trade day to its much lower day-ahead schedule based on the resources submitted high price bids in the first hours of this second trade day. Recall that the day-ahead market does not optimize beyond the twenty four hour period, which means that it does not consider the high bid prices in the early hours of the next day as it schedules resources in the late hours of two consecutive day-ahead markets. Therefore, at the start of each day-ahead market the ISO must establish the expected *initial condition* of each resource before executing the day-ahead market run. To establish these initial conditions, the day-ahead software includes logic regarding the initial condition of each unit during the last hour of the prior trade day. In most cases, such as in this example, the initial condition of the unit is set at the resource's day-ahead schedule for the last hour of the prior trade date.

Figure 1: Illustration of Inter-day Ramping Issue

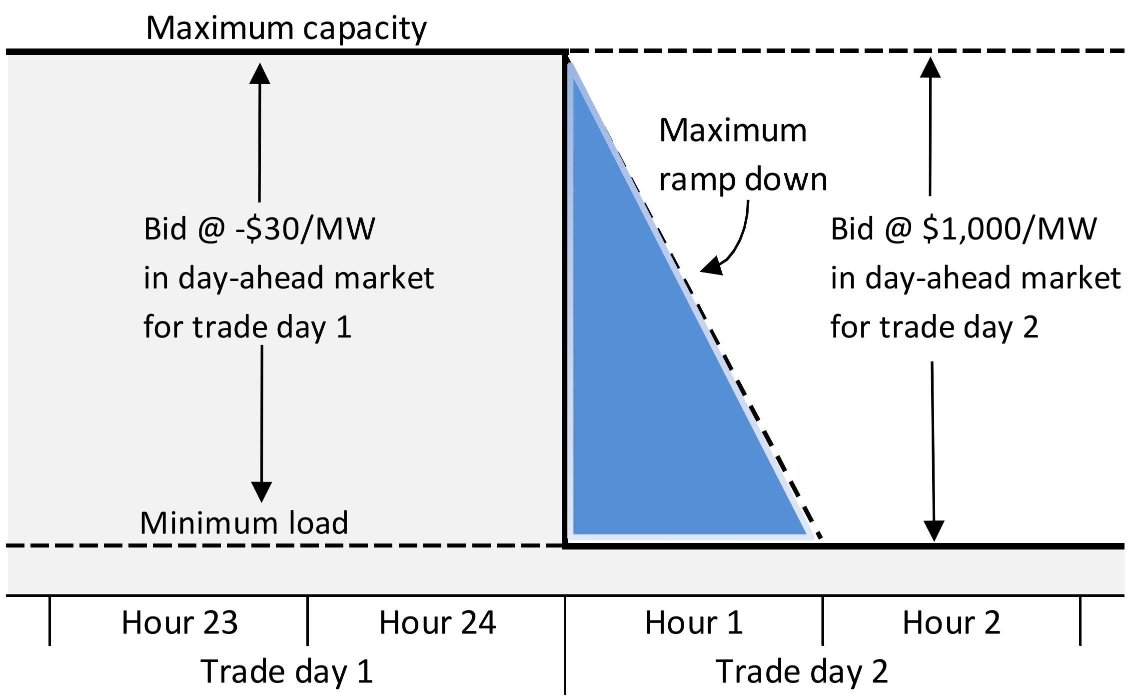
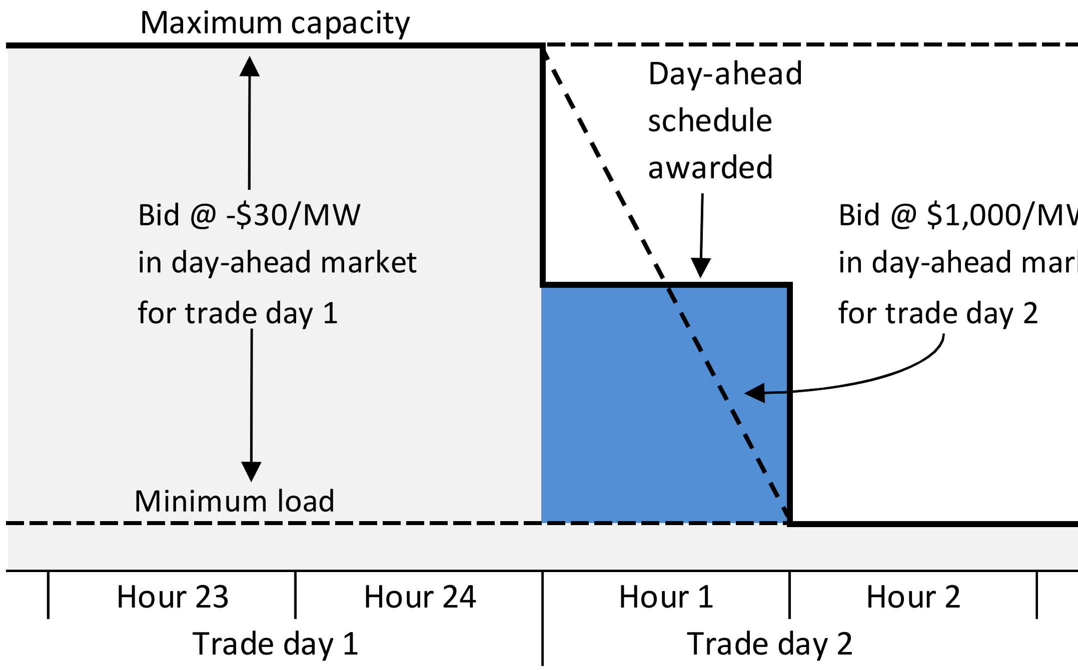


Figure 2: Illustration of Inter-day Ramping Issue – Final day-ahead schedules with ramping energy



Q. Does the day-ahead market software recognize and address this issue?

A. Not from a complete economic perspective. In this example, the day-ahead market optimization for the first trade day (trade day 1) would not be able to consider the unit's $1,000/MW bids for hour 1 of the following trade day (trade day 2). Currently, the day-ahead market optimization is is run only for the 24-hour period covered by the applicable trade day. At the time this 24-hour market optimization is performed, the unit's $1,000/MW bids for hour 1 of the subsequent trade day (trade day 2) may not have been submitted or could be modified prior to the market optimization for this second trade day. Thus, the optimal solution in the day-ahead optimization given the unit's -$30/MW energy bids for the final hours of the first trade day is to schedule the unit at its maximum operating level. This optimization does not consider the fact that the energy bid price for ramping this unit down was $1,000/MW in hour 1 of the following trade day. Clearly, if the optimization extended into the second trade day and considered this $1,000/MW bid price, the unit would not be ramped up to its maximum load in the final hours of this first trade day.

Q. Doesn't the day-ahead market software recognize the $1,000/MW bid price of ramping energy in hour 1 of the second trade day?

A. Yes. The day-ahead market for this second trade day recognizes that during the first hours of this second trade day, it is only economic to schedule the unit at its minimum load as a result of its $1,000/MW energy bids. However, during the second trade day the day-ahead software recognizes that it is infeasible to ramp the unit down from its day-ahead schedule in the final hour of the prior trade day (or the unit's *initial conditions*) to its economic minimum load schedule in the first hour of this second trade day. In order to issue a feasible energy schedule to the unit, the day-ahead software would need to award the unit a day-ahead schedule above minimum load for this first hour of this second trade day, as depicted in Figure 2, regardless of the unit's $1,000/MW bid for this addition energy above minimum load.

Q. Does the day-ahead software consider the bid price of this inter-day ramping energy when determining whether to continue committing a unit?

A. On this second trade day, the day-ahead software recognizes that the additional energy needed to ramp the unit down from its day-ahead schedule in the final hour of the prior trade day is a fixed or sunk cost at that point, despite the $1,000/MW bid price for this ramping energy. Consequently, the optimization for this second day does not consider the bid price for this ramping energy in the decision of whether to commit this unit on the second trade day. However, even if the unit was not economical to be committed in the day-ahead market the second day, the software would still need to award the unit a day-ahead schedule above minimum load for this first hour to reflect how the unit would need to ramp down before going off-line. Again, this reflects the fact that the day-ahead software recognizes that the additional energy needed to ramp the unit down from its day-ahead schedule in the final hour of the prior trade day is a fixed or sunk cost at that point, despite the $1,000/MW bid price for this ramping energy.

Q. **Why is this problematic?**

A. This is problematic because the additional ramping energy above minimum load that is scheduled by the day-ahead software during the first hours of the second trade day is eligible to be paid bid cost recovery based on its energy bid price: $1,000/MW in this example. This can – and has – resulted in additional bid cost recovery payments of over $100,000 per day for several individual units.

Q. Does a unit automatically receive its bid price though bid cost recovery in this situation?

A. No. Because the MEAF is applied to day-ahead bid costs, the degree to which the unit receives its bid price for this ramping energy depends on the level at which it actually operates in real-time during the first few hours the trade day.

Q. Can you provide an example of this?

A. **Y**es. I will do this by building on the same basic scenario shown in Tables 1 to 3. As previously noted, the unit in this example can ramp from its 25 MW minimum load up to 125 in MW one hour and can then ramp up to its maximum capacity of 300 MW in the second hour. It can ramp down from 300 MW to 125 MW in one hour and then down to its minimum load operating level of 25 MW the next hour. I will further assume that this bidding strategy is employed two day in a row, so that during the final hour of the first day the unit is scheduled at its maximum level of 300 MW in the day-ahead market. Table 4 shows results of this scenario in the day-ahead market. Under this scenario, during hour 1 of this second day the unit cannot be scheduled by the day-ahead market software any lower the 125 MW as a result of its 300 MW schedule in hour 24 the prior trade day. As shown in Table 4, this causes the unit to be scheduled at 125 MW in hour 1 despite the fact that all energy above the unit's 25 minimum operating level are bid at $1,000 in this hour. As shown below Table 4, this causes the units total bid costs to increase by $100,000, so that its total day-ahead bid costs are $157,000, compared to revenues of only about $62,000.

Q. Wouldn't his make it uneconomic for the market software to commit the unit?

A. No. Although the unit's total day-ahead bid costs greatly exceed its market revenues, the unit is still economic to commit since the additional 100 MW of energy bid at $1,000 needed to ramp the unit down in hour 1 is treated as a fixed or sunk cost by the market software because the ramp down would need to occure regardless if the resource were committed or not committed the balance of the day after the ramp down to minimum load. In other words, excluding this $100,000, the units bid costs are only $57,000 compared to market revenues of about $62,000.

Q. How would the unit's real-time market activity impact bid cost recovery payments for this day?

A. This is shown in Table 5 and Table 6. In this example, I assume the unit had been ramped up to its day-ahead schedule in hours 23 and 24 of the prior operating day, so that it also generates at its full 125 MW day-ahead scheduled in hour 1 of this trade day as it ramps down to its minimum load of 25 MW. This results in a MEAF of 1.0 for this hour. The supplier can ensure that this occurs by bidding at relatively low price in the real-time time energy market during hours 23 and 24, as shown in Table 5. The supplier could also ensure this occurs by self-scheduling the unit at its day-ahead energy schedule in the real-time market during these hours.

