Regional Resource Adequacy

Straw Proposal

February 24, 2016

Table of Contents

1. Executive Summary

On October 7, 2015, California Governor Jerry Brown approved Senate Bill No. 350 ("SB 350"), the Clean Energy and Pollution Reduction Act of 2015. The bill provides for the potential transformation of the California Independent System Operator Corporation ("ISO"), which already operates regional markets and provides interstate transmission service, into a more regional organization, with the approval of the Legislature pursuant to a specified process. As entities located outside of the ISO's current balancing authority area ("BAA") express interest in potentially joining the ISO, it will be necessary that the ISO's rules for resource adequacy ("RA") work effectively in a multi-state environment because RA is integral to reliably operating the electric power system. This straw proposal describes a framework for expanding the ISO while ensuring there are adequate resource capabilities to reliably operate the system. The ISO will continue to engage with stakeholders to develop the details of this RA framework, with this initiative culminating in a proposal that ISO management currently expects to present to the ISO's Board of Governors at the Board's June 28-29, 2016 meeting.

RA is a critical feature that allows the ISO to effectively serve load and reliably operate the electric system. RA serves to ensure that the ISO has sufficient resources offered into its markets to meet reliability needs and acts as an important market power mitigation measure to protect against physical withholding. The must-offer obligations of the RA program ensure that a sufficient pool of resources with the necessary attributes are available in the right locations and offered into the ISO market. Reliability is ensured through the RA forward planning and resource "showings" processes, which provide adequate resources to meet system, local and flexible operational needs. A multi-state ISO should provide lower procurement costs over time due to the synergies and geographic diversity obtained through a larger balancing authority footprint.

The primary objective of this initiative is to implement a multi-state process that ensures that sufficient capacity is offered into the ISO's market to serve load and reliably operate the electric system. The ISO proposes to build on existing, proven mechanisms to create a multi-state ISO. A key principle that will guide this effort is to develop an approach that will allow state regulatory commissions and load serving entities ("LSEs") to continue their existing procurement programs. This approach recognizes the states' traditional role with respect to RA, while ensuring a workable regional RA program that will effectively maintain reliability. The proposed framework provides the flexibility for LRAs and LSEs to maintain their current capacity procurement programs. The ISO will help to facilitate these programs by clearly communicating to state regulatory commissions, local regulatory authorities ("LRAs"), and LSEs the forecast regional balancing authority' reliability needs to inform capacity procurement decisions.

In this straw proposal, the ISO presents a high-level framework for discussion. The framework does not have all of the details spelled out at this time, as the framework is intended to be high level proposal that can be further refined as the stakeholder process moves forward. More detailed proposals will be presented to stakeholders by the ISO over the coming months, after discussion on the initial proposed concepts. The proposed framework includes the following elements: (1) The ISO provides an analysis of reliability needs and LSE allocations of those needs to state regulatory commissions, LRAs and LSEs well before the time when RA resources must be made available to the ISO market. (2) State regulatory commissions, LRAs and LSEs secure capacity using their preferred procurement process, such as integrated resource planning ("IRP") processes or the current RA program in California. (3) Through RA reports, LSEs "show" the ISO the RA capacity that has been secured. (4) The ISO performs a reliability assessment to ensure that the minimum system, local and flexible reliability needs of the BAA are met. (5) If the minimum reliability needs of the BAA are not met, the ISO notifies LSEs of the amount of additional capacity that is needed to cure the shortfall. (6) LSEs can cure the shortfall themselves. (7) In the event that LSEs do not choose to cure the shortfall, the ISO may then procure additional capacity to maintain reliability through the ISO's backstop authority.

The current RA program, which is based on a bilateral procurement framework overseen by the California Public Utilities Commission ("CPUC") and other LRAs, has worked well for the current BAA and has provided many benefits. The proposed RA framework will continue to rely on the RA programs and bilateral procurement processes overseen by state regulatory commissions and LRAs. The ISO only intends to change those tariff provisions that require modification to make RA work in the context of an expanded BAA that spans multiple states. This stakeholder initiative is focused on "need to have" items for an expanded BAA. The ISO does not intend for this initiative to explore broader changes to the general RA construct as the ISO regularly conducts stakeholder initiatives to consider improvements to the RA provisions of the ISO tariff and any such changes are more appropriately addressed in those initiatives. It is important that the provisions for a multi-state ISO be put in place through an order by the Federal Energy Regulatory Commission ("FERC") by the end of 2016, so that the regulatory approval process can begin by early 2017 for entities that may be interested in joining an expanded BAA.

Under the proposed framework, the ISO's RA provisions can be simplified as part of this effort. However, the ISO has identified the following six tariff provisions that will need to be either revised or added to implement the proposed multi-state RA framework:

