CALIFORNIA ISO

California Independent
System Operator

August 27, 2003

Via Electronic Filing

The Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: California Independent System Operator Corporation
Docket No. ER03-1046-000

Dear Secretary Salas:

Enclosed please find the Motion for Leave to File Answer and Answer of the California Independent System Operator Corporation to Motions to Intervene, Comments, and Protests, submitted in the captioned docket.

Thank you for your attention in this matter.

Respectfully submitted,

(AJJ)

Charles F. Robinson

Counsel for the California Independent System Operator Corporation

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing documents upon each person designated on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R § 385.2010).

Dated at Folsom, California, on this 27th day of August, 2003.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER03-1046-000**

MOTION FOR LEAVE TO FILE ANSWER AND ANSWER OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO MOTIONS TO INTERVENE, COMMENTS, AND PROTESTS

I. INTRODUCTION AND SUMMARY

On July 8, 2003, the California Independent System Operator Corporation ("ISO")[1] filed Amendment No. 54 to the ISO Tariff in the above-captioned proceeding ("Amendment No. 54"). Amendment No. 54 would modify the ISO Tariff to further the Real Time Imbalance Energy Market design elements in Phase 1 of the ISO's Comprehensive Market Redesign ("MD02") initiative and complement the market design changes that were implemented on October 30, 2002 as part of MD02 Phase 1A.

A number of parties have submitted motions to intervene, comments, and protests concerning Amendment No. 54.[2] The ISO does not oppose the

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[1] Capitalized terms not otherwise defined herein shall have the meaning set forth in the Master Definitions Supplement, Appendix A to the ISO Tariff.

[2] The following entities filed motions to intervene, comments, and/or protests: Automated Power Exchange, Inc.; California Department of Water Resources State Water Project ("CDWR-SWP"); California Electricity Oversight Board ("EOB"); Cites of Redding and Santa Clara, California, and the M-S-R Public Power Agency ("Cities/M-S-R"); Cogeneration Association of California; Duke Energy North America, LLC and Duke Energy Trading and Marketing, L.L.C. (collectively, "Duke Energy"); Dynegy Power Marketing, Inc., El Segundo Power LLC, Long Beach Generation LLC, Cabrillo Power I LLC, and Cabrillo Power II LLC (collectively, "Dynegy"), Williams Energy Marketing & Trading Company ("Williams"), Western Power Trading Forum ("WPTF"), and Independent Energy Producers of California ("IEP") (considered all together, "Dynegy, *et al.*"); FPL Energy, LLC ("FPLE"); The Metropolitan Water District of Southern

interventions of parties that have sought leave to intervene in the proceeding. Moreover, a number of the parties explain that they support some or all of the concepts behind Amendment No. 54, the specific proposals in Amendment No. 54, or both. *See* CDWR-SWP at 2; CPUC at 1-2; Dynegy, *et al.* at 2, 3; EOB at 2-3; FPLE at 1-2; MWD at 5-6; PG&E at 4, 7, 8; SMUD at 1. However, some parties also raise concerns and criticisms with regard to Amendment No. 54. Pursuant to Rules 212 and 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212, 385.213, the ISO hereby requests leave to file an answer, and files its answer, to the comments and protests submitted in this proceeding.[3] As explained below, the Commission should accept Amendment No. 54 in its entirety, except for the limited modifications noted below.

California ("MWD"); Modesto Irrigation District; Northern California Power Agency ("NCPA"); Pacific Gas and Electric Company ("PG&E"); Powerex Corp. ("Powerex"); Public Utilities Commission of the State of California ("CPUC"); Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. (collectively, "Reliant"), Mirant Americas Energy Marketing, LP, Mirant California, LLC, Mirant Delta, LLC, and Mirant Potrero, LLC (collectively, "Mirant") (considered all together, "Reliant/Mirant"); Sacramento Municipal Utility District ("SMUD"); Southern California Edison Company ("SCE"); Transmission Agency of Northern California; Tucson Electric Power Company; Turlock Irrigation District; and WPTF. In addition, on July 21, 2003, the California Generators (composed of Duke Energy, Dynegy, Mirant, Reliant, and Williams) and IEP (considered all together, "California Generators/IEP") submitted their joint motion to intervene and request for additional time to submit comments.

[3] To the extent this answer is deemed an answer to protests, the ISO requests waiver of Rule 213 (18 C.F.R § 385.213) to permit it to make this Answer. Good cause for this waiver exists here because the answer will aid the Commission in understanding the issues in the proceeding, provide additional information to assist the Commission in the decision-making process, and help to ensure a complete and accurate record in this case. *See, e.g.*, *Entergy Services, Inc.*, 101 FERC ¶ 61,289, at 62,163 (2002); *Duke Energy Corporation*, 100 FERC ¶ 61,251, at 61,886 (2002); *Delmarva Power & Light Company*, 93 FERC ¶ 61,098, at 61,259 (2000). For similar reasons, the ISO asserts that good exists for waiver of Rule 213 to allow the ISO to respond to assertions made by the California Generators/IEP in their July 21, 2003 filing.

II. ANSWER[4]

A. The ISO's Proposal To Implement Real Time Security Constrained Economic Dispatch Is Reasonable

1. PG&E's Proposal To Shorten the Time In Which Schedules Are Fixed Is Unnecessary

While PG&E states that it generally supports real-time security constrained economic Dispatch, it goes on to assert that the ISO should be encouraged to continue to shorten the horizon within which pre-schedules are fixed. PG&E at 5-6. The ISO notes that the current deadline for submitting Final Hour-Ahead Schedules (135 minutes before the operating hour[5]) was established by the Commission in its Order issued in the MD02 proceeding on January 17, 2003. *California Independent System Operator Corporation*, 102 FERC ¶ 61,050, at P 12 (2003) ("January 17 Order"). Amendment No. 54 does not propose to modify that deadline.

The ISO initially proposed to move the deadline for submitting Final Hour-Ahead Schedules to 60 minutes before the operating hour as part of its MD02 market redesign. After discussions with Market Participants, who expressed a desire for a "re-bid" opportunity for the Real Time Market after the Hour-Ahead Market, and after re-examining all the market software processing requirements,

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[4] Many of the subject headings in this section of the answer are titled similarly to the subject headings in the Amendment No. 54 transmittal letter, and are presented in the same order as in the transmittal letter. This section of the answer also notes the subjects that were discussed in the Amendment No. 54 transmittal letter but with regard to which no party appears to raise an issue.

[5] While PG&E indicates that "Final Hour-Ahead schedule adjustments are now restricted to three hours in advance of the operating hour," the deadline for submitting Final Hour-Ahead Schedules is 135 minutes before the operating hour.

the ISO proposes to leave the deadline for submitting Final Hour-Ahead Schedules and bidding into the Hour-Ahead Market[6] at 120 minutes prior to the operating hour. Accordingly, PG&E's request goes beyond the scope of the proceeding. *See, e.g.*, *California Independent System Operator Corporation*, 94 FERC ¶ 61,265, at 61,919 (2001).

2. The Proposed "No Pay" Provision Is Reasonable

In Amendment No. 54, the ISO proposed a new "No Pay" mechanism, set forth in Sections 2.5.26.2 *et seq.* and 2.5.26.3 of the ISO Tariff, that would rescind Ancillary Services payments for Ancillary Services capacity that was awarded or self-provided according to a greater ramp rate than the ramp rate at which the resource could actually deliver the Energy from such capacity and to rescind Regulation Up and Regulation Down payments for regulating capacity that spans Forbidden Operating Regions. The ISO also proposed to make the order in which Ancillary Services payments are rescinded consistent with the new way Ancillary Services capacity is allocated to the Single Energy Bid Curve from lowest quality service to highest quality service to preserve the highest quality service.

Dynegy, *et al.* argue that the No Pay tolerance band for rescission of Ancillary Service capacity payments should be specified in the ISO Tariff and that it not be smaller than the proposed Uninstructed Deviation Penalty ("UDP") deadband. They also claim that implementation of Ancillary Service No Pay

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[6] There is currently no Hour-Ahead auction market. At the urging of Market Participants, the ISO has proposed to implement such a market in its MD02 redesign.

could result in a Generator that is able to fully perform in its provision of Ancillary Service not getting paid for the service. Dynegy, *et al.* at 21-23. Dynegy, *et al.*'s request to define the Ancillary Service No Pay deadband seeks a change in the ISO Tariff that is not part of the scope of Amendment No. 54. The only change the ISO proposed to the approved Section 2.5.26.3 that deals with No Pay was to change the word "BEEP" to "Settlement." Dynegy, *et al.* are seeking to accomplish through a protest to a Tariff amendment what they have never sought to change through more appropriate methods. *See, e.g.*, *Entergy Services, Inc.*, 52 FERC ¶ 61,317, at 62,270 (1990). In the event that the Commission determines that Dynegy, *et al.*'s proposed revision of the deadband is ripe for consideration, the ISO argues that it should be rejected on the grounds that the No Pay deadband is used to verify delivery of a capacity service essential to reliable operations and that a different deadband is justified. Dynegy, *et al.* included a numeric example that purported to show how a Generating Unit would be lose a portion of its capacity payment if its Generating Unit was starting from a operating level that is below its expected operating level, even if the Generating Unit delivered the full amount of the incremental energy instructed. If the Generating Unit was instead starting from an operating level that included a positive uninstructed deviation, then the Generating Unit would be required to deliver only a small fraction of the incremental instructed Energy to be deemed to have fulfilled its capacity obligation and to avoid an adjustment under No Pay. Such an outcome neuters the No Pay incentive to deliver the incremental energy required from a reliability reserve service. It is inappropriate, therefore, to expand the No Pay deadband.

Reliant/Mirant argue that the ISO's proposed application of a No Pay mechanism to Ancillary Service capacity fails to recognize legitimate operating constraints, and unfairly subjects participants to allegations of gaming activity simply because of the ISO's chosen market design. Reliant/Mirant assert that although Amendment No. 54 will modify the ISO's software to recognize operating-level specific ramp rates when Dispatching Ancillary Service-related Energy, the ISO will only accept Ancillary Service bids for a *particular* ramp rate. As a result, they contend, if an operator delivers Ancillary Service Energy at a ramp rate differing from the ramp rate specified in that unit's bid, that unit will be subject to a No Pay penalty. Reliant/Mirant at 1-2, 5-6.

The ISO acknowledges that a Generator runs the risk of not being paid for Ancillary Services it sells to the ISO assuming a certain ramp rate but subsequently cannot deliver in real time if the unit is operating at a different level (either because it has accepted an ISO Dispatch Instruction or entered into a bilateral contract), and the unit's ramp rate at that level is less than the ramp rate it specified when it sold the service. While Reliant/Mirant assert this problem stems from the ISO's market design, the ISO fails to see how this problem could be alleviated except by preventing the Generating Unit from operating at an operating point other than the operating point specified by the Generator when it was awarded Ancillary Services.

