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39. Market Power Mitigation Procedures

39.1 Intent of CAISO Mitigation Measures; Additional FERC Filings

These CAISO market power mitigation measures ("Mitigation Measures") are intended to provide the means for the CAISO to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the CAISO Markets while avoiding unnecessary interference with competitive price signals. These Mitigation Measures are intended to minimize interference with an open and competitive market, and thus to permit, to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the Mitigation Measures authorize the mitigation only of specific conduct identified through explicit procedures specified below. In addition, the CAISO shall monitor the markets it administers for conduct that it determines constitutes an abuse of market power but is not addressed by the market power mitigation procedures specified below. If the CAISO identifies any such conduct, it shall make a filing under Section 205 of the Federal Power Act, 16 U.S.C. § 824d, with FERC requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the CAISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the CAISO's justification for imposing that mitigation measure.

39.2 Conditions for the Imposition of Mitigation Measures

39.2.1 Conduct Inconsistent with Competitive Conduct

In general, the CAISO shall consider a Market Participant's conduct to be inconsistent with competitive conduct if the conduct would not be in the economic interest of the Market Participant in the absence of market power. The categories of conduct that are inconsistent with competitive conduct include, but may not be limited to, the four categories of conduct specified in Section 39.3 below.

39.3 Categories of Conduct that May Warrant Mitigation

39.3.1 Conduct Regarding Bidding, Scheduling or Facility Operation

Mitigation Measures may be applied to bidding, scheduling or operation of an Electric Facility or as specified in Section 39.3.1. The following categories of conduct, whether by a single firm or by multiple firms acting in concert, may cause a material effect on prices or generally the outcome of the CAISO Markets if exercised from a position of market power. Accordingly, the CAISO shall monitor the CAISO

Markets for the following categories of conduct, and shall impose appropriate Mitigation Measures if such conduct is detected and the other applicable conditions for the imposition of Mitigation Measures are met:

(1) Physical withholding of an Electric Facility, in whole or in part, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving a CAISO Market. Such withholding may include, but not be limited to: (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become totally or partially unavailable, (ii) refusing to offer Bids for an Electric Facility when it would be in the economic interest, absent market power, of the withholding entity to do so, (iii) declining Bids called upon by the CAISO (unless the CAISO is informed in accordance with established procedures that the relevant resource for which the Bid is submitted has undergone a forced outage or derate), or (iv) operating a Generating Unit in Real-Time to produce an output level that is less than the Dispatch Instruction.

(2) Economic withholding of an Electric Facility, that is, submitting Bids for an Electric Facility that are unjustifiably high (relative to known operational characteristics and/or the known operating cost of the resource) so that: (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the Bids will set LMPs.

(3) Uneconomic production from an Electric Facility that is, increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a Transmission Constraint.

(4) Bidding practices that distort prices or uplift charges away from those expected in a competitive market, such as registering Start-Up Cost and Minimum Load Cost data or submitting Bid Costs on behalf of an Electric Facility that are unjustifiably high (relative to known operational characteristics and/or the known operating cost of the resource) or misrepresenting the physical operating capabilities of an Electric Facility resulting in uplift payments or prices significantly in excess of actual costs.

39.3.2 Market Effects of Rules, Standards, Procedures, Other Items

Mitigation Measures may also be imposed to mitigate the market effects of a rule, standard, procedure, design feature, or known software imperfection of a CAISO Market that allows a Market Participant to manipulate market prices or otherwise impair the efficient operation of that market, pending the revision of such rule, standard, procedure design feature, or software defect to preclude such manipulation of prices or impairment of efficiency.

39.3.3 Using Different Prices in Other Markets as Appropriate

Taking advantage of opportunities to sell at a higher price or buy at a lower price in a market other than a CAISO Market shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

39.3.4 Foregoing Category List Subject to Amendment as Appropriate

The CAISO shall monitor CAISO Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices in a CAISO Market or other payments. The CAISO shall seek to amend the foregoing list as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the CAISO Markets.

39.4 Sanctions for Physical Withholding

The CAISO may report a Market Participant the CAISO determines to have engaged in physical withholding, including providing the CAISO false information regarding derating or outage of an Electric Facility, to the Federal Energy Regulatory Commission in accordance with Section 9.3.10.5. In addition, a Market Participant that fails to operate a Generating Unit in conformance with CAISO Dispatch Instructions shall be subject to the penalties set forth in Section 11.23.

39.5 FERC-Ordered Measures

In addition to any mitigation measures specified above, the CAISO shall administer, and apply when appropriate in accordance with their terms, such other mitigation measures as it may be directed to implement by order of the FERC.

39.6 Rules Limiting Certain Energy, AS, and RUC Bids

39.6.1 Maximum Bid Prices

Notwithstanding any other provision of this CAISO Tariff, maximum Bid price provisions of this Section 39.6.1 shall apply to limit, Energy Bids, RUC Availability Bids, and Ancillary Service Bids.

39.6.1.1 Energy Bid and Minimum Load Cost Caps

39.6.1.1.1 Soft Energy Bid Caps

All Energy Bids, except for Virtual Bids or Bids for Non-Resource-Specific System Resources, are subject to the Soft Energy Bid Cap. Scheduling Coordinators may submit Energy Bids that are subject to the Soft Energy Bid Cap in excess of the Soft Energy Bid Cap, which the CAISO will process pursuant to Section 30.11.

39.6.1.1.2 Hard Energy Bid Cap

All Energy Bids are subject to the Hard Energy Bid Cap. Scheduling Coordinators may submit Energy Bid prices in excess of the Hard Energy Bid Cap, which the CAISO will cost-verify pursuant to the rules specified in Section 30.11.

39.6.1.1.3 Minimum Load Cost Hard Cap

All Minimum Load Bids are subject to the Minimum Load Cost Hard Cap. Scheduling Coordinators may submit Minimum Load Bid prices in excess of the Minimum Load Cost Hard Cap, which the CAISO will cost-verify pursuant to the rules specified in Section 30.11.

39.6.1.2 Maximum RUC Availability Bid Prices

The maximum RUC Availability Bid price shall be $250/MW/h.

39.6.1.3 Maximum Ancillary Services Bid Prices

The maximum level for Ancillary Services Bid prices shall be $250/MWh.

