Comments of Pacific Gas & Electric Company

Day Ahead Market Enhancements – June 19th Working Group

Submitted by	Company	Date Submitted
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Pacific Gas and Electric Company (PG&E) respectfully offers the following comments on the California Independent System Operator's (CAISO) Day Ahead Market Enhancements June 19th Working Group.

Given the complexity and scope of the Day-Ahead Market Enhancements (DAME) initiative as well as the impact of the proposed changes, PG&E recommends the CAISO carry out this initiative in phases. In the first phase, PG&E recommends that CAISO focus on changing the time-step in IFM and RUC to 15 minutes from hourly. The work in the first phase would not involve integrating IFM and RUC or adding a Day-Ahead (DA) Flexible Ramping Product (FRP). Integrating IFM and RUC or adding a DA FRP should be evaluated in later phases—after the successful implementation of the initial phase.

While the formulation of the market engines that would implement a 15-minute time step in IFM and RUC is fairly well understood, stakeholders have questions regarding the market impacts of using a 15-minute time step in the Day-Ahead Market. The ISO should focus on developing the changes needed to implement 15-minute granularity. Such work should address bid submission in DAME, settlements, and other market operations required by the 15-minute granularity in DA IFM and RUC. It should also consider whether any changes in FMM and RTD should be made to smoothly integrate the resulting Day-Ahead Market with the Real-Time Markets.

Successful implementation of 15-minute granularity in IFM and RUC, even without integrating IFM and RUC or adding a DA FRP, should improve the ability of the market to deal with ramp requirements in Day-Ahead and to address the need to improve scheduling of Variable Energy Resources (VER). As mentioned above, the scope of the software and market changes to implement this step is fairly well understood, while the scope of the work needed to integrate IFM and RUC as well as to implement DA FRP is much less clear and requires further refinement by CAISO and evaluation by stakeholders. PG&E recommends the CAISO provide a second revised straw proposal focused on increasing the time-step granularity of the IFM and RUC in Day-Ahead and postpone working on the integration of IFM and RUC and developing DA FRP until after the initial phase is complete.

1. <u>Simply increasing DAM granularity to 15-minute intervals is already a substantial change, with implementation details to work through.</u>

As shown in CAISO's Design Element Matrix[1], 17 out of the 36 changes from the Revised Straw Proposal (RSP) pertain to changing DA Market granularity to 15-minute intervals. Many of these changes impact market operations and thus market participants. Rolling out such a change will require IT system and operations upgrades by both CAISO and participants. The CAISO should focus its efforts on a successful rollout the 15-minute interval in the DAM first.

PG&E requests the CAISO address some questions/concerns related to changing the granularity of the Day-Ahead Market to 15 minutes in a second revised straw proposal.

- To better model ramp requirements on a 15-minute interval in Day-Ahead Market, load and renewables would have to be able to bid or submit schedules on a 15-minute basis. Today, the Day-Ahead Market accepts hourly bids. Please provide details on how the ISO will enable Scheduling Coordinators to bid load and renewables on a 15-minute basis in DA.
- If IFM and RUC in Day-Ahead move to 15-minute intervals for awards of energy and reserves, the ISO may be planning to allow VERs and non-participating loads to submit schedules or bids for 15-minute intervals rather than hourly intervals. Should all resources be allowed to submit bids that can vary by 15-minute intervals to better model availability that may change within an hour? If the CAISO plans to treat VERs differently than other resources, the CAISO should provide a fixed definition of VERs (particularly whether or not it includes run-of-river hydro resources).
- With the change in granularity, the Day-Ahead Market would produce schedules that can vary from one 15-minute interval to another. When FRP is added in a later phase, FRU and FRD awards also could vary by 15-minute interval to meet changing ramp needs. Today, the bids in the Real-Time markets are hourly. As a consequence, the only way for a participant to provide the awards from the DA market on 15-minute intervals in the RT Markets would be to provide hourly bids that could reach the award, potentially exposing participants to additional costs or risks. CASIO should consider modifying the FMM and RTD markets to allow participants to submit bids and schedules on a 15-minute basis so that the participants can submit bids in RT that meet the DA awards. If CAISO does not make this change in the RT markets, could CAISO provide details on how resources could submit hourly bids in RT to meet 15-minute DA awards and discuss the likely effects on participants.
- The CAISO should consider allowing internal resources to provide bids that must be dispatched at a constant level over an hour through a legacy transition period. Participants may have contracts with supplies with provisions that prevent 15-minute day-ahead dispatch.
- How does the CAISO plans to incorporate or modify the existing Standard Ramping process to fit the new 15-minute award methodology? Also, please explain any differences if a resource uses the requested constant dispatch over an hour and whether changing from hourly dispatch to 15-minute dispatch in adjacent hours will affect the ramping process.
- The CAISO should provide more information on how the HASP reversal rule is affected by the change to 15-minute intervals in Day-Ahead.

