Stakeholder Comments on
Generation Contingency and RAS Modeling
Revised Straw Proposal

Submitted by	Company	Date
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PG&E appreciates the opportunity to comment on the California ISO's (CAISO) Revised Straw Proposal on "Generator Contingency and RAS Modeling," dated March 15, 2017 and the discussion in the stakeholder web conference on March 22, 2017.

In response, PG&E has a number of questions and comments.

1. **CAISO should evaluate the potential cost savings that would be achieved by modeling generation contingencies and RAS in the market rather than using exceptional dispatch to treat them.**
   PG&E appreciates CAISO's goal of improving its ability to model the response of the system to generator contingencies and to the operation of Remedial Action Schemes so that it can reduce its need to use exceptional dispatch. This is a laudable goal. To better aid participants in evaluating the benefits to be derived from the proposed changes, PG&E requests that CAISO provide a quantitative evaluation of the potential cost savings that would result from modeling generator contingencies and RAS in the markets as opposed to using exceptional dispatch to address them.

2. **CAISO should track the effect on Real-Time Congestion Offset of the way that changes in commitment between Day-Ahead and real-Time affect the RAS model once the changes are implemented to ensure that the impact remains small**.
   PG&E would like to thank CAISO for analyzing the effect that changes in commitment between the Day-Ahead Market and the Real-Time Market would have had on Real-Time Congestion Offset as a result of its proposed method for modeling RAS in the markets over the past year. CAISO's analysis indicates that changes in commitment should not cause a material risk of underfunding in the Real-Time Market that would be handled via RTCO. This analysis addressed the concern that PG&E expressed in its last comments. However, going forward, participant behavior may change as a result of modeling generator contingencies and RAS in the markets. PG&E would ask that CAISO track the effect that changes in commitment between DA and RT have on RTCO after the changes are implemented to ensure that the impact on RTCO remains small.

3. **The Remedial Action Schemes that could be modeled in the market should be general enough to include dropping load or reconfiguring the transmission system by switching elements in addition to dropping generation.**
   The Remedial Action Schemes described in the draft proposal would drop specified generators in response to a transmission contingency. This may not cover all of the potential actions that a RAS could incorporate as a response to a transmission contingency. It is conceivable that a RAS would also include dropping specified loads or switching transmission elements to reconfigure the system. The framework for RAS that CAISO proposes should be general enough to handle such responses in addition to dropping specified generators.

Modeling Remedial Action Schemes and Generator Contingencies in the CRR allocation and auction will be a challenge since both model anticipated changes in generation after a contingency to keep post-contingency flows on transmission within emergency limits. The market can model the impact of a RAS or a Generator Contingency on post-contingency flows and congestion since the market explicitly models generation and load. The CRR allocation and auction do not model generation and load so the CRR allocation and auction cannot model the impact of Remedial Action Schemes and Generator Contingencies directly. PG&E appreciates CAISO outlining three approaches to address this problem. However, evaluating the impact of the approaches presented in the draft proposal on the CRR process and on CRR revenue adequacy is a complex problem. The stakeholders should be given additional time to consider the approaches outlined as well as to identify alternatives that may be better. PG&E also has some specific comments and questions regarding the three approaches outlined in the draft proposal.

4. **CAISO should elaborate on the method for calculating the Generation Distribution Factors (GDFs) in the first approach.**
   In the first approach CAISO, proposes to use historic data to calculate GDFs that it would use when modeling (a) dropping injection and withdrawal used to model CRRs at a node whose generation would be cut in a RAS or Generator Contingency, and (b) moving the injection and withdrawal to other nodes. An approach along these lines may be viable but changes would likely be needed.
   - The approach for calculating GDFs to use in the CRR processes as outlined in the draft proposal and as corrected in the stakeholder presentation is not consistent with the approach used to calculate GDFs in the Day-Ahead market. The market assumes that generation dropped by a RAS or in a Generator Contingency will be spread to frequency responsive generators in proportion to their committed capacity. That is, generation dropped at o_g, will be allocated to the set of frequency responsive generators G^F using GDFs defined as:

$$GDF_{o_g,j} = \begin{cases} -1 \; if \; j = o_g \\ \dfrac{\delta_j \cdot G_j^{MAX}}{\sum_{\substack{i \in G^F \\ i \neq o_g}} \delta_i \cdot G_i^{MAX}} \; if \; j \neq o_g \; and \; j \in G^F \\ where \; \delta_i = \begin{cases} 0 \; if \; generator \; i \; is \; not \; committed \\ 1 \; if \; generator \; i \; is \; committed \end{cases} \end{cases}$$