39.6.1.3.1 Maximum Regulation Mileage Bid Price

The maximum Mileage Bid price shall be $50.

39.6.1.4 Minimum Bid Price for Energy Bids

The minimum Energy Bid price shall be negative $150/MWh. These rules apply to all Energy Bids, including Virtual Bids.

39.6.1.5 Minimum Bid Price for Ancillary and RUC Bids

Ancillary Service Bids and RUC Availability Bids submitted into CAISO markets must have Bid prices not less than $0/MW/h.

39.6.1.5.1 Minimum Regulation Mileage Bid Prices

Regulation Mileage Bids submitted into CAISO markets must have Bid prices not less than $0.

39.6.1.6 Maximum Start-Up Cost and Minimum Load Cost Registered Cost Values

The maximum Start-Up Cost and Minimum Load Cost values registered in the Master File by Scheduling Coordinators for capacity of non-Multi-Stage Generating Resources that are eligible and elect to use the Registered Cost methodology in accordance with Section 30.4 cannot exceed the Minimum Load Cost Hard Cap and will be limited to one hundred fifty percent (150%) of the Projected Proxy Cost. The maximum Start-Up Cost and Minimum Load Cost values registered in the Master File by Scheduling Coordinators for capacity of Multi-Stage Generating Resources that are eligible and elect to use the Registered Cost methodology in accordance with Section 30.4 will be limited to one hundred fifty percent (150%) of the Projected Proxy Cost for each MSG Configuration of the resources. The Projected Proxy Cost for natural gas-fired resources will include a gas price component, a major maintenance expense component, if available, a volumetric Grid Management Charge component, and, if eligible, a projected Greenhouse Gas Allowance Price component calculated as set forth in this Section 39.6.1.6. The Projected Proxy Cost for non-natural gas-fired resources will be based on costs provided to the CAISO pursuant to Section 30.4.5.2, a major maintenance expense component, if available, a volumetric Grid Management Charge component, and, if eligible, a projected Greenhouse Gas Allowance Price component calculated as set forth in this Section 39.6.1.6.

39.6.1.6.1 Gas Price Component of Projected Proxy Cost

For natural gas-fired resources, the CAISO will calculate a gas price to be used in establishing Default Start-Up Bids and Default Minimum Load Bids after the twenty-first (21^{st}) day of each month and post it on the CAISO Website by the end of each calendar month. The price will be applicable for Scheduling Coordinators for natural gas-fired Use-Limited Resources electing to use the Registered Cost methodology set forth in Section 30.4.7 until a new gas price is calculated and posted on the CAISO Website. The gas price will be calculated as follows:

(1) Daily closing prices for monthly natural gas futures contracts at Henry Hub for the next calendar month are averaged over the first twenty-one (21) days of the month, resulting in a single average for the next calendar month.

(2) Daily prices for futures contracts for basis swaps at identified California delivery points, are averaged over the first twenty-one (21) days of the month for the identified California

delivery points as set forth in the Business Practice Manual.

(3) For each of the California delivery points, the average Henry Hub and basis swap prices are combined and will be used as the baseline gas price applicable for calculating the Default Start-Up Bids and Default Minimum Load Bids for Use-Limited Resources electing to use the Registered Cost methodology set forth in Section 30.4.7. The most geographically appropriate prices will apply to a particular resource.

(4) The applicable intra-state gas transportation charge as set forth in the Business Practice Manual will be added to the baseline gas price for each Use-Limited Resource that elects to use the Registered Cost methodology set forth in Section 30.4.7 to create a final gas price for calculating the Default Start-Up Bids and Default Minimum Load Bids for each such resource.

For non-natural gas-fired resources, the Projected Proxy Costs for Default Start-Up Bids and Default Minimum Load Bids will be calculated using the information as registered in the Master File used for calculating the Proxy Cost, as set forth in the Business Practice Manual.

39.6.1.6.2 Projected Greenhouse Gas Allowance Price

For resources that are registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the CAISO will calculate a projected Greenhouse Gas Allowance Price component to be used in establishing maximum Default Start-Up Bids and Default Minimum Load Bids after the twenty-first (21st) day of each month and will post it on the CAISO Website by the end of that month. The projected Greenhouse Gas Allowance Price component will be applicable for Scheduling Coordinators on behalf of eligible Use-Limited Resources electing to use the Registered Cost methodology until a new projected Greenhouse Gas Allowance Price component is calculated and posted on the CAISO Website. The projected Greenhouse Gas Allowance Price component will be calculated by averaging the applicable daily Greenhouse Gas Allowance Prices calculated over the first twenty (20) days of the month using the methodology set forth in Section 39.7.1.1.1.4.

39.6.1.6.3 Major Maintenance Expense Component

The major maintenance expense component is determined based on the process set forth in Section 30.4.5.4.

39.6.1.6.4 Volumetric Grid Management Charge Component

The volumetric Grid Management Charge component is set forth in Sections 39.7.1.1.1.1 and 39.7.1.1.1.2.

39.6.1.7 Maximum Transition Cost Values

Scheduling Coordinators for capacity of Multi-Stage Generating Resources that are eligible and elect to use the Registered Cost methodology in accordance with Section 30.4 must register Transition Costs for each feasible transition between a lower MSG Configuration and a higher MSG Configuration, between zero and a maximum of 150 percent of the difference between the Projected Proxy Cost for the Start-Up Costs for the higher MSG Configuration, minus the Projected Proxy Cost for the Start-Up Costs for the lower MSG Configuration. If the result of this calculation is negative for any transition between two MSG Configurations, then the associated Transition Cost shall be zero.

39.7 Local Market Power Mitigation for Energy Bids

Local Market Power Mitigation is based on the assessment and designation of Transmission Constraints as competitive or non-competitive pursuant to Section 39.7.2. The local market power mitigation processes are described in Section 31.2 for the DAM and Sections 34.1.5 for the RTM.