Because the MEAF is 1.0 for hour 1, the unit's $1,000 bid price for energy in hour 1 needed to ramp the unit down over this hour is included in the bid cost recovery calculations. As shown below in Table 6, the bid cost for this ramping energy adds a net of amount of about $90,000 to the bid cost recovery calculations. As a result, unit would ultimately receive over $114,000 in bid cost recovery payments this day.

Table 4. Day-ahead Market Bidding and Results (Inter-day ramping scenario)

Hour	Day-ahead energy bid price	Day-ahead LMP	Day-ahead schedule (MW)	Day-ahead revenues		Day-ahead bid costs	
				Minimum load energy	Energy above minimum load	Minimum load bid cost	Energy above minimum load
1	$1,000	$18	**125**	$450	$1,800	$4,000	$100,000
2	$1,000	$12	25	$300	$0	$4,000	$0
3	$1,000	$5	25	$125	$0	$4,000	$0
4	$1,000	$4	25	$100	$0	$4,000	$0
5	$1,000	$6	25	$150	$0	$4,000	$0
6	$1,000	$13	25	$325	$0	$4,000	$0
7	$1,000	$24	25	$600	$0	$4,000	$0
8	$1,000	$34	25	$850	$0	$4,000	$0
9	$1,000	$35	25	$875	$0	$4,000	$0
10	$1,000	$34	25	$850	$0	$4,000	$0
11	$1,000	$37	25	$925	$0	$4,000	$0
12	-$30	$38	125	$950	$3,800	$4,000	-$3,000
13	-$30	$37	125	$925	$3,700	$4,000	-$3,000
14	$1,000	$37	25	$925	$0	$4,000	$0
15	$1,000	$35	25	$875	$0	$4,000	$0
16	$1,000	$35	25	$875	$0	$4,000	$0
17	$1,000	$31	25	$775	$0	$4,000	$0
18	$1,000	$29	25	$725	$0	$4,000	$0
19	$1,000	$27	25	$675	$0	$4,000	$0
20	-$30	$38	125	$950	$3,800	$4,000	-$3,000
21	-$30	$47	200	$1,175	$8,225	$4,000	-$5,250
22	-$30	$37	300	$925	$10,175	$4,000	-$8,250
23	-$30	$29	300	$725	$7,975	$4,000	-$8,250
24	-$30	$23	300	$575	$6,325	$4,000	-$8,250
		Daily totals	**2,000**	**$16,625**	**$45,800**	**$96,000**	**$61,000**

Day-ahead (before applicatin of MEAF)

	Revenues	Bid costs
Minimum load	$16,625	$96,000
Energy	$45,800	$61,000
Total	$62,425	$157,000

Table 5. Real-time Market Bidding and Results (Inter-day ramping scenario)

Hour	Day-ahead schedule (MW)	Real-time energy bid price	Real-time LMP	Real-time dispatch (MW)	Real-time energy (MW)	Real-time energy revenue	Real-time energy bid cost	MEAF for day-ahead bid costs
1	**125**	$1,000	$27	**125**	0	$0	$0	1.00
2	25	$1,000	$24	25	0	$0	$0	--
3	25	$1,000	$8	25	0	$0	$0	--
4	25	$1,000	$10	25	0	$0	$0	--
5	25	$1,000	$8	25	0	$0	$0	--
6	25	$1,000	$13	25	0	$0	$0	--
7	25	$1,000	$15	25	0	$0	$0	--
8	25	$1,000	$36	25	0	$0	$0	--
9	25	$1,000	$34	25	0	$0	$0	--
10	25	$1,000	$34	25	0	$0	$0	--
11	25	$1,000	$29	25	0	$0	$0	--
12	125	$62	$33	25	-100	-$3,300	-$6,217	0.00
13	125	$65	$37	25	-100	-$3,700	-$6,466	0.00
14	25	$1,000	$30	25	0	$0	$0	--
15	25	$1,000	$33	25	0	$0	$0	--
16	25	$1,000	$32	25	0	$0	$0	--
17	25	$1,000	$32	25	0	$0	$0	--
18	25	$1,000	$25	25	0	$0	$0	--
19	25	$1,000	$23	25	0	$0	$0	--
20	125	$46	$35	25	-100	-$3,500	-$4,560	0.00
21	200	$56	$43	25	-175	-$7,525	-$9,870	0.00
22	300	$44	$40	25	-275	-$11,000	-$12,210	0.00
23	300	**$20**	$34	**125**	-175	-$5,950	-$3,500	0.36
24	300	**$20**	$26	**300**	0	$0	$0	1.00
Total	**2,000**			**1,075**	**-925**	**-$34,975**	**-$42,823**	

Table 6. Bid Cost Recovery Results (Inter-day ramping scenario)

				Day-ahead revenues		Day-ahead bid costs			
Hour	Day-ahead energy bid price	Day-ahead LMP	Day-ahead schedule (MW)	Minimum load energy	Energy above minimum load	Minimum load bid cost	MEAF	Energy above min load	Energy above min load (MEAF adjusted)
1	$1,000	$18	**125**	$450	$1,800	$4,000	1.00	$100,000	$100,000
2	$1,000	$12	25	$300	$0	$4,000	--	$0	$0
3	$1,000	$5	25	$125	$0	$4,000	--	$0	$0
4	$1,000	$4	25	$100	$0	$4,000	--	$0	$0
5	$1,000	$6	25	$150	$0	$4,000	--	$0	$0
6	$1,000	$13	25	$325	$0	$4,000	--	$0	$0
7	$1,000	$24	25	$600	$0	$4,000	--	$0	$0
8	$1,000	$34	25	$850	$0	$4,000	--	$0	$0
9	$1,000	$35	25	$875	$0	$4,000	--	$0	$0
10	$1,000	$34	25	$850	$0	$4,000	--	$0	$0
11	$1,000	$37	25	$925	$0	$4,000	--	$0	$0
12	-$30	$38	125	$950	$3,800	$4,000	0.00	-$3,000	$0
13	-$30	$37	125	$925	$3,700	$4,000	0.00	-$3,000	$0
14	$1,000	$37	25	$925	$0	$4,000	--	$0	$0
15	$1,000	$35	25	$875	$0	$4,000	--	$0	$0
16	$1,000	$35	25	$875	$0	$4,000	--	$0	$0
17	$1,000	$31	25	$775	$0	$4,000	--	$0	$0
18	$1,000	$29	25	$725	$0	$4,000	--	$0	$0
19	$1,000	$27	25	$675	$0	$4,000	--	$0	$0
20	-$30	$38	125	$950	$3,800	$4,000	0.00	-$3,000	$0
21	-$30	$47	200	$1,175	$8,225	$4,000	0.00	-$5,250	$0
22	-$30	$37	300	$925	$10,175	$4,000	0.00	-$8,250	$0
23	-$30	$29	300	$725	$7,975	$4,000	0.36	-$8,250	-$3,000
24	-$30	$23	300	$575	$6,325	$4,000	1.00	-$8,250	-$8,250
		Daily totals	**2,000**	**$16,625**	**$45,800**	**$96,000**		**$61,000**	**$88,750**

Day-ahead (after MEAF)		Revenues	Bid costs
	Minimum load	$16,625	$96,000
	Energy	$45,800	$88,750
	Total	$62,425	$184,750
		Day-ahead BCR =	$122,325

Real-time		Revenues	Bid costs
	Energy	-$34,975	-$42,823
		Real-time BCR =	-$7,848
		Total BCR	$114,477

Q. How is this issue related to the first bid cost recovery issue you discussed?

A. The first scenario – negative day-ahead bid prices that are subsequently canceled out of bid cost recovery calculations when this energy is not delivered in the real-time market – facilitates getting units committed in the day-ahead market, and scheduled at their maximum load in the final hours of the operating day and at their minimum load during the first hours of the next operating day, by dramatically reducing the costs of this strategy. As shown in my first example, this bidding strategy ensure that the unit gets committed and covers virtually its entire minimum load cost, even on days when they unit may not be economic to be in operation based on its actual costs. This sets up the conditions necessary for this second issue to become highly problematic in terms of creating even more excessive bid cost recovery payments.

Q. When did this ramping issue become a problem in terms of creating high bid cost recovery?

A. This second issue first began to occur only after the ISO's tariff revisions to include all day-ahead market revenues in bid cost recovery calculations, as approved by the Commission in the May 4 order. As illustrated in these examples, this scenario results in high bid cost recovery only when – among other things – the scheduling coordinator for a supplier bids extremely high prices in the first hour or two of an operating day and is still committed by the ISO so that it is eligible for bid cost recovery. This scenario only began to occur frequently in April 2011.

B. OUT-OF-SEQUENCE DAY-AHEAD SCHEDULES NEEDED TO ENSURE FEASIBILITY OF SELF-SCHEDULED ENERGY

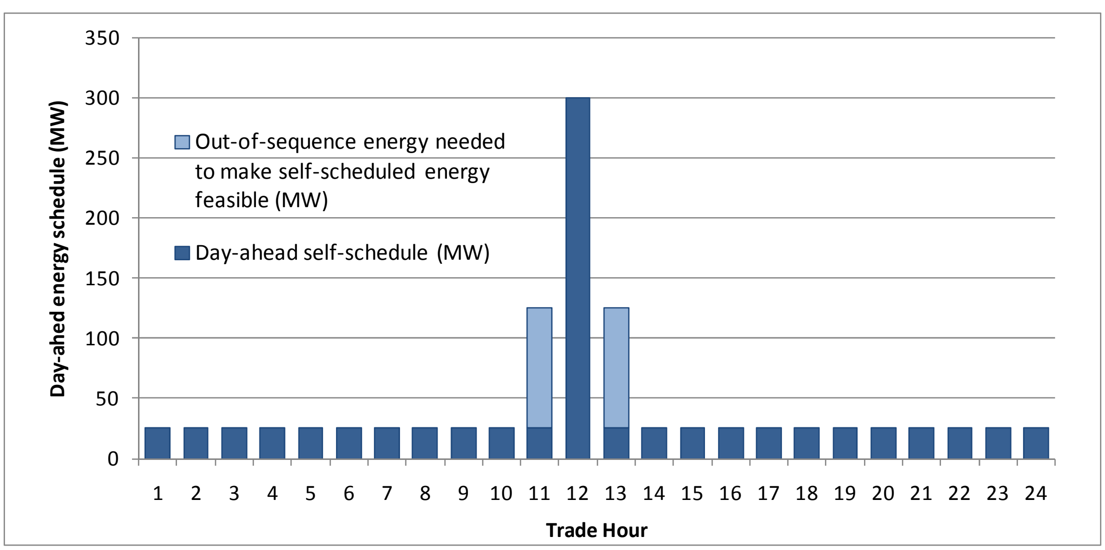
Q. Please describe the issue involving out-of-sequence day-ahead schedules that are needed to ensure the feasibility of self-scheduled energy.

A. ISO market rules allow entities to self-schedule different amounts of energy in the day-ahead market on an hourly basis. Hourly self-schedules must range between the unit's minimum load and it maximum available capacity. The software checks to ensure that if a unit is self-scheduled during any hour, it is self-scheduled at or above its minimum operating level for its minimum operating time. Self-schedules not meeting this criteria are not accepted by the market software. However, the software does not check that the hour-to-hour changes in self-schedules submitted by participants are feasible given the unit's actual ramp rate and other operating limitations. To the extent a resource must be dispatched at a higher level during one hour to make its self-schedule in the next hour feasible, the day-ahead software may need to accept energy bids from the unit in addition to the scheduled energy. Thus, by self-scheduling a unit at different levels in different hours, a participant could force acceptance of extremely high-priced bids for any additional energy needed to make these schedules feasible.