[1] CAISO Day-Ahead Market Enhancements – Design Elements Matrix

- Discuss any changes that would be needed for bid cost recovery (BCR) for resource start-up, transition, and minimum load costs as well as details on whether and how BCR will be applied if a resource restricts its DA schedule to be constant over an hour.
- Provide the projected implementation timeline associated with this initiative. The timeline is important because significant IT planning and business process changes by CAISO as well as by participants will be needed to adapt to these changes.
- Provide information of the increase in time required to solve the day-ahead market to the same level of accuracy as now with four times as many intervals.

2. PG&E believes there are risks to moving too quickly in integrating IFM and RUC in a single process and in rolling out a new DA FRP. Instead, a phased approach would yield more benefits.

The Day-Ahead market settles more than 90% of all wholesale market transactions, so any change to the Day-Ahead market will have a significant impact on market participants. Trying to implement multiple changes simultaneously can easily lead to unforeseen complications for the ISO and for participants. Phasing the implementation allows the market and the CAISO to adjust to each new design element in isolation and assess the impact of each phase's change on market efficiency. This will also allow the CAISO to isolate and remedy any problems that arises during the implementation phase in a targeted manner.

3. PG&E believes the integration of IFM and RUC and the design of Day Ahead FRP requires further development.

Undertaking the creation of a Day Ahead FRP is a complicated and ambitious task as is integrating IFM and RUC. Despite the substantial work the CAISO has put into this effort, PG&E believes the integration of IFM and RUC and the development of the DA FRP require further refinement. PG&E would like to offer the CAISO the following comments to illustrate the additional details necessary for a successful rollout at a later stage. It would be beneficial to continue a stakeholder process for refining these design elements.

Issues Related to Integrating IFM and RUC

- The market optimization formulation outlined for integrating IFM and RUC does not appear to correctly model several aspects of system operations that are modeled in the current RUC. These should be investigated and corrected before proceeding with the integration of IFM and RUC.

  In PG&E's understanding, when RUC changes unit commitment it ensures that energy schedules from physical resources in IFM plus the dispatch of changed commitment in RUC will:

  - Satisfy the ISO's forecast of demand (RUC power balance)
  - Satisfy the transmission constraints

- Satisfy ramp limitations on physical resources from one period to the next (*i.e*. for a physical resource *i*)

  $$RampRate_{i,t-1}^{Down} \leq \left(Schedule_{i,t}^{IFM} + Additional\_Dispatch_{i,t}^{RUC}\right) - \left(Schedule_{i,t-1}^{IFM} + Additional\_Dispatch_{i,t-1}^{RUC}\right) \leq RampRate_{i,t-1}^{Up}.$$

Consider the modeling of transmission constraints in the RUC portion first. It is necessary to model the transmission constraints to ensure that the energy scheduled from physical resources in IFM and the change in dispatch on physical resources in RUC can be delivered to forecast demand. However, in the combined IFM and RUC described in the DAME straw proposal, only the transmission constraints on the IFM portion of the dispatch are described. The transmission constraints on the IFM schedules plus the change in dispatch by RUC do not seem to be modeled to ensure that capacity that is committed by the RUC portion of the model can be dispatched and delivered to the forecast demand. Also, forecast demand in the RUC portion only seems to be modeled on a system-wide basis and not by location which would be needed to model the effect of transmission constraints.

The ramp constraints also seem to be incorrectly modeled in the combined IFM/RUC formulation. (We will ignore the FRP portion for now to simplify.)

The ramp constraints on a physical resource seem to be modeled as:

$$RampRate_{i,t-1}^{Down} \leq \left(Schedule_{i,t}^{IFM} + Additional\_Dispatch_{i,t}^{RUC}\right) - Schedule_{i,t-1}^{IFM} \leq RampRate_{i,t-1}^{Up}$$

That is, it seems to require that there be sufficient ramp rate to move a physical resource's schedule from IFM in a period (ignoring any additional dispatch from RUC in that period) to its schedule from IFM in the next period plus the additional dispatch on the resource from RUC in the next period.