39.7.1 Calculation of Default Energy Bids

Default Energy Bids shall be calculated by the CAISO, for the on-peak hours and off-peak hours for both the DAM and RTMs, pursuant to one of the methodologies described in this Section. The Scheduling Coordinator for each Generating Unit owner or Participating Load must rank order the following options of calculating the Default Energy Bid starting with its preferred method. The Scheduling Coordinator must provide the data necessary for determining the Variable Costs unless the Negotiated Rate Option precedes the Variable Cost Option in the rank order, in which case the Scheduling Coordinator must have a negotiated rate established with the CAISO. If no rank order is specified for a Generating Unit or Participating Load, then the default rank order of (1) Variable Cost Option, (2) Negotiated Rate Option, (3) LMP Option will be applied. For the first ninety (90) days after changes to resource status and MSG Configurations as specified in Section 27.8.3, including the first ninety (90) days after the effective date of Section 27.8.3, the Default Energy Bid option for the resource is limited to the Negotiated Rate Option or the Variable Cost Option. Default Energy Bids used for purposes other than for calculating

Reasonableness Thresholds will be subject to the Soft Energy Bid Cap, unless the CAISO has approved a Reference Level Change Request pursuant to Section 30.11 in support of an Energy Bid above the Soft Energy Bid Cap. Scheduling Coordinators for storage resources participating as Non-Generator Resources also may rank the storage resource option among their options. If no rank is specified for a storage resource participating as a Non-Generator Resource, then the default rank will be (1) Variable Cost Option and (2) LMP Option. Scheduling Coordinators for storage resources participating as Non-Generator Resources must provide the data necessary for determining the storage resource option if that option is the first in rank order.

39.7.1.1 Variable Cost Option

For natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by adding incremental cost (comprised of incremental fuel cost plus a volumetric Grid Management Charge adder plus a greenhouse gas cost adder if applicable) with variable operation and maintenance cost, by multiplying the sum by the Default Energy Bid Multiplier, adding a Bid Adder if applicable for a Frequently Mitigated Unit, and adding Variable Energy Opportunity Costs, if any. For non-natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by summing incremental fuel or fuel-equivalent cost plus a volumetric Grid Management Charge plus a greenhouse gas cost adder if applicable, multiplying the sum by the Default Energy Bid Multiplier, adding a Bid Adder if applicable for a Frequently Mitigated Unit, and adding Variable Energy Opportunity Costs, if any. For any Default Energy Bids calculated under the Variable Cost Option that exceed $1,000 per MWh because of an approved Reference Level Change Request, any ten percent (10%) adder or Frequently Mitigated Unit adder shall not exceed $100 per MWh.

39.7.1.1.1 Incremental Cost Calculation Under the Variable Cost Option

39.7.1.1.1.1 Natural Gas-Fired Resources

(a) Calculation of incremental fuel cost - For natural gas-fueled units, incremental fuel cost is calculated based on an incremental heat rate curve multiplied by the natural gas price calculated as described below.

Resource owners shall submit to the CAISO average heat rates (Btu/kWh) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average heat rate curve formed by the (Btu/kWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average heat rate pairs yield one (1) incremental heat rate segment that spans two (2) consecutive operating points. The incremental heat rates (Btu/kWh) in the incremental heat rate curve are calculated by converting the average heat rates submitted by resource owners to the CAISO to requirements of heat input (Btu/h) for each of the operating points and dividing the changes in requirements of heat input from one (1) operating point to the next by the changes in MW between two (2) consecutive operating points as specified in the Business Practice Manual. For each segment representing operating levels below eighty (80) percent of the unit's PMax, the incremental heat rate is limited to the maximum of the average heat rates for the two (2) operating points used to calculate the incremental heat rate segment.

The unit's final incremental fuel cost curve is calculated by multiplying this incremental heat rate curve by the applicable natural gas price, and then, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. Heat rate and cost curves shall be stored, updated, and validated in the Master File.

(b) Calculation of greenhouse gas cost adder - For each natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the CAISO will calculate a greenhouse gas cost adder as the product of the resource's incremental heat rate, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price.

(c) Calculation of volumetric Grid Management Charge adder - For each natural gas-fired resource, the CAISO will include a volumetric Grid Management Charge adder that consists of: (i) the Market Services Charge; (ii) the System Operations Charge; and (iii) the Bid Segment Fee divided by the MW in the Bid segment.

39.7.1.1.1.2 Non-Natural Gas-Fired Resources

For non-natural gas-fueled units, incremental fuel cost is calculated based on an average cost curve as described below.

Resource owners for non-natural gas-fueled units shall submit to the CAISO average fuel or fuel equivalent costs ($/MW) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average cost curve formed by the ($/MWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average cost pairs yield one (1) incremental cost segment that spans two (2) consecutive operating points. For each segment representing operating levels below eighty percent (80%) of the unit's PMax, the incremental cost rate is limited to the maximum of the average cost rates for the two (2) operating points used to calculate the incremental cost segment. The unit's final incremental fuel cost curve is then adjusted, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. The CAISO will include, if applicable: (i) greenhouse gas allowance costs for each non-natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator for the resource; (ii) variable operation and maintenance cost; and (iii) a volumetric Grid Management Charge adder that consists of: (a) the Market Services Charge; (b) the System Operations Charge; and (c) the Bid Segment Fee divided by the MW in the Bid segment. Cost curves shall be stored, updated, and validated in the Master File.

39.7.1.1.1.3 Calculation of Natural Gas Price

(a) The CAISO will use different gas price indices for the Day-Ahead Market and the Real-Time Market. If a gas price index is unavailable for any reason, the CAISO will use the most recent available gas price index as set forth in Section 39.7.1.1.1.3(c).

(b) For all Trading Days of the Day-Ahead Market, except for Mondays when the Monday-only gas price index is available and meets the liquidity criteria described below, the CAISO will calculate a gas price index based on natural gas commodity prices reported by the Intercontinental Exchange one (1) day prior to the applicable Trading Day between

8:00 a.m. and 9:00 a.m. Pacific Time for natural gas deliveries on the Trading Day. The natural gas commodity prices reported by the Intercontinental Exchange are volume-weighted average gas prices reported during its next-day trading window. For Monday Trading Days, the CAISO will use the Monday-only gas price index when it is reported by the Intercontinental Exchange three (3) days prior to the Monday Trading Day, provided:

(i) The historical average volume of the Monday-only gas price index at a given location, using no more than ninety (90) days of trading, is at least 25,000 MMBTUs based on the CAISO's test of whether the volume at a given location is above 25,000 MMBTUs at least once every six (6) months; and

(ii) On any given day the Monday-only gas price index published at the locations that meet the requirement in subsection (b)(i) above represents at least five (5) transitions.