Q. Can you provide an example of this?

A. Yes. Figure 5 provides an illustration of this scenario over the 24 hours of a trading day. As shown by the dark bars in Figure 5, in hour ending 12 the unit is self-scheduled at its maximum capacity of 300 MW and in all other hours it is self-scheduled at its minimum operating level of 25 MW. The unit bids all of its energy above its self-schedule at the $1,000 MW bid cap. Again, assume this unit can ramp from its minimum load level to an average of 125 MW in one hour and from 125 MW to 300 MW in a second hour. Thus, during hour ending 11, the unit must be scheduled to ramp up to 125 MW in order to make its 300 MW self-schedule in hour 12 feasible. During hour ending 13, the unit must be scheduled to ramp down to 125 MW in order to make its 25 MW self-schedule in hour 14 feasible. This effectively forces the day-ahead software to accept 100 MW of the unit's $1,000/MW energy bids during these two hour (see light blue bar in hours 11 and 13). This pattern could even be repeated numerous times throughout the day.

Figure 5: Example of infeasible self-schedules for energy



Q. You said the self-schedules "effectively force" the software to schedule additional energy bids even at very high bid prices. Is this really the case, no matter how high these energy bids are?

A. It seems safe to say that **t**hese additional energy bids will always be accepted even if they are at the $1,000 bid cap. Even at such high bid prices, the optimization will determine that it is less costly to accept these bids than to violate the other constraints in the model. For example, one option within the optimization would be to reduce some of the self-schedules so that no additional ramping energy is needed in other hours. However, in the software these self-schedules are protected with negative bids or *penalty prices* of -$1,100/MW. Thus, the optimization will find it less costly to schedule additional ramping energy at $1,000/MW before curtailing these self-schedules at a price of -$1,100/MW.

Q. How would day-ahead bid cost recovery be calculated under this scenario?

A. In this scenario, day-ahead bid cost recovery is calculated based only the bid costs for energy scheduled beyond the unit's self-schedules and the revenues from this additional energy. As shown in Table 6, this equates to $200,000 in energy bid costs, compared to about $6,800 in energy revenues for this 200 MW of ramping energy. This would equate to a day-ahead bid cost recovery payment of $192,600. Under this scenario, the market participant would obviously want the unit to operate in the real-time market at or near this day-ahead schedule during hours it was eligible for day-ahead bid cost recovery so that these extremely high bid costs would not be cancelled out of the bid cost recovery calculations due to application of a low MEAF.

Table 6. Day-ahead bid cost recovery results (self-scheduling example)

Hour	Day-ahead energy bid price	Day-ahead LMP	Day-ahead self-schedule (MW)	Out-of-sequence energy needed for feasibility	Day-ahead schedule (MW)	Revenues (self-scheduled energy)	Revenues (non self-scheduled energy)	Bid Costs (non self-scheduled energy)
1	$1,000	$18	25	0	25	$450	$0	$0
2	$1,000	$12	25	0	25	$300	$0	$0
3	$1,000	$5	25	0	25	$125	$0	$0
4	$1,000	$4	25	0	25	$100	$0	$0
5	$1,000	$6	25	0	25	$150	$0	$0
6	$1,000	$13	25	0	25	$325	$0	$0
7	$1,000	$24	25	0	25	$600	$0	$0
8	$1,000	$34	25	100	125	$850	$3,400	$100,000
9	$1,000	$35	300	0	300	$10,500	$0	$0
10	$1,000	$34	25	100	125	$850	$3,400	$100,000
11	$1,000	$37	25	0	25	$925	$0	$0
12	$1,000	$38	25	0	25	$950	$0	$0
13	$1,000	$37	25	0	25	$925	$0	$0
14	$1,000	$37	25	0	25	$925	$0	$0
15	$1,000	$35	25	0	25	$875	$0	$0
16	$1,000	$35	25	0	25	$875	$0	$0
17	$1,000	$31	25	0	25	$775	$0	$0
18	$1,000	$29	25	0	25	$725	$0	$0
19	$1,000	$27	25	0	25	$675	$0	$0
20	$1,000	$38	25	0	25	$950	$0	$0
21	$1,000	$47	25	0	25	$1,175	$0	$0
22	$1,000	$37	25	0	25	$925	$0	$0
23	$1,000	$29	25	0	25	$725	$0	$0
24	$1,000	$23	25	0	25	$575	$0	$0
		Daily totals	**875**	**200**	**1,075**	**$26,250**	**$6,800**	**$200,000**

Q. Would this be profitable for the unit over the whole day?

A. Yes. In this scenario, the unit would receive a total of $227,075 – or $26,250 in revenues from self-scheduled energy, $6,800 from non-self-scheduled energy, plus a day-ahead bid cost recovery payment of

$192,600. Based on the costs previously described in my testimony, its actual minimum load costs over the day would be $87,600 (25 MW x $160/MW x 24 hours). Assuming an incremental cost of energy above minimum load of $40/MW, the cost of this additional energy would be $19,000 (475 MW x $40). This represents total revenues of $227,075 compare to actual costs of $106,600. As previously noted, the unit could be self-scheduled to create additional bid cost recovery multiple times in the same day. Each time the unit ramped up and down as shown in this example, it would receive an additional $192,000 in bid cost recovery compared to additional incremental energy costs of only $19,000.

V. ISSUE 3: EXCEPTIONAL DISPATCHES TO ENSURE FEASIBILITY OF MARKET SCHEDULES

Q. How does this bidding practice affect exceptional dispatch?

A. In certain cases, the ISO may need to ensure that a unit operates above its minimum operating level by issuing an exceptional dispatch. This can occur for several reasons – all of which involve limitations in the ISO market software that can cause schedules and market-awarded ancillary services and residual unit commitment capacity established by the software to be infeasible in the real-time market under certain conditions. These situations are described in more detail in the testimony of Ms. Deborah A. LeVine. In these situations, the ISO must issue an exceptional dispatch in the real-time market to ensure system reliability regardless of the bid price offered by the supplier. While in some cases there may in theory be less costly alternatives to exceptionally dispatching these resources to make previous ancillary service awards residual unit capacity commitments feasible, in practice, these alternatives cannot be identified and evaluated in real-time by grid operators without compromising normal system operations and reliability.

Q. Has this actually occurred?

A. Yes. In April the ISO needed to exceptionally dispatch several units that were employing the general bidding strategy previously described in my testimony. In each case, these units were scheduled to operate at minimum load over the most critical morning and evening hours when market energy prices and reliability concerns are generally highest. All of the units' energy above minimum load was bid just below the $1,000/MW bid cap. All of the units had ancillary services awards for many hours of the days involved that would have been infeasible and unavailable unless the ISO issued exceptional dispatches. In just five days, during a total of 24 hours, almost $5.3 million in exceptional dispatch payments were incurred for energy bids at prices approximately equal to the $1,000/MW bid cap. About $3.6 million of these exceptional dispatches payments were incurred when units with infeasible ancillary service awards were dispatched above minimum load to a level at which they had a much higher ramp rate that would make these awards feasible.

Q. Can you provide a more specific example of an infeasible ancillary service award?

A. Yes. The most common situation is that a unit's day-ahead ancillary service award is infeasible in real-time because the unit was scheduled to be providing energy at a relatively low level in the day-ahead market. Consider the unit I previously described, which has a relative low ramp rate when operating at its 25 MW minimum operating level. Because of this low ramp rate, the unit can only provide a limited about of spinning reserve. Spinning reserve is a 10 minute product – *i.e.,* the energy from the reserved capacity must be available within 10 minutes. As I described earlier, from its minimum operating point, the unit can ramp to 125 MW in one hour, representing a ramp rate of 1.67 MW/minute. Thus, when the unit is scheduled at minimum load, it can only provide only about 17 MW of spinning (1.67 MW/minute x 10 minutes). Once operating at 125 MW, it can ramp up at a rate of 6 MW/minute, and thus can provide up to 60 MW of spinning reserve (6 MW/minute x 10 minutes). If the unit is awarded 60 MW of spinning reserve, but is operating at minimum load, the spinning reserve award is infeasible.

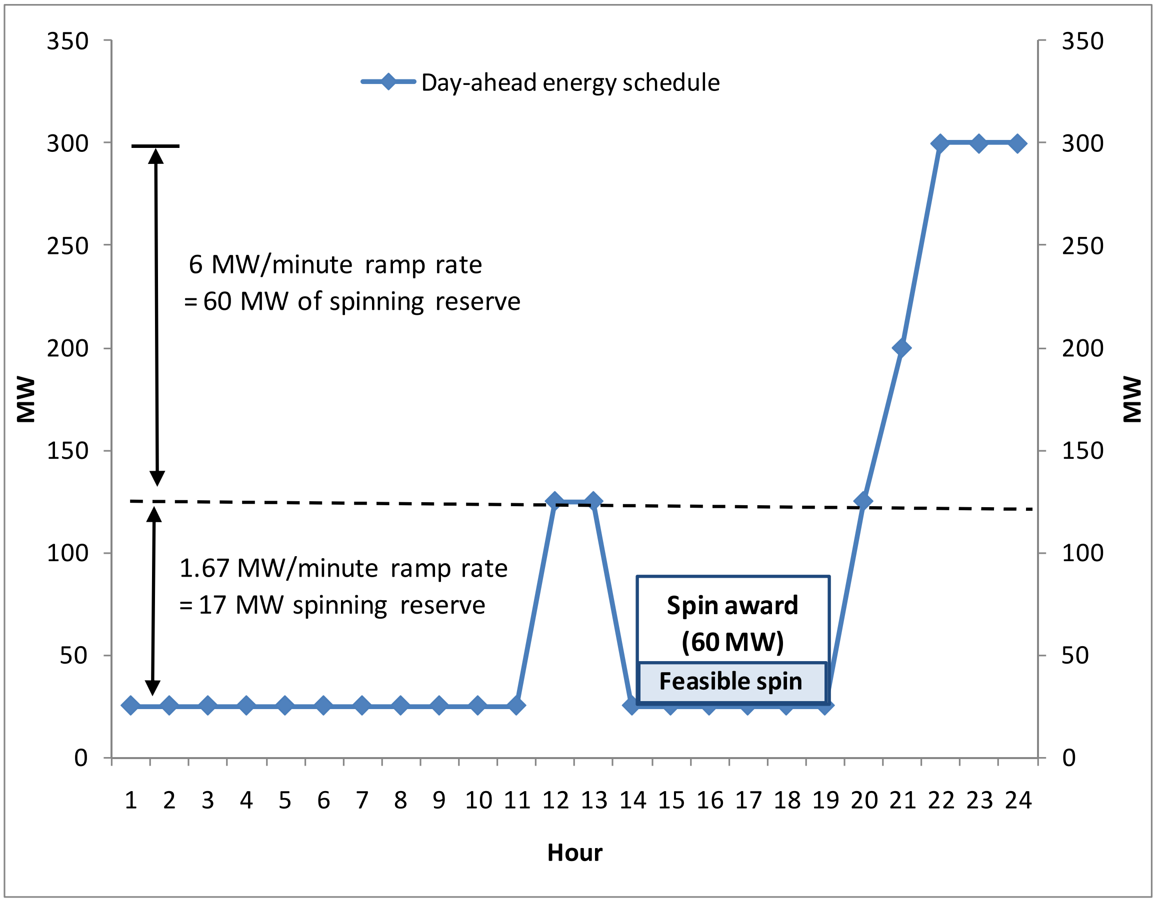
Q. How can this situation occur?