Consider the following example. Assume that the ISO could use the same operating ramp rate "function" in the bids provided to its Ancillary Services markets as the operational ramp rate function it proposes under Amendment No. 54. That function could look something like this:

Operating Level	Ramp Rate
50-100 MW	3 MW/Min
100-200 MW	5 MW/Min
200-250 MW	3 MW/Min

Assume further that the unit's Day-Ahead Schedule is 100 MW. It is awarded 50 MW of Ancillary Services in the Day-Ahead Market using a ramp rate of 5 MW/min. Then assume that the unit enters into a bilateral sale in the Hour-Ahead Markets that requires it to operate at 200 MW. The unit has a full 50 MW of operating capability left, but the unit can no longer ramp at 5 MW/min. The unit can no longer provide 50 MW of Energy within ten minutes – the Ancillary Services it was awarded in the Day-Ahead Market. It is not just and reasonable to expect the Market Participants to pay for 50 MW of Ancillary Services when the unit could only provide 30 MW at its new operating point, particularly when another resource not awarded the Ancillary Service schedule might have been capable of ramping at the same ramp rate across the entire operating range. The ISO does not discriminate in selecting Ancillary Services based on the consistency of the available ramp rate across the relevant operating range. While the ISO could fix this problem by eliminating the forward Ancillary Services markets and procuring Ancillary Services only in real time (where it would know where the unit was operating and what the ramp rate was at that level), this could be detrimental to reliability. Furthermore, suppliers with ramp rates that change based on operating level would be in the same position – the only difference being that they would not be awarded the Ancillary Services that they are incapable of delivering. The No Pay adjustment is not a penalty. It merely adjusts the payment to reflect the actual ability of the seller to provide the contracted-for service in real time to ensure Market Participants that are responsible for paying for Ancillary Services are getting the deliverable capacity that they paid for.

B. The ISO's Proposed Incorporation of Additional Operating Constraints into Dispatch Instructions is Reasonable

The Commission, in its July 17, 2003 Order in the MD02 proceeding, conditioned the ISO's implementation of UDP upon incorporation of multiple ramp rates, reflecting different operational levels, into ISO Dispatch Instructions. *See California Independent System Operator Corporation*, 100 FERC ¶ 61,060 at PP 140-41 ("July 17 Order"). While the Commission expressly directed the ISO only to account for multiple ramp rates when issuing Dispatch Instructions, the ISO in Amendment No. 54 recognized that other related operational constraints must be considered as well to account for units' operating capabilities. Thus, Amendment No. 54 proposed to account for multiple ramp rates, other operating constraints (both static and dynamic), the Ancillary Service ramp rate, and the Reliability Must-Run ("RMR") ramp rate.

1. Multiple Ramp Rates

Duke Energy argues that the Commission should reject the ISO's proposal to use a Must-Offer Generator's "high ramp rate" as its default ramp rate, and asserts that the Commission should require the ISO to modify its Tariff proposal to specify that the "low ramp rate" of a Must-Offer Generator shall be its default ramp rate. Duke Energy at 5-6. The ISO erred in using the "high ramp rate" and agrees with Duke Energy that the default ramp rate should be the "low ramp rate."

2. Other Operating Constraints

a. The ISO's Proposal Is Reasonable and Goes Beyond What Was Required by the Commission

Reliant/Mirant criticize the ISO's proposal on the grounds that it does not sufficiently account for all of the operating constraints. Reliant/Mirant at 2, 6-8. This criticism is misplaced. As the ISO explained at length in the Amendment No. 54 transmittal letter, it has proposed the incorporation of a variety of additional operating constraints into Dispatch Instructions in order to accurately account for the operating capabilities of Generating Units. Transmittal Letter for Amendment No. 54 at 7-12. These additional operating constraints represent the ISO's effort to accommodate the concerns of Market Participants, and to *expand* on the directive in the July 17 Order, which *only* required the incorporation of multiple ramp rates, reflecting different operational levels, into Dispatch Instructions. *See* July 17 Order at PP 140-41.

Moreover, Reliant/Mirant contradict themselves in different filings they have made in this proceeding. In their own protest, they complain that the ISO's proposal does not sufficiently account for operating constraints. But in the filing submitted by the California Generators/IEP (which include Reliant and Mirant), they criticize the ISO on the grounds that Amendment No. 54 goes beyond what the Commission originally contemplated in the MD02 proceeding. *See infra* Section II.N.1. It is inconsistent for Reliant/Mirant to argue, on the one hand, that the ISO has not sufficient accounted for operating constraints, and to criticize the ISO, on the other hand, for going beyond what the Commission originally contemplated (e.g., for going beyond the portion of the July 17 Order requiring only the incorporation of multiple ramp rates, not other operating constraints).

b. The ISO Recognizes the Need to Monitor Compliance

PG&E states that it generally supports the incorporation of the most current available information about unit availability and operating constraints in the ISO's Dispatching processes. PG&E urges the Commission to recognize that there may be consequences of adopting operating constraints specified by individual producers. According to PG&E, the ISO should, in its review of the performance of the modifications proposed in Amendment No. 54, examine the degree to which it issues Dispatch Instructions by resource type to determine whether it is signaling reliance excessively on a limited sector of the market.

PG&E at 6-7. Much of Amendment No. 54 is designed to allow the ISO to recognize Generating Unit limitations and account for those limitations when issuing Dispatch Instructions. This, in turn, will help the ISO's markets produce prices that are just and reasonable, both for buyers and sellers. The ISO does not expect that enhanced accounting for unit constraints will lead to increased reliance on hydro-electric generation; rather, because the real capabilities of Generating Units will be considered, the ISO can make better Dispatch decisions and achieve a more realistic response from the resources it Dispatches.

3. Ancillary Service Ramp Rate

The ISO proposed to modify the ISO Tariff to make it clear that, beginning with Phase 1B, Real Time Dispatch Instructions will use the operating level-specific ramp rate function that is submitted with the single Energy Bid Curve to Dispatch both Supplemental Energy bids and Energy related to awarded capacity for Ancillary Services. No party appears to raise an issue concerning this subject.

4. Reliability Must Run Ramp Rate

The ISO proposed to extend to all RMR Generating Units an opportunity to amend Schedule A to the RMR Contract to use the ramp rate function submitted in the Day-Ahead Market for use in ISO Dispatch Instructions similar to that proposed for non-RMR Participating Generating Units. No party appears to raise an issue concerning this subject.

5. CDWR-SWP's Requests for Further Changes to the Master File Go Beyond the Scope of the Proceeding Concerning the ISO Master File Should Be Rejected

As CDWR-SWP notes, Amendment No. 54 properly exempts Participating Load from UDP.[7] However, CDWR-SWP also asserts that, to ensure improved communications and Dispatch, and to provide CDWR-SWP with additional protection from unwarranted investigations attributable to infeasible Dispatch, the Commission should order the ISO to maintain in its Master File the operating characteristics of large Participating Loads capable of providing such data. CDWR-SWP at 3.

CDWR-SWP's proposed changes to the ISO Master File are outside of the scope of the changes proposed in Amendment No. 54. CDWR-SWP acknowledges that the ISO has proposed to exempt Participating Loads from UDP. This acknowledgement calls into question the efficiency of expending additional moneys to modify further ISO systems to accommodate additional information on specific Participating Loads. The ISO does not agree with the presumption that disputes will be frequent or that it is not better to handle any disagreements between the ISO and CDWR-SWP regarding the Dispatch of specific CDWR-SWP Participating Loads through the normal ISO dispute process, not through additional narrowly tailored and potentially expensive modifications to ISO systems.

[7] Exemptions from UDP are discussed further in this answer in Section II.F.2, below.

C. The ISO's Proposal Regarding Transmission Losses Is Reasonable

The ISO proposed to make the Generator's meter the reference point for all Dispatch Instructions and Final Hour-Ahead Schedules, but still to allow Scheduling Coordinators to self-provide losses for their Final Hour-Ahead Schedule. Any Scheduling Coordinator that elects to self-provide losses for their Final Hour-Ahead Schedule would be required to: (1) first notify the ISO that it is self-providing losses through the use of a flag, and (2) generate enough Energy to account for the Generator Meter Multipliers ("GMMs") to avoid the application of UDP.

1. The ISO's Proposal Does Not Discriminate Against System Resources

Powerex argues that the ISO's proposed modification to Section 7.4 of its Tariff and addition of Section 7.4.1 is discriminatory and will have a detrimental impact on the participation by System Resources in the ISO markets. It asserts that the ISO should permit all Scheduling Coordinators (not just Scheduling Coordinators representing Generators or System Units) to physically self-provide for Transmission Losses. Powerex at 7-9. FPLE requests clarification of the ISO's proposed treatment of UDP as it relates to System Resources. FPLE states that the clear intention of proposed Section 11.2.4.1.2 of the ISO Tariff is to create an incentive for Generators to meet Hour-Ahead Schedules or Dispatch orders, but the application of the Tariff language to System Resources appears ambiguous. FPLE at 2-3 & n.1. In addition, FPLE argues that if the ISO intends to apply UDP to losses, System Resources should be treated with other resources on a non-discriminatory basis; specifically, System Resources should be allowed to self-schedule Energy associated with physical losses. FPLE at 3. FPLE states that, alternatively, the ISO should exclude losses from the determination of UDP for System Resources. FPLE notes that it understands the ISO's intent to be that, as long as the Control Area checkout confirms that the Scheduling Coordinator scheduling System Resources has delivered an amount of Energy equivalent to the Final Hour-Ahead Schedule, as modified by any Dispatch orders received 40 minutes before the operating hour, there will be no assessment of uninstructed deviation charges. FPLE requests that the Commission direct the ISO to revise its filing to reflect this intent, or to modify its Tariff to provide for the self-scheduling of losses during this phase of MD02. FPLE at 4.

The ISO confirms FPLE's understanding that no UDP will apply to System Resources that deliver Energy in the full amount of their Schedule. The ISO cannot, however, allow System Resources to self-provide Transmission Losses. The following example demonstrates why the ISO cannot provide for this. Assume that a System Resource had a 100 MW Schedule to the ISO Control Area. The ISO and the adjacent Control Area in which the System Resource is located would agree on a 100 MW Schedule, which would be reflected in the Control Area net interchange numbers that each Control Area would enter into its Automatic Generation Control ("AGC") systems. To self-provide the losses, the System Resource would have to over-generate their 100 MW Schedule by some amount. Since the Control Area net interchange amounts have already been determined through the inter-Control Area checkout process, this additional amount would appear as inadvertent interchange, not as the provision of losses.

System Resources cannot self-provide Transmission Losses today. System Resources must "buy" those losses from the ISO's Imbalance Energy market. The modifications proposed in Amendment No. 54, while changing how the ISO will treat losses for resources inside the ISO Controlled Grid, do not affect this current practice. The ISO cannot accommodate the requests of Powerex and FPLE, which are beyond the scope of Amendment No. 54.

2. The ISO Should Not Be Required To Provide for Self-Provision of Losses in Real Time

Reliant/Mirant assert that the ISO has not provided adequate justification for prohibiting the self-supply of resources in real time. Further, they argue that the ISO should permit such self-supply, and that even if self-provision is not feasible in real time, the ISO has not provided adequate detail about how it plans to allocate Imbalance Energy charges that it incurs to remedy Transmission Losses in real time. Reliant/Mirant at 2, 8-9.