(c) For all Trading Days of the Real-Time Market, except for Mondays when the Monday-only gas price index is available and meets the liquidity criteria described below, the CAISO will calculate a gas price index using at least one (1) price from the following publications: Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, or Platt's Gas Daily. The CAISO will update the gas price indices for the Real-Time Market between 7:00 p.m. and 10:00 p.m. Pacific Time using the natural gas prices published one (1) day prior to the applicable Trading Day for natural gas deliveries on the Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published gas prices that are available. For Monday Trading Days, the CAISO will use the Monday-only gas price index when it is reported by the Intercontinental Exchange three (3) days prior to the Monday Trading Day, provided:

(i) The historical average volume of the Monday-only gas price index at a given location, using no more than ninety (90) days of trading, is at least 25,000 MMBTUs based on the CAISO's test of whether the volume at a given location is above 25,000 MMBTUs at least once every six (6) months; and

(ii) On any given day the Monday-only index gas price published at the locations that meet the requirement in subsection(c)(i) above represents at least five (5) transactions.

39.7.1.1.1.4 Calculation of Greenhouse Gas Allowance Price

To calculate the Greenhouse Gas Allowance Price, the CAISO will average two prices from the following vendors: the Intercontinental Exchange and ARGUS. If a greenhouse gas price from a vendor is unavailable for any reason, the CAISO will use the most recent available greenhouse gas price from that vendor. If for any reason the CAISO cannot calculate a Greenhouse Gas Allowance Price, it will use the most recently calculated value. The CAISO will update the Greenhouse Gas Allowance Price by approximately 22:00 Pacific Time each day (T). The daily Greenhouse Gas Allowance Price will be used in the next day's Real-Time Market (T+1) and in the Day-Ahead Market for the following Trading Day (T+2). The CAISO will calculate each Greenhouse Gas Allowance Price during a year using prices for greenhouse gas allowances from that same year.

39.7.1.1.2 Variable Operation and Maintenance Cost Under the Variable Cost Option

The default value for the variable operation and maintenance cost portion will vary by fuel source or technology as follows: (1) solar $0.00/MWh; (2) nuclear $1.00/MWh; (3) coal $2.00/MWh; (4) wind $2.00/MWh; (5) hydro $2.50/MWh; (6) natural gas-fired combined cycle and steam units $2.80/MWh; (7) geothermal $3.00 WMh; (8) landfill gas $4.00/MWh; (9) combustion turbines and reciprocating engines $4.80/MWh; and (10) biomass $5.00/MWh. Resource-specific values may be negotiated with the CAISO charged with calculating the Default Energy Bid. Default operation and maintenance values as well as any negotiated values will also be used to calculate Default Minimum Load Bids pursuant to Section 30.4.

39.7.1.1.3 Variable Energy Opportunity Costs Under the Variable Cost Option

The CAISO will determine eligibility for Variable Energy Opportunity Costs for Use-Limited Resources pursuant to Section 30.4.6.

39.7.1.2 LMP Option

The CAISO will calculate the LMP Option for the Default Energy Bid as a weighted average of the lowest quartile of LMPs at the Generating Unit PNode in periods when the unit was Dispatched during the preceding ninety (90) day period for which LMPs that have passed the price validation and correction process set forth in Section 35 are available. The weighted average will be calculated based on the quantities Dispatched within each segment of the Default Energy Bid curve. Each Bid segment created under the LMP Option for Default Energy Bids will be subject to a feasibility test, as set forth in a Business Practice Manual, to determine whether there are a sufficient number of data points to allow for the calculation of an LMP based Default Energy Bid. The feasibility test is designed to avoid excessive volatility of the Default Energy Bid under the LMP Option that could result when calculated based on a relatively small number of prices.

39.7.1.3 Negotiated Rate Option

39.7.1.3.1 Submission Process

Scheduling Coordinators that elect the Negotiated Rate Option for the Default Energy Bid shall submit a proposed Default Energy Bid along with supporting information and documentation as described in a BPM. Within ten (10) Business Days of receipt, the CAISO will provide a written response. If the CAISO accepts the proposed Default Energy Bid, it will generally become effective within eleven (11) Business Days from the date of acceptance by the CAISO and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If the CAISO does not accept the proposed Default Energy Bid, the CAISO and the Scheduling Coordinator shall enter a period of good faith negotiations that terminates sixty (60) days following the date of submission of a proposed Default Energy Bid by a Scheduling Coordinator. If at any time during this period, the CAISO and the Scheduling Coordinator agree upon the Default Energy Bid, it will generally become effective within eleven (11) Business Days of the date of agreement and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If by the end of the sixty (60)-day period the CAISO and the Scheduling Coordinator fail to agree on the Default Energy Bid to be used under the Negotiated Rate Option, the Scheduling Coordinator has the right to file a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act. During the sixty (60)-day period following the submission of a proposed negotiated Default Energy Bid by a Scheduling Coordinator, and pending FERC's acceptance in cases where the CAISO fails to agree on the Default Energy Bid for use under the Negotiated Rate Option and the Scheduling Coordinator filed a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act, the Scheduling Coordinator has the option of electing to use any of the other options available pursuant to Section 39.7. If the Scheduling Coordinator does not elect to use any of the other options available pursuant to Section 39.7, or if sufficient data do not exist to calculate a Default Energy Bid using any of these options, the CAISO may establish a temporary Default Energy Bid as specified in Section 39.7.1.5. Any negotiated Default Energy Bid for a resource that includes an opportunity cost component as of April 1, 2019, will remain in effect, subject to the CAISO's renegotiation rights pursuant to Section 39.7.1.3.2.1, unless the Scheduling Coordinator pursues an Opportunity Cost pursuant to Section 30.4.6.1.2. If a Scheduling Coordinator pursues an Opportunity Cost pursuant to Section 30.4.6.1.2, the Scheduling Coordinator must either elect the Variable Cost Default Energy Bid or the CAISO will renegotiate the negotiated Default Energy Bid to, at a minimum, utilize the Variable Energy Opportunity Cost as a component of the negotiated Default Energy Bid in place of any previously negotiated Opportunity Cost value.

