Deliverability Assessment Methodology Revisions

Draft Final Proposal

October 30, 2019

Regional Transmission

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Deliverability Assessment Methodology Final Draft Proposal

1 Introduction

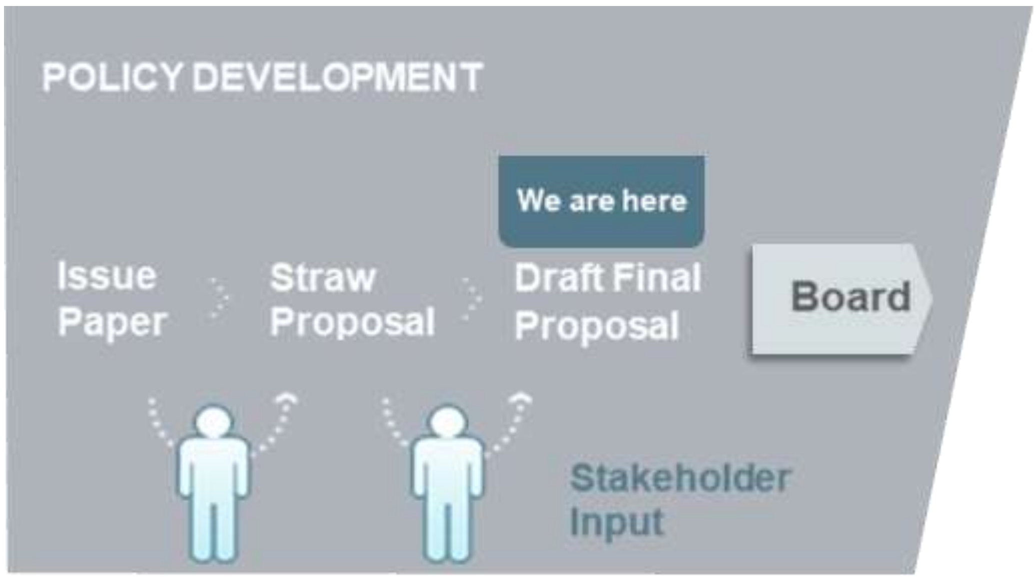
The deliverability assessment methodology is a CAISO methodology developed for generation interconnection study purposes pursuant to the CAISO tariff, and is used in support of resource adequacy assessments. The CAISO last modified the existing methodology in 2009, and it has largely remained unchanged since its initial development in 2004. Given the significant changes in the composition of the existing generation fleet and the further changes anticipated over the forecast horizon, the CAISO is considering revisions to the study assumptions used in the existing methodology.

The focus of these CAISO's deliverability assessment methodology considerations is to adapt the study assumptions in the On-Peak Deliverability Assessment methodology to changing system conditions that affect or drive when resource adequacy resources are needed the most. The CAISO initially proposed revisions in the course of its 2018-2019 transmission planning cycle, and based on stakeholder feedback, the CAISO has undertaken this separate stakeholder initiative to review the issue more comprehensively and address stakeholder concerns with the potential impacts of the proposed revisions.

2 Stakeholder Process

The CAISO first proposed possible revisions to the on-peak generation deliverability assessment methodology originally discussed in the 2018-2019 transmission planning process meeting on November 16, 2018. The CAISO then held a stakeholder call on December 18, 2018 to offer a more in-depth review of the proposed revisions. Stakeholders' written comments were generally supportive of the proposed changes, but raised various concerns regarding impacts to other processes and existing generation and recommended that the CAISO take more time to address these concerns. The CAISO considered those comments and decided to reconsider the proposed revisions through a broader stakeholder initiative and to continue to apply the current methodology in studies required by the Generation Interconnection and Deliverability Allocation Procedures for Cluster 11 phase 2 and Cluster 12 phase 1 efforts. The CAISO posted an issue paper and started the stakeholder initiative on April 25. The first stakeholder call was held on May 2, 2019 to garner additional stakeholder input needed to develop a straw proposal that addresses the comments provided on the proposed on-peak generation deliverability methodology revisions. The CAISO reviewed comments to the issue paper and then developed the straw proposal on July 29. The second stakeholder meeting was held on August 5 that further clarified the on-peak deliverability methodology revision and introduced an off-peak deliverability methodology revision to address stakeholders' concerns. The CAISO reviewed the comments to the straw proposal and refined the straw proposal in a draft final proposal posted on September 27, 2019. A third stakeholder meeting was held on October 4, 2019 and the ISO has posted this Revised Draft Final Proposal. CAISO responses to comments from the October 4, 2019 meeting will be posted in a separate document along with the stakeholder comments.

Figure 1: Stakeholder Process for Deliverability Assessment Methodology



3 Background and Issues

In the Issue Paper the CAISO explained that the addition of large amounts of solar resources have resulted in reducing the resource adequacy value of these resources, and therefore the deliverability assessment methodology needs to be revised to reflect these changing system conditions. The Issue Paper notes that starting in 2018, the CPUC has replaced the exceedance based Qualifying Capacity (QC) calculation with an Effective Load Carrying Capability (ELCC) approach to account for the growth of intermittent resources. In response to this change, the CAISO began this initiative to revise the on-peak deliverability methodology assumptions. An objective of this initiative is to examine the impacts of load peak shifting and the factors underpinning the shift to ELCC-based QC calculations on the appropriateness of the current deliverability methodology. As noted previously, the ELCC methodology considers the potential contribution of the particular resources in supporting additional firm load while maintaining an overall probabilistically determined reliability level over a period of time, generally a year, so the transmission system reasonably also needs to be able to deliver that contribution over a broader range of times than a single peak load period. Regarding the load peak shifting to later in the day, the load shape seen from the transmission grid will continue to change as the behind-the-meter distributed generation grows significantly in the future. The load peak will continue to shift to a later hour in the day when the solar production has dropped and the load consumption is still high. As well, a certain amount of the solar resources can be needed for system resource adequacy during the peak gross consumption hour, which occurs earlier in the day when customers' gross consumption is at its highest, but sales have been reduced by behind-the-meter generation. However, the incremental reliability benefit to the peak gross consumption hour of adding more solar hits a saturation point after enough capacity is installed. Additional solar resources provide a much lower incremental reliability benefit to the system than the initial solar resources, because their output profile ceases to align with the need during the peak sale hour that has shifted from the gross consumption period to later in the day. As a result, the need for transmission upgrades identified under the peak gross consumption condition to support deliverability of additional solar resources becomes more of an economic or policy decision focused on reducing curtailment of solar resources due to transmission limitations than a reliability decision. In other words, there may be an economic or policy benefit derived from these transmission upgrades relieving curtailment, but there is less likely to be a substantial capacity benefit because there is more likely to be sufficient capacity during the peak gross consumption hour with very high solar production both behind the meter, and in other unconstrained areas. A separation of the transmission upgrades driven by resource adequacy need from those driven by economic or policy benefit is necessary. Transmission upgrades to deliver renewable energy reliably and economically is evaluated and approved through the CAISO transmission planning process. However, there is a concern with the TPP's ability to identify the upgrades timely enough for generation development, especially those depending on the exact point of interconnection of the future generations. Therefore, additional studies through the generation interconnection study could fill in the gap by identifying curtailment risk and tranmssion upgrades to reduce such risk at the early generation development stage.