In Amendment No. 54, the ISO is proposing to allow resources to self-provide Transmission Losses associated with their Final Hour-Ahead Schedule – an improvement over the current systems, which do not provide that capability. Currently, a generator could "self-provide" losses by over-generating, but the hedge is not perfect because, under the current two-price system, the price it is paid for the over-generation may not equal the price it is charged for losses.

The changes proposed in Amendment No. 54 will eliminate the two-price system and institute a single price system. The losses associated with the Final Hour-Ahead Schedule can be determined in advance. Thus, when Amendment No. 54 is implemented, the generator will know what those losses are because those losses will be part of its real-time instruction. The generator could also determine what the losses associated with its Final Hour-Ahead Schedule are because it will know the Final Hour-Ahead GMM that applies to its unit by real time. In contrast, the generator will not know the real-time GMM that applies to any additional real-time instruction, and could only estimate what losses would be associated with a real-time instruction. Because the ISO proposes to eliminate the two-price system, a generator could effectively "self-provide" its losses up to the Tolerance Band by over-generating, since the price it is paid for the over-generation (up to the Tolerance Band) will now equal the price it is charged for losses associated with its real-time instructions. The generator cannot self-provide losses associated with real-time instructions above the Tolerance Band, however, since any deviation above the Tolerance Band will be subject to UDP. To allow otherwise, the ISO would have to create a flexible, complicated and likely expensive Tolerance Band. In regards to how charges for real-time losses will be allocated, Section 7.4.1 indicates that "all Scheduling Coordinators for Generators and System Units must be financially responsible for all respective transmission losses associated with their respective Imbalance Energy Dispatch Instructions in Real Time…" so such charges are allocated to the Scheduling Coordinator for the resource issued a Dispatch Instruction.

D. The ISO's Proposal to Utilize Five-Minute Dispatch Intervals Is Reasonable – The Concerns Expressed by PG&E and Duke Energy Are Unwarranted

PG&E states that it questions the ISO proposal for adoption of five-minute Dispatch, given that the ISO has not quantified or demonstrated that the benefits of this proposal exceed any additional complexity it produces. PG&E argues that the ISO's explanation that the "standard software" for other independent system operators uses five-minute Dispatch Intervals may not be a sufficient basis for adopting any kind of operating or financial procedure. PG&E also argues that five-minute Dispatch, combined with operating constraints identified by some resources, may have unintended consequences of over-reliance on generation which is flexible. Moreover, according to PG&E, five-minute Dispatch may have the unintended consequence of less Dispatch flexibility and not more. Additionally, PG&E asserts that to the extent the ISO intends to impose penalties for not meeting its Dispatch Instructions, doubling the frequency of Dispatch Instructions does have some increased risk of penalties or deviations. PG&E at 9-10.

While the ISO has proposed to move to a five-minute Dispatch Interval, it has proposed to retain the 10-minute settlement interval. Because UDP will be determined on a 10-minute basis, not a five-minute basis, the risk of incurring penalties will not greatly increase. Moreover, since Market Participants will be consistently receiving Dispatch Instructions every five minutes, rather than on the current sporadic, as-needed basis, there should be less uncertainty about where the resource is expected to be operating. Modeling and accounting for additional unit constraints will also reduce the uncertainty about the unit's ability to respond to the instruction. With less uncertainty, the risk of incurring penalties should be reduced.

Duke Energy asserts that the Commission should not approve simultaneous implementation of UDP and five-minute Dispatch Intervals, and should require the ISO to specify the "special circumstances" under which intra-interval Dispatch Instructions may be issued. Duke Energy argues that the proposed limits on the ability of Generating Units to set the Market Clearing Price ("MCP") under certain conditions also may give the ISO the incentive to game Dispatch Instructions so that they units cannot return to the Final Hour-Ahead Schedules. Further, Duke Energy states, since the ISO is now proposing a five-minute Dispatch Interval, the risk that Generators subject to a Participating Generator Agreement ("PGA") will be subjected to erroneous UDP is substantially heightened; moreover, the burden will be on the Generator to demonstrate that the penalties assessed by the ISO software were in error. Duke Energy argues that in these circumstances, it would be appropriate to delay imposition of UDP until the ISO has demonstrated that its software works in the real world. Alternatively, Duke Energy suggests, the Commission should require the ISO to modify its UDP structure and adopt a graduated (or sliding) scale of penalties for the range of deviations outside the Tolerance Band, which will still give an incentive for Generators to comply with Dispatch Instructions without excessively punishing minor offenders. Duke Energy at 7-8.

As a practical matter, the ISO cannot specify every "special circumstance" that may require it to issue Dispatch Instructions within a five-minute intervals. In general, the ISO will issue Dispatch Instructions within a five-minute interval when it must immediately respond to a real-time event, such as the loss of a generating resource or the outage of a transmission line, either to prevent the network from overloading or to meet applicable reliability or control performance criteria.[8] Duke's proposal to create a "sliding scale" for penalties will only complicate a market that Market Participants already criticize for being too complex. In regards to Duke Energy's suggestion to delay implementation until the software has been proven, the ISO will be conducting two months of market simulation with Market Participants prior to implementing the software to make sure the new software is working as intended. Should any Market Participant feel that the ISO is implementing software that is not working as proposed, it may file with the Commission to seek to delay implementation.

E. The ISO's Proposal Concerning Real Time Interactive Communication of Changes in Resource Operating Constraints (SLIC) Is Reasonable

The CPUC states that it supports the proposal by the ISO that Scheduling Coordinators submit requests for custom load aggregation, given the large amount of hydroelectric, geothermal, and intermittent resources in California.

8 For example, the ISO must return its Area Control Error to zero at least every ten minutes. Additionally, the ISO must return its Area Control Error to zero within fifteen minutes of the loss of a generating resource if that resource is no larger than the amount of contingency reserve the ISO must maintain.

This approach will accommodate the particular resources in California and avoid unnecessary and unreasonable deviation penalties. CPUC at 3-4.

MWD supports the ISO's efforts to incorporate additional operating constraints into Dispatch Instructions, but asserts that some modification is required for consistency and reconciliation of the ISO's proposed changes with other Tariff provisions. MWD states that the ISO should be required to provide electronic confirmation of the ISO's scheduling and logging system ("SLIC") entry communicating an inability to comply with Dispatch Instructions. Additionally, according to MWD, it is unclear whether UDP apply in the absence of an electronic Dispatch; it would be unjust and unreasonable to apply UDP in the absence of a recorded electronic Dispatch Instruction. MWD at 6-7.

De-rates and outage information communicated through SLIC will be confirmed electronically. Dispatch Instructions will be provided electronically through the Automated Dispatch System ("ADS") as long as that system is operating. Should the ISO need to provide Dispatch Instructions via phone, a taped record of the conversation will be retained and can be used to resolve disputes.

PG&E requests that the ISO confirm that SLIC communications capabilities will also be available to PG&E for communicating ETC schedule availability for status changes. PG&E at 6. The ISO notes that the Commission conditioned the implementation of UDP on the ISO's ability to allow generators to electronically communicate real-time operating information on outages and de-rates. July 17 Order at P 141. The ISO has not contemplated, nor was it required, to provide for similar electronic communicating capabilities for ETC Schedule changes. Such changes are beyond the scope of Amendment No. 54. In addition, ETC schedule changes are exempt from UDP.

Reliant/Mirant state that more detail is required as to how the ISO will settle de-rate events when a Generator has notified the ISO through SLIC in time to avoid UDP. Reliant/Mirant at 2-3, 9-10. The ISO clarifies that if a unit reports a real-time de-rate, the ISO will issue a decremental instruction to move the unit from its Final Hour-Ahead Schedule to its new limited operating point. The unit will be appropriately charged the MCP for the instruction, since the ISO must procure Imbalance Energy to make up the shortfall. The unit, though it has not moved from its limited operating point, will be deemed to have complied with the instruction (it is also appropriate to consider that it is the instruction that is deemed in this case) and, though the Scheduling Coordinator will be charged the MCP for the decremental instruction, UDP will not apply to the shortfall.

F. The ISO Has Reasonably Proposed to Implement Penalties for Uninstructed Deviations

1. Aggregation

Dynegy, *et al.* argue that the Commission should require the ISO to file its final operating procedure for the aggregation approval process and thereby make it subject to further comments and protests. Dynegy, *et al.* at 17-18. This argument is without merit. The ISO filed the first draft of the aggregation operating procedure in Attachment E to Amendment No. 54, *for informational purposes only*. *See* Transmittal Letter for Amendment No. 54 at 16. The ISO also commits to publishing the final procedure on the ISO Home Page. However, because the document in question is an operating procedure (rather than a Tariff or Protocol change), there is no requirement that the ISO file it with the Commission. The Commission has never imposed a blanket requirement that operating procedures be filed. Moreover, the July 17 Order did not require that the ISO file any aggregation procedures it might develop (*see* July 17 Order at PP 144-46).[9]

In addition, Dynegy, *et al.* argue that the ISO's proposed UDP aggregation criteria are inadequately documented and should be re-filed. Specifically, Dynegy, *et al.* state, the ISO has failed to adequately justify the requirement that "effectiveness factors" of aggregated units be within +/- 10 percent of each other. Dynegy, *et al.* argue that the Commission should order the ISO to re-file its aggregation criteria justifying the 10 percent tolerance limit and to limit the number of paths that a group of units be evaluated against to a reasonable number. Absent this, Dynegy, *et al.* recommend that effectiveness factors within 50 percent are adequate to assure grid reliability. Further, according to Dynegy, *et al.*, the ISO should provide each Scheduling Coordinator with the effectiveness factors of their units with respect to the ISO's identified constrained paths. Dynegy, *et al.* at 18-20.

The fundamental premise behind the ISO's aggregation proposal is that any unit in the aggregation can provide the same service as any other unit. Thus, units that are connected to the same grid point and at the same voltage

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[9] The July 17 Order also noted that if a Market Participant believes it was improperly denied the ability to aggregate deviations, it can request dispute resolution under the provisions

level almost always satisfy that premise, though as discussed immediately below, that general conclusion can break down under certain conditions due to switching or maintenance. Units in a custom aggregation, however, may not be connected at the same grid point or at the same voltage level. Under those circumstances, the ISO must ensure that the aggregated units are capable of providing the same service. Where no Congestion exists, and where the service the ISO requires is system-wide Imbalance Energy, units connected at different points in the grid often can provide that same service, and a negative uninstructed deviation from one unit can be netted against a positive uninstructed deviation from another unit. But when the ISO must Dispatch particular units because of Congestion, a negative uninstructed deviation from one unit may not be cancelled out by a positive uninstructed deviation from another facility. The ISO understands the desire of Market Participants to limit their exposure to deviations by netting the deviations in as large a portfolio as possible. But that desire must be tempered by the reality of the system – that units cannot always substitute for each other depending on what service is required.