A. Currently, the ISO's day-ahead market software considers the amount of spinning reserve available from on-line units based on a fixed operating reserve ramp rate in the ISO master file. This fixed ramp rate represents the maximum amount of spinning reserve the unit is certified to provide, which in this case would reflects the higher 6 MW/minute ramp rate. Based on this ramp rate, the ISO's day-ahead software may award the unit up to 60 MW of spinning reserve, even when it is scheduled to operating at minimum load and can only provide 17 MW of spinning reserve. This scenario is illustrated in Figure 3.

Q. What happens if a unit has an infeasible ancillary service award?

A. As described in Ms. Le Vine's testimony, this can depend on system and market conditions, including the amount of ancillary services that may be infeasible in real-time. In many cases, the ISO may determine that it still has sufficient operating reserves so that no action is necessary. In other cases, ISO cancels the infeasible ancillary service schedules and purchases replacement ancillary services capacity from different resources in real-time ancillary market, which runs every 15 -minutes. In some cases, however, the supply of other ancillary service capacity may be limited in this real-time market. Under this scenario, the ISO may determine it has no choice but to issue an exceptional energy dispatch to ramp the unit up to a level at which the unit would be able to provide the awarded but infeasible ancillary service capacity, even though the energy is bid at an extremely high and uncompetitive price.

Figure 3: Example of infeasible ancillary service award



Q. How would this work for the example in Figure 3?

A. In the example depicted in Figure 3, the unit would receive an exceptional dispatch to increase its energy output by 100 MW, *i.e.*, to increase generation from its day-ahead energy schedule at its 25 MW minimum load up to the 125 MW level at which its ramp rate would be high enough to make this ancillary services award feasible. Given the unit's $1,000/MW bid cost, this would earn the unit $100,000 per hour under a pay-as-bid (non-mitigated and not netted under bid cost recovery) exceptional dispatch energy settlement. If this were necessary over the peak hours of the day when the unit was scheduled at minimum load (hours 14 to 19), this would equate to $500,000.

Q. How long has this ancillary service issue existed?

A. The day-ahead software has allowed infeasible ancillary service awards to be awarded since the start of the ISO's new market in April 2009. The infeasible ancillary service awards have been reasonably managed in real-time. However, it appears that this issue has only become a significant problem recently as a result of the bidding patterns I have described above. As I previously noted, this new bidding strategy is specifically designed to have units scheduled at minimum load during the morning and evening hours when loads are increasing most rapidly and the need to be prepared for contingencies is greatest. During these hours, all of the unit's capacity is also bid into the real-time market at or near the $1,000 MW bid cap. Employing this strategy on numerous units at the same time, as has been done, increases the amount of ancillary service capacity that is infeasible and can only be made feasible by exceptionally dispatching $1,000/MW bids. By bidding these units at the $-30/MW bid floor during other hours to get committed by the day-ahead software, this strategy can decrease the commitments in the day-ahead market of other units that bid more normally and competitively, units that might also have been awarded ancillary services and residual unit commitment capacity. Units not committed in the day-ahead market may also not be available in the real-time market if needed.

Q. Why not limit the amount of ancillary service capacity that can be bid in to the minimum amount the unit could provide (e.g. while operating at minimum load)?

A. This would have the unfortunate effect of artificially restricting the amount of ancillary services actually available to the market. This could also provide a way for suppliers to withhold capacity from the ancillary service market. The ISO tariff includes a key provision designed to specifically prevent this by requiring that resource adequacy units make their full ancillary service capacity available in the market. Again, this issue has only become a significant problem due to the anomalous bidding strategy that has just recently begun to occur. The changes included in the ISO's filing target this behavior without creating detrimental impacts to the market or other participants.

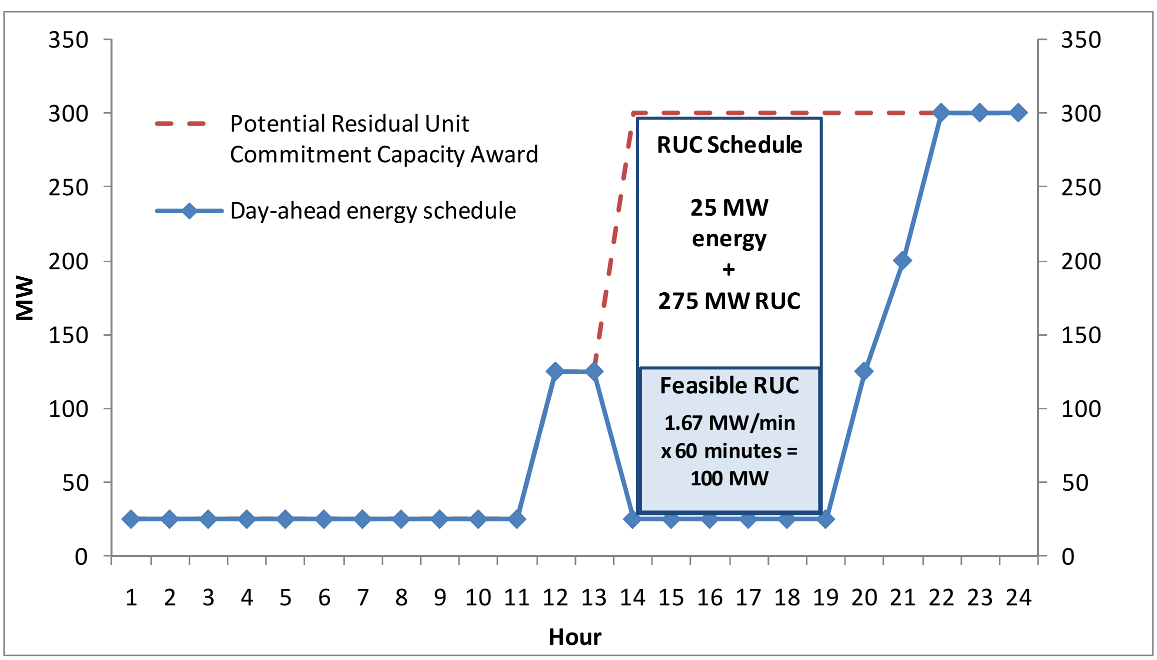
Q. Is there another way this ancillary service issue can be addressed?

A. The ISO is developing a software enhancement – referred to as dynamic ancillary services procurement – that will incorporate the unit's operational ramp rate at different operating levels into the day-ahead software optimization. This would ensure that a unit is not more ancillary service capacity that it could provide based on its operational ramp rate at its day-ahead energy schedule. Since the software co-optimizes energy and ancillary services, this enhancement allow the software to determine the optimal level at which to schedule the unit for energy. In the example I have been discussing, the unit would be unlikely to be awarded 60 MW of spinning reserve since it would not be economic to pay the unit its energy bid price of $1,000/MW to schedule the unit at the level needed to provide 60 MW of spinning reserve (125 MW). Although this software enhancement will reduce the incidence of infeasible ancillary services awards in the day-ahead market, the bidding practice of reselling energy in the real-time market could render day-ahead feasible ancillary services awards infeasible in the real time market. The ISO believes this software modification and the related tariff modifications can be completed on a schedule that would allow implementation within the next few weeks. A technical bulletin on this software enhancement has been posted on the ISO website at: http://www.caiso.com/2b82/2b82d66d39490.pdf.

Q. Can you provide an example of how an exceptional energy dispatch may be needed to make a unit's residual unit commitment schedule feasible?

A. Yes. An example of this is provided in Figure 4. This example assumes that this unit is needed for residual unit commitment over the peak hours 14 to 19. During these hours the scheduling coordinator makes sure that the unit is scheduled at its minimum operating level by bidding all of the unit's capacity at the $1,000/MW bid cap in the day-ahead market. Because the residual unit commitment is based on a 24-hour optimization during which units may be ramped up or down each hour from their residual unit commitment schedule the previous hour, the unit could be awarded a residual unit commitment schedule of 275 MW – representing the unit's full unloaded capacity during the peak hours. In this example, as part of the residual unit commitment optimization, the unit may be ramped up from its energy schedule of 125 MW in hour 13 to its maximum capacity of 300 MW in hour 14 for residual unit commitment capacity. Given this residual unit commitment schedule in hour 14, the unit could then continue to be scheduled at its maximum capacity in hours 15 to 19 in the residual unit commitment optimization. In real-time, however, if the unit continues to operate at its minimum load energy schedule then only 100 MW of this 275 MW of residual unit commitment capacity would be available over any individual hour, as depicted in Figure 4. In order to make this full 275 MW available, the unit would need to be ramped up to 125 MW through an exceptional dispatch.

Figure 4: Example of infeasible residual unit commitment capacity schedules



Q. Is there other way this residual unit commitment issue be addressed?

A. First, it is important to note that, as in the case of infeasible ancillary services awards, this scenario does not seem to have posed a significant problem until recently, and has become a concern at this point only due to the very anomalous type of bidding and volume that has just recently begun to occur. Also, in many cases, sufficient capacity may be available from other resources so that an exceptional dispatch would not be required in this situation. Fully eliminating the possibility of this scenario would appear to require a substantial redesign of the ISO's residual unit commitment process. For example, one option might be to limit the amount of residual unit commitment capacity that could be awarded to the level that could be delivered within 60 minutes when the unit is operating at its final day-ahead energy schedule. However, this significant change in the market design would seem to depart from the principle upon which the residual unit commitment market and resource adequacy requirements are based. Currently, units operating under the resource adequacy program are required to offer all of their available unloaded capacity into the residual unit commitment process at a bid price of $0/MW. This reflects the principle that these units have received compensation from load-serving entities and in turn have an obligation to make this capacity available in the ISO market. Thus, there does not seem to be promising short-term solution for entirely eliminating this scenario.

Q. Does this behavior constitute an exercise of market power?

A. Definitely. Market power is broadly defined as the ability of a supplier to unilaterally set prices significantly in excess of levels that would result in a competitive market. For example, a generator has market power if they can effectively demand any price for their energy as a result of a lack of other supply alternatives or demand elasticity. As described in Ms. LeVine's testimony, when the supply of replacement ancillary service capacity is limited in this real-time market, the ISO may determine it has no choice but to issue an exceptional energy dispatch to ramp the unit up to a level at which the unit would be able to provide its day-ahead ancillary service schedule, even though this energy is bid at an extremely high and uncompetitive price. This represents the equivalent of unilateral market power by the supplier: the demand for this ancillary service capacity cannot be reduced without compromising reliability, and there are no supply alternatives at that point that can be effectively substituted by grid operators. As described earlier in my testimony, this market power has been exercised to generate payments of over $1 million per day at a price of about $1,000/MW. Moreover, the day-ahead bidding scheme described in my testimony has been employed to specifically create the conditions that dramatically increase the likelihood that this unilateral market power will exist.

VI. PROPOSED SOLUTIONS

Q. How is the ISO proposing to address the first issue you discussed regarding the application of MEAF to negatively priced bids?

