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Appendix C

Locational Marginal Price

The CAISO shall calculate the price of Energy at Generation PNodes, Scheduling Points, and Aggregated Pricing Nodes, as provided in the CAISO Tariff. The CAISO establishes Trading Hub prices and LAPs as provided in the CAISO Tariff. The LMPs at PNodes, including Scheduling Points, and Aggregated Pricing Nodes include separate components for the marginal cost of Energy, Marginal Cost of Congestion, and Marginal Cost of Losses. As provided in Sections 6.5.3.2.2 and 6.5.5.2.4, Day-Ahead Market LMPs are calculated and posted on a Day-Ahead basis for each hour of the Day-Ahead Market and for each interval of the Real-Time Market.

A. LMP Composition in the Day-Ahead Market

The CAISO calculates the LMP for each PNode, which is based on the Bids of sellers and buyers selected in the Day-Ahead or Real-Time Market as calculated below. The CAISO designates a distributed Reference Bus, r, for calculation of the Locational Marginal Prices. The Locational Marginal Prices are not determined by resources that are not eligible to set the Locational Marginal Price as defined in Sections 31.3.1.4 and 34.20.2.3. For each bus other than the Reference Bus, the CAISO determines separate components of the LMP for the System Marginal Cost, Marginal Cost of Congestion, and Marginal Cost of Losses relative to the Reference Bus, consistent with the following equation:

$LMP_i = SMEC_r + MCC_i + MCL_i$

$LMP_r = SMEC_r$

where:

- $SMEC_r$ is the LMP component representing the marginal cost of Energy at the Reference Bus, r (System Marginal Energy Cost).
- MCC_i is the LMP component representing the Marginal Cost of Congestion at bus *i* relative to the Reference Bus.
- MCL_i is the LMP component representing the Marginal Cost of Losses at bus *i* relative to the Reference Bus.

B. LMP Composition in the Real-Time Market

In each 15-minute interval and each 5-minute interval of the Fifteen Minute Market and Real-Time Dispatch, respectively, the CAISO calculates the LMP for each PNode, based on the Bids of sellers and buyers selected in those markets as specified in the FMM Schedule and 5-minute Real-Time Dispatch Instructions. The CAISO designates a Reference Bus, r, for calculation of the System Marginal Energy Cost (SMECr), which is the shadow price of the system power balance constraint. The CAISO uses the distributed load in the EIM Area as the Reference Bus to calculate loss sensitivities and shift factors used to linearize the power balance and Transmission Constraints. Resources that have constraints that prevent them from being marginal are not eligible to set the Locational Marginal Price. For each bus other than the Reference Bus, the CAISO determines separate components of the LMP for the marginal cost of Energy, Marginal Cost of Congestion, Marginal Cost of Losses, and EIM Bid Adder relative to the Reference Bus, consistent with the following equation:

$LMP_i = SMEC_r + MCC_i + MCL_i + MCG_i$

$LMP_r = SMEC_r$

where:

- MCG_i is the LMP component representing the marginal cost of the EIM Bid Adder in Dispatching Energy from the relevant EIM Participating Resources to serve load in the CAISO Balancing Authority Area (Marginal Greenhouse Gas Cost).

For each PNode within an EIM Entity Balancing Authority Area, the LMP shall include a fourth component, the EIM Bid Adder component.