As PG&E understands, the current RUC models the dispatch of resources to meet forecast demand in each interval over the time horizon. In modeling ramp constraints, it models changes from the dispatch (IFM + RUC) in one interval to meet forecast demand in that interval to the dispatch (IFM + RUC) in the next interval to meet forecast demand in the next interval. The constraints in the combined IFM/RUC presented in DAME seem to model the ramp on physical resources from the IFM dispatch in one interval to meet cleared demand in the IFM portion to the dispatch (IFM + RUC) in the next interval to meet forecast RUC demand in the next interval.

This model does not recognize that if the RUC forecast materializes in subsequent markets, the ISO will redispatch while constraining ramp from the revised dispatch from one interval to the next. If the IFM clears less energy on physical resources than the demand forecast, the model in the combined IFM/RUC would overestimate the ramp up required from one interval to the next while underestimating the ramp down required. This could cause the price for ramp up to be inappropriately high (possibly even using the ramp shortage price while there was adequate ramp to meet system needs from one RUC dispatch to the next). It could also set the price for ramp down too low. If IFM clears more than the demand forecast, the situation could be reversed.

- The CAISO should work on the transmission constraints and ramp constraints in the combined IFM/RUC.
- The CAISO should provide some analysis to show the likely impact on prices of combining RUC and IFM as compared to prices with IFM only to address stakeholder concerns expressed in the meeting.
- CAISO should explain the market where commitment cost recovery will be assigned for start-up, transition, and minimum load costs for long start resources procured for FRP committed in the combined IFM/RUC, for short start resources procured in the combined IFM/RUC and committed in the RTM, and for short start resources procured in the combined IFM/RUC and not committed in the RTM.

Issues Related to FRP

- PG&E has questions regarding the approach that the ISO outlined for settling deviations between markets. The straw proposal states that the deviations between DA and FMM will be settled as[2]:

$$\left[\left(EN_{i,t}^{FMM} + FRU_{i,t}^{FMM}\right) - \left(EN_{i,t}^{DA} + IRU_{i,t}^{DA}\right)\right] \cdot \rho_t^{FMM}$$
$$\left[\left(EN_{i,t}^{FMM} + FRD_{i,t}^{FMM}\right) - \left(EN_{i,t}^{DA} + IRD_{i,t}^{DA}\right)\right] \cdot \sigma_t^{FMM}$$

  Similarly, the straw proposal states that the deviations between FMM and RTD will be settled as:

$$\left[\left(EN_{i,t}^{RTD} + FRU_{i,t}^{RTD}\right) - \left(EN_{i,t}^{FMM} + FRU_{i,t}^{FMM}\right)\right] \cdot \rho_t^{RTD}$$
$$\left[\left(EN_{i,t}^{RTD} + FRD_{i,t}^{RTD}\right) - \left(EN_{i,t}^{FMM} + FRD_{i,t}^{FMM}\right)\right] \cdot \sigma_t^{RTD}$$

  This is not consistent with the way that deviations between FMM and RTD are settled today since ramp from Forecast Movement is settled as well as ramp procured for uncertainty. The straw proposal contends that the formulas essentially fold the Forecasted Movement Settlement into the FRU/FRD award settlement. PG&E believes that this is incorrect. An example that demonstrates the problem with these settlements formulas is provided in an appendix that follows this document. PG&E requests that CAISO provide the derivations of the proposed settlements formulas.

- The CAISO should provide details on how they propose to set zonal Imbalance Reserve Requirements (Flexible Ramp Product requirements). The CAISO should provide more detail

[2] We will use $IRU_{i,t}^{DA}$ to represent ramp up capability for uncertainty purchased in DA rather than $FRU_{i,t}^{DA}$ to be consistent with the notation in the straw proposal even though CAISO indicated that it plans to change notation. Similarly, we will use $IRUD_{i,t}^{DA}$ to represent ramp down capability for uncertainty purchased in DA rather than $FRD_{i,t}^{DA}$.

on how they plan to ensure that FRP procured can be delivered to meet zonal requirements without overly restricting the procurement of FRU and FRD. Finally, the CAIISO should explain how they will use a system-wide demand curve in procuring FRP to meet zonal requirements.