Dynegy, *et al.* further assert that basic aggregations, once approved, should not be subject to temporary suspensions. They argue that allowing the ISO to suspend basic aggregations will only cause settlement disputes and will not provide the ISO with any added ability to control grid reliability. Dynegy, *et al.* at 20. The ISO disagrees. Aggregations that pose no problems under normal conditions, i.e., when all network components are in service, could become unworkable if the network configuration changes due to maintenance or the

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of the ISO Tariff. July 17 Order at P 145.

forced outage of a connecting component such as a breaker between bus sections. The ISO recognizes, however, that it may be possible to identify many of these circumstances in advance so that both the ISO and the Market Participant have a common understanding of when the units may or may not be aggregated. Such an agreement would minimize any potential for subsequent disputes.

Reliant/Mirant argue that the ISO appears to impose an overly restrictive "physical operating interrelationship" condition upon the aggregation of generation. They assert that the ISO did not propose this condition to the Commission in its original MD02 filing on May 1, 2002, and therefore the condition was not approved or required by the Commission in the July 17 Order. Reliant/Mirant at 3, 10-11. Reliant/Mirant misinterpret the requirements of the draft UDP Aggregation procedure. The procedure requires requesting parties to submit "a detailed description of the resources' physical operating interrelationships." This information will allow the ISO to understand how separate units connected at different places on the grid may be required to operate together (*e.g.*, because share a fuel source) and will inform the approval process. It is entirely reasonable to require the applicant to furnish this information to the ISO so that the ISO is aware of any interrelationships that may exist when it evaluates the applicant's proposal. The procedure does not, however, condition approval of a custom aggregation on the demonstration of a physical operating interrelationship. Contrary to Reliant/Mirant's assertion, the

ISO is not seeking to impose a condition on aggregation that the Commission did not impose in the July 17 Order.

SCE asserts that item 7 (page 2) of the aggregation operating procedure should be modified to state that UDP Aggregations cannot include Participating Intermittent Resources, rather than that UDP Aggregations cannot include just intermittent resources (as the item currently reads). SCE at 3. SCE provides no explanation at all for its recommendation. The ISO does not believe the proposed change is warranted.

2. Exemptions from UDP

Dynegy, *et al.* assert that proposed Section 11.2.4.1.2 of the ISO Tariff states that UDP will not be assessed on any entity for positive uninstructed Energy during System Emergencies, but that the Amendment No. 54 transmittal letter implies that this exemption applies only to System Resources. Dynegy, *et al.* at 16-17. The ISO questions how Dynegy, *et al.* reach this inaccurate conclusion, but in any case, the Tariff language itself reflects the ISO's intention, which is that the exemption during System Emergencies applies to both System Resources and internal generation. Section 11.2.4.1.2 (a), as proposed in Amendment No. 54, states:

> The Uninstructed Deviation Penalty for negative Uninstructed Imbalance Energy will be calculated and assessed in each Settlement Interval. The Uninstructed Deviation Penalty for positive Uninstructed Imbalance Energy will be calculated and assessed in each Settlement Interval in which the ISO has not declared a Staged System Emergency.

Therefore, the exemption of penalties during staged emergencies applies to all System Resources and Generating Units.

Dynegy, *et al.* also assert that RMR Contracts are bilateral contracts and units under RMR Condition 2 do not freely participate in the ISO Energy markets, and therefore should not be subject to UDP. Therefore, in the view of Dynegy, *et al.*, the ISO should add language to proposed Section 11.2.4.1.2 of the ISO Tariff to clarify that Condition 2 RMR units are exempt from UDP. Dynegy, *et al.* at 17. The ISO agrees with Dynegy, *et al.* that RMR Condition 2 Units should be exempt from UDP, though not for the reasons Dynegy *et. al.* state. An uninstructed deviation from a Condition 2 Unit has the same detrimental effects on grid reliability as an uninstructed deviation from any other unit that can freely participate in the ISO's markets. Nevertheless, Condition 2 units should be exempt from UDP because the settlement mechanisms of the RMR Contract could otherwise create unintended consequences for the Responsible Utility. A Condition 2 RMR Unit is required to refund all market revenues to the Responsible Utility. At present, if a Condition 2 RMR Unit produces a positive uninstructed deviation, the RMR Owner does not keep the Imbalance Energy payment for the uninstructed deviation, but must refund it to the Responsible Utility. Under the ISO's UDP proposal, the RMR Owner would not be paid for the positive uninstructed deviation outside the Tolerance Band, so the Responsible Utility would lose this refund. On the other side, if the Condition 2 RMR Unit does not fully provide the amount of instructed Energy, the RMR Owner foregoes a corresponding portion of the unit's Availability Payment. The ISO believes that this foregone payment should suffice to deter under-delivery and that no penalty is needed for negative uninstructed deviations. Therefore, the ISO offers to include an additional item, Section 11.2.4.1.2 (u), which would read:

> **11.2.4.1.2 (u)** Condition 2 RMR Units shall be exempt from Uninstructed Deviation Penalties.

PG&E asserts that in addition to the exemptions from UDP already provided by the ISO, the Tariff should also exempt UDP resulting from AGC operations of the ISO beyond the ISO's expected Regulation range if it can be demonstrated that it was in fact the ISO use of AGC that produced any deviation. PG&E at 7. The ISO agrees that a regulating unit operating outside of its regulating range as a result of the ISO's direct control and not the result of any limitation imposed by the generator should be exempt from UDP. The ISO therefore proposes to amend 11.2.4.1.2 (g) as shown in ***bold italics*** below

> **11.2.4.1.2** (**g**) The Uninstructed Deviation Penalty will not apply to ~~Generators~~ **Generating Units providing Regulation and dynamically scheduled System Resources** providing Regulation to the extent that **Uninstructed Deviations from such resources** ~~the Generators' Uninstructed Deviations~~ **exceed** ~~are within the range of their~~ **each resource's** actual Regulation range **plus the applicable Tolerance Band. Resources providing Regulation and generating within their relevant Regulating range *(or outside their relevant Regulating Range as a direct result of ISO control or instruction)* will be deemed to have zero deviations for purposes of the Uninstructed Deviation Penalty.**

Further, PG&E argues, to the extent that a Market Participant is required to accommodate RMR Energy it did not choose to purchase and this necessitates schedule deviations, the proposed UDP should not apply. PG&E at 7-8. As to PG&E's request to not apply UDP to RMR Energy a Market Participant did not choose to purchase but is required to accept, the ISO, in

Amendment No. 56 to the Tariff (filed in Docket No. ER03-1221-000 on August 18, 2003), has proposed to exempt such Market Participants from penalties and charges associated with the amount of RMR Energy the Market Participant was unable to Schedule after having exercised commercially reasonable efforts to do so.

PG&E also states that the ISO should also exempt from UDP those schedules or delivery changes necessary to honor Existing Contracts scheduling connected with the terms of such contracts. PG&E at 8. Amendment No. 54 proposes such an exemption already: Section 11.2.4.1.2(q) provides that adjustments to any Generating Unit, Curtailable Demand, and System Resource Final Hour-Ahead Schedules made in accordance with the terms of Existing Contracts will not be subject to UDP.

Powerex argues that the ISO needs to comply with the Commission's direction, in its January 17, 2003 Order in the MD02 proceeding, to file tariff language providing that all interconnection resources are exempt from UDP during a *force majeure* event (e.g., forced outage of a generating or transmission facility), or else to provide an explanation why such a change would be inappropriate. Powerex at 1, 4-6 (citing January 17 Order at P 17). The ISO agrees that it needs to comply with the Order, but the change requested by Powerex is unnecessary. Section 15.1 of the ISO Tariff already provides that "[n]either the ISO nor a Market Participant will be considered in default of any obligation under this ISO Tariff if prevented from fulfilling that obligation due to the occurrence of an Uncontrollable Force." An Uncontrollable Force includes, *inter alia*, "any act of God, . . . fire, storm, flood, earthquake, . . . or any other cause beyond the reasonable control of the ISO or Market Participant which could not be avoided through the exercise of Good Utility Practice." ISO Tariff, Section 15.1. Thus, the definition of Uncontrollable Force encompasses *force majeure* events (including the forced outage of a generating or transmission facility), and the occurrence of an Uncontrollable Force excuses any Market Participant from its obligation not to engage in actions that would otherwise result in UDP being assessed.

In addition, Powerex asserts that it is not clear from Amendment No. 54 that the Scheduling Coordinator that curtails a wheeling Schedule will not be charged 150 percent of the Imbalance Energy price for the curtailed import and paid nothing for the curtailed export. Powerex argues that absent the ability to aggregate uninstructed deviations under these circumstances, this would result in a double penalty for an action that has no impact on the ISO Imbalance Energy market. Powerex also argues that in the event that the import and export are in different real-time Congestion Zones, the appropriate penalty is already assessed in that the import will be assessed a deviation charge different from the export. Accordingly, Powerex states, the ISO should clarify that the deviation penalty is inappropriate in the case of wheeling transactions. Powerex at 6-7.

The ISO agrees that a balanced change to a balanced –wheel-through Schedule should be exempt from UDP. Under the current two-price system, Market Participants are exposed to charges from changes to wheel-through Schedules made under the terms of Existing Transmission Contracts after Final

Hour-Ahead Schedules are issued, because the cut import is treated as a negative deviation and charged the incremental price, while the cut export is treated as a positive deviation and paid the decremental price. Because the two prices may be different, charges may result. This problem will go away when Amendment No. 54 is implemented and a single price replaces the two-price system, because, absent real-time Congestion, the price charged will equal the price paid and the settlements will cancel each other out.

Reliant/Mirant argue that the ISO's proposal to exempt Participating Load and System Resources from UDP in many cases is unduly discriminatory. Similarly, they contend, System Resources that decline to operate pursuant to bids that the ISO has accepted and pre-Dispatched any time after 40 minutes before the operating hour will be exempt from the UDP, and therefore will have commercial opportunities unavailable to Control Area resources. Reliant/Mirant further argue that exemptions from UDP during System Emergencies and when the MCP is below zero should apply to all resources, not only System Resources. Reliant/Mirant state they recognize that System Resources may be subject to the rules and protocols of other Control Areas that can affect service into the ISO markets. To accommodate these rules, Reliant/Mirant argue, the Commission should require that the ISO modify its proposal so as to align itself with neighboring Control Areas by providing UDP exceptions for System Resources that experience deviations due to the decisions of other Control Area operators. Reliant/Mirant at 3, 11-13.

Exempting Participating Load from UDP is not unduly discriminatory, but a recognition that Participating Load is different from generating resources. While a generating unit exists only for one reason – to produce electricity – Load, including Participating Load, does not exist solely to "consume" electricity. Rather, it "consumes" electricity to serve some other primary purpose, such as to support an industrial process or pump water. When a Participating Load is called on to reduce its "consumption", it must curtail the activity that is the primary reason for it to be "consuming" electricity in the first place. A Participating Load's availability to be Dispatched depends on its ability and willingness to curtail its primary activity – which, with unlike a Generating Unit, is not the production or "consumption" of electricity. The argument that Participating Loads and Generating Units should be treated exactly the same is therefore flawed. Consequently, it is not unreasonable to provide some incentive – such as waiving UDP – to Participating Load to encourage it to participate in the ISO's markets. Encouraging Participating Load will enhance Demand response and will help foster competitive electricity markets.