C. The System Marginal Energy Cost Component of LMP (Day-Ahead and Real-Time Market)

The SMEC shall be the same for each location throughout the system. SMEC is the sensitivity of the power balance constraint at the optimal solution. The power balance constraint ensures that the physical law of conservation of Energy (the sum of Generation and imports equals the sum of Demand, including exports and Transmission Losses) is accounted for in the network solution. This system level power balance constraints is enforced over the CAISO Balancing Authority Area for the Day-Ahead Market and over the EIM Area in the Real-Time Market. For the designated reference location the CAISO will utilize a distributed Load Reference Bus for which constituent PNodes are weighted using the Reference Bus distribution factors. The Load distributed Reference Bus distribution factors are based on the Load Distribution Factors at each PNode that represents cleared Load in the Integrated Forward Market or forecast Load for MPM, RUC and RTM. In the Integrated Forward Market, in the event that the market is not able to clear based on the use of a distributed load Reference Bus, the CAISO will use a distributed generation Reference Bus for which the constituent nodes and the weights are determined economically within the running of the Integrated Forward Market based on available economic bids. In the event that the CAISO employs a distributed generation Reference Bus, it will notify Market Participants of which Integrated Forward Market runs required the use of this backstop mechanism. A distributed Load Reference Bus will be used for RUC and RTM regardless of whether a distributed Generation Reference Bus were used in the corresponding Integrated Forward Market run. If the market-clearing problem is limited by the system-level power balance constraint, the market clearing process would create a Shadow Price for the power balance constraint only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.

D. Marginal Congestion Component Calculations (Day-Ahead and Real-Time)

The CAISO calculates the Marginal Costs of Congestion at each bus as a component of the bus-level LMP. The Marginal Cost of Congestion (MCCi) component of the LMP at bus i is calculated in the Day-Ahead Market using the equation:

$$MCC_i = -\sum_{m=1}^{M}\sum_{j=1}^{J_m} c_{j,m}\, PTDF_{i,j}\, \mu_m - \sum_{k=1}^{K}\sum_{m=1}^{M} PTDF_{i,m}^{k}\, \mu_m^{k}$$
$$-\sum_{g=1}^{K_g}\sum_{m=1}^{M}\left(PTDF_{i,m}^{g} + \delta_{O_g,i}\sum_{n=1}^{N} PTDF_{n,m}^{g}\, GLDF_{O_g,n}\right)\mu_m^{g}$$

where:

- i is a node index.
- n is a node index.
- m is the constraint or monitored element index.
- k is the preventive contingency case.
- g is the generation contingency case.

- Og is the node index associated with the generator contingency case g.
- j is the transmission component index of Transmission Constraint m. When Transmission Constraint m is a Nomogram, there can be more than one transmission component. When Transmission Constraint m is any other Transmission Constraint, there shall be only one transmission component.
- N is the number of preventive contingencies.
- K is the number of preventive transmission contingencies.
- Kg is the number of preventive generation contingencies.
- M is the number of monitored elements.
- Jm is the number of transmission components for constraint m.
- $PTDF_{i,j}$ the Power Transfer Distribution Factor for the bus i on transmission component j of the Transmission Constraint *k* which represents the flow across that transmission component j when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.
- $C_{j,m}$ is the constraint coefficient for the transmission component j in constraint m. When constraint m is a Nomogram, this represents the relevant coefficient for that component. When constraint m is any other Transmission Constraint, this coefficient will always be one.
- μm is the constraint Shadow Price on constraint m and is equivalent to the reduction in system cost expressed in \$/MWh that results from a marginal increase of the capacity on constraint m. If the market-clearing problem is limited by any Transmission Constraint including Interties, branch groups, flowgates, nomograms, and Energy Imbalance Market-related transmission constraints (EIM Transfer constraints and power balance constraint for a Balancing Authority Area), the market clearing process would create a Shadow Price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.