- The CAIISO should explain how it plans to use the existing ancillary service zones for procuring FRP to meet sub-regional requirements. The CAISO should also explain how it plans to prevent stranded FRP capacity due to limited transmission availability.
- When developing FRP at a later stage, CAISO should give more detail on the characteristics a resource must have to allow it to be committed to provide FRP and the characteristics the resource must have to provide FRP without commitment in the IFM/RUC. Similarly, CAISO should clarify the conditions under which a resource that is on-line can be de-committed to provide FRD in the combined Day-Ahead IFM/RUC.
- Can the CAISO better explain the interaction between flexible RA products compensation vs. imbalance reserve award compensation?
- Can the CAISO further clarify the settlement implications of how physical and virtual bids on the same node can be modeled differently in the CAISO's DAME optimization?

4. PG&E also offers the following general comments that is relevant to all phases of this initiative.

- Can the ISO explain when the no pay provision is triggered?
- Can the CAISO further describe the applicably of no pay provisions and other potential penalties necessary to ensure performance?
- Can the CAISO utilize numerous scenarios for testing to ensure that the entire range of potential market outcomes are thoroughly addressed? For example, the DA Flexible Ramping Product requires scenarios that consider the impact of self-schedules, imports, changes in commitment, and biddable variable energy resources (VER) to product requirements.
- CAISO should continue to provide updates of the market optimization formulation in a timely manner throughout this process and to conduct full testing and evaluation of the formulation on market awards, market prices, and settlements before proceeding to implementation.
- CAISO should ensure that an appropriate implementation timeline is adopted to perform end-to-end testing of the market enhancements.

Appendix: Issue with Settlements Formulas for Deviations

To demonstrate the issue with the settlements formulas presented in the straw proposal, we consider an example in which we settle deviations between FMM and RTD. To illustrate the issue as simply as possible, we assume that the schedules in FMM for energy, FRU and FRD are all zero. This simplifies the settlement of deviations from FMM to RTD to simply settling energy and ramp in RTD. This avoids any possible confusion related to assigning FMM energy and ramp to intervals in RTD since those are not the areas we wish to explore.

In the RTD market as defined today, the ISO would pay a resource:

- the RTD power balance shadow price times its RTD energy scheduled in the binding interval
- the sum of the RTD shadow price for ramp up requirement constraint plus the RTD shadow price for ramp down requirement constraint times its movement from its RTD energy schedule in the binding interval to its RTD forecast energy schedule in the first advisory interval
- the RTD shadow price for the ramp up requirement constraint times its RTD Flexible Ramp Up capacity to cover upward uncertainty in the first advisory interval
- the RTD shadow price for ramp down requirement constraint times its RTD Flexible Ramp Down to cover downward uncertainty in the first advisory interval.

We consider a simple problem with two five-minute periods (t_1 and t_2), one non-dispatchable generator (G_1), and two dispatchable generators (G_2 and G_3).

Offer Data for Dispatchable Generators

Generator	Minimum (MW)	Maximum (MW)	Cost ($/MWh)	Max Ramp Up in 5 min (MW)	Min Ramp Down in 5 min (MW)	Initial Schedule at t_0 (MW)
G_2	0	190	40	10	-10	170
G_3	0	40	35	40	-40	0

Schedules for Demand and Non-Dispatchable Generator

	Schedule in Period t_1 (MW)	Schedule in Period t_2 (MW)
Demand (D)	185	270
G_1	0	50

Flexible Ramp Requirement from t1 to t2

EU (MW)	ED (MW)	Cost for Shortage of Up Ramp ($/MWh)	Cost for Shortage of Down Ramp ($/MWh)
9	-10	50	-50

Optimal Dispatch

	Dispatch in Period t_1 (MW)	Dispatch in Period t_2 (MW)
G_2	179	180
G_3	6	40

Flexible Ramp Capacity from Dispatchable Generators from t1 to t2

Generator	Flexible Ramp Up (MW)	Flexible Ramp Down (MW)
G_2	9	0
G_3	0	-10
Total	9	-10

Shadow Price in $/MWh Using Original Formulation of SCED

	Period t_1	Period t_2
Power Balance	40	40
Ramp Up Constraint	5	-
Ramp Down Constraint	0	-

In RTD, the ISO settles the energy schedules in the binding interval only and the ramping from the binding interval to the first advisory interval.