A. The ISO is proposing simply not to apply the MEAF to negatively-priced bids when calculating bid costs for energy scheduled in the day-ahead market.

Q. Will this effectively mitigate the problem you identified?

A. Yes. This modification is relatively simple to implement and will effectively target the bidding strategies that have used negative day-ahead energy bids to get units committed and then inflate bid cost recovery payments.

Q. Would this modification have any detrimental impacts on participants who might submit negative energy bids in the day-ahead market?

A. No. Excluding the strategies I have described, a very limited number of negatively priced bids have been submitted by generating units since the ISO's new market began in April 2009. Table 6 provides a summary of all negatively-priced bids submitted by other resources since April 2009 through May 2011. As shown in Table 6, these other negatively priced bids have all been submitted by hydro and renewable energy units and are likely to reflect operating constraints that essentially required these units to generate during some hours. Virtually all of these negatively priced bids were above -$7/MW (See Table 6, Column F). Most importantly, virtually all of the day-ahead energy with these negatively priced bids was actually delivered in the real-time market (See Table 6, Column G). The proposed modification would have no significant financial impact on resources submitting negative bids and operating in this manner.

Table 7. Other units submitting negative bids in day-ahead market

A	B	C	D	E	F	G
Unit	**Type**	**Total day-ahead energy scheduled (MW)**	**Day-ahead energy with negative bid price (MW)**	**Percent of day-ahead energy with negative bid price**	**Average negative bid price of day-ahead energy**	**Percent of day-ahead energy with negative bid price delivered in real-time**
1	Hydro	1,299,963	138,299	11%	-$6.18	95%
2	Hydro	1,547,903	136,174	9%	-$6.26	95%
3	Hydro	1,355,684	72,785	5%	-$0.14	88%
4	Hydro	7,108,999	64,341	1%	-$0.01	76%
5	Renewable	1,268,299	59,905	5%	-$2.46	100%
6	Renewable	1,450,687	56,926	4%	-$2.46	100%
7	Hydro	482,120	49,770	10%	-$2.75	92%
8	Renewable	1,059,860	48,473	5%	-$1.75	99%
9	Hydro	2,108,881	46,186	2%	-$0.09	75%
10	Hydro	756,071	44,815	6%	-$2.51	91%
11	Hydro	765,842	44,727	6%	-$2.51	90%
12	Renewable	1,074,283	43,235	4%	-$2.46	100%
13	Hydro	506,059	41,978	8%	-$2.19	91%
14	Renewable	871,000	40,504	5%	-$2.46	98%
15	Renewable	1,000,921	40,178	4%	-$1.76	100%
16	Renewable	866,339	39,360	5%	-$1.75	100%
17	Renewable	818,863	38,905	5%	-$2.46	100%
18	Renewable	786,515	33,463	4%	-$2.44	99%
19	Hydro	359,785	33,143	9%	-$3.97	92%
20	Hydro	357,685	32,936	9%	-$3.97	94%
21	Renewable	684,387	32,760	5%	-$2.46	99%
22	Renewable	622,413	28,545	5%	-$2.46	100%
23	Renewable	461,012	18,135	4%	-$2.46	100%
24	Hydro	299,737	10,594	4%	-$1.77	100%
25	Hydro	214,887	9,769	5%	-$1.75	100%
26	Renewable	816,839	8,536	1%	-$17.92	98%
27	Hydro	338,259	3,398	1%	-$0.80	92%

Q. How is the ISO proposing to address bid cost recovery for inter-day ramping energy?

A. The ISO is proposing an approach that will generally exclude these bid costs and market revenues from bid cost recovery calculations. With this approach, the ISO will first calculate any ramping energy that may be needed to transition a unit from its initial condition at start of a trade date to its economic schedule during the first few hours of the trade date. The ISO will then net the bid costs and revenues all of this ramping energy for all hours in which the unit needed to transition from its initial condition at the end of the prior trade day to its economic day-ahead schedule in the first hours of the next trade day. If the bid costs for this ramping energy exceed market revenues from this energy, these bid costs and revenues will be excluded from the bid cost recovery calculation. A more detailed description of this approach is provided in the ISO's tariff filing on this matter.

Q. Will this effectively mitigate the problem you identified?

A. Yes. This modification is will eliminate the obvious gaming opportunity previously described in my testimony.

Q. Would this modification have any detrimental impacts on participants not engaging in such behavior?

A. It should not have any significant impacts. In fact, analysis of data for the complete 2010 calendar year indicates that this special settlement provision will be triggered in an extremely limited number of cases and will result in minimal reduction in bid cost recovery payments.

Q. Can you describe this analysis?

A. Yes. The first step was to identify all hours in 2010 when units were being ramped down over the first few operating hours of each trade day in order to transition from their initial conditions to their economically optimal schedules for those hours given their bids and market prices. This was done using a program developed by the ISO specifically for this purpose. This is the same basic algorithm that will actually be used by the ISO to implement this settlement provision. Second, units/hours identified by this program were merged with daily bid cost recovery data from the ISO settlement system. If a unit did not receive any bid cost recovery during the day, it was dropped from the analysis. This reflects the fact that if a unit did not actually receive any bid cost recovery on any given day, then this new settlement rule would not have had any impact in terms of reducing its bid cost recovery payment on that day. Finally, the remaining unit/hours were merged with the corresponding hourly day-ahead energy bid costs and revenues used in settlement calculations. These hourly energy bid costs and revenues were then summed up. We then took the minimum of this sum or the total bid cost recovery paid to the units on those days. This total represents the approximate amount of any reduction in the units bid cost recovery payments resulting from this new settlement rule for ramping energy needed to transition a unit from its initial conditions during the first few hours of each trade day.

Q. What were the results of this analysis?

A. Results of this analysis show that if this rule had been in effect during the 2010 calendar year:

- A total of only 9 units would have had bid cost recovery payments reduced;
- bid cost recovery payments would have been reduced in a total of only 53 unit/hours; and
- bid cost recovery payments would have been reduced in a total of only about $88,000 over this entire 12 month period.

Q. How is the ISO proposing to address the need to issue exceptional dispatches to ensure the feasibility ancillary services and residual commitment awards?

A. The ISO is proposing to implement the mitigated exceptional dispatch settlement rules whenever the ISO must issue an exceptional dispatch to access market-awarded but infeasible ancillary services and residual unit commitment capacity. The mitigated exceptional dispatch settlement rules settle the incremental exceptional dispatch energy at the higher of the resource's default energy bid or the locational marginal price. Resources would only be eligible to be paid as bid if the capacity subject to the exceptional dispatch was not resource adequacy capacity and the scheduling coordinator elected supplemental revenues rather than a capacity payment under the ISO's capacity procurement mechanism tariff provisions.

Q. Will this effectively mitigate the problem you identified?

A. Yes. This mitigation is needed to address the obvious opportunities for uncompetitive bidding and market power previously described earlier in my testimony.

Q. Would this modification have any detrimental impacts?

A. No. This modification is designed to ensure that units are still paid the higher of the market price or default energy bid if they are exceptionally dispatched for any energy needed to make their market schedules feasible in these limited situations. Generators are allowed to select from a variety of options for the default energy bid to ensure that this price covers their true marginal costs.

Q. How is the ISO proposing to address the issue you identify above regarding ramping periods associated with self-schedules?

A. The ISO is proposing to address this issue by applying the same settlement rule that will be applied to ramping energy needed to transition a unit from its initial conditions to its economic day-ahead market schedules during the first few hours of each trade day. This approach will essentially exclude from bid cost recovery calculations the bid costs and market revenues associated with ramping energy needed to ramp to or from a unit's self-schedule. A more detailed description of this approach is provided in the ISO's tariff filing on this matter.

Q. Would this modification have any detrimental or unfair impacts on participants engaging in normal market behavior?

A. It should not have any significant detrimental or unfair impacts. As previously noted, this provision is being added as a preventative measure, rather than to address any behavior already observed. Participants who do choose to self-schedule should know their own unit operating characteristics and be able to schedule and bid accordingly to manage how their units are scheduled. Moreover, I believe an argument can be made that participant's who do self-schedule some of their energy should be limited in their ability to receive bid cost recovery payments. Clearly, if the ISO's day-ahead market software must schedule additional energy to make a unit's self-schedules feasible, this should not be eligible for bid cost recovery. Also, suppliers self-schedules a unit for energy, they presumably do this because their expected revenues exceed the costs of these self-schedules. However, none of these revenues or costs are included in daily bid cost recovery calculations. Therefore, if a unit that is self-scheduled for some energy also gets scheduled by the ISO market software, bid cost recovery calculations based only on these market schedules exclude all of the net revenues associated with the unit's self-schedules. Thus, any modest reductions in bid cost recovery that might result from this provision for unit's self-scheduling energy are unlikely to be detrimental or unfair.

Q. Does this conclude your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System)
Operator Corporation)

Docket Nos. ER11-____

DECLARATION OF
DR. ERIC HILDEBRANDT

I, Eric W. Hildebrandt, affirm under penalty of perjury that the statements in the Direct Testimony of Dr. Eric Hildebrandt, submitted in this docket, are true and correct to the best of my knowledge, information, and belief.

E Hildebrandt

Eric W. Hildebrandt

Executed this 20th day of June, 2011.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System	**)**	**Docket No. ER11-____**
Operator Corporation	**)**	

ATTACHMENT D

PREPARED DIRECT TESTIMONY
OF
DEBORAH A. LE VINE

ON BEHALF OF

THE CALIFORNIA INDEPENDENT SYSTEM

OPERATOR CORPORATION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER11-____-___**

PREPARED DIRECT TESTIMONY OF DEBORAH A. LE VINE ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Deborah A. Le Vine. I am employed as Director of System Operations for the California Independent System Operator Corporation (the "ISO"). My business address is 250 Outcropping Way, Folsom, CA 95630.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AT THE ISO?

A. As the Director of System Operations, I am responsible for ensuring that the ISO's day-to-day grid and market operations maintain compliance with system reliability criteria and standards established by the North American Electric Reliability Council (the "NERC") and the Western Electricity Coordinating Council (the "WECC") for the ISO balancing authority area, transmission operators, and transmission service providers, and fulfill the market responsibilities set forth in the ISO tariff. I also oversee and provide state-mandated reporting and public notifications relative to emergency system conditions as required. In addition, I ensure that the resources of the state and external sources meet capacity obligations as outlined by the WECC and NERC Standards.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Bachelor of Science degree in Electrical Engineering from San Diego State University in San Diego, California in May 1981. In May 1987, I received a Master in Business Administration from Pepperdine University in Malibu, California. In December 2002, I completed an Executive Program in Driving Government Performance: Leadership Strategies that Produce Results from the John F. Kennedy School of Government, Harvard University in Cambridge, Massachusetts. In August 2007, I completed an Advanced Masters Certificate program in Project Management from Villanova University in Villanova, Pennsylvania. Additionally, I am a registered Professional Electrical Engineer in the State of California.