4 Stakeholder Inputs

4.1 Study Assumptions and Network Upgrade Identification in On-Peak Deliverability Assessment

Stakeholder Input

Stakeholders generally support the proposed revisions to the on-peak deliverability methodology. However, several stakeholders still have questions on the study assumptions in the on-peak deliverability methodology. The questions are around why the wind and solar deliverability is not tested at the ELCC levels, why a 20% production exceedance level is used for the highest system need (HSN) assessment while a 50% exceedance level is used for the secondary system need (SSN) assessment, and what the study assumptions are for hybrid projects involving energy storage. Also, EDF Renewables, Nextera, and LSA proposed that Local Delivery Network Upgrades (DNUs) be triggered in the SSN assessment.

CAISO Response

The QC ELCC factor calculated by CPUC is a monthly number based on an hourly stochastic simulation of resource and load profiles. It represents the equivalent perfect capacity to provide the same reliability benefit. To achieve this equivalent capacity, the wind/solar must produce higher than the ELCC level in many hours to compensate for the other hours when the output is lower than the ELCC value. Therefore, the deliverability methodology uses two scenarios which are the HSN and SSN assessments to evaluate deliverability. The HSN represents the most important hours for resource adequacy purposes and reflects the reality that the solar resources contribute little to the system reliability during this period. The SSN represents the hours when solar resources contribute to the system reliability. As such, the study assumption for solar in the SSN assessment should be higher than the summer month ELCC factor. Comparing the study assumptions for solar in the SSN to the ELCC factor, the study amount for solar in SDG&E is lower than the July ELCC factor (Table 4.1). This is because ELCC factor is calculated for the entire CAISO, while the study assumptions are derived at a higher geographic granularity. To account for this technical difference, the CAISO has included in the straw proposal that the study amount shall not be lower than the average summer month ELCC factor, which is 40.2% in SDGE based on 2019 ELCC factor. The ELCC factors are anticipated to reduce in the future as more and more solar is installed. The 2020 ELCC factors are shown in the table below and are incrementally lower than the 2019 ELCC factors that are shown in the Deliverability Assessment Issue Paper. The study assumptions, on the other hand, are based on a subset of the output profiles of solar resources in a time window and remained relatively stable when comparing the 2018 data with the 2019 data. However, the CAISO will continue to monitor the ELCC values and the study assumptions and update the study assumptions through stakeholder consultations, as needed.

Table 4.1: On-Peak Solar Generation Assumption vs. CPUC ELCC Factors

ELCC for Solar PV and Solar Thermal		Study Assumptions for Solar PV and Solar Thermal in SSN		
Month	**CY 2020 Solar ELCC**		**Area**	**Study Amount**
1	4.0%	Issue Paper	SDG&E	35.9%
2	3.0%		SCE	42.7%
3	18.0%		PG&E	55.6%
4	15.0%			
5	16.0%	Straw Proposal	SDG&E	40.2%
6	31.0%		SCE	42.7%
7	39.0%		PG&E	55.6%
8	27.0%			
9	14.0%			
10	2.0%			
11	2.0%			
12	0.0%			

The CAISO proposed study assumptions reasonably ensure system reliability and account for saturation effect of incremental installed capacity. For the same reason, a lower output (50% exceedance level instead of 20% exceedance level) is used in the SSN assessment for solar and wind resources and only ADNUs are identified in the SSN assessment. In either the generation interconnection study or the TPP policy study, there is often a significant over-supply during the high load consumption hours. Therefore, generation from one or two small local pockets not being deliverable is less likely to affect the overall system reliability than generation not deliverable in a larger area. Therefore, the SSN assessment focuses only on the area constraints. The need for local transmission upgrades under a higher solar output assumption is more effectively addressed in the off-peak deliverability assessment.

The study assumptions for energy storage resources and hybrid resources were provided in the initial straw proposal and are reiterated below –

For energy storage generation, the Pmax is set to the 4-hour discharging capacity limited by the requested maximum output from the generator. For hybrid projects, the study amount for each technology is first calculated separately as above. Then the total study amount among all technologies is based on the sum of each technology, but then limited by the requested maximum output of the generation project.

4.2 Study Assumptions in Off-Peak Deliverability Assessment

Stakeholder Input

LSA asked for a definition of the off-peak hours that are studied in the off-peak deliverability assessment.

CAISO Response

The peak load levels are defined in the on-peak deliverability methodology as the 1 in 5 peak sale level and the 1 in 5 peak consumption level. However, these load levels can be considered to generally represent when load exceeds 90% of the peak load level, and the hours that occurs. In the context of this off-peak deliverability study methodology, all hours other than the peak hours are off-peak. It is an extensive window of time. Therefore, the off-peak assessment methodology does not focus on a particular time window. Instead, the assessment is established upon system conditions when the generation is likely to be curtailed due to transmission constraints, but there is also sufficient capacity in the system to substitute for the constrained capacity, without system oversupply. As explained in the straw proposal, the system condition selected for study in the off-peak deliverability methodology is 55% to 60% of the summer peak load and about 6000 MW import. This generally corresponds to spring afternoon or fall morning conditions.

4.3 Value and Impact of OPDS to Market Operation

Stakeholder Inputs

Avangrid Renewables, AWEA-California, First Solar stated that the value of OPDS is not clear. They pointed out that there currently isn't much curtailment of self-scheduling. AvanGrid Renewables, BAMx, EDF Renewables, Nextera, LSA, Intersect Power, SPower noted that OPDS scheduling priority is not understood and could create adverse incentives.