1. *Load Forecasting* – The ISO proposes that the coincident system load forecast for an expanded BAA would be created each year by the ISO based on load forecast data created by and submitted by LSEs. The ISO is not proposing to change the manner in which load forecasts are developed for LSEs, and envisions that existing methods and arrangements would continue to be used. For example, the California Energy Commission ("CEC") would continue to determine the load forecast for LSEs in the existing ISO BAA and entities outside of the current BAA would create their own load forecasts and submit those forecasts to the ISO. The ISO would calculate the coincidence factor and determine the allocation of the coincident load to each LSE in the BAA.
2. *Maximum Import Capability* – The ISO proposes to revise the existing methodology used to calculate the Maximum Import Capability ("MIC") MW values to reflect the different peak time periods in which non-coincident peaking areas without commonly known constraints experience their own maximum simultaneous imports.
3. *Internal RA transfer capability constraints* – The ISO proposes to add maximum RA transfer limits between different areas of the expanded BAA to ensure reliable operation of the grid by limiting the transfers of RA resources between internal areas. The ISO will build on the methodology that is currently being used to address the "Path 26 transfer capability constraint."
4. *Allocating RA Requirements to LRAs/LSEs* – The ISO tariff currently requires the ISO to allocate local and flexible capacity requirements to LRAs. The ISO proposes to modify the tariff so that the ISO will directly submit to LRAs their allocation of local and flexible capacity requirements so that they can allocate such requirements to their jurisdictional LSEs. If an LRA does not want to receive the allocations, the ISO would allocate the requirements directly to the LSEs.
5. *Updating ISO Tariff Language to be More Generic* – The ISO proposes to make the ISO tariff language more generic to accommodate additional entities by using more universal language than the terms currently in use. The ISO will also specify the existence of multiple time zones in an expanded BAA. The intent of this item is to avoid creating any unintentional barriers or consequences associated with the California-centric language that is currently used.
6. *Reliability Assessment* – To ensure reliable operation of the BAA, each month the ISO will conduct a reliability assessment for the upcoming month using the information submitted by LSEs in RA showings and generators in supply plans. The assessment will consider system, local and flexible RA requirements and the RA capacity that has been provided to the ISO by LSEs for each RA requirement. To do the reliability assessment, the ISO proposes to use a system Planning Reserve Margin ("PRM") that would be established through a study conducted under a stakeholder process, with the study updated when significant changes occur to the ISO's BAA. The ISO would also develop consistent counting methodologies for the amount of MWs that each type of resource could qualify for, which would be used in the reliability assessment to assess how well the resources that are provided to the ISO

meet reliability needs. The reliability assessment will look at the total amount of RA resources provided and assess whether the RA capacity collectively provided is sufficient to meet reliability needs. LRAs and LSEs can establish their own PRM and resource counting rules; however, if different PRMs or counting rules are used there is a risk that minimum reliability needs may not be collectively met. The reliability assessment will mitigate the potential for inappropriate "leaning" on the RA requirements by individual LSEs. If the ISO identifies any shortfalls after considering all of the RA capacity provided, the ISO will provide LSEs an opportunity to cure the shortfall. If a shortfall still remains after the opportunity to cure has passed, the ISO would have the ability to procure backstop capacity if needed and allocate costs to LSEs that are short.

The ISO believes that a PRM and consistent counting methodologies, together with the RA and IRP frameworks already in place within each state, are the minimum provisions needed for the ISO to conduct a reliability assessment in order to ensure that adequate resources are available throughout the multi-state ISO for reliable operation of the system.

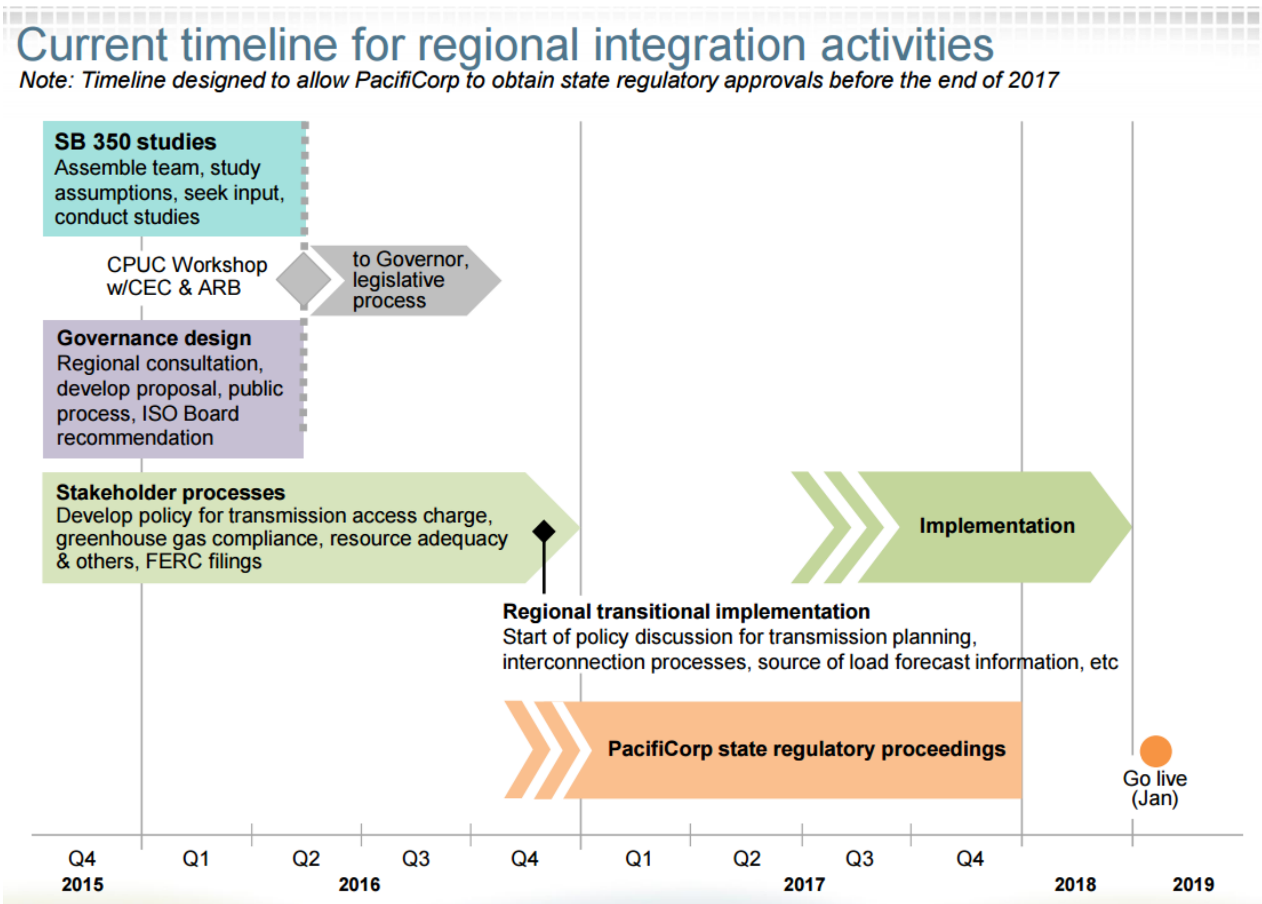
2. Stakeholder Comments on Issue Paper

The ISO has received written comments from stakeholders in response to the December 9, 2015 issue paper. Stakeholders provided numerous comments on the various topics covered in the issue paper, with comments on issues ranging from the initiative's scope, schedule, and principles, to more technical comments on RA methodologies and reliability requirements. For additional information on stakeholder's comments and the ISO's responses to those comments, please see Appendix 1, which contains a detailed description of the written stakeholder comments that have been received and the ISO's response to each comment.