39.7.1.3.2 Negotiated Values and Informational Filings

39.7.1.3.2.1 Renegotiation of Values

The CAISO may require the renegotiation of any components including adders or interim adders for major maintenance expenses determined pursuant to Sections 30.4.5.1, 30.4.5.2, and 30.4.5.4, any Opportunity Costs negotiated pursuant to Section 30.4.6.3, any Default Energy Bids negotiated pursuant to this Section 39.7.1.3, any temporary Default Energy Bids established pursuant to Section 39.7.1.5, or any custom operation and maintenance adders negotiated pursuant to Section 39.7.1.1.2, that have become outdated, are possibly erroneous, or for which the Scheduling Coordinator has changed. In the renegotiation process, the CAISO may review and propose modifications to such values, and may require the Scheduling Coordinator to provide updated information to support continuation of such values.

39.7.1.3.2.2 Informational Filings with FERC

The CAISO shall make an informational filing with FERC of any adders or interim adders for major maintenance expenses determined pursuant to Sections 30.4.5.1, 30.4.5.2, and 30.4.5.4, any Opportunity

Costs calculated pursuant to Section 30.4.6.2 or negotiated pursuant to Section 30.4.6.3, any Default Energy Bids negotiated pursuant to this Section 39.7.1.3, any temporary Default Energy Bids established pursuant to Section 39.7.1.5, or any custom operations and maintenance adders negotiated pursuant to Section 39.7.1.1.2, no later than seven (7) days after the end of the month in which the Default Energy or operations and maintenance values were established.

39.7.1.4 Frequently Mitigated Unit Option

A Frequently Mitigated Unit that is eligible for a Bid Adder may select a fourth Default Energy Bid option, which is equal to the Variable Cost Option plus the Bid Adder as described in Section 39.7.

39.7.1.5 Temporary Default Energy Bid

If the Scheduling Coordinator does not elect to use any of the other options available pursuant to Section 39.7.1, or if sufficient data do not exist to calculate a Default Energy Bid using any of the available options, the CAISO will first seek to obtain from the Scheduling Coordinator any additional data required for calculating the Default Energy Bid options available pursuant to 39.7.1. If the provision of additional data by a Scheduling Coordinator results in additional or modified Default Energy Bid options pursuant to 39.7.1, the Scheduling Coordinator will have another opportunity to elect one of these options as its temporary Default Energy Bid. If the Scheduling Coordinator does not elect to use any of the options available pursuant to Section 39.7.1, or if sufficient data still do not exist to calculate a Default Energy Bid using any of the available options, the CAISO may establish a temporary Default Energy Bid based on one or more of the following: (1) operating cost data, opportunity cost, and other appropriate input from the Market Participant; (2) the CAISO's estimated operating costs of the Electric Facility, taking the best information available to the CAISO; (3) an appropriate average of competitive Bids of one or more similar Electric Facilities; or (4) any of the other options for determining a Default Energy Bid for which data are available.

39.7.1.6 Default Energy Bids for RMR Resources

The Scheduling Coordinator for the RMR Resource must rank order its preferences between the Variable Cost Option and the Negotiated Rate Option, which shall be the default rank order if no rank order is specified by the Scheduling Coordinator. These preferences will be used to determine the Default Energy Bids for the capacity for each RMR Resource. RMR Units are not eligible to receive the ten percent adder under the Variable Cost Option pursuant to Section 39.7.1.1 or the Bid Adder pursuant to Section 39.8.

39.7.1.7 Hydro Default Energy Bid

Scheduling Coordinators may request a Hydro Default Energy Bid for a hydroelectric resource with storage capability located in the CAISO Balancing Authority Area or any EIM Entity Balancing Authority Area.

39.7.1.7.1 Computation

For each Trading Day, the CAISO will calculate the Hydro Default Energy Bid as the maximum of the (a) gas floor, (b) short-term component, and (c) long-term/geographic component, which are all calculated as specified below.

39.7.1.7.1.1 Gas Floor

The CAISO will calculate the gas floor as the most recent average heat rate for a typical gas turbine generator obtained from the Energy Information Administration, multiplied by the gas price for the fuel region applicable to the location of the hydroelectric resource, multiplied by 1.1.

39.7.1.7.1.2 Short-Term Component

The CAISO will calculate the short-term component as 1.4 multiplied by the maximum of:

(a) the day-ahead peak price at the applicable electric pricing hub;

(b) the on-peak balance of the month on peak futures price for the current month at the applicable electric pricing hub; and

(c) the on-peak monthly index on peak futures price at the applicable electric pricing hub for one (1) month after the current month.

39.7.1.7.1.3 Long-Term/Geographic Component

A Scheduling Coordinator may request that the long-term/geographic component be calculated based on multiple electric pricing hubs in addition to the default electric pricing hub consistent with Section 39.7.1.7.2.1. The CAISO will calculate the long-term/geographic component as 1.1 multiplied by the maximum of:

(a) the day-ahead on-peak price at the applicable electric pricing hub(s);

(b) the on-peak balance of the month futures prices for the current month at the applicable electric pricing hub(s); and

(c) the on-peak monthly index futures price at the applicable electric pricing hub(s) for all future months up to the maximum storage horizon after the current month.

39.7.1.7.2 Requirements

As part of its request for a Hydro Default Energy Bid, the Scheduling Coordinator must submit to the CAISO:

(a) Annually, for each month of the upcoming year and for each electric pricing hub requested that is not the default electric pricing hub, the Scheduling Coordinator must (1) demonstrate that it holds firm transmission rights to enable delivery from the hydroelectric resource's default market region to the requested electric pricing hub or to a delivery point that is similarly priced location; or (2) provide documentation that supports a historical practice of acquiring monthly firm transmission rights to the requested electric pricing hub(s) or similarly priced location. Scheduling Coordinators may demonstrate transmission rights to multiple locations and, based on the CAISO's evaluation of such information, the CAISO may include multiple electric pricing hubs, in addition to the default electric pricing hubs, in the long-term/geographic component of the Hydro Default Energy Bid for the affected resources. The Scheduling Coordinator will attest through its submission that it reasonably expects it will be able to use the demonstrated transmission rights to deliver incremental sales from the hydroelectric resource because the rights are not fully committed and that there is an actual opportunity to use these rights. If the CAISO includes multiple electric pricing hubs in the long-term/geographic component, the Hydro Default Energy Bid calculation will use the maximum of the electric price indices published for each electric pricing hub as determined for each Trading Day. On Trading Days for which there are no relevant published electric price indices at an electric pricing hub, the CAISO will use the most recently published index for the applicable electric pricing hub.