- μ_m^k is the constraint Shadow Price on constraint m in the preventive transmission contingency case k and is equivalent to the reduction in system cost expressed in $/MWh that results from a marginal increase of the capacity on constraint m in the preventive transmission contingency case k. If the market-clearing problem is limited by any Transmission Constraint including Interties, branch groups, flowgates, nomograms, and Energy Imbalance Market-related transmission constraints (EIM Transfer constraints and power balance constraint for a Balancing Authority Area), the market clearing process would create a Shadow Price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in total cost to operate the system.
- μ_m^g is the constraint Shadow Price on constraint m in the preventive generator contingency case g and is equivalent to the reduction in system cost expressed in $/MWh that results from a marginal increase of the capacity on constraint m in the preventive generator contingency case g. If the market-clearing problem is limited by any Transmission Constraint including Interties, branch groups, flowgates, nomograms, and Energy Imbalance Market-related transmission constraints (EIM Transfer constraints and power balance constraint for a Balancing Authority Area), the market clearing process would create a Shadow Price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.
- $\delta_{O_g,i}$ is the binary parameter that identifies the node with a generator outage under generator contingency case g. This parameter is one for all nodes in index i when i is the outage node Og associated with a generator contingency case g. This parameter is zero for all nodes in index i when i is not the outage node Og associated with the generator contingency case g.
- $PTDF_{i,m}^k$ is the Power Transfer Distribution Factor for the bus i on transmission component m under the preventive contingency case k, which represents the flow across that transmission component m when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.

- $PTDF_{i,m}^{g}$ is the Power Transfer Distribution Factor for the bus i on transmission component m under the generator contingency case g, which represents the flow across that transmission component m when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.
- $PTDF_{n,m}^{g}$ is the Power Transfer Distribution Factor for the bus n on transmission component m under the generator contingency case g, which represents the flow across that transmission component m when an increment of power is injected at bus n and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.
- $GLDF_{Og,n}$ is the generation of loss distribution factor in the preventive generator contingency case g. The value is negative one when n is Og. This value is zero when n is not Og, and when n is not associated with a frequency response capable generator. This value is the committed generator output at n divided by the sum of the output from all committed frequency response capable generators when n is not Og and n is associated with a frequency response capable generator.

The MCC at PNodes in an EIM Entity Balancing Authority Area j in the Real Time Market includes an additional contribution from the shadow price of the power balance constraint for that Balancing Authority Area, λ_j, as follows:

$$MCC_i = \lambda_j - \sum_{m=1}^{M} PTDF_{ij} \cdot \mu_m - \sum_{k=1}^{K} \sum_{m=1}^{M} PTDF_{i,m}^{k}\, \mu_m^{k} - \sum_{g=1}^{K_g} \sum_{m=1}^{M} \left(PTDF_{i,m}^{g} + \delta_{O_g,i} \sum_{n=1}^{N} PTDF_{n,m}^{g}\, GLDF_{O_g,n} \right) \mu_m^{g}$$

A power balance constraint is not formulated for the CAISO Balancing Authority Area alone in the RTM. The shadow price of the power balance constraint for EIM Entity Balancing Authority Area j (λ_j) has the following contributions:

a) the shadow price of the EIM Transfer distribution constraint (φ_j), which distributes the EIM Transfer for Balancing Authority Area j to Energy transfers on interties with other Balancing Authority Areas in the EIM Area; and

b) the shadow price of the EIM Transfer scheduling limit for Balancing Authority Area j, upper (ν_j) or lower (ξ_j):

$$\lambda_j = \varphi_j - \nu_j + \xi_j$$

Where λ_j is zero for the CAISO Balancing Authority Area since the power balance constraint is not formulated for it.

The difference between the shadow prices of the EIM Transfer distribution constraints for two Balancing Authority Areas j and k in the EIM Area has the following contributions from any intertie l used for energy transfers between these two Balancing Authority Areas:

a) the EIM Transfer schedule cost that applies to that intertie l (c_l);

b) the shadow price of the Energy transfer schedule limit from Balancing Authority Area j to Balancing Authority Area k that applies to that intertie l, upper limit (ρ_l) or lower limit (σ_l); and

c) the shadow price of the scheduling limit that constrains both Energy transfers and additional schedules to Balancing Authority Area j on that intertie l, upper limit (ζ_l) or lower limit (η_l):

$$\varphi_j - \varphi_k = -c_l - \rho_l + \sigma_l + \zeta_l - \eta_l$$

There may be multiple scheduling limits under (c) above that constrain schedules on a given EIM Intertie.