3. Plan for Stakeholder Engagement

This initiative is one of several regional integration activities stakeholder initiatives that the ISO is conducted to provide for a multi-state ISO. Figure 1 below provides a high-level overview of the overall effort underway and timeline to address regional integration activities. As shown in Figure 1, this RA initiative is one of several initiatives that are targeted to be completed by the end of 2016 so that entities that are exploring joining a multi-state ISO can conduct their regulatory outreach during 2017, working toward a potential go-live date of 2019.

Figure 1 - Current Timeline for Regional Integration Activities



The diagram in Figure 1, and additional information on regional integration activities, are provided at the following link: http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx.

For this RA initiative, ISO management currently expects to present its proposal to the ISO Board of Governors at the Board's June 28-29, 2016 meeting. The current schedule for this initiative is shown below. Additional information on this initiative is available at the following website:
http://www.caiso.com/informed/Pages/StakeholderProcesses/RegionalResourceAdequacy.aspx.

Table 1 - Regional Resource Adequacy Stakeholder Process

Date	Milestone
Dec 9, 2015	Post issue paper
Dec 16	Stakeholder meeting on issue paper (Salt Lake City, UT)
Jan 7, 2016	Stakeholder comments due on issue paper
Jan 13	Working Group meeting (Seattle, WA)
Feb 23	Post straw proposal
Mar 2	Stakeholder meeting on straw proposal (Folsom, CA)
Mar 16	Stakeholder comments due on straw proposal
Apr 4	Post revised straw proposal
Apr 12	Stakeholder meeting on revised straw proposal (location TBD)
Apr 22	Stakeholder comments due on revised straw proposal
May 10	Post draft final proposal
May 19	Stakeholder meeting on draft final proposal (Folsom, CA)
May 31	Stakeholder comments due on draft final proposal
Jun 28-29	Present proposal to ISO Board of Governors

Stakeholders have commented that the schedule for this initiative is aggressive and have requested that the ISO allow more time for the stakeholder process. The ISO will evaluate the schedule following the March 2 stakeholder meeting and written stakeholder comments have been submitted on March 16.

4. Introduction

RA is a critical feature that ensures that the ISO can effectively serve load and reliably operate the electric system. RA serves to ensure that the ISO has sufficient resources offered into its markets to meet reliability needs and acts as an important market power mitigation measure to protect against physical withholding. The must-offer obligations of the RA program ensure that a sufficient pool of resources with the necessary attributes are available in the right locations and offered into the ISO market. Reliability is ensured through the RA forward planning and resource "showings" processes, which provide adequate resources to meet system, local and flexible operational needs.

Utilities throughout the west have well-established programs that ensure reliable electric service and the ability to meet load. These programs include the RA procurement programs within the current ISO footprint as well as IRP programs throughout the western states. A multi-state ISO will provide synergies and lower procurement costs through shared resources and the diversity of resources over a larger footprint. The ISO proposes to build on existing, proven mechanisms to create a multi-state ISO. Given that many essential elements for a multi-state ISO are already in place through the potential expanded footprint, minimal changes are required to the existing structures to develop a framework that works for a multi-state ISO.

It is envisioned that the roles of state regulatory commissions and LRAs would not change significantly under an RA paradigm. They would continue to direct long-term planning, direct procurement and approve rates. Under an RA paradigm, the obligations of new utility companies and LSEs would change in just two primary ways. First, they would have to submit RA showings of system, local and flexible capacity. Second, they would need to submit bids or schedules into the ISO market for the shown RA resources, where the ISO market would then optimize available resources for dispatch. The ISO would perform a check to ensure that the collective resources that are provided in RA showings and supply plans meet the operational needs of the ISO such that the ISO can reliably operate the grid and effectively serve load.

The goal of this initiative is to implement a multi-state process that ensures that sufficient capacity is offered into the ISO's market to meet reliability needs. The ISO proposes to continue to rely on an RA framework that relies on bilateral procurement by LSEs overseen by state regulatory commissions and LRAs. Under this framework, the ISO would only engage in backstop procurement in limited, specified circumstances to maintain reliability, and only as a last resort if LSEs have not cured shortfalls communicated to them by the ISO in advance. This framework has worked well to date and has allowed the ISO to maintain system reliability.

The ISO proposes the following three principles to guide this initiative.

1. Provide an approach that will allow state regulatory commissions and LSEs to continue their existing procurement programs.
2. Develop rules so that LSEs provide sufficient capacity to meet their share of the minimum forecast operating needs to avoid capacity leaning.
3. Provide incentives for LSEs to provide resource portfolios to the ISO that are aligned with the operational needs that have been clearly communicated to them by the ISO well in advance of the due date for RA showings and supply plans.

5. Straw Proposal

In this straw proposal, the ISO presents a high-level framework for discussion. The framework does not have all of the details spelled out at this time, as the framework is intended to be a high level proposal that can be further refined as the stakeholder process moves forward. More detailed proposals will be presented to stakeholders by the ISO over the coming months, after discussion on the initial proposed concepts. The proposed framework includes the seven elements listed below.