CAISO Response

Option 5 is constructed to provide an incentive for the interconnection customers to up-front fund the local inexpensive transmission upgrades. The OPDS scheduling priority is intended to encourage resources to develop in locations that do not trigger upgrades or trigger only low cost localized transmission upgrades. Conversely, it should discourage resources from developing in locations that trigger high cost transmission upgrades. Having the OPDS label as part of the framework is intended to maximize the incentive for generators to site in good locations from a transmission perspective and to minimize excessive curtailment risk. The OPDS scheduling priority together with reimbursable funding is a viable tool for the interconnection customer to proactively manage curtailment risk due to local transmission constraints. This is the intended value of Option 5. In addition, it provides valuable information for those reviewing the resource project for financing purposes. As pointed out by Avangrid, AWEA-California and other stakeholders, it is expected that "off-takers" will require OPDS.

The scheduling priority associated with OPDS also addresses the free-rider concern. This is accomplished by differentiating resources that select OPDS and potentially need to fund transmission upgrades from resources that do not select OPDS.

4.4 Scheduling Priority of FCDS Resources

Stakeholder Inputs

Avangrid and SPower objected to a proposal where OPDS resources would have a higher scheduling priority than FCDS resources.

CAISO Response

The CAISO proposes an alternative approach for implementing the scheduling priority. With this alternative, no new penalty prices are introduced, which eases the concerns on how the penalty prices would be set. The generators that are eligible for OPDS, but not selecting OPDS, will not be allowed to self-schedule in the day-ahead or real-time markets. In other words, they must submit economic bids in the day-ahead and real-time markets. The OPDS generators are allowed to self-schedule in either the day-ahead or real-time markets. The new generators that are not eligible for OPDS will be allowed to self-schedule based on selecting full capacity deliverability status. Relative to the approach described in the original straw proposal, this new alternative approach should result in fewer self-schedules and more economic bids for market efficiency. Currently, a resource, regardless of the technology type, can self schedule in the real-time market up to its day-ahead award; this feature will remain in place for all generators, regardless if they are OPDS or not.

4.5 Scheduling Priority under All Conditions

Stakeholder Inputs

Many stakeholders, including AvanGrid Renewables, BAMx, EDF Renewables, Nextera, LSA, Intersect Power, SPower, expressed concern that the scheduling priority associated with OPDS is applied under all conditions.

CAISO Response

The scheduling priority is to provide some incentive for the interconnection customers to select the OPDS option and if necessary, up-front fund inexpensive local transmission upgrades. As described in the response above, the scheduling priority associated with the OPDS label is to maximize the incentive for generators to site in good locations from a transmission perspective and to minimize excessive curtailment risk. Ideally, the generators will not trigger any transmission upgrades or at most only simple low cost transmission upgrades. The reward for siting their resource in a good location from a transmission perspective includes a scheduling priority regardless of whether transmission upgrades are triggered or not. It is not necessary and not feasible to associate the priority with a specific transmission constraint and a specific time period. First, if the local constraint identified in the off-peak deliverability study were not mitigated, then it would be expected to be binding before the system gets into oversupply conditions as well as during over-supply conditions, so the scheduling priority is aligned with the local constraint even during over-supply conditions. Secondly, accurate association of generation curtailment with a transmission upgrade is not feasible during the market runs, especially when there are multiple binding constraints.

4.6 Funding Off-Peak Deliverability Upgrades

Stakeholder Inputs

Some stakeholders, e.g. BAMx and SDGE, do not agree with full reimbursement of off peak transmission upgrades. They believe this would lead to upgrades that are not in the ratepayer's interest. BAMx stated that Option 5 is not needed because the TEAM is adequate and curtailment is not a issue.

CAISO Response

The straw proposal elaborated on the principles and objectives of the off-peak deliverability assessment. The cost being reimbursable is a strong incentive for the generators to elect OPDS and up-front fund inexpensive local upgrades. Such upgrades, due to low cost and only moving forward together with generation development, are expected to improve the market efficiency and benefit the ratepayers. Not identifying the need for these local upgrades could result in poor generation siting decisions from a transmission and ratepayer perspective. Procurement processes take into account the cost of identified upgrades in their selection process of renewable generation contracts, so the combined cost of the resource and the upgrades are considered and the transmission costs are only triggered if they are in the ratepayer's interest.

4.7 Transition into the Revised Methodology

Stakeholder Inputs

With the revised on-peak deliverability assessment assumptions, it is expected that more generation would be deliverable without further transmission upgrades. One benefit would be that more Transmission Plan Deliverability (TPD) allocation would become available. First Solar and LS Power proposed that EO (converted from FC due to not allocated TPD) should have a one-time opportunity to receive a TPD allocation ahead of other queue projects seeking TPD. First Solar, Golden State Clean Energy and LS Power also asked for a one-time option for EO to get OPDS.

CAISO Response

Please see section 6.2 for the CAISO's response to the comment regarding the incremental TPD created due to the on-peak deliverability assumption changes.

The CAISO agrees that resources have not had the opportunity to select the OPDS option, so a one-time opportunity should be provided for the EO generation projects to request OPDS in the next cluster window upon approval and implementation of the proposal. They will be studied together with that cluster window projects and share cost responsibility, as needed.

4.8 Implementation Details

Stakeholder Inputs

There are some comments regarding the interconnection procedure details. EDF-R, LSA and SPower raised the question that OPDS is selected before knowing the upgrade cost and there is no opportunity to de-select.

ISO response:

Additional implementation details have been added to the final proposal. Between Phase I and Phase II, the IC can de-select OPDS. After that, the IC could always request an MMA for changing from OPDS to non-OPDS.

5 Draft Final Proposal to Revise the Deliverability Assessment Methodology

The deliverability assessment will be a test under multiple system conditions: the highest system need scenario, the secondary system need scenario, and off- peak scenario.

The highest system need scenario and the secondary system need scenario assessments follow the current deliverability assessment procedure. The dispatch assumptions align with the particular load condition being studied. The two scenarios play a different role in determining the available transmission capability and the required delivery network upgrades.

The off-peak (*i.e.* non-summer peak) scenario is a supplemental study to determine the available transmission capability and the required delivery network upgrades needed to reduce the risk of excessive renewable curtailment. The study conditions in the off-peak scenario are in general not aligned with resource adequacy purposes. This straw proposal recommends the evaluation of the off-peak scenario and the assignment of local area, low cost upgrades to generation interconnection projects, as needed, to avoid excessive local curtailment, but relying on the transmission planning process to comprehensively identify transmission upgrades needed to address large area, high cost transmission constraints to avoid large area renewable curtailment.