Q. HAVE YOU PROVIDED EXPERT TESTIMONY PREVIOUSLY?

A. Yes. I have previously been a witness on behalf of the ISO in Docket Nos. ER98-997-000, et al., regarding the application of the ISO’s Participating Generator Agreement to qualifying facilities; Docket No. EL99-93-000, et al., regarding the Turlock Irrigation District and Modesto Irrigation District complaint; Docket No. EL00-105-007, et al., concerning the revenue requirement of the City of Vernon, CA; Docket No. ER00-2019-000, et al., involving the ISO's transmission Access Charge filing as required by

California State Legislation; Docket No. ER00-2360-000, et al., regarding the PG&E Reliability Service Tariff; Docket No. ER01-313-000, et al., regarding the ISO's position with regard to certain billing determinants for the ISO's Grid Management Charge; and Docket No. EL03-15-000, et al., concerning the revenue requirement of the Cities of Anaheim and Riverside California. I also submitted prefiled testimony in nine other proceedings in which hearings did not take place. Additionally, I have testified in a number of proceedings before the California Public Utilities Commission, California Legislature, and in a number of arbitration disputes

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain how operational and reliability needs may require the ISO to issue exceptional dispatches in order to ramp resources up to their "dispatchable Pmin" so that the capacity is available and usable by the ISO as operating reserve and residual unit commitment capacity. In the majority of instances, these circumstance arise when resources have ancillary services awards or residual unit commitment capacity that will be either entirely unavailable or of only very limited use unless the ISO issues an exceptional dispatch to ramp the resource to a dispatch level that is consistent with the day-ahead ancillary services or residual unit commitment capacity. This situation creates the opportunity for the scheduling coordinator to earn monopoly-type revenues by submitting uncompetitively high energy bids for those resources in expectation that the ISO will need to issue exceptional dispatches to ramp the resources up to a dispatch level that would make the ancillary services awards or residual unit commitment capacity feasible and useful. Several resources have taken advantage of this opportunity and earned exceptional dispatch revenues far in excess of their costs or prevailing market prices.

Q. WHAT IS AN EXCEPTIONAL DISPATCH?

A. An exceptional dispatch occurs when the ISO dispatches a resource – incrementally or decrementally – outside of the order determined by the ISO's market optimization software.

Q. UNDER WHAT CIRCUMSTANCES DOES THE ISO ISSUE EXCEPTIONAL DISPATCHES?

A. The ISO issues exceptional dispatches when a resource is needed for system reliability or for certain other specific needs identified in the ISO tariff, but the resource has not been awarded a dispatch through the ISO's software or has been awarded a dispatch that is either inconsistent with resource constraints or otherwise infeasible. Exceptional Dispatch authority is described in section 34.9 of the ISO tariff.

Q. WHAT ARE THE RELIABILITY REQUIREMENTS THAT THE ISO HAS TO MEET WITH RESPECT TO OPERATING RESERVE?

A. WECC and NERC require that each Balancing Authority maintain operating reserve equal to (1) regulating reserve, which is sufficient spinning reserve immediately responsive to automatic generation control to provide sufficient regulating margin to meet NERC's *Control Performance Criteria;* plus (2) contingency reserve, which is an amount of spinning and non-spinning reserve sufficient to meet the disturbance control standard and is the greater of the most severe single largest contingency or the sum of 5% of the load responsibility served by hydroelectric generation and 7% of the load responsibility served by thermal generation; plus (3) additional reserve for interruptible imports which is an amount of reserve that can be made effective within ten minutes following notification, equal to interruptible imports; plus 4) additional reserve for on-demand obligations, which is an amount of reserve that can be made effective within ten minutes following notification, equal to on-demand obligations to other entities or control areas.

Q. WHAT ARE THE REQUIREMENTS FOR SPINNING AND NON-SPINNING RESERVES?

A. The ISO's responsibility under the WECC/NERC requirements for "contingency reserve," which is defined as "Operating Reserve" in the ISO tariff, varies based on the supply but is typically between 6% and 7% of the ISO's load responsibility, depending on conditions. The ISO's operating reserve includes both spinning reserve and non-spinning reserve. Both spinning and non-spinning reserve must be capable of being loaded, *i.e.,* must be capable of producing all of the energy from the specified reserved capacity, in 10 minutes. The WECC requires that at least 50% of the ISO's operating reserve be met with spinning reserve. Because spinning reserve is operating reserve that is already synchronized to the grid, units providing spinning reserve must be operating during the period of the award. Thus, if the ISO is relying upon a resource to provide a certain amount of spinning reserve, the resource must be operating at a point where it can ramp up to provide the energy from the amount of capacity awarded in 10 minutes.

Q. WHAT IS RESIDUAL UNIT COMMITMENT?

A. Residual unit commitment is the process in the day-ahead market that the ISO uses, following the execution of the integrated forward market, to ensure that there is sufficient on-line operating capacity to meet the ISO's demand forecast. Resources with residual unit commitment capacity are obligated to submit energy bids in the real-time market.

Q. YOU SPOKE OF DISPATCHABLE PMIN. WHAT ARE PMIN AND DISPATCHABLE PMIN?

A. PMin refers to a resource's minimum operating point, i.e. the lowest operating level that the resource can reliably operate. It is determined by the resource's operating characteristics. A resource that the ISO has committed, *i.e.,* directed to be operating and available, but which has no energy scheduled, operates at PMin. The ISO uses the term dispatchable PMin to mean the point in the power curve where the unit is considered operationally dispatchable. For example, if there is an ancillary services award, the dispatchable PMin must is the operating level that will permit the resource to ramp at its “operating reserve ramp rate.” Scheduling coordinators provide the ISO with information regarding a resource’s “operating ramp rate” and operating reserve ramp rate. The operating ramp rate is the rate at which a resource can “ramp,” *i.e.* the MW/minute rate at which the unit can increase its energy output, if dispatched at a given operating level. A number of large units in the ISO’s fleet have a much lower MW/minute ramp rate at PMin that is not considered to be dispatchable. The defined operating reserve ramp rate is a single number – the ramp rate at which the resource is certified to provide operating reserve. The operational ramp rate, in contrast, is dynamic and can be slower (or faster) than the operating reserve ramp rate. For example, a 250 MW resource may have a PMin of 25 MW, and be capable of ramping at 1.5 MW/minute when operating between 25 and 125 MW, and 5 MW/minute when operating between 126 and 250 MW. If it is certified to provide operating reserve at 5 MW/minute, its dispatchable Pmin for purpose of an ancillary service award is thus 126 MW.

Q. UNDER WHAT CIRCUMSTANCES MUST THE ISO ISSUE AN EXCEPTIONAL DISPATCH IN ORDER TO RAMP A RESOURCE THAT HAS AN ANCILLARY SERVICES AWARD UP TO ITS DISPATCHABLE PMIN?

A. It is common for a resource, based on its bids, to be scheduled to provide a combination of ancillary services and energy in the day-ahead market plus an additional commitment of residual unit commitment capacity. The energy and ancillary services schedule and award results from the ISO's co-optimization using the resources' bids. A problem may arise when a unit receives an ancillary services award for operating reserves that is based on an operating reserve ramp rate that is higher than the operating ramp rate of the resource when it is operating at the output specified in its energy schedule. This occurs most dramatically when the resource is merely committed at PMin and the dispatchable PMin is much higher. As described in the example discussed in Dr. Hildebrandt's testimony, a resource may have a PMin of 25 MW and an operational ramp rate of 1.67 MW/minute when operating between 25 and 125 MW. Thus, when the unit is scheduled at PMin, it can provide only about 17 MW of spinning reserve (1.67 MW/minute x 10 minutes). Once the resource is operating at 125 MW, it can ramp up at a rate of 6 MW/minute and can provide up to 60 MW of spinning reserve (6 MW/minute x 10 minutes). Currently, the ISO's day-ahead market software considers the amount of spinning reserve available from on-line units based on the fixed operating reserve ramp rate in the ISO's master file. This fixed ramp rate represents the maximum amount of spinning reserve the unit is certified to provide, which in this case would reflect the higher 6 MW/minute ramp rate. Thus, even when this unit is scheduled to operate at only 25 MW in the day-ahead market, the unit may be awarded up to 60 MW of spinning reserve.

This can create a situation where the unit is awarded 60 MW of spinning reserve when it can only provide 17 MW of spinning reserve. In such circumstances, the ISO may need to issue exceptional dispatches to move the resource to its dispatchable PMin.

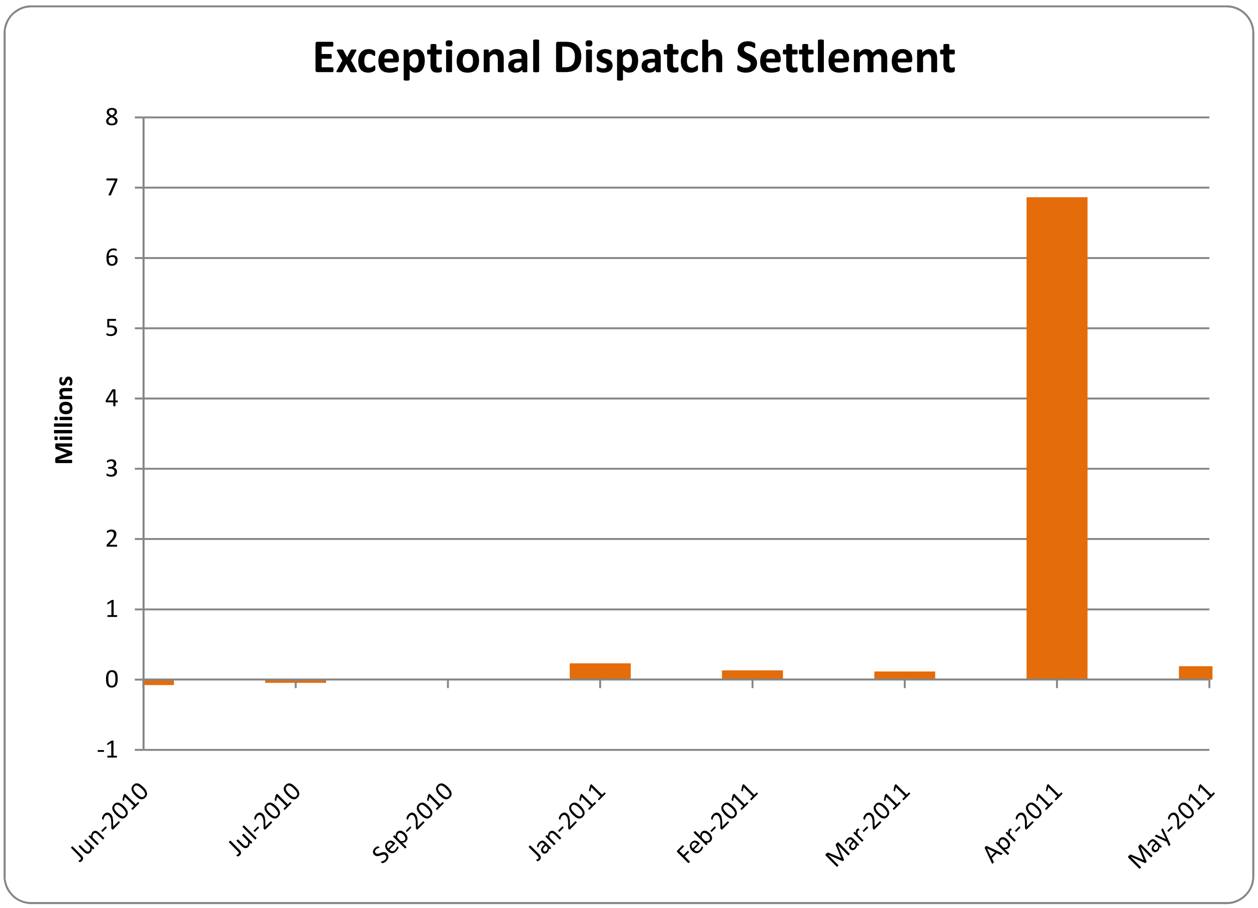
Q. DOES DISPATCHABLE PMIN ALSO HAVE AN IMPACT ON RESIDUAL UNIT COMMITMENT CAPACITY?