In the binding period, t_1, the market would pay

- $40/MWh for energy scheduled in t_1
- $5/MWh for ramp up provided by the change in schedule from period t_1 to period t_2 or (energy scheduled in t_2 - energy scheduled in t_1)
- $0/MWh for ramp down provided by the change in schedule from period t_1 to period t_2 or (energy scheduled in t_2 - energy scheduled in t_1)

In settling dispatchable resources in period t_1 the market would also pay the generators for flexible ramp up and flexible ramp down (which is defined as incremental ramp up and down beyond ramp from schedule change in the Business Requirements Specifications document for FRP), FRU and FRD provided are settled at the shadow price of the relevant ramp requirement constraint:

- $5/MWh for flexible ramp up
- $0/MWh for flexible ramp down

Settling non-dispatchable generator G_1 in period t_1 the market would pay:

- $40/MWh * 0MWh / 12 = $0 for energy
- $5/MWh * (50MWh – 0MWh)/12 = $20.83 for ramp up
- $0/MWh * (50MWh – 0MWh)/12 = $0 for ramp down

Settling dispatchable generator G_2 in period t_1 the market would pay:

- $40/MWh * 179MWh / 12 = $596.67 for energy
- ($5/MWh * (180MWh – 179MWh) + $5/MWh * 9MWh) /12 = $4.17 for ramp up
- ($0/MWh * (180MWh – 179MWh) + $0/MWh * 0MWh) /12 = $0 for ramp down

Settling dispatchable generator G3 the market would pay:

- $40/MWh * 6MWh / 12 = $20 for energy
- ($5/MWh * (40MWh – 6MWh) + $5/MWh * 0MWh) /12 = $14.17 for ramp up
- ($0/MWh * (40MWh – 6MWh) + $0/MWh * (-10MWh)) /12 = $0 for ramp down

The total payments to the generators for the binding interval are:

- G_1 paid $20.83
- G_2 paid $600.84
- G_3 paid $34.17

The settlement formulas in the straw proposal for DAME produce incorrect payments. In the binding period, t_1, the market would pay

- $40/MWh for energy scheduled in t_1
- $5/MWh for ramp up provided by the energy schedule in period t_2
- $0/MWh for ramp down provided by the energy schedule in period t_2

In settling dispatchable resources in period t_1 the market would also pay the generators for flexible ramp up and flexible ramp down at the shadow price of the relevant ramp requirement constraint:

- $5/MWh for flexible ramp up
- $0/MWh for flexible ramp down

Settling non-dispatchable generator G_1 in period t_1 the market would pay:

- $40/MWh * 0MWh / 12 = $0 for energy
- $5/MWh * 50MWh/12 = $20.83 for ramp up
- $0/MWh * 50MWh/12 = $0 for ramp down

Settling dispatchable generator G_2 in period t_1 the market would pay:

- $40/MWh * 179MWh / 12 = $596.67 for energy
- ($5/MWh * 180MWh + $5/MWh * 9MWh) /12 = $78.75 for ramp up
- ($0/MWh * 180MWh + $0/MWh * 0MWh) /12 = $0 for ramp down

Settling dispatchable generator G_3 the market would pay:

- $40/MWh * 6MWh / 12 = $20 for energy
- ($5/MWh * 40MWh + $5/MWh * 0MWh) /12 = $16.67 for ramp up
- ($0/MWh * 40MWh + $0/MWh * (-10MWh)) /12 = $0 for ramp down

The total payments to the generators for the binding interval are:

- G_1 paid $20.83
- G_2 paid $675.42
- G_3 paid $36.67

The changed settlement formulas would overpay generators by $77.08. This approach over-compensates generators for the ramp provided by schedule changes from the binding interval to the first advisory interval.

For the settlement formulas in DAME to work, the FMM and RTD market optimizations would have to be reformulated. It is possible to reformulate the FMM and RTD market optimizations to produce the same primal solution (energy, FRU and FRD schedules) but different shadow prices. The power balance shadow price for the binding interval in the revised formulation would incorporate the shadow price of the ramp requirement constraints. Done properly, the settlements formulas in DAME would incorporate the forecast movement for physical resources. However, a different issue arises in that the power balance shadow price used to settle deviations from DA to FMM for energy schedules for physical resources would be different for that used to settle deviations from DA to FMM for energy schedules for virtual resources since the virtual resources provided no ramp capability in DAME. The details provided in the straw proposal are insufficient to determine whether the ISO plans such changes in the FMM and RTD markets.