1. The ISO provides an analysis of reliability needs and allocations of those needs to state regulatory commissions, LRAs and LSEs well before the time when RA resources must be made available to the ISO market.
2. State regulatory commissions, LRAs and LSEs secure capacity using their preferred procurement process, which can include IRP processes.
3. Through RA reports, LSEs "show" to the ISO the RA capacity that has been secured.
4. The ISO performs a reliability assessment to ensure that the minimum reliability needs of the BAA are met.
5. If the minimum reliability needs of the BAA are not met, the ISO notifies LSEs of the amount of additional capacity that is needed to cure the shortfall.
6. LSEs can cure the shortfall themselves.
7. In the event that LSEs do not choose to cure the shortfall, the ISO may then procure additional capacity to maintain reliability through the ISO's backstop authority, but only as a last resort.

The current RA program, which is based on a bilateral procurement framework overseen by the CPUC and other LRAs, has worked well for the current BAA and has provided many benefits. The proposed RA framework will continue to rely on the RA programs and bilateral procurement processes overseen by state regulatory commissions and LRAs. The ISO only intends to change those tariff provisions that require modification to make RA work in the context of an expanded BAA that spans multiple states. This stakeholder initiative is focused on "need to have" items for an expanded BAA. The ISO does not intend for this initiative to explore broader changes to the general RA construct as the ISO regularly conducts stakeholder initiatives to consider improvements to the RA provisions of the ISO tariff and any such changes are more appropriately addressed in those initiatives. It is important that the provisions for a multi-state ISO be put in place through an order by the FERC by the end of 2016, so that regulatory outreach can occur by early 2017 by entities that may be interested in joining an expanded BAA.

The ISO has reviewed its RA tariff provisions and found that the majority of its current tariff provisions will continue to work well for a more regional ISO. The ISO also believes that the ISO's RA provisions can be simplified as part of this effort. The ISO has identified the following six tariff provisions that will need to be either revised or added to implement the proposed multi-state RA framework. These six items are discussed in detail in sections 5.1 through 5.6 below.

1. Load forecasting (section 5.1)
2. Maximum Import Capability (section 5.2)
3. Internal RA transfer capability constraints (section 5.3)
4. Allocating RA requirements to LRAs/LSEs (section 5.4)
5. Updating ISO Tariff language to be more generic (section 5.5)
6. Reliability Assessment (section 5.6)

The ISO believes that a PRM and consistent counting methodologies, together with the RA and IRP frameworks already in place within each state, are the minimum provisions needed for the ISO to conduct a reliability assessment in order to ensure that adequate resources are available throughout the multi-state ISO for reliable operation of the system.

5.1. Load Forecasting

Background

Part of the ISO's proposed framework includes revising the process for developing load forecasts that LSEs can utilize for RA. The ISO will need to develop a process to consolidate sources of load forecasting data to be able to discern peak load coincidence throughout an expanded footprint and allocate each LSE's portion of the coincident system forecast. The ISO will also need to be able to coordinate this load forecasting process with the load forecasts used for transmission planning and allocation of congestion revenue rights.

California's current RA program consists of one-year-ahead and one-month-ahead resource showings of each LSE's capacity to meet its expected load, plus a 15-17% PRM (this is the PRM requirement for CPUC jurisdictional entities). The ISO, CEC, CPUC and other LRAs, including publicly-owned/municipal utilities, work together under unified planning assumptions to preserve grid reliability and ensure adequate resources are available to satisfy demand. The CEC prepares independent load forecasts every year to determine LSE procurement requirements. This forecast spans 10 years and covers all load within California and the load of Valley Electric Association in Nevada.

The peak demand for each Transmission Access Charge ("TAC") area in the ISO is the non-coincident annual peak for that area. The peak demand forecast for the ISO is the result of multiplying a coincidence factor with the sum of the non-coincidence peaks in the TAC areas. Because each area may experience its peak demand on a different day or hour, the ISO annual peak will be less than the sum of the individual TAC area peak demands. The coincidence factor used in forecasts come from the historic coincidence patterns between TAC areas. The CEC determines the Coincidence Peak based on this data and analysis. 115% of the Coincidence Peak demand determines total RA system requirements, which are allocated to individual LSEs based on a *pro rata* load ratio share.

The CEC also assesses the reasonableness of demand forecasts by comparing LSEs' load forecasts to their historic load and recent monthly forecasts. The CEC may make monthly "plausibility" adjustments to LSE forecasts if the forecast diverges unreasonably from the LSE's actual peak loads or historical usage, taking into account load migration patterns.

Appendix 2 of this straw proposal provides additional detail on the CEC load forecast process.

Proposal

The ISO must balance the current California load forecasting process with the needs of a broader organization in which many potential new entities effectively conduct their own load forecasting. The ISO believes an approach that blends the ability of LRAs and LSEs to provide their own load forecasts, with aspects of the current load forecasting methodology in the current BAA, *i.e.*, calculating coincidence, will allow the ISO to develop accurate and transparent load forecasts for use in an expanded ISO BAA.

The ISO proposes that the coincident system load forecast for an expanded BAA would be created each year by the ISO based on load forecast data created by and submitted by LSEs. The ISO is not proposing to change the manner in which load forecasts are developed for LSEs, and envisions that existing methods and arrangements would continue to be used. For example, the CEC would continue to determine the load forecast for LSEs in the existing ISO BAA and entities outside of the current BAA would create their own load forecasts and submit those forecasts to the ISO. The ISO would calculate the coincidence factor and determine the allocation of the coincident load to each LSE in the BAA

All hourly load forecasts should include impact from Demand Response, Additional Achievable Energy Efficiency, and Distribution Generation. The ISO would then review LSE forecasts and make adjustments to submitted forecasts if an LSE forecast diverges unreasonably from the LSE's actual peak loads or historical usage and the LSE cannot demonstrate their forecast is reasonable. This is similar to current CEC practice where CEC staff determines whether an LSE's forecast is plausible (see Appendix 2). The ISO would then use all hourly load forecasting data sources to determine system coincidence peak and allocate their respective share of the system needs to each LSE.