5.1 Highest System Need Scenario

The highest system need (HSN) scenario represents when the capacity shortage is most likely to occur. In this scenario, the system reaches peak sale with low solar output. The highest system need hours are hours ending 18 to 22 in the summer months with an unloaded capacity margin less than 6% in the CAISO annual summer assessment or identified as loss of load hour in the CPUC ELCC study for wind and solar resources.

The CEC 1-in-5 peak sale forecast for each planning area is distributed to all the load buses in study.

The net scheduled imports at all branch groups as determined in the latest annual Maximum Import Capability (MIC) assessment set the imports in the study. Approved MIC expansions, if not yet implemented, are added to the import levels.

The study amount for each generator, the maximum output tested in the deliverability assessment, depends on the technology, the installed capacity and the Qualitying Capacity.

The intermittent resources are modeled based on the output profiles during the highest system need hours. A 20% exceedance production level for wind and solar resources during these hours sets the study amount tested in the deliverability assessment. The CAISO will review the latest available CPUC ELCC study data and CAISO annual summer assessment data to annually update the modeling assumptions, as needed.

The study amount for the non-intermittent resources are set to the highest summer month Qualifying Capacity in the last three years. For proposed new non-intermittent generators that do not have Qualifying Capacity value, the study amount is the capacity requesting full deliverability. For energy storage generation, the study amount is set to the 4-hour discharging capacity limited by the requested maximum output from the generator. For hybrid projects, the study amount for each technology is first calculated separately as above. Then the total study amount among all technologies is based on the sum of each technology, but limited by the requested maximum output of the generation project.

Table 5.1: Modeling Assumptions for Highest System Need Scenario

Selected Hours	HE18 ~ 22 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in CAISO summer assessment)
Load	1-in-5 peak sale forecast by CEC
Non-Intermittent Generators	Study amount set to highest summer month Qualifying Capacity in last three years
Intermittent Generators	Study amount set to 20% exceedance level during the selected hours
Import	MIC data with expansion approved in TPP

The deliverability assessment then follows the steps in the current methodology. Deliverability constraints are identified and delivery network upgrades are identified for each constraint. The delivery network upgrades are categorized as either LDNUs or ADNUs following the current study process.

5.2 Secondary System Need Scenario

The secondary system need (SSN) scenario represents when the capacity shortage risk will increase if the intermittent generation while producing at a significant output level is not deliverable. In this scenario, the system load is modeled to represent the peak consumption level and solar output is modeled at a significantly high output. The secondary system need hours are hours ending 15 to 17 in the summer months with an unloaded capacity margin less than 6% in the CAISO annual summer assessment or identified as loss of load hour in the CPUC ELCC study for wind and solar resources.

The hour with the highest total net imports among all secondary system need hours from the latest MIC assessment data is selected. Net scheduled imports for the hour set the imports in the study. Approved MIC expansions, if not yet implemented, are added to the import levels.

The intermittent resources are modeled based on the output profiles during the secondary system need hours. A 50% exceedance production level for wind and solar resources during the selected hours sets the study amount tested in the deliverability assessment. The CAISO will review the latest available CPUC ELCC study data and CAISO annual summer assessment data to annually update the modeling assumptions, as needed.

The study amount for the non-intermittent resources are set to the highest summer month Qualifying Capacity in the last three years. For proposed new non-intermittent generators that do not have Qualifying Capacity value, the study amount is the capacity requesting full deliverability. For energy storage generation, the Pmax is set to the 4-hour discharging capacity limited by the requested maximum output from the generator. For hybrid projects, the study amount for each technology is first calculated separately as above. Then the total study amount among all technologies is limited by the requested maximum output of the generation project.

Table 5.2: Modeling Assumptions for Secondary System Need Scenario

Select Hours	HE15 ~ 17 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in CAISO summer assessment)
Load	1-in-5 peak sale forecast by CEC adjusted to peak consumption hour
Non-Intermittent Generators	Study amount set to highest summer month Qualifying Capacity in last three years
Intermittent Generators	Study amount set to 50% exceedance level during the selected hours, but no lower than the average QC ELCC factor during the summer months
Import	Highest import schedules for the selected hours

The deliverability assessment then generally follows the steps in the current methodology. As the load is lower, it may not be feasible to dispatch all existing generators at 80% ~ 92% of the Pmax. The initial dispatch may be lowered to less than 80%, but not lower than the LCR requirement in each LCA.

5.3 Delivery Network Upgrades – Use of HSN and SSN Scenarios

Network upgrades are identified to mitigate all the deliverability constraints from both the primary and the secondary system need scenarios.

In the generation interconnection process,

- The highest system need scenario represents when a capacity shortage is most likely to occur. As a result, if the addition of a resource will cause a deliverability deficiency determined based on a deliverability test under the highest system need scenario, then the constraint will be classified as either a Local Deliverability Constraint or an Area Deliverability Constraint.

- The secondary system need scenario represents when the capacity shortage risk will increase if the intermittent generation while producing at a significant output level is not deliverable. If the addition of a resource will cause a deliverability deficiency determined based on a deliverability test under the secondary system need scenario, and is not identified in the highest system need scenario, then the constraint can be classified as an Area Deliverability Constraint following the classification guidelines in the BPM for the Generator Interconnection and Deliverability Allocation Procedures.

In the transmission planning process,

- Transmission upgrades identified under the highest system need scenario are approved as policy driven upgrades.
- Transmission upgrades identified under the secondary system need scenario need additional economic or reliability justification to be approved as policy driven or economic upgrades. The transmission planning process could make a determination that no upgrades are needed for the secondary system need deliverability constraint. If the transmission planning process decides not to pursue upgrades to support the deliverability test in the secondary system need scenario, generation up to the amount assessed for the renewable portfolio behind the associated deliverability constraints are deemed deliverable in the Transmission Plan Deliverability allocation and annual NQC determination.