System Resources are also different from Generating Units. System Resources must be Scheduled in accordance with WECC practices and timelines. These requirements constrain the performance of System Resources just as physical constraints (which Amendment No. 54 now recognizes) constrain the performance of Generating Units. The exemption afforded to System Resources is a refinement of to the previously accepted tariff language in which the ISO would penalize any System Resource for a declined bid if such bid had not be recalled prior to being instructed. The T-40 minute exemption proposed in Amendment No. 54 provides for a more transparent implementation that still recognizes the differences in constraints for System Resources and Generating Units.

SMUD contends that the ISO's proposal to exempt intermittent resources from UDP only if the units in question are subject to a PGA is unreasonably discriminatory. SMUD asserts that it can think of no legitimate operational or market concern as a rationale the ISO's proposal. SMUD at 3-5. Contrary to SMUD's contentions, it is equitable for an intermittent resource to receive the benefit of the exemption from UDP only if, in return, the intermittent resource is made subject to the terms described in the PGA (as well as subject to the other requirements for becoming a Participating Intermittent Resource). In contrast, in SMUD's view, an intermittent resource should be able to receive the benefit without having to undertake any such responsibility. The ISO believes SMUD's view should not be given any credence.[10]

3. Calculation of UDP

[10] SMUD also argues that a PGA is not essential to exemption from UDP because Section 11.2.4.1.2(e) of the ISO Tariff carves out an exception to the PGA requirement for Qualifying Facilities ("QFs"). SMUD at 5. This argument is inapposite. SMUD omits to mention the last clause in Section 11.2.4.1.2(e), which states that the exemption for QFs applies "*pending resolution of QF-PGA issues at the Commission*" (emphasis added). Thus, the exemption for QFs will continue to apply while these issues are being resolved; the resolution of the issues will determine whether QFs will continue to receive the exemption. The issues have not yet been resolved, however. On August 12, 2003, the Commission issued an order concerning the treatment of QFs in which, *inter alia*, it required the ISO to file (within 60 days) a *pro forma* QF-specific PGA. *California Independent System Operator Corporation*, 104 FERC ¶ 61,196, at ordering paragraph B. The ISO has not yet submitted the required filing.

Powerex argues that the Commission should require the ISO to provide the applicable Uninstructed Imbalance Energy calculation for System Resources under Section D 2.1.1 of Appendix A to the Dispatch Protocol,[11] and should require the ISO to make explicit in the Tariff that Transmission Losses are not considered uninstructed deviation Energy for the purpose of assessing UDP. Powerex at 7.

The ISO proposes to include the following formula in Section D 2.1.1 of Appendix A of the Settlements and Billing Protocol to provide the Uninstructed Imbalance Energy calculation for System Resources:

$$IE_{i,h,o} = \sum_{1}^{k}\sum_{1}^{v} REAL\_TIME\_FLOW_{i,h,o,k,v} - SE_{i,h,o}$$

Where;

REAL_TIME_FLOW is the real-time actual flow for System Resource i during Dispatch Interval k during Settlement Interval o of hour h for Real Time Flow Type index v. Real Time Flow Type v is one of the following: FIRM, NFIRM, SUPP, WHEEL, DYN, ESPN, ENSPN, OOM, ERPLC;

$SE_{i,h,o}$ is the Scheduled Energy from resource i during Settlement interval o of hour h.

The ISO attempted to make this issue clear in the Section 11.2.4.1.2 (b) where it provided that the UDP would only apply the pre-dispatched portion of a System Resource that is declined, except in the case of the dynamically-Scheduled System resources, which, like Generating Units, are able to adjust their output. However, the ISO agrees that it is beneficial to explicitly indicate

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[11] The Appendix D to which Powerex is referring is actually Appendix D of the Settlements

that, for non-Dynamically scheduled System Resources, no UDP will apply to adjustments from their Final Hour-Ahead Schedule. The ISO believes this is appropriate because, except for control-area initiated adjustments and adjustments made pursuant to Existing Transmission Contract rights, a Scheduling Coordinator's Final Hour Ahead Schedule cannot be adjusted after Final Hour Ahead Schedules are issued. However, while the ISO believes that the two conditions under which Final Hour-Ahead Schedules for System Resources may change are sufficiently narrow to allow for the exemption, the ISO does not want this exemption to suddenly lead to unilateral changes to Final Hour-Ahead Schedules from System Resources. If the ISO observes behavior that is inconsistent with these principles the ISO may seek reconsideration such an exemption for UDP for adjustments to System Resources.

4. Allocation of UDP Revenue

As proposed in the ISO's May 1, 2002 MD02 filing and modified in its August 16, 2002 MD02 compliance filing, Section 11.2.4.1.2 of the ISO Tariff provides that amounts collected as UDP shall: (1) first be assigned to reduce the portion of above MCP costs which would otherwise be assigned *pro rata* to all SCs in the Settlement Interval pursuant to Section 11.2.4.2.2 of the ISO Tariff and (2) any remaining amounts shall then be treated in accordance with Settlement and Billing Protocol ("SABP") Section 6.5.2 (first used to offset ISO expenses, losses or costs, with the balance deposited into the ISO Surplus Account).

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and Billing Protocol, not the Dispatch Protocol.

PG&E states it agrees that the ISO's proposal for the allocation of revenues is "certainly supportable." However, PG&E also asserts that it may be desirable to apply more of the UDP revenue to offset above-MCP costs beyond the interval in which they are received. In addition, PG&E asserts that the application of offset other ISO expenses, losses, or costs should be clarified. PG&E at 8-9.

The ISO believes that no further modification or explanation concerning its allocation proposal needs to be made. The allocation proposal is consistent with the July 17 Order, and is the same as the proposal submitted in the ISO's August 16, 2002 MD02 compliance filing. Transmittal Letter for Amendment No. 54 at 20.[12]

5. The ISO's Proposal Generally

Dynegy, *et al.* argue that the proposed UDP should be suspended or modified in light of changing market conditions and the risks associated with the rollout of the ISO's Real-Time Dispatch ("RTD") Software. They assert that the Commission should reevaluate the entire concept of UDP, which was approved in the July 17 Order, in light of changing market conditions and new information. Dynegy, *et al.* at 7-16. Dynegy, *et al.* assert that if the Commission is unwilling to defer approval of the UDP proposal, pending subsequent review of real operating performance once the new software is implemented, the monetary penalties contained in the UDP proposal should be suspended for a period of one year

[12] The ISO notes that it has proposed further modifications to the allocation methodology in Amendment No. 55 to the ISO Tariff.

pending such an evaluation of Generator performance under the RTD Software. Dynegy, *et al.* state that the ISO should be allowed to go forward with signaling of compliance within Tolerance Bands and even compute UDP on an advisory basis. However, Dynegy, *et al.* contend, penalties would not be assessed in settlements and no liability would accrue until such time as the monetary penalties are implemented. Additionally, Dynegy, *et al.* argue that the ISO and stakeholders should further review a fair penalty scheme based on performance of RTD and Generating Units, market conditions, and the rest of the MD02 issues. Lastly, Dynegy, *et al.* assert, UDP should be re-evaluated at least on a yearly basis and, as part of such re-evaluation, the ISO should be required to justify the continued existence of UDP. Dynegy, *et al.* at 16.

The ISO agrees that market conditions change – and will change again – but disagrees that changing market conditions warrant re-examining the UDP provisions approved by the Commission. The facts that market power has moderated and that there is less reliance on the real-time Imbalance Energy market since the ISO first proposed UDP in its May 1, 2002 MD02 filing do not negate the fact that excessive uninstructed deviations create reliability problems and costs to the market. As the Commission is well aware, system conditions, market competitiveness, and the level of spot market volumes can change rapidly and in ways that are difficult to predict. The decision to provide appropriate market rules and financial incentives for suppliers to responsibly follow Dispatch Instructions should not be based on the expected degree of these negative impacts. The impacts are always negative and can never be fully predicted in advance, and therefore should always be discouraged. The primary purpose of prior negative experience is to create the things that prevent its reoccurrence. For these reasons, the ISO sees no merit to Dynegy, *et al.*'s assertion that UDP should be re-examined in light of changing market conditions. Moreover, Amendment No. 54 implicitly acknowledges the age of the generation fleet by creating systems that recognize additional legitimate operating constraints, including the ability to electronically communicate real-time operating information on outages and de-rates, and avoid issuing Dispatch Instructions that would violate those constraints. As discussed elsewhere, the ISO is providing substantial Market Participant testing to ensure the systems work as designed prior to implementation, so there is no need to impose any additional trial period. Finally, there is no need either to mandate an ongoing re-evaluation period or an ongoing reporting requirement. The ISO reports on the performance of its markets to its Governing Board and to its Market Surveillance Committee at regular intervals at public meetings attended by Market Participants and by Commission staff.

CDWR-SWP requests that the Commission clarify the application of UDP to OOM transactions by deleting Section 11.2.4.1.2(o) of the ISO Tariff and amending the text of Section 11.2.4.1.2 to state that the tolerances and other aspects of UDP apply equally to Energy bids and to out-of-market ("OOM") transactions. CDWR-SWP at 3-4. CDWR-SWP ignores the fact that the ISO's proposed application of UDP to OOM transactions was a feature of the May 1, 2002 MD02 filing. In the July 17 Order, the Commission approved the ISO's

UDP proposal subject to certain conditions that *did not* include any conditions (or other restrictions) on the application of UDP to OOM transactions. *See* July 17 Order at PP 140-41. Therefore, the Commission has already approved the application of UDP to OOM transactions.

Moreover, the application of UDP to OOM transactions is supported by a number of considerations. First, the non-delivery of an authorized OOM instruction can have an impact on reliability. Further, each PGA imposes an obligation to respond to ISO Dispatch Instructions pursuant to Section 5.6.1 of the ISO Tariff. *See pro forma* PGA, Section 4.2. The ISO does not propose to apply UDP to any System Resource that does not enter into an OOM transaction. The ISO proposes only to apply UDP to OOM transaction with System Resources if the ISO and Scheduling Coordinator for the System Resource agree on the OOM transaction and the Energy agreed to in that transaction is then not delivered.

G. The ISO's Proposal Concerning Use of Adjustment Bids in Real Time Is Reasonable

Duke Energy asserts that two of the proposals in Amendment No. 54 are based on a premature presumption of the Commission's acceptance of Amendment No. 50 to the ISO Tariff. Duke Energy argues that the proposed changes to Amendment No. 50 should not be incorporated in Amendment No. 54 until the Commission issues a "final order" in the Amendment No. 50 proceeding. Duke Energy at 13.

The ISO strongly disagrees. Duke Energy's suggested approach does not reflect the reality of the status of Amendment No. 50. Most of Amendment

No. 50 was accepted outright in the Commission's May 30, 2003 Order on the amendment;[13] as to the rest of Amendment No. 50, the Commission directed modifications that the ISO has already submitted to the Commission in compliance filings. *See California Independent System Operator Corporation*, 103 FERC ¶ 61,265. Thus, the ISO believes it is entirely justified in building on language in Amendment No. 50 to draft provisions in Amendment No. 54. Moreover, Duke Energy's approach, if adopted, would most likely cause an unacceptable delay in the implementation of those Amendment No. 54 provisions.