(b) For resources that Scheduling Coordinators demonstrate a quantity of firm transmission rights to a requested electric pricing hub or similarly priced location that is less than the hydro resource's capacity, the CAISO will include the requested electric pricing hub up to the quantity demonstrated transmission rights, and apply a proportional weighting of the resource's transmission rights to calculate a weighted average of those bilateral electric pricing hub prices when calculating the value of the long-term/geographic component of the Hydro Default Energy Bid.

(c) In the absence of supporting transmission rights information when calculating the Hydro Default Energy Bid, the CAISO will revert to the default bilateral electric pricing hub specified in Section 39.7.1.7.3.

(d) If during the term of the annual period the Scheduling Coordinator no longer has the firm annual transmission rights previously demonstrated, or can no longer continue a historical practice of acquiring monthly firm transmission rights, the Scheduling Coordinator must inform the CAISO within five (5) Business Days of no longer holding such firm transmission rights.

(e) The CAISO may audit the Scheduling Coordinator and request additional information in support of the Scheduling Coordinator's assertions.

(f) If the CAISO determines the Scheduling Coordinator has submitted inaccurate information, the CAISO may revert the resource to the default electric pricing hubs as specified in Section 39.7.1.7.3.

39.7.1.7.2.2 Maximum Storage Horizon

The maximum hydroelectric resource storage horizon submitted by the Scheduling Coordinator must:

(a) Reflect the typical storage duration of a hydroelectric resource's reservoir, defined as the length of time between which the reservoir cycles from a maximum elevation to a new maximum elevation during a hydro cycle. The Scheduling Coordinator shall compute the reservoir's cycling time based on multiple years of reservoir elevation data.

(b) Be supported by (1) a written attestation by a representative who has the authority to bind the company stating that the value submitted to the CAISO as the maximum storage horizon is consistent with the requirements specified in Section 39.7.1.7.2.2 (a); or (2) corroborating information submitted to the CAISO, which may include several years of historic reservoir levels for the specific hydroelectric resource and regulatory filings related to the operations of the hydroelectric resource.

39.7.1.7.3 Default Electric Pricing Hubs

The default electric pricing hubs will be as specified in the Business Practice Manuals, which will also include a process for modifying or adding electric pricing hubs to the list of default electric pricing hubs.

39.7.1.8 Storage Resource Option

For storage resources participating as Non-Generator Resources, the storage resource option will calculate the Default Energy Bid by selecting the maximum of (1) the sum of the expected energy cost and the variable storage operation cost and, in the RTM, (2) the storage opportunity cost. The calculation is completed by adding ten percent (10%) to the value. To calculate the Default Energy Bid, the CAISO will use the PMin, PMax, Run Times, and other charging and discharging parameters registered in the Master File.

The expected energy cost represents the average cost to procure the amount of energy needed to charge the resource during the lowest-priced continuous block of time such that the resource can discharge completely, accounting for the resource's charging duration and round-trip efficiency, and excluding losses. To calculate this component in the Day-Ahead Market, the CAISO will use the average price of Energy during the lowest priced hours based upon the final Energy Supply Bids from the MPM process at the relevant PNode, not to be below $0/MWh. To calculate this component in the Real-Time Market, the CAISO will use the average price of Energy during the lowest priced hours based upon the LMP from the IFM at the relevant PNode on the Trading Day, not to be below $0/MWh.

The variable storage operation cost represents the variable costs of operating a storage resource beyond its designed daily cycling range, submitted by the Scheduling Coordinator in $/MWh. The CAISO will validate the storage operation cost based on manufacturer warranty, available data, and supporting documentation submitted by the Scheduling Coordinator. The storage opportunity cost represents the opportunity cost of being dispatched during lower-priced RTM intervals, equal to the cost of Energy the resource could discharge during the highest-priced continuous RTM block, accounting for the resource's discharge duration. To calculate this component in the Real-Time Market, the CAISO will use the lowest price of Energy during the highest priced period over which the resource could have discharged, based upon the LMP from the IFM at the relevant PNode on the Trading Day.

39.7.2 Competitive Path Designation

39.7.2.1 Timing of Assessments

For the DAM and RTM, the CAISO will make assessments and designations of whether Transmission Constraints are competitive or non-competitive as part of the MPM runs associated with the DAM and RTM, respectively. Only binding Transmission Constraints determined by the MPM process will be assessed in the applicable market.

39.7.2.2 Criteria

(A) Notwithstanding the provisions in Section 39.7.2.2(B), when the CAISO enforces the natural gas constraint pursuant to Section 27.11, the CAISO may deem selected internal constraints to be non-competitive for specific days or hours based on its determination that actual electric supply conditions may be non-competitive due to anticipated electric supply conditions in the Southern California Gas Company and San Diego Gas & Electric Company gas regions.

(B) Subject to Section 39.7.3, for the DAM and RTM, a Transmission Constraint will be non-competitive only if the Transmission Constraint fails the dynamic competitive path assessment pursuant to this Section 39.7.2.2.

(a) Transmission Constraints for the DAM - As part of the MPM process associated with the DAM, the CAISO will designate a Transmission Constraint for the DAM as non-competitive when the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(a):

(i) Counter-flow to the Transmission Constraint means the delivery of Power from a resource to the system load distributed reference bus. If counter-flow to the Transmission Constraint is in the direction opposite to the market flow of Power to the Transmission Constraint, the counter-flow to the Transmission Constraint is calculated as the shift factor multiplied by the resource's scheduled Power.

Otherwise, counter-flow to the Transmission Constraint is zero.

(ii) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers and all internal Virtual Supply Awards not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource's Energy Bid adjusted for Self-Provided Ancillary Services and derates.

(iii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply and Virtual Supply Awards that provide counter-flow to the Transmission Constraint.

(iv) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint.

(v) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Section 4.5.1.1.12 and all effective internal Virtual Supply Awards of the Scheduling Coordinator and/or Affiliate. Effectiveness in supplying counter-flow is determined by scaling generation capacity and/or Virtual Supply Awards by the shift factor from that location to the Transmission Constraint being tested.