5.4 Off-Peak Deliverability Assessment

Once the precise location and amounts of future resources are known, the most robust approach to approve transmission upgrades to deliver renewable energy reliably and economically is through the transmission planning process framework of reliability, economic and policy upgrades. However, there is a concern with the TPP's ability to identify the upgrades timely enough for generation development, especially those depending on the exact point of interconnection of the future generations. Therefore, a supplemental study that focuses on renewable energy delivery during hours outside of the summer peak load period would inform generators of their curtailment risk and how to reduce such risk at the early development stage. The generators would be given an opportunity to fund network upgrades. To enable this, the CAISO proposes revisions to the off-peak deliverability assessment around the following principles:

1. Identify transmission bottlenecks that would cause excessive renewable curtailment, but the study assumptions should focus on system conditions when oversupply is not likely.
2. Identify transmission upgrades for local constraints that tend to be less expensive. The need for such upgrades are highly dependent on the development of specific generation projects interconnecting in a small localized area. These local constraints are hit by a relatively high simultaneous output of local generation before the system-wide over supply situation occurs.
3. It is prudent to rely on the TPP framework to approve transmission upgrades for area constraints that tend to be expensive. For area constraints, the general placement of new renewable generation in the portfolio is sufficient to identify the need.

4. The curtailment risk is regardless of the generator's deliverability status, so this study should consider both full capacity and energy only generators.

The CAISO proposed five options to revise the off-peak deliverability study procedure in the straw proposal. After considering stakeholders' comments, the CAISO adopted Option 5 with an alternative implementation of scheduling priority. The key elements of the off-peak deliverability assessment revision include:

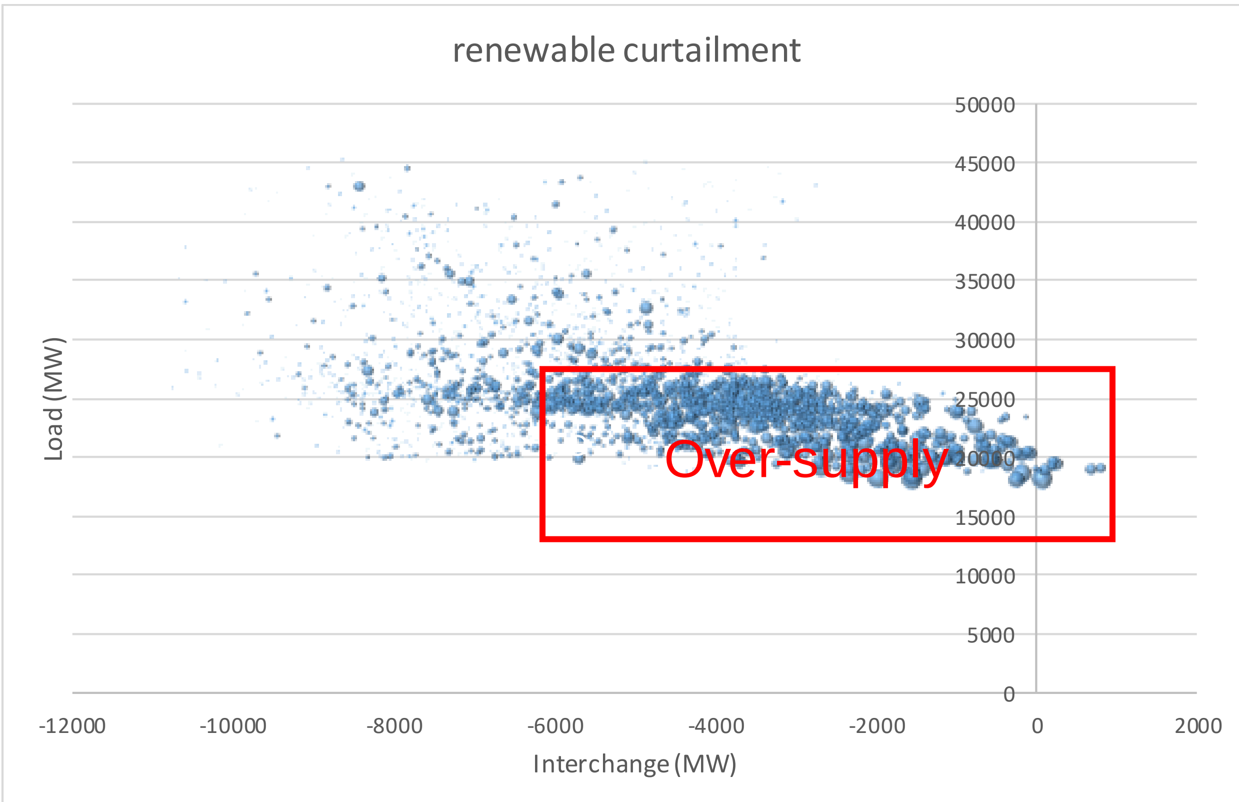
1. Update the off-peak deliverability methodology assumptions and include solar as a resource that primarily produces during the off-peak period.
2. Resources that primarily produce during the off-peak period would be eligible to select an Off-Peak Deliverability Status (OPDS).
3. Identify local and area off-peak deliverability constraints. Classification of the local vs. area contraints follows the same methodology as for the on-peak deliverability methodology.
4. Area constraints are for information only – provide conceptual upgrades and deliverable amount without upgrades.
5. Upgrades to mitigate local constraints are mandatory for the ICs that request OPDS to fund.
6. The local upgrades belong to their own cost category, not under the current cost responsibility and maximum cost responsibility for LDNUs and RNUs.
7. The upgrade costs would be fully reimbursed.
8. Require interconnection financial security posting for the upgrades.
9. The upgrade costs funded by the interconnection customer would be capped.
10. The upgrades could be identified, upsized or reconfigured in the TPP and the cost responsibility would be removed from the interconnection customers.
11. The following future generators could be self-scheduled in the market:
    a. OPDS generators
    b. FCDS/PCDS generators not eligble for OPDS
12. All existing generators could self-schedule in the market.

Details of the CAISO proposal are discussed below.

General System Conditions for the Off-Peak Deliverability Assessment

As renewable penetration increases, curtailments are expected to be more severe under lighter load conditions. Therefore, the off-peak condition would be studied to supplement the on-peak deliverability assessment. The objective of the off-peak deliverability assessment is to identify transmission upgrades needed to relieve excessive renewable curtailment caused by transmission constraints. The general system study conditions should capture a reasonable scenario of the load, generation, and imports that stress the transmission system, but not coinciding with an over-supply situation. The renewable curtailment data from 2018 was examined to establish this general system condition. Figure 2 shows an hourly renewable curtailment scatter plot with assocated load and import levels. The size of the bubbles in the figure are proportional to the MW being curtailed. The curtailments in the right lower corner of the scatter plot are most likely to be due to system-wide over-supply. The general system conditions to assess the off-peak transmission constraints are selected just outside the top left corner of the box in Figure 2 to stress the transmission system. The load is 55% to 60% of the summer peak load and the import is about 6000 MW.