H. The ISO's Revisions to the Eligibility Criteria for Setting the Market Clearing Price Are Reasonable

1. Constrained Output Resources

Constrained-Output Resources are "block-loaded" or "inflexible" generating resources, such as some Combustion Turbines, that typically are either off or operating at one optimal load level, usually at full load, for their unit-specific Minimum Run Time. The ISO proposes that such resources be eligible to set the MCP for such Dispatch Intervals only when it is necessary for the ISO to Dispatch such a resource to serve Load.

Duke Energy argues that the Commission should reject the ISO's proposed treatment of constrained-output resources as being inconsistent with competitive market outcomes and subject to potential gaming by the ISO. It asserts that the ISO's proposal is simply an attempt to artificially lower the MCP

[13] The Order on Amendment No. 50 was issued over a month before Amendment No. 54 was filed.

by ignoring the realities of the operation of constrained-output resources. Duke Energy at 9. Similarly, PG&E expresses a concern that the ISO's proposal that constrained-output resources be eligible to set the MCP during those Dispatch Intervals that any portion of the unit's output is needed for real-time load, is inconsistent with marginal unit pricing and could result in unwarranted real-time costs. PG&E recommends that the ISO treat block generation similar to the treatment of minimum load Energy, i.e., an individual unit's recovery of its Energy costs or bids would be assured, however, these constrained units would not contribute to setting the MCP. PG&E at 10-11. Duke Energy's allegation of the ISO's gaming the MCP is without merit. As explained more detail below, the ISO's proposal is consistent with the manner in which the Commission *required* the New York Independent System Operator, Inc. ("NYISO") to treat constrained-output resources.[14] The ISO also proposes its treatment of constrained-output resources in order to strike a balance between competing interests. To show how interests compete, as noted below, PG&E suggested that block generation should be treated as minimum load Energy (i.e., could recover its costs but not set the MCP). The ISO's balanced proposal for allowing constrained generation to set the MCP is completely consistent with the criteria offered in the Commission's Notice of Proposed Rulemaking on the Standard Market Design.[15]

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14 *See also* Transmittal Letter for Amendment No. 54 at 23.

15 *See* Notice of Proposed Rulemaking on Standard Market Design, Docket No. RM01-12-000 (issued July 31, 2002), at P 318 ("SMD NOPR").

Dynegy, *et al.* argue that the ISO's criterion to allow a unit's accepted bid to set the MCP is redundant with UDP and should be rejected. Given that the ISO has received approval of UDP in concept, their argument goes, there will be sufficient incentives for resource owners to follow instructions. Dynegy, *et al.* also assert that thermal generators will have difficulty consistently operating within the Tolerance Band. They argue that in light of the realities associated with controlling thermal units and reduced accuracy associated with telemetered output data, there is a real risk of a collapsing price where multiple generators, all responding to Dispatch Instructions, fail to meet the MCP eligibility criteria as proposed by the ISO; as a result, there will hardly be any units available to set the MCP and the true transparent cost of electricity at that moment will be entirely masked. They also assert that if the Commission does not reject the ISO's proposed criterion, the MCP eligibility deadband should include an absolute minimum quantity. Dynegy, *et al.* at 23-26. The ISO notes that none of these scenarios has apparently materialized in the PJM markets, which, as the ISO has proposed in Amendment No. 54, use *ex post* pricing with a 10 percent performance band.

Reliant/Mirant argue that the ISO's proposal to limit the payments it makes to constrained output resources under certain circumstances is confiscatory. Reliant/Mirant contend that under the ISO proposal, constrained output resources that are Dispatched and must operate through their minimum run time but are not needed for system Energy may not set the MCP. Instead, they assert, the ISO will pay each constrained output resource its bid price offset by net market revenues earned by the constrained output resource. Reliant/Mirant assert this proposal fails to recognize the realities of generation operations and unfairly penalizes Generators that are simply following ISO Dispatch Instructions. Reliant/Mirant at 3-4, 13. The ISO is not sure how a constrained unit producing Energy the ISO does not want due to an operating constraint is following ISO Dispatch Instructions. Again, the ISO's proposal for constrained resources is intended to strike a balance – to allow constrained resources to set the MCP when their output is needed to serve load, but not to let them set the price but only earn their bid price when the output is only produced to meet an operating constraint.

2. The ISO's Performance Requirement Is Reasonable

Duke Energy asserts that the Commission should reject the ISO's proposal to establish a new 10 percent performance requirement in order for a Generator to be eligible to set the MCP, because it will artificially depress the MCP and penalize all Generators who have complied with their Dispatch Instructions. In Duke Energy's view, the ISO's assertion that "a unit should set the MCP only if the unit actually performed to the instruction" is simply conclusory, and not based on the economic principles that underlie the single MCP auction. Duke Energy also states that, in contrast to the ISO's proposal, a real-time *ex post* locational pricing system allows Market Participants to respond to economic incentives. Further, Duke Energy asserts, neither PJM nor the NYISO has adopted an approach such as the market-strangling "belt-and-suspenders" performance requirement now proposed by the ISO. Duke Energy then asserts that the ISO's justification of the performance requirement based on an improbable example of misconduct by one Generator is not a sound basis to distort the MCP and penalize the entire market. According to Duke Energy, the better approach is to address intentional misconduct by a Market Participant using the mechanisms already available to the ISO and to the Commission. Duke Energy at 9-11. The ISO does not know how a generator that fails to deliver the Energy instructed by the ISO, when such instruction accounts for legitimate operating constraints, is penalized by not being able to set the MCP. Conversely, it seems more a penalty to those entities purchasing Energy from the Real Time Market to allow a generator that has not fully delivered a Dispatch Instruction to set the MCP. The Commission's SMD NOPR recommended *ex post* pricing, acknowledged that uninstructed deviations may increase the costs of balancing services, and sought comment as to whether penalties for uninstructed deviations should be included in the Standard Market Design. SMD NOPR at P 316. The SMD NOPR did not preclude the simultaneous application of *ex post* pricing and penalties. Finally, the ISO disagrees with Duke's assertion that misconduct is best handled on a case-by-case basis. It is more transparent and equitable to establish clear rules and conditions for setting the MCP than to try to selectively enforce general guidelines through the dispute process.

3. Duke Energy's Gaming Concern Is Unfounded

Duke Energy argues that the Commission should reject the ISO's proposal to exclude units from setting the real-time MCP if it Dispatches them to operating points that do not allow them to return to their Final Hour-Ahead Schedules, because the proposal enables the ISO to “game” the real-time MCP. Duke Energy asserts that the proposed limitations on setting the MCP give the ISO an incentive to anticipate Imbalance Energy requirements for the next intervals, and the next hour, and to Dispatch Generating Units whose bids might otherwise set the MCP to a Dispatch operating point that results in extra-marginal instructed Energy. Duke Energy at 4-5.

Duke Energy’s assertion that the ISO will intentionally “game” the MCP by instructing units – ostensibly, specific high cost units – to operating points from which they cannot return to their next hour’s Hour-Ahead Schedule, causing them to produce extra-marginal Energy, and therefore preventing them from setting the MCP, is absurd and unfounded. A unit will be operating at a point from which it cannot return to its Hour-Ahead Schedule either because it has been Dispatched by the ISO according to its bid or because it is deviating without instruction. If it is deviating without instruction, it should not set the MCP; to allow otherwise would undermine all of the corrections to the market design that are proposed in Amendment No. 54 and would re-create all the incentives that spawned the abysmal generator performance that plagued ISO operations for years. If the unit has been Dispatched by the ISO according to its bid, that unit will earn its bid price but should not be allowed to “stick” the MCP because of its slow response. The real-time MCP should be set by the marginal unit, i.e., the unit capable of responding to meet the next increment of demand. The real-time MCP should not reflect the price of Energy that must be produced solely because of a resource's operating limitations. The ISO's proposal to pay extra-marginal Energy according to its bid price but not allow that extra-marginal Energy to set the MCP represents a fair balance between fairly compensating suppliers for the Energy they produce and establishing an accurate Imbalance Energy price signal in a paradigm where physical reality dictates that suppliers cannot respond instantaneously and completely to changes in Demand. In an Order concerning the NYISO, the Commission recognized the appropriateness of this approach:

> The Commission agrees with NYISO that fixed block generation resources should be allowed to set the market price for energy so long as that resource reflects the marginal cost of supplying one more unit of energy. However, this is not the point that NYSEG disputes. What is in dispute is the marginal cost of supplying the next increment of load when fixed block resources are dispatched and other generation resources, with bid prices less than the fixed block resource, are backed down out of merit order to make room for the fixed block resource. On this matter, however, the ISO Tariff is clear. If it is the case that generation resources, with lower bid prices, are dispatched downward to accommodate more expensive fixed block resources, then the marginal cost of supplying the next increment of load is equal to the bid price of the least expensive unit that has been backed down.
>
> If the price is set in this manner, there should be no need to pay generators that are backed down any opportunity costs, and the fixed block resource can have its costs covered through the BPCG that has already been approved by the Commission.

New York Independent System Operator, Inc., 92 FERC ¶ 61,073, 61,306 (2000) (footnote omitted).

I. The ISO's Proposal Concerning Financial Settlements Is Reasonable

1. Five-Minute Dispatch Instructions and Ten-Minute Settlement Intervals

No party appears to raise an issue concerning this subject.

2. Exemptions and Allocation of Above-Market Clearing Price Costs

CDWR-SWP argues that the ISO has not justified the allocation of above-MCP costs as described in Amendment No. 54. According to CDWR-SWP, such allocation of costs should not be authorized absent an evidentiary hearing on the subject. CDWR-SWP at 1-2, 4-9. MWD also protests the ISO's proposed allocation of certain costs as being inconsistent with fundamental cost-causation principles. MWD at 8-10.

In making these arguments, CDWR-SWP and MWD fail to acknowledge and address the supporting precedent the ISO cited in the Amendment No. 54 transmittal letter (at 27-28). CDWR-SWP and MWD miss or ignore the critical point that the Commission approved a similar allocation of above-market Energy bid costs, through Charge Type ("CT") 487, in its Order concerning Amendment No. 42 to the ISO Tariff. *California Independent System Operator Corporation*, 98 FERC ¶ 61,327, at 62,379-80 (2002). The Commission explained that:

> TANC, Cities/M-S-R, Vernon, and SoCal Ed all raise concerns that the proposed change in allocation of CT 487 violates the cost-causation principle. In its Answer, the ISO responds that the Cal ISO's procurement of such energy benefits the entire Cal ISO Controlled Grid by balancing supply and demand, thus enhancing reliability for all entities using the grid. The Commission agrees that this proposal is fully in accordance with cost-causation principles.

Id. at 62,379. Thus, the arguments of CDWR-SWP and MWD are without merit.[16]

[16] For similar reasons, the Commission should reject the arguments made by Reliant/Mirant that exports should not bear the costs of extra-marginal Energy. *See* Reliant/Mirant at 1, 13-14.