E. Marginal Losses Component Calculation

The CAISO calculates the Marginal Cost of Losses (MCLi) at each bus i as described in Section 27.1.1.2. The MCL component of the LMP at any bus i within the CAISO's Balancing Authority Area is calculated in the Day-Ahead Market and the Real-Time Market using the equation:

$$MCL_i = MLF_i * SMEC_r$$

The MCL component of the LMP at any bus *i* within an EIM Balancing Authority Area is calculated in the Real-Time Market using the equation:

$$MCL_i = MLF_i * (SMEC_r + \lambda_j - \psi)$$

Where:

- MLFi (the marginal loss factor for PNode i to the system Reference Bus) = $-\partial L/\partial G_i$, Where:

L = system losses;

Gi = “generation injected” at PNode *i*; and

$\partial L/\partial G_i$ is the partial derivative of system losses with respect to generation injection at bus *i.*

- SMECr is the marginal cost of Energy at the Reference Bus r (System Marginal Energy Cost).
- λ_j = the shadow price of the power balance constraint for the Balancing Authority Area in which the bus is located; and
- ψ = the shadow price of the EIM export allocation constraint.

The MCL at PNodes in an EIM Entity Balancing Authority Area *j* in the Real Time Market includes additional contributions from the shadow price of the power balance constraint for that Balancing Authority Area (λ_j) and the shadow price of the net imbalance energy export allocation constraint for greenhouse gas regulation (ψ):

$$MCL_i = MLF_i * (SMEC_r + \lambda_j - \psi)$$

F. Marginal Greenhouse Gas Cost Component Calculation

For EIM Participating Resources within an EIM Entity Balancing Authority Area and Energy imported to or exported from an EIM Entity Balancing Authority Area, the CAISO will include the marginal cost of the EIM Bid Adder in dispatching Energy from the relevant EIM Participating Resources to serve load in the CAISO Balancing Authority Area. The CAISO will allocate the Net Imbalance Energy Export optimally to EIM Participating Resources. This allocation does not depend on the location of the EIM Entity Participating Resource; i.e. the CAISO does not use a shift factor in the allocation. If the Net Imbalance Energy Export from all EIM Entity Balancing Authority Areas as a group is negative or zero, there is no associated Net Imbalance Energy Export allocation or EIM Bid Adder cost. Otherwise the net imbalance energy export allocation constraint is binding with a Shadow Price (ψ). If the market-clearing process would create a Shadow Price for the Marginal Greenhouse Gas Cost constraint only when the relaxation of the constraint would result in reduction in the total cost to operate the system. The CAISO determines the Marginal Greenhouse Gas Cost component of the LMP at a PNode in an EIM Entity Balancing Authority Area and LMPs for imports and exports between that EIM Entity Balancing Authority Area and a non-EIM Balancing Authority Area as the negative of the Shadow Price of the net imbalance energy export allocation constraint.

$$MCG_i = - \psi$$

G. Trading Hub Price Calculation

The CAISO calculates Existing Zone Generation Trading Hub prices, as provided in Section 27.3, based on the LMP calculations described in this Attachment and in Section 27.2.

H. Load Zone Price Calculation

The CAISO calculates LAP prices as described in Sections 27.2.2

I. Intertie Scheduling Point Price Calculation

The CAISO calculates LMPs for Scheduling Points, which are represented in the FNM as PNodes or aggregations of PNodes, external to the CAISO Balancing Authority Area, through the same process that is used to calculate LMPs within the CAISO Balancing Authority Area. In some cases, facilities that are part of the CAISO Controlled Grid but are external to the CAISO Balancing Authority Area connect some Intertie Scheduling Points to the CAISO Balancing Authority Area, and in these cases the Scheduling Points are within external Balancing Authority Areas. In both of these cases, the Scheduling Points are represented in the FNM. The CAISO places injections and withdrawals at the Scheduling Point PNodes to represent Bids and Schedules whose supporting physical injection and withdrawal locations may be unknown, and the LMPs for Settlement of accepted Bids are established at the Scheduling Point PNodes.