However, the CRR process as described will base the GDFs on historical dispatch of the generators during a season (or month) and time period of interest:

$$GDF_{o_g,j} = \begin{cases} -1 \; if \; j = o_g \\ \dfrac{G_{season,month,time,j}^{output}}{\sum_{\substack{i \in G^F \\ i \neq o_g}} G_{season,month,time,i}^{output}} \; if \; j \neq o_g \; and \; j \in G^F \end{cases}$$

To maintain consistency between the Day-Ahead Market and the CRR processes, the historic GDFs used in the CRR processes should be based on committed capacity.

- Consider one possible way to modify the formula to work with committed capacity.

$$Let \; H \; be \; the \; set \; of \; hours \; in \; the \; season \; (or \; month) \; in \; the \; time \; period \; of \; interest \; (e.g. peak \; or \; off-peak)$$

One possible modification of the above formula to use committed capacity rather than dispatch would be:

$$GDF_{o_g,j} = \begin{cases} -1 \; if \; j = o_g \\ \dfrac{\sum_{t \in H} \delta_{j,t} \cdot G_{j,t}^{MAX}}{\sum_{\substack{i \in G^F \\ i \neq o_g}} \sum_{t \in H} \delta_{i,t} \cdot G_{i,t}^{MAX}} \; if \; j \neq o_g \; and \; j \in G^F \\ where \; \delta_{i,t} = \begin{cases} 0 \; if \; generator \; i \; is \; not \; committed \; in \; hour \; t \\ 1 \; if \; generator \; i \; is \; committed \; in \; hour \; t \end{cases} \end{cases}$$

Using this formula, the GDFs calculated for use in the CRR process may not reflect how the dropped generation would be picked up “on average” in the Day-Ahead Market.

Consider a simple example with two hours in the season of interest and three frequency responsive generators (not including the generator which would be dropped in a RAS or Generator Contingency). Assume that the capacity committed on these generators in each hour is given in the following table.

hour	Committed Capacity G_1	Committed Capacity G_2	Committed Capacity G_3
1	100	100	0
2	100	0	400

Using the above formula, the GDFs calculated for use in the CRR processes would be:

GDF G_1	GDF G_2	GDF G_3
0.286	0.143	0.571

This differs from the average of the GDFs used in the two hours of the Day-Ahead Market of interest. The GDFs in each hour of interest in the Day-Ahead Market are given in the following table.

hour	GDF G_1	GDF G_2	GDF G_3
1	0.5	0.5	0
2	0.2	0	0.8

Taking the average of the hourly GDFs from the Day-Ahead Market would give the average response of the generators in the Day-Ahead to the RAS or Generator Contingency.

GDF G_1	GDF G_2	GDF G_3
0.35	0.25	0.4

This differs from the values calculated using the above formula. Rather, the average could be calculated using:

$$GDF_{o_g,j} = \begin{cases} -1 \; if \; j = o_g \\ \left(\frac{1}{N}\right) \cdot \sum_{t \in H} \left(\frac{\delta_{j,t} \cdot G_{j,t}^{MAX}}{\sum_{\substack{i \in G^F \\ i \neq o_g}} \delta_{i,t} \cdot G_{i,t}^{MAX}} \right) if \; j \neq o_g \; and \; j \in G^F \\ where \; \delta_{i,t} = \begin{cases} 0 \; if \; generator \; i \; is \; not \; committed \; in \; hour \; t \\ 1 \; if \; generator \; i \; is \; committed \; in \; hour \; t \end{cases} \\ and \; N \; is \; the \; number \; of \; hours \; in \; H \end{cases}$$

PG&E requests that CAISO investigate methods for calculating GDFs for use in the CRR processes and recommend the approach that would be most appropriate.