Duke Energy argues that the Commission should reject the ISO's proposal to net expected future market revenues from extra-marginal bid cost recovery, at least until a capacity market is developed in California. Duke Energy states that although the ISO claims its approach is consistent with the approaches adopted by other independent system operators and the Commission's SMD NOPR, the ISO fails to acknowledge the relevant distinction that California does not have a capacity market in which a Generator can earn a return on investment. As a consequence, the proposed netting and settlement process compromises a Generator's compensation for recovery of its fixed costs because such recovery is *net* of its expected market revenues during the trade day. In a similar context, according to Duke Energy, the Commission previously prohibited the ISO from reducing a Generator's recovery of its Minimum Load Costs in one hour, based on market revenues that the Generator may earn in another hour. Additionally, Duke Energy also argues that extra-marginal Energy should be allowed to set the MCP. Duke Energy at 11-12.

As indicated in its July 22, 2003 MD02 filing,[17] a *de facto* capacity market (or, at least, a payment stream covering fixed costs equal to or better than what a formal capacity market would provide) exists in California as a result of the extensive and expensive long-term power contracts entered into during the 2000-2001 energy crisis, the RMR contracts and the ISO's unique Ancillary Services markets. Furthermore, California is currently addressing its resource adequacy requirements through a proceeding before the CPUC. With regard to Duke

Energy's argument that extra-marginal Energy be allowed to set the MCP, the ISO addressed this issue in Section II.H.3, above.

3. Ramping Energy

No party appears to raise an issue concerning this subject.

J. The ISO's Proposal Concerning Minimum Load Cost Compensation Is Reasonable

Dynegy, *et al.* argue that Minimum Load Cost Compensation ("MLCC") payment eligibility should remain on a one-hour basis. They contend that the ISO's proposed modification of one of the performance requirements for eligibility to receive MLCC has not been shown to be just or reasonable, or been shown to be consistent with prior Commission orders. Dynegy, *et al.* assert that additional changes to the interim MLCC mechanism should not be made; instead, changes should be made as part of the implementation of the comprehensive market redesign. Also, they argue that the MLCC Tolerance Band should only apply when a unit is at the minimum generating output level ("Pmin"), as has previously been argued in the California refund proceeding in Docket Nos. EL00-95, *et al.* Dynegy, *et al.* at 26-27.

The ISO disagrees. The ISO believes it is far more equitable to assess compliance and revoke minimum load cost compensation on a ten-minute basis than on an hourly basis. Assessing compliance on an hourly integrated basis does not provide sufficient incentive for a unit to be operating at its instructed

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[17] *See Amendment to Comprehensive Market Design Proposal*, Docket Nos. ER02-1656-

point at any given moment through that hour, since there is too much leeway for a unit first to deviate within an interval and then to deviate in the opposite direction in later intervals to make up the previous deviation. Assessing performance and, if necessary, revoking payment on a ten-minute basis synchronizes the ISO's settlement systems with is compliance systems and reduces the size of any necessary adjustments for non-compliance.

The City of Santa Clara ("Santa Clara") (which is one of the members of Cities/M-S-R) asserts that certain aspects of Amendment No. 54 will adversely affect the Metered Subsystem ("MSS") Agreement between the ISO and the City of Santa Clara. Santa Clara argues that under the MSS Agreement, Santa Clara balances its own loads and resources and is subject to a substantial penalty for failure to balance loads and resources in accordance with the MSS Agreement's requirements. As part of Amendment No. 54, Santa Clara asserts, the ISO proposes to revise Section 23.16.3 of its Tariff to assess to MSS Operators, presumably including Santa Clara, a share of the Minimum Load Costs, allocated based on metered Demand. Santa Clara argues this proposed revision should be rejected on grounds that it is not based on concepts of cost causation. Santa Clara states that it incorporates by reference NCPA's arguments concerning the proposed revision. Cities/M-S-R at 6-7.

NCPA, in turn, argues that the ISO's proposed change to Section 23.16.3 of its Tariff to allocate a portion of Minimum Load Costs to MSS Operators would unilaterally impose entirely new and enormous payment obligations on MSS Operators, despite the ISO's stated commitment to continue to pay Minimum

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015 and ER01-68-028 (filed July 22, 2003), at 21-22.

Load Cost compensation based on the MSS Agreement. NCPA asserts this proposed change is unsupported by basic ratemaking and cost-causation principles, is inconsistent with NCPA's MSS Agreement (which expressly addresses charges for emissions and start-up costs, but does not provide for the ISO to charge NCPA for Minimum Load Costs), and is a violation of Section 3.5 of the NCPA MSS Agreement (which expressly requires the ISO to consider cost causation and the impact on Metered Subsystems in making amendments to the ISO Tariff). NCPA at 3-7. The MSS Agreement establishes the exemptions from the ISO Tariff that apply to MSS Operators. When the MSS Agreement was initially executed in July 2002, it had not been determined if MSS Operators should be exempted from Minimum Load Costs, either partially or completely, and so consequently this issue was not addressed in the initial MSS Agreement. The Commission's December 19 Order directed the ISO to pay Minimum Load Costs and required the ISO to allocate such Minimum Load Costs on metered Demand and exports.[18] This payment is for minimum load costs associated with the units the ISO must take off of Must-Offer waivers to ensure the reliability of the ISO Control Area.[19]

Santa Clara is correct that the MSS Agreement provides for substantial penalties if the MSS Operator that elects to balance its Loads and resources and

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[18] The ISO is allocating Minimum Load Costs in the manner the Commission directed. The Commission directed the ISO to recover Minimum Load Costs "consistent with the methodology utilized for the recovery of emissions and start-up fuel costs." *San Diego Gas and Electric Company*, 97 FERC ¶ 61,293, at 62,363 (2001) ("December 19 Order"). In the same Order, the Commission confirmed that "the use of gross load as the basis for assessment of emissions and start-up fuel costs is appropriate in that all uses of the transmission grid will be assigned these costs consistent with the ISO's markets performing a reliability function." *Id* at 62,370.

does not do so. However, to the extent that an MSS Operator purchases Energy from the ISO, it should pay for that Energy on the same basis as all other Scheduling Coordinators. Consistent with this cost causation principle, if Santa Clara is relying on the markets units and/or the ISO Controlled Grid to supply its Load, it should pay ISO costs like all Scheduling Coordinators. Thus the ISO revised Section 23.16.3 of the ISO Tariff to allocate Minimum Load Costs on a net metered Demand basis when the MSS Operator elects to follow its Load.

In regards to NCPA's assertions, the issue of Minimum Load Costs is not addressed in the MSS Agreement, and, absent being specifically addressed in the MSS Agreement, the ISO Tariff provisions govern in accordance with Section 3.3 of the MSS Agreement. Additionally, the ISO believes that it has followed cost causation principles in accordance with Section 3.5 of the MSS Agreement. If a Scheduling Coordinator must pay the Minimum Load Costs because it uses the ISO Controlled Grid to serve Load and exports, and NCPA uses the ISO Controlled Grid similar to other Scheduling Coordinators, then NCPA should pay for the reliability of the ISO Control Area. However, consistent with the proposed amendment to Section 23.16.3, if internal Generation is serving internal Load and not using the ISO Controlled Grid, then NCPA should not incur the costs associated with such metered Demand (i.e. net metered Demand)

PG&E asserts that the compensation for Minimum Load Costs may be too high as proposed in Amendment No. 54. According to PG&E, the ISO should require Generators to forego Minimum Load Costs whenever they operate, due

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[19] For the period from May 1, 2001 through May 31, 2003, Generators have been paid, and Load and exports have paid over $98 Million in MLCC.

either to ISO Dispatch Instructions, or bilateral sales, and to notify the ISO of their operation at above Pmin. PG&E argues that given the ISO's intention to have electronic reporting of outage or decreased availability or other constraints, the ISO should also be possible to have electronic reporting which automatically flags unit operation above minimum load levels, and correspondingly terminate minimum cost payments. PG&E at 11-12.

While the ISO agrees that payments for minimum load should be revoked if a Generating Unit deviates without instruction from its minimum load point, any proposal to eliminate paying Minimum Load Costs when the unit is instructed will have a perverse effect of forcing owners of Generating Units to seek to recover their minimum load costs through their market bids. The ISO strongly prefers that Minimum Load Costs be paid separately so that Energy from capacity above minimum load can be bid in at the unit's true incremental cost and not at the unit's average cost.[20]

K. The ISO's Proposal Concerning System Resources Is Reasonable

Dynegy, *et al.* argue that the ISO should not discriminate between System Resources and Generators that are subject to PGAs; the ISO should either allow System Resources to set the MCP or, alternatively, should allow Generators that are subject to PGAs to participate in an hourly "pre-Dispatch" market and receive

[20] The ISO has proposed to use three-part bids in its new market design. One part of the bid would be for start-up costs; a second would be for minimum load costs, and the third for incremental energy costs. *See Amendment to Comprehensive Market Design Proposal*, ER02-1656-015 and ER01-68-028 (filed July 22, 2003), at 12-13.

bid cost recovery. Dynegy, *et al.* assert that by giving System Resources bid cost recovery (essentially, to be paid as bid), the ISO will be able to manipulate the market – specifically, the ISO will be allowed to artificially suppress the in-state MCP by over-procuring System Resources and then under-procuring in-state PGA resources. By doing so, according to Dynegy, *et al.*, the ISO could lower the total cost of real-time Energy by incurring some pay-as-bid uplift in return for a lower overall MCP. They contend that the ISO can only do this if it has the ability to pay System Resources as bid without paying that price to all resources that participate in the ISO real-time markets. Dynegy, *et al.* at 28, 29.

Further, Dynegy, *et al.* argue, the Commission has not ordered the ISO to pay System Resources as-bid. Dynegy, *et al.* at 28. Dynegy, *et al.* do not consider that the ISO proposed to pay System Resources as-bid in Section 8.6.3 of the Dispatch Protocol, which the ISO submitted in its May 1, 2002 MD02 filing as part of its proposals to implement real-time economic Dispatch. In the July 17 Order, the Commission approved the ISO's proposal to use real-time economic Dispatch (*see, e.g.*, July 17 Order at P 128); although the Commission did not expressly state that it was accepting Section 8.6.3 of the Dispatch Protocol, its approval of the use of real-time economic Dispatch implicitly included an approval of that section.[21] Thus, the Commission *has* accepted the ISO's proposal to pay System Resources as-bid. Moreover, the Commission's

[21] Tellingly, in the July 17 Order, the Commission also explained that "[t]he majority of interveners support the CAISO's real-time economic dispatch proposal, with the noted exception of Dynegy who 'suspects [the proposal is] an attempt to lower prices in [the CAISO's] imbalance energy market.'" July 17 Order at P 127 (quoting filing by Dynegy). Despite Dynegy's suspicions, the Commission accepted the ISO's proposal. Dynegy's argument, as discussed in the July 17 Order, is similar to the argument presented by Dynegy, *et al.* in the present proceeding and discussed above.

acceptance of the proposal is consistent with the Commission's directives relaxing the zero-bid requirement.

Duke Energy makes arguments similar to those of Dynegy, *et al.* Duke Energy argues that the ISO's proposes disparate and discriminatory treatment of Generators that are subject to PGAs and System Resources. It asserts that the Commission should allow in-state generation to participate in the ISO's Hourly Pre-Dispatch process on the same terms as System Resources. Specifically, Duke Energy states, the Commission should direct the ISO to modify its Tariff to allow Generators that are subject to PGAs the option of submitting bids to be pre-Dispatched in the same manner as System Resources; Generators that are subject to PGAs that elect not to be pre-Dispatched would remain eligible to set the MCP in each Dispatch Interval. Duke Energy at 6-7.