(vi) A portfolio of a net seller means any portfolio that is not a portfolio of a net buyer. A portfolio of a net buyer means a portfolio for which the average daily net value of Measured Demand minus Supply over a twelve (12) month period is positive. The average daily net value is determined for each portfolio by subtracting, for each Trading Day, Supply from Measured Demand and then averaging the daily value for all Trading Days over the twelve (12) month period. The CAISO will calculate whether portfolios are portfolios of net buyers in the third month of each calendar quarter and the calculations will go into effect at the start of the next calendar quarter. The twelve (12) month period used in this calculation will be the most recent twelve (12) month period for which data is available. The specific mathematical formula used to perform this calculation will be set forth in a Business Practice Manual. Market Participants without physical resources will be deemed to be net sellers for purposes of this Section 39.7.2.2(a)(vi).

(vii) In determining which Scheduling Coordinators and/or Affiliates control the resources in the three (3) identified portfolios, the CAISO will include resources and Virtual Supply Awards directly associated with all Scheduling Coordinator ID Codes associated with the Scheduling Coordinators and/or Affiliates, as well as all resources that the Scheduling Coordinators and/or Affiliates control pursuant to Resource Control Agreements registered with the CAISO as set forth Section 4.5.1.1.13. Resources identified pursuant to Resource Control Agreements will only be assigned to the portfolio of the Scheduling Coordinator that has control of the resource or whose Affiliate has control of the resource pursuant to the Resource Control Agreements.

(b) Transmission Constraints for the RTM - As part of the MPM processes associated with the RTM, the CAISO will designate a Transmission Constraint for the RTM as non-competitive when the sum of the supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint and the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(b):

(i) Counter-flow to the Transmission Constraint has the meaning set forth in Section 39.7.2.2(a)(i).

(ii) Supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint means the minimum available capacity from internal resources controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. The minimum available capacity for the current market interval will reflect the greatest amount of capacity that can be physically withheld. The minimum available capacity is the lowest output level the resource could achieve in the current market interval given its dispatch in the last market interval and limiting factors including Minimum Load, Ramp Rate, Self-Provided Ancillary Services, Ancillary Service Awards (in the Real-Time Market only), and derates.

(iii) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint that can be withheld. Counter-flow supply to the Transmission Constraint that can be withheld reflects the difference between the highest capacity and the lowest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute FMM interval or the preceding five (5) minute RTD interval, as applicable (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM. In determining whether to designate a Transmission Constraint as non-competitive for the RTM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of sixty (60) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval of the FMM. In determining whether to designate a Transmission Constraint as non-competitive for the FMM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of fifteen (15) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval.

(iv) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to

Sections 4.5.1.1.12 and 39.7.2.2(a)(vii). Effectiveness in supplying counter-flow is determined by scaling generation capacity by the shift factor from that location to the Transmission Constraint being tested.

(v) A portfolio of a net seller has the meaning set forth in Section 39.7.2.2(a)(vi).

(vi) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute interval of the FMM or five (5) minute interval of the RTD, as applicable (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM.

(vii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply that provides counter-flow to the Transmission Constraint.

39.7.3 Default Competitive Path Designations

The CAISO will maintain default competitive path designation sets for the Day-Ahead Market and for the Real-Time Market, which the CAISO will use in order to determine the competitiveness or non-competitiveness of Transmission Constraints under two circumstances: (1) in the event of a failure of the CAISO Markets software to perform an assessment of whether Transmission Constraints are competitive or non-competitive pursuant to Section 39.7.2; and (2) in order to determine whether Exceptional Dispatches are related to a non-competitive Transmission Constraint for purposes of mitigation of Exceptional Dispatches of resources under Section 39.10(1). Default competitive path designations will be determined pursuant to the methodology set forth in this Section 39.7.3 and will be updated no less frequently than once every seven (7) days. Until the CAISO has developed sufficient information to develop default competitive path designations, the CAISO will continue to utilize the most recent list of competitive path designations determined prior to the effective date of this tariff provision.

39.7.3.1 Methodology for Determining Day-Ahead Default Competitive Path Designations for Transmission Constraints other than Path 15 and Path 26 Transmission Constraints

The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the Day-Ahead Market only if both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more hours of the days for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in seventy-five (75) percent or more of the instances in which the Transmission Constraint was binding when tested. These calculations will be made utilizing data from the Day-Ahead Market for the most recent sixty (60) Trading Days for which data is available. The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as non-competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.1(1) and 39.7.3.1(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

39.7.3.2 Methodology for Determining HASP/RTM Default Competitive Path Designations for Transmission Constraints other than Path 15 and Path 26 Transmission Constraints

The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the HASP/RTM only if both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more of the hours for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in seventy-five (75) percent or more of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the Real-Time Market for the most recent sixty (60) Trading Days for which data is available. If the Transmission Constraint was binding during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be binding for the entire hour. If the Transmission Constraint was determined to be non-competitive during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be non-competitive for the entire hour. The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as non-competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.2(1) and 39.7.3.2(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

39.7.3.3 Methodology for Determining Day-Ahead Competitive Path Designations for Path 15 and Path 26 Transmission Constraints

The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the Day-Ahead Market unless both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more hours of the days for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in fewer than seventy-five (75) percent of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the MPM for the Day-Ahead Market for the most recent sixty (60) Trading Days for which data is available. The CAISO will designate the Path 15

Transmission Constraint or the Path 26 Transmission Constraint as competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.3(1) and 39.7.3.3(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

39.7.3.4 Methodology for Determining RTM Default Competitive Path Designations for Path 15 and Path 26 Transmission Constraints

The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the RTM unless both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more of the hours for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in fewer than seventy-five (75) percent of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the MPM for the Real-Time Market for the most recent sixty (60) Trading Days for which data is available. If the Transmission Constraint was binding during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be binding for the entire hour. If the Transmission Constraint was determined to be non-competitive during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be non-competitive for the entire hour. The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.4(1) and 39.7.3.4(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

39.8 Eligibility for Bid Adder

A Scheduling Coordinator submitting Bids for Generating Units is eligible to have a Bid Adder applied to a Generating Unit for the next operating month if the criteria in Section 39.8.1 are met as determined on a monthly basis in the preceding month.