I.1 Intertie Scheduling Point Price Calculation for IBAAs

1.1.1 Scheduling Point Prices

As described in Section 27.5.3, the CAISO’s FNM includes a full model of the network topology of each IBAA. The CAISO will specify Resource IDs that associate Intertie Scheduling Point Bids and Schedules with supporting injection and withdrawal locations on the FNM. These Resource IDs may be specified by the CAISO based on the information available to it, or developed pursuant to a Market Efficiency Enhancement Agreement. Once these Resource IDs are established, the CAISO will determine Intertie Scheduling Point LMPs based on the injection and withdrawal locations associated with each Intertie Scheduling Point Bid and Schedule by the appropriate Resource ID. In calculating these LMPs the CAISO follows the provisions specified in Section 27.5.3 regarding the treatment of Transmission

Constraints and losses on the IBAA network facilities. Unless otherwise required pursuant to an effective MEEA, the default pricing for all imports from the IBAA(s) to the CAISO Balancing Authority Area will be based on the SMUD/TID IBAA Import LMP and all exports to the IBAA(s) from the CAISO Balancing Authority Area will be based on the SMUD/TID IBAA Export LMP. The SMUD/TID IBAA Import LMP will be calculated based on modeling of supply resources that assumes all supply is from the Captain Jack substation as defined by WECC. The SMUD/TID IBAA Export LMP will be calculated based on the Sacramento Municipal Utility District hub that reflects Intertie distribution factors developed from a seasonal power flow base case study of the WECC region using an equivalencing technique that requires the Sacramento Municipal Utility District hub to be equivalenced to only the buses that comprise the aggregated set of load resources in the IBAA, with all generation also being retained at its buses within the IBAA. The resulting load distribution within each aggregated set of load resources within the IBAA defines the Intertie distribution factors for exports from the CAISO Balancing Authority Area.

I.1.2 Applicable Marginal Loss Adjustment

For import Schedules to the CAISO Balancing Authority Area at the southern terminus of the California-Oregon Transmission Project at the Tracy substation or at the applicable Scheduling Point that connects the CAISO Balancing Authority and the Western Area Power Administration system, the CAISO will replace the Marginal Cost of Losses at the otherwise applicable source for such Schedules with the Marginal Cost of Losses at the Tracy substation or at the applicable Scheduling point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system, provided that the Scheduling Coordinators certify as discussed further below that the Schedules originate from transactions that use: (a) the California-Oregon Transmission Project; or (b) transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA. In addition, as described further below, the Scheduling Coordinator must certify that the Schedules are subject to: (a) charges for losses by the Western Area Power Administration for the use of transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA; or (b) charges for losses by the Transmission Agency of Northern California for the use of the California-Oregon Transmission Project. The CAISO will establish Resource IDs that are to be used only to submit Bids, including Self-Schedules, for the purpose of establishing Schedules that are eligible for this loss adjustment.