The ISO must coordinate the proposed load forecasting approach with the development of load forecasts used for the ISO's Transmission Planning Process ("TPP") and Congestion Revenue Rights ("CRR") processes.

5.2. Maximum Import Capability

Background

The methodology for calculating the MIC values in an expanded BAA may need slight adjustment to properly reflect the maximum amount of imports that can be reliably depended on for RA. The ISO assesses the deliverability of imports using the MIC methodology. For most interties, the ISO calculates MIC megawatt amounts based on historical usage, looking at the maximum amount of simultaneous energy schedules into ISO BAA, at the ISO coincident peak system load hours over last two years. This historically-based MIC methodology establishes a baseline set of values for each intertie. Furthermore, the ISO performs a power flow study in the ISO's TPP to test these values ensure each intertie MIC can accommodate all state and federal policy goals; if any intertie is found deficient, the ISO establishes a forward looking MIC and plans the system is to accommodate this level of MIC in the TPP and RA.

The ISO examines the prior two years of historical import schedule data during high load periods. The sample hours are selected by choosing two hours in each year, and on different days within the same year, with the highest total import level when peak load was at least 90% of the annual system peak load. The ISO calculates the historically-based MIC values based on the scheduled net import values for each intertie, plus the unused Existing Transmission Contract ("ETC") rights and Transmission Ownership Rights ("TOR"), averaged over the four selected historical hours.

MIC values for each intertie are calculated annually for a one-year term and a 13-step process is used to allocate MIC to LSEs. MIC allocations are then made available to LSEs on each intertie for use in procuring RA capacity from external resources. MIC allocations are not assigned directly to external resources, rather LSEs choose the portfolio of imported resources they wish to elect for utilization of their MIC allocations.

Proposal

The ISO believes that the current MIC calculation and allocation methodology are still appropriate in most respects. However, the ISO has identified one minor change to the MIC methodology that is necessary to perform MIC calculations using non-simultaneous base case studies. This is appropriate to capture the benefits of regional diversity and allow for the calculation of truly maximum reliable MIC values when there are no simultaneous constraints between certain areas of an expanded ISO BAA and the areas peak at non-simultaneous times.

The ISO is assessing whether revisions to section 40.4.6.2 of the tariff are needed to facilitate this change. At this time, the ISO believes that the only change required is an edit to a note in the ISO Reliability Requirements Business Practice Manual ("BPM") on page 80: where it states: "The sample hours are selected by choosing two hours in each year, and on different days within the same year, with the highest total import level when peak load was at least 90% of the annual system peak load." The ISO proposes to change the above text so that it reads: "The sample hours are selected by choosing two hours in each year, and on different days within the same year, with the highest total import level when peak load was at least 90% of the annual peak load for each relevant simultaneously constrained part of the grid."

5.3. Internal RA Transfer Capability Constraints

Background

The ISO proposes to establish the concept of intra-BAA transfer capability constraints under the ISO tariff to ensure that any constraints that may potentially limit the transfers of RA resources between major internal areas in an expanded BAA are properly respected in the ISOs related processes. This concept is similar to the "Path 26 Counting Constraint" that is currently utilized by CPUC jurisdictional LSEs within the ISO BAA, which could also be described as a zonal RA transfer constraint methodology.

As part of Decision 07-06-029, the CPUC adopted the Path 26 Counting Constraint proposal. Similar to the ISO's Import Capability Allocation process under the ISO tariff Section 40.4.6.2.1, the Path 26 Counting Constraint proposal is a multi-step, iterative process to allocate Path 26 capability that will prevent over reliance by LSEs on the limited transfer capability across this transmission path when meeting RA requirements.

Proposal

The ISO proposes to add tariff and BPM language to determine and implement RA transfer limits between different areas of the BAA, thereby ensuring that any reliability constraints that limit the transfers of RA resources between major internal areas in an expanded BAA are properly respected. The ISO will build on methodology that is currently being used to address the Path 26 Counting Constraint.

The ISO proposes to identify major internal transfer constraints in an expanded BAA through the TPP process. The ISO will determine every year the capability in each direction for these internal constraints and then provide base line allocations to LSEs on each constrained transmission path based upon *pro rata* load ratio share at the ISO coincident peak. Part of this baseline allocation calculation is to protect entities existing ETCs, TORs and Pre-RA Commitments (contracts). The ISO will then allow for netting of RA contracts across each designated major constraint in order to increase the allocation amounts for LSEs willing to participate in this netting process. The LSEs participating in the netting process commit themselves to provide the same physical units, unit specific contracts, and import RA contracts as part of their year-ahead RA showings and their month-ahead RA showings. This also commits them to retain their import allocation for these specific import RA contracts. Once the ISO has calculated the netting a final allocation is calculated, based upon confidentially submitted contracts share of the netting benefit and allocates any additional capability to LSE proportional to their MW share of the submitted netting contracts.

This concept will be important in a multi-state ISO so that LRA and LSE procurement programs are able to consider and reflect these potential major internal RA transfer limits in their planning and procurement decisions.

The maximum megawatt amounts of intra-BAA RA transfer capability will be preserved in deliverability studies similar to how the Path 26 transfer constraint is accounted for today.

5.4. Allocation of RA Requirements to LRAs/LSEs

The ISO proposes to provide a process for LRAs to receive their allocation of local and flexible capacity requirements directly from the ISO so that they can allocate the requirements among their jurisdictional LSEs. Alternatively, if the LRA does not want to allocate these requirements to its LSEs, the ISO would allocate the requirements directly to the LSEs. This will allow LRAs to elect whether they want to work with the ISO to receive the allocation and then allocate requirements to their jurisdictional LSEs, or whether they would elect to have the ISO perform the allocations and deliver them directly to LSEs. This allows LRAs that do not wish to take on the role of receiving and allocating requirements to its LSEs to permit the ISO to deliver the allocations directly to LSEs.