39.8.1 Bid Adder Eligibility Criteria

To receive a Bid Adder, a Generating Unit must: (i) have a Mitigation Frequency that is greater than eighty (80) percent in the previous twelve (12) months; and (ii) must not have a contract to be a Resource Adequacy Resource for its entire Net Qualifying Capacity, or be designated under the CPM for its entire Eligible Capacity, or be subject to an obligation to make capacity available under this CAISO Tariff. If a Generating Unit is designated under the CPM for a portion of its Eligible Capacity, the provisions of this section apply only to the portion of the capacity not designated. Scheduling Coordinators for Generating Units seeking to receive Bid Adders must further agree to be subject to the Frequently Mitigated Unit option for a Default Energy Bid. Run hours are those hours during which a Generating Unit has positive metered output. After the first twelve (12) months from the effective date of this Section, the Mitigation Frequency will be based entirely on a Generating Unit being mitigated under the MPM procedures in Sections 31 and 33.

39.8.2 New Generating Units

For new Generating Units, with less than twelve (12) months of operation, determination of eligibility for the Bid Adder will be based on data beginning with the first date the Generating Unit participated in the CAISO Markets through the end date of the period for which the Mitigation Frequency is being calculated. The 200 run hour criteria will be pro-rated for the proportion of a twelve (12)-month period that the new Generating Unit submitted effective Bids in the CAISO markets.

39.8.3 Bid Adder Values

The value of the Bid Adder will be either: (i) a unit-specific value determined in consultation with the CAISO; or (ii) a default Bid Adder of $24/MWh. For Generating Units with a portion of their capacity identified as meeting an LSE's Resource Adequacy Requirements, that Generating Unit's Bid Adder value will be reduced by the percent of the Generating Unit's capacity that is identified as meeting an LSE's Resource Adequacy Requirements. The reduced Bid Adder will be applied to that Generating Unit's entire Default Energy Bid Curve.

39.9 CRR Monitoring and Affiliate Disclosure Requirements

The CAISO will monitor the CRR holdings and CAISO Markets activity for anomalous market behavior, gaming, or exercise of market power resulting from CRR ownership concentrations that are not aligned with actual transmission usage as a result of secondary market auction outcomes. If the CAISO identifies such behavior it may seek FERC approval to impose position limits on the total number or MW quantity of CRRs that may be held by any single entity and its Affiliates. Each CRR Holder or Candidate CRR Holder must notify the CAISO of any Affiliate that is a CRR Holder, Candidate CRR Holder, or Market Participant, any Affiliate that participates in an organized electricity market in North America, and any guarantor of any such Affiliate.

39.10 Mitigation of Exceptional Dispatches of Resources

The CAISO shall apply Mitigation Measures to Exceptional Dispatches of resources when such resources are committed or dispatched under Exceptional Dispatch for purposes of: (1) addressing reliability requirements related to non-competitive Transmission Constraints; (2) ramping resources with Ancillary Services Awards or RUC Capacity to a dispatch level that ensures their availability in Real-Time; (3) ramping resources to their Minimum Dispatchable Level in Real-Time; and (4) addressing unit-specific environmental constraints not incorporated into the Full Network Model or the CAISO's market software that affect the dispatch of Generating Units in the Sacramento Delta and are commonly known as "Delta Dispatch".

39.10.1 Measures for Resources Eligible for Supplemental Revenues

In all cases where a resource is subject to Mitigation Measures under Section 39.10, and the resource is eligible for supplemental revenues pursuant to Section 39.10.3, FMM Exceptional Dispatch Energy or RTD Exceptional Dispatch Energy delivered by the resource shall be settled as set forth in either Section 11.5.6.7.1 or Section 11.5.6.7.3, whichever is applicable.

3.10.2 Resources Not Eligible for Supplemental Revenues

In all cases where a resource is subject to Mitigation Measures under Section 39.10, and the resource is not eligible for supplemental revenues pursuant to Section 39.10.3, FMM Exceptional Dispatch Energy or RTD Exceptional Dispatch Energy delivered by the resource shall be settled as set forth in either Section 11.5.6.7.2 or Section 11.5.6.7.3, whichever is applicable.

39.10.3 Eligibility for Supplemental Revenues

Except as provided in Section 39.10.4, a resource that is committed or dispatched under Exceptional Dispatch shall be eligible for supplemental revenues only during such times that the capacity from the resource dispatched under Exceptional Dispatch is Eligible Capacity, the Eligible Capacity does not have an offer into the applicable CSP, and has declined an Exceptional Dispatch CPM designation offered under Section 43A.2.5.

39.10.4 Limitation on Supplemental Revenues

Supplemental revenues authorized under this Section 39.10 shall not exceed within a 30-day period (this 30-day period begins on the day of the first Exceptional Dispatch of the resource and re-starts on the day of the first Exceptional Dispatch of the resource following the end of any prior 30-day period) the CPM Soft Offer Cap, for which the resource would be eligible pursuant to Section 43A.7 had its Eligible Capacity been designated as CPM Capacity.

39.10.5 Calculation of Exceptional Dispatch Supplemental Revenues

The amount of Exceptional Dispatch supplemental revenues accrued by a resource within any 30-day period as defined in Section 39.10.4 shall be a running total of the sum of supplemental revenues received during that 30-day period. The calculation of supplemental revenues accrued by a resource within a 30-day period is based on the higher of (a) the Energy Bid price for the resource minus the Default Energy Bid price for the resource or (b) the relevant FMM or RTD LMP minus the Default Energy Bid price for the resource. The greater of (a) or (b) is multiplied by the amount of Energy provided by the resource under Exceptional Dispatch, and the results of that multiplication are summed across the successive hours of the 30-day period. Once the resource has reached the limit on supplemental revenues described in Section 39.10.4 based on the calculation above, then the Settlement for the resource will be as provided in Section 11.5.6.7.2 and the resource will not be eligible for additional supplemental revenues for the rest of the 30-day period.

39.11 Market Power Mitigation Applicable to Virtual Bidding

39.11.1 Affiliate Disclosure Requirements

Each Convergence Bidding Entity must satisfy the Affiliate disclosure requirements set forth in Section 4.14.2.1.

39.11.2 Monitoring of Virtual Bidding Activity

The CAISO and DMM will monitor virtual bidding activity for anomalous market behavior, gaming, or the exercise of market power.