The ISO proposes to treat System Resources differently in recognition of the specific circumstances that result from being located outside the ISO Control Area. Energy from System Resources comes in to the ISO Control Area via inter-Control Area Schedules. Established WECC scheduling practice holds that such Schedules must be established and "checked out" (i.e., verified with the adjacent Control Area) 30 minutes prior to the operating hour. WECC scheduling practice also mandates that Inter-Control Area schedules, except for automated dynamic Schedules implemented through dedicated communications equipment with the computer control system of the applicable Control Area, are not to be changed in the middle of an hour except for *force majeure* reasons. Non-dynamically Scheduled System Resources are not individually visible to the ISO and are represented through interchange schedules. In contrast, Generating Units within the ISO Control Area are directly visible to the ISO's computer control system. The ISO can and will pre-dispatch Generating Units with legitimate physical constraints that prevent those units from changing output levels over the course of an hour. It is not unreasonable to expect that if the ISO created a venue in which it agreed to pre-dispatch Generating Units (even those Generating Units that did not have minimum run-time constraints) prior to the hour and to not to change those units' outputs over the course of an hour, that the vast majority of Generating Units would want to participate only in that venue, leaving the ISO with few resources to be able to match supply and Demand in real time as required. That would completely undermine the purpose of the real-time Imbalance Energy market. The ISO's Imbalance Energy market reflects how most utilities followed changes in Demand with supply prior to the creation of an imbalance energy market. Regulating units were used to follow minute-by-minute changes in Demand. Utilities' portfolios were economically re-dispatched at regular intervals to match the Demand trend, returning regulating units to their normal operating points and restoring their regulating capabilities. Thermal units were not always block-loaded; they were expected to ramp to follow changes in Demand while faster-responding units provided Regulation. The ISO has no intention of ramping thermal units needlessly. No one, including the ISO, benefits if Generating Units are worn out more quickly by constant movement. But creating a separate hourly market for resources that are continuously variable would diminish system response and further complicate a market that Market Participants already claim is too complicated.

The CPUC states that its understanding is that the uplift charge the ISO is proposing, in order to mitigate some of the supplier's price risk, will be in the form of the neutrality charge. The CPUC would like the ISO to confirm that all Market Participants will pay this charge since the entire Control Area benefits from imports and increased reliability. Also, the CPUC desires assurance and specificity regarding the efforts the ISO is taking to reduce the variability in the MCP and increase the level of price stability.[22] CPUC at 2-3. In response, the ISO explains as follows. Deviations are created by the physical limitations of the resource, and operation of the resource benefits the entire market. Further, optimization and netting is done on a 24-hour basis. In Amendment No. 54, the ISO has acted to limit the size of uplifts (1) through use of the netting mechanism, and (2) by reducing, through the use of penalties, excess costs. These excess costs are different from uplift costs, but since excess costs and uplift costs are allocated the same way, the allocation of each will have the same effect.

Further, the CPUC asserts, since tracking uplift charges becomes difficult once they are thrown into the mix of neutrality charges, the CPUC would like the ISO to track these uplift charges separately to provide Market Participants with an indication of the magnitude of these costs. CPUC at 3. The ISO will track these charges separately. In fact, the ISO has already created two new charge

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[22] The CPUC notes that the deviation penalties proposed in Amendment No. 54 will be a step forward in increasing price stability.

types ("CTs") for that purpose. CT 4680 will track all uplift payments made to resources, and CT 1680 will track how those uplifts are recovered from Market Participants.

L. New Defined Terms

No party appears to raise an issue concerning this subject.

M. Correction to the ISO's April 11, 2003 Compliance Filing

No party appears to raise an issue concerning this subject.

N. Miscellaneous Issues

1. The Scope of Amendment No. 54 Is Appropriate

The California Generators/IEP assert that, as previously identified by the Commission, Phase 1B of MD02 was to implement UDP and move to real-time economic Dispatch (i.e., elimination of the target price mechanism), and that Amendment No. 54 contains proposals that are more extensive than what the Commission initially contemplated. California Generators/IEP at 8. This criticism is without merit. As the filing utility, the ISO has the right and the obligation to implement the necessary market improvements as efficiently as possible.[23]

Moreover in making this argument, the California Generators/IEP fail to give sufficient consideration to the fact that Amendment No. 54 includes changes that are necessary to implement real-time economic Dispatch and UDP, and

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[23] *Atlantic City Electric Co. v. FERC*, 329 F.3d. 856, 859 (D.C. Cir. 2003) ("We reaffirm our prior decision that FERC has no jurisdiction to enter limitations requiring utilities to surrender their rights under § 205 of the FPA to make filings to initiate rate changes.").

includes modifications and clarifications that are necessary to facilitate implementation of the design elements previously approved for MD02 Phase 1 and to reconcile various provisions in the ISO Tariff. *See* Transmittal Letter for Amendment No. 54 at 2, 24. Thus, these changes are *required* to allow the ISO to move from a merit order Dispatch paradigm to an economic Dispatch paradigm. In addition, the proposals in Amendment No. 54 will be responsive to recognizing resource constraints. *See* Transmittal Letter for Amendment No. 54 at 5-6 & n.6. Further, the ISO notes that Amendment No. 54 contains proposals that are consistent with the mechanisms used by other independent system operators that perform economic dispatch. *See, e.g.*, Transmittal Letter for Amendment No. 54 at 14, 23, 24. In sum, the changes in Amendment No. 54 are required for the proper operation of MD02 Phase 1, enhance the California electricity market, and are entirely appropriate.

2. The ISO Commits to Ensure the Use of Defined Terms Employed in Amendment No. 54 Consistently Throughout the ISO Tariff and Protocols

MWD asserts that the ISO should review its proposed Tariff changes to ensure that defined terms are correctly used and that similar concepts are expressed consistently throughout the Tariff and Protocols. Specifically, MWD mentions the use of the terms Dispatched Load, Curtailable Demand, Load, and Participating Load, Uninstructed Deviation Penalty, and Deviation Penalties, in the Tariff and Protocols. MWD at 7-8.

The ISO recognizes the importance of using terms in a consistent manner throughout the tariff and has developed the extensive set of Defined Terms in Appendix A to achieve this objective. The ISO acknowledges that the term "Curtailable Demand", not the term "Dispatchable Load", should be consistently used to describe Load whose Demand can be curtailed in real time at the direction of the ISO. The ISO also acknowledges that the term "Uninstructed Deviation Penalty" should be used in place of the words "Deviation Penalty". The ISO will correct any inconsistent use of terms in its compliance filing.

3. PG&E's Request for an Interim Report Is Unnecessary

While PG&E states that it generally supports a number of the proposals in Amendment No. 54, it also requests that the Commission should make approval of some of the ISO's proposals conditional upon an ISO commitment to report to the Commission on the measures after a period of time such as 6-9 months after implementation, and resolve any unanticipated effects of MD02 Phase 1B through mitigation and simplification of the ISO's operating procedures. PG&E at 3-4.

While the ISO fully recognizes the need to constant monitoring of the implementation of all the MD02 elements, including those for Phase 1B, the Commission should not require the specific restrictions and report proposed by PG&E. As explained above, the ISO's proposals are necessary for the proper implementation of MD02 Phase 1; they should therefore not be subject to restrictions such as those PG&E proposes, which would treat Amendment No. 54

as merely a “pilot program” rather than as a critical part of completing the MD02 Phase 1 process. Further, the ISO’s and the Department of Market Analysis and Market Surveillance Committee already monitor the operation of the ISO’s markets. Their responsibilities will necessarily encompass monitoring the performance of the features of MD02 Phase 1B. Additionally, Section 19 the ISO Tariff explains the rights of Market Participants to bring complaints against the ISO pursuant to Section 206 of the Federal Power Act. If a Market Participant believes it is aggrieved by procedures in MD02 Phase 1B, it can always bring a complaint.

4. With the Modifications Described Herein, the ISO’s Proposed Effective Date Is Appropriate

Duke Energy asserts that, given that the software needed to implement Amendment No. 54 is not expected to be fully developed and tested until early 2004, the Commission should grant only conditional approval to Amendment No. 54, subject to the ISO filing a status report after the software changes have been fully implemented and market-tested. Duke Energy also requests that the Commission expressly permit entities to supplement and update their comments on Amendment No. 54 at a later date after the filing of such a status report. Duke Energy at 13-14.

Duke Energy’s requests should be denied. In Amendment No. 54, the ISO explains the specifics of the ISO’s proposals. The ISO does not expect that the development and testing of the software needed to implement Amendment No. 54 will reveal that the proposals need to be modified. Moreover, if changes are necessary, the ISO would need to file an amendment with the Commission and Market Participants would have an opportunity to comment at that time. The ISO has filed Amendment No. 54 at this time in order to obtain Commission approval prior to expending significant resources on implementation. Thus, there is no need for the Commission to conditionally approve the amendment

In addition, the ISO believes no reason exists for postponing the effective date of the proposals in Amendment No. 54 concerning Adjustment Bids, which are addressed at pages 21-22 of the Amendment No. 54 transmittal letter. These measures should be allowed to go into effect 60 days from the filing. As to the other elements of the proposal, the ISO requests that the Commission grant the effective date described in the Amendment No. 54 transmittal letter at page 32.

5. Reliant/Mirant's Request for Rejection Will Improperly Delay Needed Market Reforms

Reliant/Mirant request that the Commission reject Amendment No. 54 as filed and require the ISO to file a revised proposal that includes the changes proposed by Reliant/Mirant. They assert that requiring this will not harm the ISO or delay implementation of MD02, because Amendment No. 54 is not expected to become effective until early 2004. Reliant/Mirant at 4. Reliant/Mirant's request should be denied. First, as the filing utility, the ISO has the right to propose changes to its tariff. *Atlantic City Electric Co. v. FERC*, 295 F.3d 1 at 9-10 (D.C. Cir. 2002).

In addition, the ISO has already explained in this answer the various reasons that Reliant/Mirant's proposals should be rejected by the Commission. Furthermore, Reliant/Mirant are incorrect in stating that having to re-file

Amendment No. 54 would not delay its implementation. Reliant/Mirant suggest wholesale changes to the proposals in Amendment No. 54. Assuming *arguendo* that the suggestions in Reliant/Mirant's protest were adopted, it would be well past early 2004 by the time the proposals in Amendment No. 54 had been rewritten as Reliant/Dynegy suggest, the new filing had been submitted, the software needed to implement the new filing had been developed and tested, parties had submitted comments and protests on the new filing, the ISO had answered the comments and protests, and the Commission had issued on order on the new filing. Thus, if Reliant/Mirant's protest were adopted, the implementation of MD02 Phase 1B would be significantly delayed.

III. CONCLUSION

Wherefore, for the foregoing reasons, the ISO respectfully requests that the Commission accept Amendment No. 54 in its entirety, except for the limited modifications noted herein.

Respectfully submitted,

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