5.5. Updating ISO Tariff Language to be More Generic

The ISO proposes to make the language in the ISO tariff more generic to accommodate additional entities by using more universal language than the terms currently in use. The ISO tariff contains numerous references to CPUC and non-CPUC jurisdictional entities, as well as references to the CPUC and LRAs. To transition to a multi-state ISO, the ISO will need to make the language in the ISO tariff more generic to accommodate additional regulatory authorities beyond the current CPUC and non-CPUC jurisdictional entities. The ISO will also need to amend the tariff to reflect the existence of multiple time zones in an expanded BAA. The intent of this item is to update the ISO tariff provisions to avoid creating any unintentional barriers or consequences associated with the California-specific language that is currently used throughout the tariff.

5.6. Reliability Assessment

Once the ISO communicates its operational and reliability needs to the responsible entities and they have provided the ISO with RA showings and supply plans, the ISO proposes to conduct a reliability assessment. A reliability assessment is necessary to ensure that LSE and LRA procurement programs have accounted for adequate resources to be committed to the ISO markets to allow the ISO to reliably operate the system. The assessment will mitigate the potential for undue "leaning" on the system by individual entities. To perform this assessment, the ISO requires three elements.

- A system PRM to evaluate total system-wide procurement levels;
- Consistent methods for assessing the capacity value that each resource type can provide towards meeting the ISOs reliability needs; and
- Revisions to the current backstop procurement authority and cost allocation tariff language that incorporate the reliability assessment.

These three elements and the ISO's proposal for each is discussed in greater detail through the remainder of this section.

Planning Reserve Margin for Reliability Assessment

The ISO must be able to assess the level of reliability on a comparable basis across the expanded BAA. Therefore, the ISO proposes to establish a system wide PRM to be used in the reliability assessment. This system wide PRM will not ascribe a fixed PRM to any individual LSE, but will be used to determine whether the sum of all LSE procurement is sufficient to ensure reliability. The ISO proposes to start the reliability assessment by determining a minimum PRM to which it can identify collective system-wide procurement of RA resources. The ISO will determine an appropriate system PRM and methodology through a study and an open and transparent stakeholder process. The ISO is only proposing a high-level framework at this time to obtain stakeholder input on the concept. The type of study, study process, inputs, assumptions, and conditions under which the study would be updated will be discussed in ISO proposals issued subsequent to this straw proposal. The ISO is interested in stakeholder input on what type of study might be done and how such a study would be developed. Regarding updates to the study, the ISO believes that it may not be necessary for the study to be updated every year, but rather only when significant changes to the system occur such as a major new participating transmission owner joins the BAA or the physical configuration of the grid and its resources dramatically change.

LRAs and LSEs can continue to establish their own PRM and procure to that level if they so choose for their planning purposes. However, there may be some risk that the ISO's reliability needs will not be met if entities employ PRMs that are significantly different than the PRM used by the ISO when the ISO conducts its monthly reliability assessment. The PRM that the ISO would establish is intended to inform parties of the ISO's reliability needs and help guide LRA/LSE procurement decisions.

Once the ISO establishes the PRM, the ISO would be able to evaluate the total system wide resources that have been procured and shown to the ISO to determine if adequate capacity has been secured to serve load and reliably operate the grid. The ISO would determine adequacy relative to the PRM using consistent counting methodologies (discussed below), to verify whether the minimum PRM has been reached by the aggregate resources that have been procured. If the sum of all procurement does not meet the minimum PRM, the ISO would notify all LSEs of the shortfall and provide an opportunity for additional capacity to be secured by LSEs and provided to the ISO. If a shortfall remains after the cure period, the ISO may utilize backstop procurement to resolve the shortfall.

Resource Counting Methodologies for Reliability Assessment

As part of conducting a reliability assessment, the ISO must have consistent counting rules such that resources in different areas and different technologies are treated comparably. Thus, the ISO proposes to develop a uniform counting methodology framework that would be applied for a reliability assessment. The counting methodology would provide consistent and transparent methodologies for evaluating the amount that each resource type is able to effectively contribute towards meeting the ISO's reliability needs. The methodologies would be determined through a transparent and open stakeholder process, and the maximum quantity of megawatts that a resource could be acquired as RA capacity would be published on the ISO web page prior to the time that year-ahead RA procurement takes place. Timely posting year-ahead will allow LSEs sufficient time and information from the ISO to inform procurement decisions. Updates to the methodology, which may be needed over time to reflect best practices, would be run through an open and transparent stakeholder process. An example of a methodology that might be used in the future is the effective load carrying capability methodology that is currently under discussion in several forums.

The ISO stresses that it is not proposing to eliminate the ability of LRAs and LSEs to develop their own resource counting methodologies. The ISO intends to continue to allow LRAs and LSEs to have discretion in developing their RA and procurement programs. However, establishing consistent counting rules that would be used by the ISO for the reliability assessment will mitigate concerns about over-counting resources by an entity, which can be considered a form of leaning of other entities. At a minimum, the ISO must determine some baseline for counting resources.

Backstop Procurement Authority for Reliability Assessment

The ISO will review its backstop procurement authority and cost allocation provisions to ensure that the costs of any backstop capacity procurement are allocated in a fair and open manner. The ISO proposes to update the backstop procurement provisions to reflect the use of the proposed reliability assessment. The ISO's ability to allocate the cost of backstop procurement to entities that are short of resources in circumstances where the aggregate amount of resources that have been procured are insufficient to meet the ISO's reliability needs is an important aspect of the reliability assessment.