Figure 2: Renewable Curtailment



The production of wind and solar resources under the selected system conditions varies widely. The production duration curves for solar and wind were examined. The production level under which 90% of the annual energy is produced set the outputs to be tested in the off-peak deliverability assessment. As seen in Figure 3 and Figure 4, the 90% energy levels are 68% of installed capacity for solar and 44% for wind.

Figure 3: Normalized CAISO Total Solar Output Duration Curve

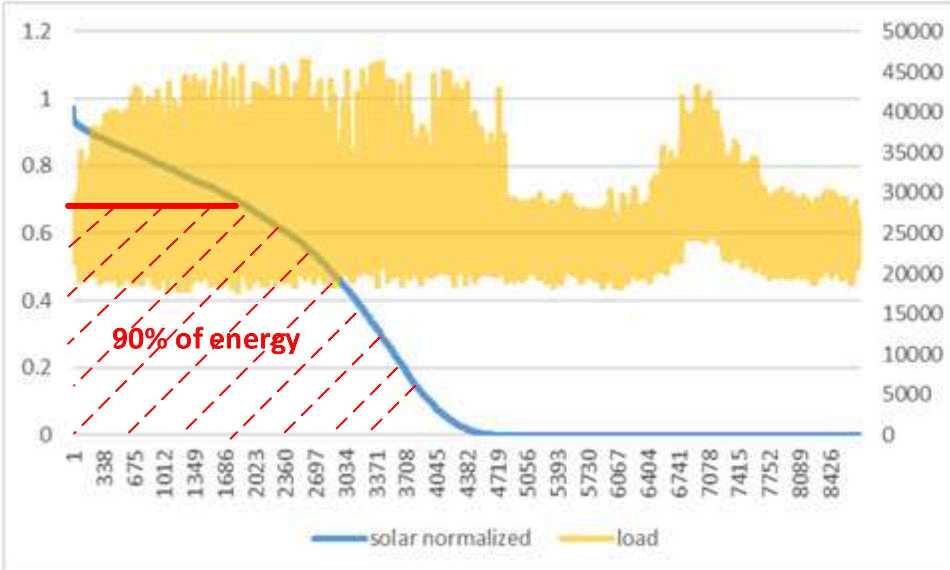
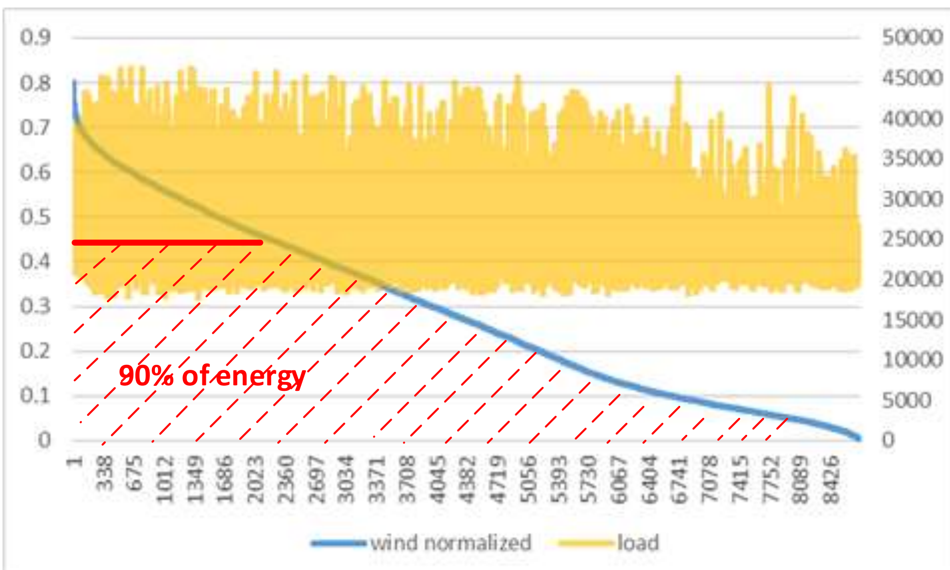


Figure 4: Normalized CAISO Total Wind Output Duration Curve



The dispatch of the remaining generation fleet is set by examining historical production associated with the selected renewable production levels. The hydro dispatch is about 30% of the installed capacity and the thermal dispatch is about 15%. All energy storage facilities are assumed offline.

The dispatch assumptions discussed above apply to both full capacity and energy-only resources. However, with the large amount generation in the interconnection study queue, it is impossible to balance load and resources under such conditions with all queued generation dispatched. The dispatch assumptions are applied to all existing generators first, then some future generators if needed to balance load and resources. This establishes a system-wide dispatch base case that is the starting case for developing each of the study area base cases that the off-peak deliverability assessments are based on. Table 5.3 summarizes the generation dispatch assumptions.

Table 5.3: CAISO System-Wide Generator Dispatch Assumptions

	Dispatch Level
wind	44%
solar	68%
Battery Storage	0
hydro	30%
thermal	15%

The off-peak deliverability assessment models all the approved transmission upgrades, as well as RNUs and LDNUs required under the on-peak deliverability assessment.

Off-Peak Deliverability Assessment Procedure

The off-peak deliverability assessment is performed for each study area separately. The study areas in general are the same as the reliability assessment areas in the generation interconnection studies. However, to avoid excessive generation being dispatch in one study area, one reliability assessment area may be broken into several smaller gen-pockets that separate wind/solar areas and align with TPP study areas. Below is the preliminary list of the study areas –

- PG&E north
- PG&E Fresno
- PG&E Kern
- SCE Northern
- SCE North of Lugo
- SCE/VEA/GWL East of Pisgah
- SCE/DCRT Eastern
- SDGE Inland
- SDGE East

Study area base cases are created from the system-wide dispatch base case. All generators in the study area, existing or new, are dispatched to a consistent output level. In order to capture local curtailment, the renewable dispatch is increased to the 90% energy level for the study area, which is higher than the system 90% energy level. The study area 90% energy level was determined from representing individual plants in different areas.

- If the renewables inside the study area are predominantly wind resources (more than 70% of total study area capacity), increase wind resource dispatch as shown in Table 5.4. All the solar resources in the wind pocket are dispatched at the system-wide level of 68%. If not a wind pocket, dispatch assumptions in Table 5.5 are used.