- Once a method for calculating an average GDF for use in CRR processes is selected, CAISO should study whether the resulting GDFs adequately capture the likely way in which the Day-Ahead Market models the response of the system to generation dropped by a RAS or in a Generator Contingency. Data on variations in the nodal GDFs from hour-to hour in the Day-Ahead may aid participants in assessing whether the average GDFs calculated for the CRR processes will adequately model RAS and Generator Contingencies in the CRR processes. PG&E requests that CAISO investigate this.

5. **The last two proposals for treating RAS and Generator Contingency effects in CRR processes may give some participants and unfair advantage over other participants.** The last two methods for modeling the effects of RAS and Generator Contingencies on CRRs would withhold capacity from the CRR auction or allocation to reduce the possibility of their providing CRRs that would be underfunded. One approach would use historical studies to determine the amount of capacity to withhold so that any CRRs allocated or sold would not be given a right to congestion rents that are not collected in the Day-Ahead Market. The other would achieve the same effect by using the global scaling factor.

   Such an approach could give a CRR that is sourced at a node whose generation would be dropped by RAS in a transmission contingency or by a Generator Contingency preferential access to the transmission capacity on lines that would be used when the dropped generation is picked up by the frequency responsive generation.

   Let's consider the first of the alternative methods. We will consider the example on slide 25 of the CAISO presentation and will only consider one contingency, an outage of Generator G1. In the example on slide 25 of the CAISO presentation, CAISO proposes not to model directly the effect of the Generator Contingency on G1 in the CRR auction or allocation. Instead, it proposes to withhold 1414 MW of transmission capacity from B to A based on historic dispatch in the Day-Ahead Market to ensure that the CRRs allocated would likely be revenue adequate when the Generator Contingency on G1 is modeled in the Day-Ahead Market.

Suppose that there were two participants in the CRR allocation process: Participant X requests 1500 MW of CRRs from G1 to L1 and Participant Y requests 1500 MW of CRRs from G3 to L1. CAISO proposes to withhold 1414 MW of transmission capacity on the lines from B to A leaving only 86 MW available. Since the Generator Contingency on G1 is not modeled in the CRR process, the CRRs requested by Participant X would not use any transmission capacity on the lines from B to A. Participant X would get all 1500 MW of CRRs that it requested from G1 to L1. The CRRs requested by Participant Y use transmission capacity on the lines from B to A. Since there is only 86 MW of transmission capacity available after CAISO withholds 1414 MW of transmission capacity from B to A, Participant Y would only be allocated 86 MW of CRRs from G3 to L1.

If the Generator Contingency on G1 were modeled in the CRR allocation process using the average GDFs from the Day-Ahead Market, we would find that the CRRs requested by both participants use the scarce transmission capacity from B to A. Using the GDFs from the CAISO example, a weighted-least-squares approach to allocating CRRs to the nominations would allocate 794.1 MW of CRRs from G1 to L1 to Participant X and 751.3 MW of CRRs from G3 to L1 to participant Y. The CRRs allocated to Participant X use 748.7 MW of capacity on the lines from A to B in the generator contingency and the CRRs allocated to Participant Y use 751.3 MW of transmission capacity from B to A. A fair allocation process should split the transmission between the participants rather than giving Participant X preferential access to the scarce transmission capacity.

The problem exists in a CRR auction as well. Suppose that Participant Y values the transmission capacity from B to A more highly than Participant X. Participant Y would not be able to procure more than 86 MW of CRRs from G3 to L1 no matter how high it bid for the CRRs while Participant X would be able to procure 1500 MW of CRRs fromG1 to L1 with a much lower bid. The proposed method tilts the playing field in favor of Participant X over Participant Y.

A similar problem exists in the other alternative proposal.

To ensure fairness, PG&E recommends that CAISO focus on developing a method that adequately models the Generator Contingencies and Remedial Action Schemes in the CRR allocation and auction.