The ISO's ability to identify whether entities are leaning on other entities and allocate them a fair share of the associated financial burden follows the ISO's principles for cost allocation. The potential for ISO backstop procurement is an appropriate mechanism to incent entities to secure adequate resources and commit those resources to the ISO to meet reliability needs and avoid inappropriately leaning on other entities that have procured their share of operational needs.

6. Next Steps

The ISO will discuss this straw proposal with stakeholders during a meeting on March 2 in Folsom, California. Stakeholders are requested to submit their written comments by March 16 to initiativecomments@caiso.com. Stakeholders should use the template at the following link to submit comments: http://www.caiso.com/Documents/CommentsTemplate-RegionalResourceAdequacy-StrawProposal.doc.

Appendix 1 - Stakeholder Written Comments and ISO Responses Matrix

Topic	Stakeholder	Question/Comment	ISO Response
Making the Tariff More Generic	Bay Area Municipal Transmission (BAMx)	The "CPUC, Local Regulatory Authority, or federal agency" references could potentially be replaced with a more general RA Regulatory Authority ("RARA").	The ISO appreciates this suggestion and will consider new terms, but at this time is continuing to use LRA to refer to state and municipal regulatory agencies.
	Northwest Intermountain Power Producers Coalition (NIPPC)	Assuming that PTOs from outside of the State of California formally join the ISO, NIPPC agrees that the ISO tariff needs to be made more generic to eliminate specific references to California regulatory bodies and to update tariff provisions that are out of date.	The ISO agrees with this comment.
	PG&E	Updating references to the more generic LRA seems appropriate, but it is unclear if this change is solely administrative. The ISO Straw Proposal should be clear on whether the changes are expected to have additional impacts on the RA program.	The ISO intends for this change to be solely administrative to avoid any unintended barriers or other consequences of the current California-centric language used in the tariff.
	California Office of Ratepayer Advocates (ORA)	ORA recognizes that regional RA would require an update to sections of the ISO's RA tariff language to change references specific to California and update sections of the tariff that do not reflect current RA policies. ORA strongly supports the ISO's stated principles to maintain consistency with the CPUC RA program and accommodate the CPUC's procurement programs, such as Long Term Procurement Planning. At the same time, ORA is concerned that the regional RA initiative would impact CPUC programs out of necessity to satisfy the needs of an expanded ISO BAA.	The ISO understands the stated concerns and will continue to strive to minimize the impact to current RA and procurement programs in developing an RA proposal.
Load Forecasting	California Department of Water Resources (CDWR)	Forecasting methodology adopted by CDWR based on its actual operations is a part of LRA RA program and should not be impacted by any standardized methods of forecasting used for retail loads, as currently, CDWR forecasts its most likely coincident peak load and provides to CEC. CDWR's power forecasts are driven by water supply and demand (and other factors such as environmental constraints), and most likely demand in real time would be the forecast as close to the month as possible. Any method prescribed for standardized demand forecast that does not support the nature of CDWR's	The ISO appreciates the related load forecasting information provided by CDWR. The ISO intends to create a multi-state load forecasting process that minimizes the impact to the RA programs and operations of LRAs and LSEs.

Topic	Stakeholder	Question/Comment	ISO Response
		pumping operations will result in higher inaccuracies and inefficiencies.	
	California Public Utilities Commission Staff (CPUC)	CPUC staff believe that load forecasts for CPUC-jurisdictional LSEs should continue to be determined by the CEC through the IEPR forecast process. This is also consistent with the California Public Utilities Code. The IEPR represents a major undertaking that occurs through a transparent, public process and CPUC staff believes that this process should continue. Furthermore, load forecasts for other jurisdictions within a regional ISO should be developed through an equally robust and transparent process.	The ISO agrees with this comment. The proposed framework for extending the load forecasting process for an expanded BAA would continue to utilize the CEC load forecasting for CPUC-jurisdictional LSEs.
	SDG&E	With the CEC agreement to produce a load forecast for the VEA, the ISO has the ability to base all of its local and system RA assessments on load forecasts that are generated using common assumptions and forecasting methods. SDG&E suggests that the CEC be consulted to see if it would likewise be agreeable to forecast loads for future expansions of the ISO BAA that involve other non-California LSEs like VEA.	The ISO will consider this suggestion, but notes that it may be more appropriate for individual LSEs to provide their own load forecasts to the ISO for areas outside of the current BAA.
	Western Grid Group, Western Resource Advocates, Natural Resources Defense Council, Interwest Energy Alliance and Vote Solar (NGOs)	We believe that PacifiCorp has the most experience with loads in its footprint and should be charged with developing forecasting information similar to that which is developed by the CEC and used by CAISO in its RA process. The ISO should compare forecasts by PacifiCorp (and other load forecasts it uses) with actual load and report results to PUCs and the public.	The ISO agrees with this comment. The proposed framework for extending the load forecasting process for an expanded BAA would utilize LSE-developed forecasts for entities in areas outside of the current BAA. The ISO agrees with the suggestion to consider making public the transparent results of individual LSE forecast accuracy.
	Western Power Trading Forum (WPTF)	WPTF asks the ISO to consider creating a standardized methodology for load forecasting. WPTF is interested in hearing more from PacifiCorp and others on how their load forecasting is done and how similar it is to the CEC forecasting methodology.	The ISO intends to create a multi-state load forecasting process that accounts for any variation in assumptions or data inputs to ensure comparable and accurate results. Information is provided in this straw proposal on how PacifiCorp does its load forecasts.
Establishing RA Requirements (System, Local, Flexible, PRM, etc.)	Bay Area Municipal Transmission (BAMx)	This should be approached carefully to ensure that the reliability enjoyed or costs experienced by jurisdictional LSEs flow from the LRA's choices in selecting a PRM. While the flexibility of having the LRAs set their PRMs is very important, it is	The ISO agrees with this statement and will develop a proposal that considers these concerns.