Table 5.4: Solar and Wind Dispatch Assumptions in Wind Area

	Wind Dispatch Level	Solar Dispatch Level
SDG&E	69%	68%
SCE	64%	
PG&E	63%	

Table 5.5: Solar and Wind Dispatch Assumptions in Solar Area

	Solar Dispatch Level	Wind Dispatch Level
SDG&E	79%	44%
SCE	77%	
PG&E	79%	

As the generation dispatch increases inside the study area, the following could be done to balance the load and resources:

- Reduce new generation outside the study area with a limitation of Path 26 4000 MW north to south or 3000 MW south to north.
- Reduce thermal generation inside the study area.
- Reduce import.
- Reduce thermal generation outside the study area.

A contingency analysis is performed for normal conditions and selected contingencies:

- Normal conditions (P0).
- Single contingency of transmission circuit (P1.2), transformer (P1.3), single pole of DC lines (P1.5) and two poles of PDCI if impacting the study area.
- Multiple contingency of two adjacent circuits on common structure (P7.1) and loss of a bipolar DC line (P7.2).
- Two adjacent transmission circuit according to WECC's Project Coordination, Path Rating and Progress Report Processes.

For overloads identified under such dispatch, resources that can be re-dispatched to relieve the overloads are analyzed first:

- Existing energy storage resources are dispatched to full four hour charging capacity to relieve the overload.
- Thermal generators contributing to the overloads are turned off.

- Imports contributing to the overloads are reduced to the level required to support out-of-state renewables in the RPS portfolios.

The remaining overloads after the re-dispatch will be mitigated by the identification of transmission upgrades. First, the overloads are identified as local constraints or area constraints. The CAISO will apply the same local vs. area constraint classification methodology as in the on-peak deliverability assessment. Then, the transmission upgrades to mitigate local constraints are labeled as off-peak local network upgrades and the transmission upgrades to mitigate area constraints are labeled as off-peak area network upgrades.

Off-Peak Network Upgrades (OPNU)

As the off-peak deliverability assessment is performed for generators regardless of their on-peak deliverability status to identify transmission contraints impacting renewable production, a new upgrade framework is needed to separate them from the Delivery Networ k Upgrades associated with the Full Capacity Deliverability Status.

Off-Peak Local Network Upgrades

The interconnection customers for wind and solar resources are provided an opportunity to fund off-peak local network upgrades in the generation interconnection process. The off-peak local network upgrades belong to a separate cost category from the Reliability Network Upgrades and Delivery Network Upgrades. Therefore, inclusion of the off-peak upgrades would not impact the cost responsibility and maximum cost responsibility for RNUs and DNUs.

The off-peak upgrades are assigned to the interconnection requests in the study cluster that have 5% or more contribution to the transmission constaint and elect OPDS. The cost is allocated among these interconnection requests in proportion to the flow impacts on the upgrade.

If the off-peak upgrades are identified, upsized or reconfigured in a subsequent TPP cycle, the network upgrade requirement and cost allocation will be removed from the interconnect customers' responsibility.

The off-peak upgrades identified for an early queue cluster may be needed to obtain FCDS/PCDS for the later clusters. In such case, the off-peak upgrades for the early cluster are Conditionally Assigned Network Upgrades (CANU) for the later clusters. Otherwise, the off-peak upgrades for the early cluster are conditionally assigned to later cluster as off-peak upgrades to be included in the cost cap for the OPNU.

The off-peak upgrade cost, including both triggered OPNU and conditionally assigne d OPNU, is capped by the lower of the allocated cost of network upgrades between the Phase I and the Phase II study. During the reassessment, the need for the OPNU is reassessed and the the cost is reallocated among the still active generation projects in the same cluster. The total reallocated OPNU cost does not exceed the maximum OPNU cost responsibility. The maximum OPNU cost responsibility is not modified by the reassessment.

Out of the total OPNU cost, the portion corresponding to the triggered OPNU is included in the overall network upgrade cost calculation for the interconnection financial security posting.

The off-peak upgrades costs assigned to the interconnection customers are reimburseable.

<u>Off-Peak Area Network Upgrades</u>

Off-peak area network upgrades are identified for information purpose only, same as the current off-peak deliverability assessment. The estimated scope and cost will be provided. In addition, information will be provided on how much renewable generation would need to be curtailed in order to mitigate the remaining overloads after the re-dispatch described above without the area network upgrades.

Off-Peak Deliverability Status (OPDS)

The off-peak deliverability status selection (OPDS/non-OPDS/NA) is made in the initial Interconnection Request. There isn't a selection for partial OPDS. OPNU cost responsibility is identified in the Phase I Interconnection Study. Between Phase I and Phase II interconnection studies, the IC may change from OPDS to non-OPDS within 10 business days from the Phase I interconnection study results meeting. At any other time, a change from OPDS to non-OPDS must be evaluated through a material modification analysis. A change from non-OPDS to OPDS is not allowed.

OPDS will provide a scheduling priority by continuing to allow self-scheduling upon commercial operation for new wind and solar resources that select OPDS. For new non wind and solar resources having FCDS will provide a scheduling priority by continuing to allow self-scheduling. OPDS is not applicable to any existing generators that are already operational before the proposed methodology becomes effective. Existing generators will continue to be allowed to self-schedule. New non wind and solar resources with Energy Only Deliverability Status and new wind and solar resources with non-OPDS will not be allowed to self schedule. Resources not allowed to self schedule cannot self-schedule in both the day-ahead and real-time markets. Tables showing which resources can self-schedule and which cannot are provided in Table 5.6 and Table 5.7. Currently, a resource can self schedule in the real-time market up to its day-ahead award; this feature will remain in place for all generators, regardless if they are OPDS, FCDS, or not.

Hybrid interconnection requests, if including solar or wind component, will elect OPDS in the same manner as a solar or wind interconnection request.

Table 5.6: Self-schedule for Wind/Solar Generation

	FCDS & PCDS		EO	
	OPDS	Non-OPDS	OPDS	Non-OPDS
Existing wind/solar generation	Self Scheduling Allowed (Grandfathered)		Self Scheduling Allowed (Grandfathered)	
New wind and solar in the queue prior to the OPDS implementation	Self Scheduling Allowed (OPDS selection assumed)		One-time chance to request OPDS	
			Self Scheduling Allowed	No-Self Scheduling
New wind and solar to the queue after the OPDS implementation	Self Scheduling Allowed	No-Self Scheduling	Self Scheduling Allowed	No-Self Scheduling

Table 5.7: Self-schedule for non-Wind/Solar Generation

	FCDS & PCDS	EO
	OPDS not applicable	
Existing non-wind/solar generation	Self Scheduling Allowed	
New non-wind/solar in the queue prior to the OPDS implementation	Self Scheduling Allowed	
New non-wind/solar generation after the OPDS implementation	Self Scheduling Allowed	No-Self Scheduling

A one-time opportunity will be provided for the EO generation projects currently in the queue to request OPDS in the next cluster window upon approval and implementation of the proposal. They will be studied together with that cluster window projects and share OPNU cost responsibility.