Prior to obtaining such Resource IDs, the relevant Scheduling Coordinator shall certify that it will only use this established Resource ID for Bids, including Self-Schedules, that originate from transactions that use: (a) the California-Oregon Transmission Project; or (b) transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA. In addition, the Scheduling Coordinator must certify that the Schedules are subject to: (a) charges for losses by the Western Area Power Administration for the use of transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA; or (b) Transmission Agency of Northern California for the use of the California-Oregon Transmission Project. Further, by actually using such Resource ID, the Scheduling Coordinator represents that such Bids, including Self-Schedules, that originate from transactions that use: (a) the California-Oregon Transmission Project; or (b) transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA. In addition, the Scheduling Coordinator must certify that the Schedules are subject to: (a) charges for losses by the Western Area Power Administration for the use of transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA; or (b) Transmission Agency of Northern California for the use of the California-Oregon Transmission Project. Schedules and Dispatches settled under such Resource IDs shall be subject to an LMP which has accounted for the Marginal Cost of Losses as if there were an actual physical generation facility at the Tracy Scheduling Point or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system as opposed to the Marginal Cost of Losses under the IBAA LMPs specified in Section G.1.1 of this Appendix. The CAISO may request information on a monthly basis from such Scheduling Coordinators to verify these certifications. Any such request shall be limited to transactions that use the designated Resource IDs during the six month prior period to the date of the request. The CAISO will calculate a re-adjustment of the Marginal Cost of Losses at the Tracy substation or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system to reflect the otherwise applicable source for such Schedules for any Settlement Interval in which the CAISO has determined that the Scheduling Coordinator’s payments did not reflect transactions that meet the above specified certification requirements. Any amounts owed to the CAISO for such Marginal Cost of Losses re-adjustments will be recovered by the CAISO from the affected Scheduling Coordinator by netting the amounts owed from

payments due in subsequent Settlements Statements until the outstanding amounts are fully recovered.
For export Schedules from the CAISO Balancing Authority Area at the southern terminus of the California-Oregon Transmission Project at the Tracy substation or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system, the CAISO will replace the Marginal Cost of Losses at the otherwise applicable sink for such Schedules with the Marginal Cost of Losses at the Tracy substation or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system, provided that the Scheduling Coordinator certifies, as discussed below, where the export Schedules use: (a) the California-Oregon Transmission Project; or (b) any transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA. In addition, the Scheduling Coordinator must certify that the affected Schedules are charged losses by: (a) the Western Area Power Administration for the use of transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA; or (b) Transmission Agency of Northern California for the use of the California-Oregon Transmission Project. The CAISO will establish Resource IDs that are to be used only to submit Bids, including Self-Schedules, for the purpose of establishing Schedules that are eligible for this loss adjustment. Prior to obtaining such Resource IDs, the relevant Scheduling Coordinator shall certify that it will only use this established Resource ID for Bids, including Self-Schedules, where the export Schedules use: (a) the California-Oregon Transmission Project; or (b) any transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA. In addition the Scheduling Coordinator must certify that the affected Schedules are charged losses by: (a) the Western Area Power Administration for the use of transmission facilities owned by the Western Area Power Administration within the SMUD/TID IBAA; or (b) Transmission Agency of Northern California for the use of the California-Oregon Transmission Project. Further, by actually using such Resource ID, the Scheduling Coordinator represents that such Bids, including Self-Schedules, are used for the above specified conditions.

Schedules and Dispatches settled under such Resource IDs shall be subject to an LMP which has accounted for the Marginal Cost of Losses as if there were an actual physical generation facility at the Tracy Scheduling Point or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system as opposed to the Marginal Cost of

Losses under the IBAA LMPs specified in Section G.1.1 of this Appendix. The CAISO may request information on a monthly basis from such Scheduling Coordinators to verify that schedules for such Resource IDs meet the above specified conditions. Any such request shall be limited to transactions that use the designated Resource IDs during the six month prior period to the date of the request.

The CAISO will calculate a re-adjustment of the Marginal Cost of Losses at the Tracy substation or at the applicable Scheduling Point that connects the CAISO Balancing Authority Area and the Western Area Power Administration system to reflect the otherwise applicable sink for such Schedules for any Settlement Interval in which the CAISO has determined that the Scheduling Coordinator's payments did not reflect transactions that met the above specified conditions. Any amounts owed to the CAISO for such Marginal Cost of Losses re-adjustments will be recovered by the CAISO from the affected Scheduling Coordinator by netting the amounts owed from payments due in subsequent Settlements Statements until the outstanding amounts are fully recovered.