A. Yes. The situation is similar. Although the ISO may not need ten minute ramping capacity for resources with residual unit commitment capacity, the ISO may need to issue an exceptional dispatch to a resource so that the energy bids that the resource is obligated to submit into the real-time market for the awarded residual unit commitment capacity can be available to the ISO. Dr. Hildebrandt's testimony provides a detailed example. In brief summary, his example illustrates a situation where less than half of the awarded residual unit commitment capacity would be available unless the ISO issues exceptional dispatches to ramp the resource to an operating level with an operational ramp rate consistent with the resource's scheduled residual unit commitment capacity.

Q. YOU STATED THAT THIS SEQUENCE OF EVENTS REQUIRING THE OPERATORS TO ISSUE EXCEPTIONAL DISPATCHES HAS ALLOWED A RESOURCE'S OWNER TO EARN EXCESSIVE ENERGY PAYMENTS. PLEASE EXPLAIN.

A. In April, the ISO exceptionally dispatched several units operating at PMin over the most critical peak demand morning and evening hours when demand and prices are at their highest. All of the energy bids above Pmin were just below the $1,000 bid cap. In just five days, during a total of 24 hours, almost $5.3 million of exceptional dispatch energy costs were incurred as a result of exceptional dispatch of such bids. Of that $5.3 million, $3.6 million in costs involved units with infeasible ancillary services awards or residual unit commitment capacity. Since that period, the ISO was repeatedly presented with stranded ancillary services awards and residual unit commitment capacity. For example, during the time period from April 19 through May 3, for the units involved in the bidding strategy, there was a total of 621 hours of stranded ancillary services (spinning reserve) awards with a typical award of approximately 64 MW. During this same time period, there was a total of 32 hours of stranded residual unit commitment capacity with hourly capacity commitments ranging from 150 and 250 MW of capacity. Although the ISO took steps to minimize the need for exceptional dispatch, the scheduling coordinator for these units earned over $6.8 million from exceptional dispatches in the month of April. As discussed in more detail below, although it has been able to avoid paying high exceptional dispatch payments to the scheduling coordinator for these units in May, the ISO has had to replace stranded ancillary services in the hour-ahead scheduling process or real-time market and in some cases issue exceptional dispatches to off-line resources when it was cheaper than exceptionally dispatching the on-line resources with higher energy bids. These alternatives impose reliability risks and costs. Figure

1, below, charts the total exceptional dispatch energy settlements for the months of January through May associated with the resources engaged in the bidding strategy described in my testimony and in Dr. Hildebrandt's and support the conclusion that the scheduling coordinator was taking advantage of this bidding strategy.



Dr. Hildebrandt's testimony will explain how this situation demonstrates the need to mitigate uncompetitively high bid prices submitted on behalf of resources with infeasible ancillary services awards or residual commitment capacity.

Q. YOU MENTIONED THAT THE ISO TOOK STEPS TO MINIMIZE EXCEPTIONAL DISPATCHES FOLLOWING THE FIRST FEW DAYS. WHAT ARE THE OPERATIONAL ALTERNATIVES TO ISSUING AN EXCEPTIONAL DISPATCH IN ORDER TO RAMP A RESOURCE UP TO ITS DISPATCHABLE PMIN UNDER SUCH CIRCUMSTANCES?

A. If ancillary services purchased in the day-ahead market are infeasible in real-time and the right combination of other resources is running, the ISO may be able to buy back the ancillary service award from the resource that is not capable of providing the awarded amount and re-award to another resource through procurement in the hour-ahead scheduling process or real-time market. In some cases, the ISO may not need all of the ancillary services purchased in the day-ahead market; in other words, the amount of ancillary services purchased by the ISO may still be sufficient due to lower than expected load or other changes in system conditions. Of course the ISO always has the authority to procure additional operating reserves in the real-time market if necessary to ensure compliance with reliability requirements. Any day-ahead infeasible ancillary services awards that remain infeasible and are not bought back will be subject to no-pay provisions of the ISO tariff. There is no alternative other than exceptional dispatch to make infeasible residual unit commitment capacity available and useful.

Q. WHY ARE THESE ALTERNATIVES NOT A SATISFACTORY RESOLUTION TO THE ISSUE?

A. First, the ISO tariff obligates the ISO to procure 100% of the ISO's ancillary services requirements in the day-ahead. The ISO made a deliberate decision that day-ahead procurement of 100% of the ISO's forecast ancillary services requirements would best ensure reliable operation of the grid. To this end, the ISO also made a deliberate decision not to permit scheduling coordinators to buy back their ancillary services awards in the hour-ahead scheduling process or the real-time market. Thus, infeasible ancillary services awards put the ISO in exactly the position that it sought to avoid and undermine the ability of the ISO to operate the grid reliably. Although the ISO has authority to procure additional operating reserves in the hour-ahead scheduling process to supplement or replace any day-ahead operating reserve awards, the operating reserves purchased in the hour-ahead scheduling process are automatically considered as only available in the event of a "contingency." In the day-ahead market, on the other hand, scheduling coordinators must select "contingency only" flag if they desire this status; otherwise the operating reserve will not be reserved for contingencies. Another undesirable outcome of hour-ahead procurement of operating reserve is that if the ISO procures an incremental amount of operating reserve from a resource with a day-ahead award, the total amount of operating reserve will be classified as "contingency only," even though the day-ahead award was not subject to this restriction. As the percentage of operating reserves classified as "contingency only" increases, even less dispatchable capacity is available to ISO operators to manage the grid absent a contingency.

Moreover, when compounded by the bidding strategy explained in Dr. Hildebrandt's testimony, the alternatives may be ineffective in avoiding the need for exceptional dispatches. In brief summary, the bidding strategy forces the ISO market software to commit resources at PMin and then to keep the resource at PMin when the ISO has the most need for ramping capacity to meet peak load as well as the awarded ancillary services and residual unit commitment capacity. This bidding strategy also has the consequence of preventing other resources that have bidding profiles more reflective of actual costs from getting committed and scheduled in the market, thus depriving the ISO of alternative dispatchable capacity from resources that are willing to provide it. The net result of these factors is that the ISO has less dispatchable capacity and more operating reserve capacity that is only available in the event of a contingency, increasing the likelihood that exceptional dispatches may be necessary. In addition, the ISO may also be forced to and has issued exceptional dispatches to off-line resources to ensure sufficient dispatchable capacity is available to operate the grid reliability when it is less costly to issue exceptional dispatches to off-line units than to units that are already on-line. Thus, the bidding scenario described in my testimony and in Dr. Hildebrandt's not only increases infeasible operating reserve awards and residual unit commitment capacity, it may also require the ISO to commit additional resources through its exceptional dispatch authority to ensure that sufficient ramping capacity is available.

Q. HAS THE BIDDING BEHAVIOR YOU HAVE DESCRIBED PERSISTED?

A. Yes. The bidding behavior has continued since April into June. So far, the ISO has been able to maintain reliability and manage costs through buying back the infeasible ancillary services and procuring replacement operating reserves in the real-time market. In addition, the ISO has sought out less costly exceptional dispatch alternatives, if necessary, including exceptional commitment and dispatch of resources with submitted bids that were off-line and move them to their dispatchable PMin.

Over the last few weeks, however, it has become necessary to commit additional resources in the day-ahead or real-time to make up for a loss of resources in the market with energy schedules that are dispatchable; this has been due not only to the stranded capacity associated with infeasible ancillary services awards and residual commitment capacity, but also to stranded capacity associated with commitment at PMin of resources with extremely slow ramp rates at PMin. For the reasons discussed in my testimony, from an operational perspective, it is suboptimal to be unable to rely on day-ahead ancillary services awards and residual unit commitment capacity – the very services that are procured day-ahead in order to ensure reliability of the grid in real-time. It is also suboptimal and *should be* uneconomic to commit off-line resource when an on-line resource – particularly one with an ancillary service award or residual unit commitment capacity – can be incremented to dispatchable PMin level. For these reasons, the ISO believes it needs the authority to apply settlement rules for mitigating bids from exceptionally dispatched resources when it issues exceptional dispatches to access infeasible ancillary services awards and residual unit commitment capacity, at least until longer term market design rules can be designed and implemented that – through disincentives or revised bidding rules – will reduce stranded ancillary services awards and residual unit commitment capacity and, thus, reduce the need to rely on exceptional dispatch.

Q. THANK YOU. I HAVE NO FURTHER QUESTIONS

DECLARATION OF WITNESS

I, Deborah A. Le Vine, declare under penalty of perjury that the statements contained in the Direct Testimony of Deborah A. Le Vine on behalf of the California Independent System Operator Corporation in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 22 day of June, 2011.

Deborah A. Le Vine

Deborah A. Le Vine

Attachment E – Description of Bid Cost Recovery Mechanism

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

June 22, 2011

Attachment E: Description of the ISO Market and Bid Cost Recovery

On April 1, 2009, the ISO began operations of its locational marginal price (LMP) based energy and ancillary services market.[1] Under the LMP-based market design, the ISO runs day-ahead and real-time energy and ancillary services markets. In these markets, supply and certain demand resources may submit economic bids that specify a price as well as self-schedules, which consist of price-taking schedules of megawatt hours (MWh) without a specified price. If resources are scheduled, dispatched or awarded in any of the ISO markets, they are paid the market clearing LMP for energy, and the ancillary services marginal price for ancillary services provided pursuant to schedules, awards, or dispatches.

Scheduling coordinators submit bids for resources in the form of energy and ancillary services bid curves, which indicate to the ISO the price at which the scheduling coordinator is willing to provide the relevant service, and the MWh amounts offered at that price. In some cases, a resource is needed for reliability but its bid does not clear the market. In order to ensure that the resource remains available, the ISO will commit the resource and essentially guarantee payment of the submitted bid price for the affected ranges.

The bid cost recovery mechanism is incorporated in a settlements process by which the ISO ensures that scheduling coordinators: 1) recover their start-up and minimum load costs for resources that are committed by the ISO, and are not otherwise self-committed by the scheduling coordinator;[2] and 2) recover the cost of their accepted energy or ancillary service bids above minimum load. The bid cost recovery rules are set forth in Section 11.8 of the ISO tariff. This section also provides the mechanisms by which all such costs are allocated to scheduling coordinators in each of the respective ISO markets. Bid cost recovery only applies to the ISO day-ahead market, which includes the IFM and the residual unit commitment (RUC) processes, and the real-time market.[3] Bid cost recovery is provided for both energy and ancillary services products.

Under the ISO tariff, all internal generators, participating loads, proxy demand resources, and resource-specific system resources[4] are eligible for recovery of their start-up and minimum load costs through the bid cost recovery process, subject to

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1 The ISO's tariff amendment in support of this new market design was conditionally accepted by the Commission in its September 2006 Order, subject to certain compliance requirements.