6 Transition into the Proposed Methodology

Assuming the proposed methodology is effective at the beginning of 2020, the one-time window for EO generation projects in the queue to request OPDS would be the Queue Cluster 13 window from April 1 to 15, 2020.

6.1 OPDS Selection for Queue Clusters 10 to 12

Wind and Solar projects in Queue Cluster 10, 11, 12 and Independent Study Process that initially requested FCDS or PCDS and have not been converted to EO, will be assumed to select OPDS.

6.2 One-Time TPD Allocation Process

The new deliverability assessment methodology will make a substantial amount of existing deliverability capacity available to interconnection customers. At the same time, the CAISO expects a generating capacity shortfall in the near future. This shortfall warrants expedited generation development to ensure the reliable operation of the CAISO controlled grid.

In light of these facts, the CAISO proposes to create a one-time TPD allocation process for the upcoming cycle. The one-time process will supplant all current rules regarding TPD allocation. The one-time process will end with this one cycle, and the CAISO will revert to the current tariff TPD allocation process thereafter.

The principle difference between the one-time process and the current process is that the one-time process will allow any interconnection customer with a completed Phase II study that is still an active project in the interconnection queue to seek deliverability by representing that it elects to proceed without a PPA, and will be subject to the restrictions described in Section 8.9.2.2 of Appendix DD going forward. Regardless of what queue cluster the interconnection customer is in, any interconnection customer selecting this option will be allocated TPD last, meaning that the previous allocation group three will now be allocation group seven, and groups previously four, five, six, and seven will move up. Allocation groups one and two are unchanged.

All interconnection customers currently designated Energy Only must submit a $60,000 study deposit to request a TPD allocation.

Only three sets of interconnection customers will be eligible to trigger the assignment and construction of new LDNUs: allocation group one, allocation group two, and interconnection customers electing to proceed without a PPA that currently have FCDS status (i.e., before this one-time TPD allocation process). Any interconnection customer that is currently designated Energy Only—regardless of what it previously requested—cannot require new LDNUs to achieve FCDS or PCDS. The one-time TPD allocation order will thus be:

(1) To Interconnection Customers in the current Queue Cluster or coming out of parking that have executed power purchase agreements, and to Interconnection Customers in the current Queue Cluster that are Load Serving Entities serving their own Load.

(2) To Interconnection Customers in the current Queue Cluster or coming out of parking that are actively negotiating a power purchase agreement or on an active short list to receive a power purchase agreement.

(3) To Interconnection Customers that have not achieved their Commercial Operation Date, originally requested Full Capacity Deliverability Status or Partial Capacity Deliverability

Status, and have executed power purchase agreements; and to Interconnection Customers that have achieved their Commercial Operation Date and have executed power purchase agreements.

(4) To Interconnection Customers that have not achieved their Commercial Operation Date, originally requested Full Capacity Deliverability Status or Partial Capacity Deliverability Status, and are actively negotiating a power purchase agreement or on an active short list to receive a power purchase agreement; and to Interconnection Customers that have achieved their Commercial Operation Date and are actively negotiating a power purchase agreement or on an active short list to receive a power purchase agreement.

(5) To Interconnection Customers that originally requested Full Capacity Deliverability Status or Partial Capacity Deliverability Status but achieved their Commercial Operation Date as Energy Only.

(6) To Interconnection Customers that achieved their Commercial Operation Date.

(7) To Interconnection Customers with a completed Phase II Interconnection Study electing to proceed without a power purchase agreement, subject to Section 8.9.2.2 of Appendix DD.

On their TPD affidavits, interconnection customers will be able to update their proposed CODs. Interconnection customers electing to update their CODs must submit a material modification assessment request and a $10,000 study deposit pursuant to Section 6.7.2 of Appendix DD. If they elect to proceed without a PPA, they will be ineligible to extend this COD after the one-time COD change (in addition to the other restrictions described in Section 8.9.2.2). The CAISO will evaluate COD extensions during the annual reassessment. Results may not be available until after TPD allocation results. If an interconnection customer fails the material modification assessment request—either because it cannot mitigate its impact or elects not to—the interconnection customer will lose its TPD allocation regardless of which TPD allocation group it selected. Interconnection customers whose COD modifications will move their CODs beyond (or further beyond) the seven or ten years in queue anticipated by the tariff will be subject to the commercial viability criteria described in Section 6.7.4 of Appendix DD (or applicable procedure).

If the CAISO does not have sufficient TPD to accommodate all interconnection customers in any particular group, it will allocate available TPD to the qualifying group based on highest numerical score. In addition to the three current scoring categories, the CAISO will include a fourth scoring category that allocates points by COD (earlier CODs receive more points). In the unanticipated event of point ties, the CAISO will use LDNU cost estimates as the tiebreaker, followed by an allocation using the weighted least square algorithm..

TPD affidavits are due December 3, 2019. Energy Only interconnection customers must also submit their $60,000 study deposits by then. Interconnection customers requesting to modify their CODs must submit their material modification requests and $10,000 deposits by then as well (in addition to their $60,000 deposit if they are Energy Only).

The CAISO recognizes that stakeholders have raised other issues with the CAISO's draft final proposal that these changes may not address. The CAISO has issued this revised draft final proposal to notify stakeholders of these substantial changes and solicit additional stakeholder feedback before presenting this proposal to the Board of Governors. The CAISO intends to continue to address stakeholders' concerns and clarify outstanding issues through the development of the draft tariff revisions and revised on-peak and off-peak deliverability assessment methodology papers the CAISO will include with its ultimate FERC filing.

7 Next Steps

In this final proposal the CAISO has summarized stakeholder's comments and completed the off-peak deliverability status proposal to address stakeholders' concern. The CAISO will hold the fourth stakeholder meeting on November 4, 2019 to review this revised draft final proposal and seek Board approval of the proposal in November.