2 Minimum load and start-up costs are bid into the ISO markets as based on either the resources registered or proxy demands, which are fixed for each month. *See* Section 30.4 of the ISO Tariff. The ISO is in the process of amending these sections to provide more flexibility in bidding such costs. *See* http://www.caiso.com/23d9/23d9c75e22ab0.html#27cbddd035020.

3 Bid cost recovery does not apply to bids submitted to Congestion Revenue Rights auctions.

4 Internal generators refer to generating units, including multi-stage generating resources. Resource-specific system resources refer to import system resources that signed a Resource-Specific System Resource Agreement and identified a specific physical resource associated to the designated system resource.

additional conditions discussed further below. System resources that are not resource-specific cannot recover start-up and minimum load bid costs from the ISO.[5]

All generating units and participating loads are eligible for recovery of their energy and ancillary services bids, and RUC bids, if any, as well as the minimum load and start-up bid costs. System resources are also eligible for bid cost recovery for their energy bids, to the extent their market revenues over the trading day are insufficient to recover such costs. But not all system resources are eligible for recovery of start-up and minimum load bid costs. Only those system resources that are representative of actual physical external resources, and are registered as such with the ISO, are eligible to submit start-up and minimum load bids. All other system resources must submit zero-bids for start-up and minimum loads.

Furthermore, in any given interval, such resources are only eligible for recovery of their start-up and minimum load bid costs to the extent that they are committed by the ISO in that interval. Therefore, if a resource is self-committed in a given interval (*i.e.*, it is providing energy pursuant to a self-schedule, or self-provided ancillary services), that resource is not eligible for bid cost recovery for its start-up and minimum load costs during those intervals. Resources that are self-committed are presumed to either be willing to operate as price-takers or are operating pursuant to a bilateral contract through which the resources likely receive compensation for their start-up and minimum load costs. It would thus be redundant and inefficient to provide further compensation to recover those costs through the ISO markets. These rules are described further below and are contained in Section 11.8.1 of the ISO's tariff.

Rationale for Bid Cost Recovery

In clearing the ISO markets, the ISO considers submitted start-up and minimum load bid costs in optimizing for the least-cost commitment or dispatch of resources. However, while scheduling coordinators submit three part bids, which include start-up, minimum load and the energy bid costs, only the energy bid cost is able to set the LMP. That is, the market clearing LMP only reflects the marginal costs of energy based on the variable energy bids, and not the fixed start-up and minimum load costs. If, however, a resource is committed or dispatched by the ISO, and it performs consistent with that commitment, the ISO assumes that the resource would have not incurred the fixed start-up and minimum load costs but for the ISO's commitment or dispatch. Although a resource committed by the ISO is not paid less than its energy bid price, there is no guarantee that the extra revenues it receives for its energy (including minimum load energy) at the applicable LMP will cover its start-up and minimum load costs. Therefore, the ISO provides a mechanism for recovering such costs. The payment for these costs is effectuated through essentially an uplift payment to the affected resources to compensate the resource for its fixed costs. In the absence of this uplift payment, scheduling coordinators would likely internalize these costs in their energy bids. By providing the opportunity to submit and recover these costs separately from

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[5] These include, for example, import resources that are just net interchanges not tied to a specific external generator.

the energy bid, the ISO is able to better ensure that the LMP derived through the market clearing process is the marginal cost of providing energy on the ISO system, as opposed to also reflecting the fixed costs of providing service.

In clearing the energy and ancillary services markets, energy bids are selected through a least cost process within a given time horizon. For example, in IFM the bids are selected with a view to minimize costs, including energy bid costs, through all hours of the applicable operating day. Throughout any given operating day, however, the resource may be subject to inter-temporal constraints such as ramping rates, minimum run times, and minimum up times. Consequently, while a resource's energy or ancillary services bid may set the price in one interval in which the ISO commits the resource, it may not be marginal (*i.e.*, its energy bid price is above the market clearing price) in other intervals of that day during which it must also run in order to be available at the required hour as a result of its ramp rate limitations. This is particularly common in the real-time market where resources are dispatched on shorter time intervals, of five minutes, and ramp rates may prevent them from reaching an otherwise optimal economic operating point in five minutes.

In its initial February 9, 2006 MRTU tariff filing, the ISO proposed that a resource not receive a bid cost recovery payment for a settlement interval if its uninstructed deviations during that Settlement Interval exceed a certain threshold.[6] The Commission denied the application of a threshold bandwidth to bid cost recovery amounts, finding that the ISO should guarantee recovery of such costs associated with energy actually delivered, but should not provide such payments to resources for deviations from their schedules or dispatch instructions. The Commission found that when a resource's energy bid exceeds the LMP, it is not appropriate to provide an uplift payment to cover the revenue gap for energy that is not actually produced when instructed. Specifically, the Commission stated:

> [A] resource that starts up and provides more energy than is instructed by the ISO should retain the original recovery calculated by the ISO in the day-ahead market, since the spot market would be receiving the full amount of energy (and more) that it agreed to pay for in the day-ahead market. However, the resource should not be eligible for any additional bid cost recovery associated with its additional, uninstructed output. Thus, the resource is paid only for scheduled energy, and is not paid for any energy in excess of its schedule. Units that are committed in the day-ahead market, and do not start-up, should not receive any bid cost recovery payments.[7]

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[6] Specifically, for purposes of calculating bid cost recovery, a resource's eligible costs for a Settlement Interval was going to be zero if the amount of uninstructed imbalance energy attributed to that resource during that Settlement Interval is in excess of the greater of: (a) five (5) MWh divided by the number of Settlement Intervals in the Trading Hour; or (b) 3% of its maximum capacity divided by the number of Settlement Intervals in a Trading Hour.

[7] September 2006 Order, at P 516.

Application of Bid Cost Recovery Based on Delivered Amounts

Based upon the Commission's findings, the ISO filed revised tariff language that eliminated the application of the tolerance bandwidth previously proposed, and incorporated the principle that bid cost recovery is provided only for resources with energy actually delivered. The ISO noted that the changes were "consistent with the Commission's requirement that resources that fall short of day-ahead dispatch instructions should only be guaranteed the recovery of costs associated with the energy actually provided, and should not receive payments for deviations from dispatch instructions."[8] The Commission approved the revised tariff language, including the application of the tolerance bandwidth only to the minimum load cost calculations.[9] The ISO also developed the metered energy adjustment factor used in the application of the bid cost recovery amounts to determine, in any given interval, whether the resource was actually delivering energy for the scheduled or dispatched amounts based on its metered data.

The ISO developed two metered energy adjustment factors to use in determining the delivered portions of schedules and dispatches. First, the day-ahead metered energy adjustment factor was developed to determine the portions of the day-ahead schedule actually delivered in real-time, taking into consideration the resource's metered energy. The factor is calculated as follows: The factor is bounded by 1 or 0, and is the ratio of the resource's (a) metered energy *minus* the day-ahead self-scheduled energy *minus* the day-ahead minimum load energy *minus* the standard ramping, and (b) the day-ahead scheduled energy *minus* the day-ahead self-scheduled energy *minus* the day-ahead minimum load energy. Second, the real-time metered energy adjustment factor used for the purposes of determining the portions of a scheduling coordinator's relevant dispatch instruction actually delivered in the real-time, taking into consideration the resource's metered energy. The factor is bounded by 1 or 0, and is the ratio of the resource's (a) metered energy *minus* day-ahead scheduled energy *minus* standard ramping *minus* real-time self-scheduled energy, and (b) total expected energy *minus* day-ahead scheduled energy *minus* standard ramping *minus* real-time self-scheduled energy. These factors are fully described in the ISO's Business Practice Manual on Settlements and Billing and were developed to accomplish the requirement in the ISO tariff that bid costs and market revenue accounting is on the basis of delivered portions.[10]

When the ISO originally filed its tariff in support of the LMP-based market design, the ISO did not specify that in accounting for the market revenues it would look at the delivered portions of the schedules or dispatches. However, prior to the start of its new market design, through testing and simulations the ISO determined that in some cases accounting for revenues for all scheduled energy posed a potential for under-recovery. Therefore, the ISO adopted the practice of accounting for market revenues based on

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[8] *Cal. Indep. Sys. Operator Corp.*, Compliance Filing, FERC Docket No. ER06-615-000, at 16 (Nov. 20, 2006).

[9] *Cal. Indep. Sys. Operator Corp.*, 105 FERC ¶ 61,313 at P 96 (2007).

[10] This Business Practice Manual is available at: https://bpm.caiso.com/bpm/bpm/doc/000000000000536.

delivered portions and included this requirement in its tariff before the start of its new market design.[11]

Netting of Market Revenues

The bid cost recovery mechanism is not intended to duplicate market revenues obtained through market sales. Therefore, bid cost recovery payments ultimately depend on whether the market revenues for each eligible resource in each ISO market are sufficient to cover the resource's costs. This determination is made by first calculating market revenues, and next applying a series of sequential netting rules, both described further below.

Netting market revenues against costs for a 24-hour period is appropriate. In all of the ISO market processes, the constraints that result in prices in some intervals being insufficient for certain resources to recover their bid costs ultimately results in a less economic solution overall than where the constraint had not been present. However, a resource that might be constrained in some intervals will be provided an opportunity to benefit in other intervals that increase the price, or both the price and the amount of infra-marginal energy dispatched and settled from that resource. It is thus appropriate, if a resource is being compensated via an uplift payment when the resource is extra-marginal (*i.e.*, not recovering its costs), that the resource internalize such payments before spreading such costs to the rest of the market. Since the effects of a constrained resource has impacts beyond one interval or one hour, and the fact that the optimization horizon is continuously shifting from one hour to the next, a 24-hour netting period for purposes of calculating bid cost recovery is reasonable.[12]

Minimum Load Costs are Registered or Proxy Costs

The ISO's market system bases unit commitment decisions on a unit's fixed start-up and minimum load bid costs, plus bid costs for energy above minimum load that may be scheduled in the market if the unit is committed. As noted above, these fixed start-up and minimum load costs are guaranteed recovery through the bid cost recovery mechanism. Market participants bidding in generating resources submit their start-up and minimum load costs to the ISO Master File. Those costs are then static for 30 days but can be changed thereafter. Market participants can specify one of two options for the start-up and minimum load values they have in the ISO Master File: (1) the proxy cost option; or (2) the registered cost option. Under the proxy cost option, start-up costs are comprised of two elements: an indexed value that changes daily depending on the natural gas price (or, for units for which that is not applicable, on the energy price), and a fixed natural gas transport adder. Minimum load costs under the proxy cost option are calculated in similar fashion, with an additional operations and maintenance (O&M) adder. Under the registered cost option, market participants can submit start-up and minimum load values up to 200% of the calculated proxy-cost value. The registered cost option gives market participants the ability to specify costs for the unit that takes

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11 *Cal. Indep. Sys. Operator Corp.*,~~,~~ FERC Docket No. ER09-918-000 (Mar. 30, 2009).

12 *See Cal. Indep. Sys. Operator Corp.*, 105 FERC ¶ 61,091 at P 94 (2003) (Commission approved 24-hour netting approach for bid cost recovery under the ISO's current market design).

into account their assessment of any additional costs that may be associated with starting up the unit and operating at minimum load.