Topic	Stakeholder	Question/Comment	ISO Response
		also important that the consequences of such a choice, positive or negative, rest with the LSEs subject to the LRA's jurisdiction.	
	California Municipal Utilities Association (CMUA)	ISO should continue to establish local and flexible RA requirements throughout its expanded BAA.	The ISO agrees and intends to continue to establish local and flexible RA requirements throughout an expanded BAA.
	Western Power Trading Forum (WPTF)	WPTF asks the ISO to consider a standardized minimum PRM. The ISO must maintain a balance between allowing the LRA flexibility in determining their own RA program and ensuring grid reliability and equity. WPTF proposes the ISO mandate a minimum PRM value as well as a default PRM value.	The ISO's proposed reliability assessment will assess system-wide reliability that will include a minimum PRM. This will still allow LRAs and LSEs to choose the level of procurement they deem acceptable, but also allow the ISO to allocate the costs of any backstop procurement to entities that do not meet ISO minimum reliability requirements, while ensuring that system reliability is maintained.
	Northwest Intermountain Power Producers Coalition (NIPPC)	RA requirements also exist to ensure that each of the LSEs is carrying its fair share of the system's total capacity needs. Regulators have an interest in approving the resource acquisitions of the LSEs under their jurisdiction. Those regulators also have an interest in ensuring that LSEs outside their jurisdiction are carrying their fair share of the resource adequacy requirements of the entire system. In the absence of enforceable RA requirements in an organized market, regulators have no mechanism to ensure that the resources acquired by the LSEs under their jurisdiction are not being "leaned on" by LSEs in neighboring jurisdictions.	The ISO agrees with these comments and believes that the proposed reliability assessment will establish enforceable RA requirements to ensure there are sufficient resources available to maintain reliability and avoid leaning.
	Northern California Power Agency (NCPA)	California's existing RA programs are enforced by multiple jurisdictional authorities and have worked very well in coordination with other planning activities conducted by the various LSEs within California. As a result, electric service to California customers has been very reliable and ISO has had sufficient access to the amount and types of capacity it needs to operate the BAA efficiently. One of the key elements of the current RA regime is that each LRA has the ability to establish its own RA program that is tailored to the meet the specific planning needs of its	The ISO agrees with these comments. The current RA program, which is based on a bilateral procurement framework overseen by the CPUC and LRAs, has worked well and provided many benefits. The ISO does not intend to move away from this construct. The RA framework will continue to rely on RA programs and bilateral procurement processes overseen by state

Topic	Stakeholder	Question/Comment	ISO Response
		respective LSEs. This shared jurisdiction, which was considered and approved by the FERC as appropriately preserving the jurisdictional prerogatives of the CPUC and the other LRAs that govern state and municipal LSEs, has been successful. Despite that the various RA programs enforced in California are not completely uniform, it is clear that all of the adopted programs have worked very well together. To NCPA's knowledge, the ISO has never indicated that the annual RA showings made by LSE's under the criteria imposed by their respective LRAs have resulted in a collective planning reserve deficiency, and ISO has never been required to procure back stop capacity due to LSEs being deficient in their obligations.	regulatory commissions and LRAs. The ISO intends to only change those tariff provisions where modification is appropriate to make RA work more effectively in the context of an expanded ISO BAA.
	PG&E	PG&E recommends that ISO continue to provide incentives for each LSE to meet its share of ISO's reliability needs for capacity and have adequate protections for allocating costs commensurate with each LSE's contribution to the ISO's reliability requirements.	The ISO agrees and intends to ensure this concept is reflected in ISO proposals.
	California Municipal Utilities Association ("CMUA")	Any RA regime must balance the need for sustainable grid reliability, result in reasonable costs, respect multiple jurisdictional authorities, and ensure no "leaning" on the system by entities not procuring and making available adequate capacity to meet system, local, and flexible capacity requirements. It should be recognized the current regime is not completely uniform and it still works well. Although the CPUC is the LRA for a bulk of LSEs within California, there are many others Publicly-Owned Utilities ("POU") LRAs that adopt RA policies, and as prudently planning entities these POU LRAs balance cost and procurement risk, along with the host of other procurement obligations inherent to serving load in California, such as renewable resource requirements. Despite this diversity of procurement policies, to our knowledge the ISO has never indicated when it reviews the annual showings, that there has been an overall shortfall or that reliability is compromised.	The ISO agrees with these comments. The current RA program, which is based on a bilateral procurement framework overseen by the CPUC and LRAs, has worked well and provided many benefits. The ISO does not intend to move away from this construct. The RA framework will continue to rely on RA programs and bilateral procurement processes overseen by state regulatory commissions and LRAs. The ISO intends to only change those tariff provisions where modification is appropriate to make RA work more effectively in the context of an expanded ISO BAA.
Counting Resources to Meet RA Requirements	Bay Area Municipal Transmission (BAMx)	Each LRA should be able to select the optimal approach for that region, as methods are likely to grow more complex with regionalization. Of specific concern is maintaining the ability of one	The ISO understands the need for balancing flexibility and ensuring fairness in procurement and maintaining reliability that the two

Topic	Stakeholder	Question/Comment	ISO Response
		state to mandate a specific approach while not forcing out-of-state LRAs to follow that mandate (e.g. one LRA may choose an ELCC method while another may prefer the older Exceedance-based approach); BAMx is concerned about developing a standardized approach for planning reserves that makes it difficult to tailor a resource portfolio to a LRA/LSE's specific needs and also makes innovation challenging (e.g. the QC of a wind/solar project may vary with geographic location and load being served).	parts of BAMX's comments describe. The ISO understands the need to allow individual LRAs/LSEs the flexibility necessary to tailor a resource portfolio to a LRA/LSE's specific needs and also encourage innovation. The ISO intends to evaluate resources through its proposed reliability assessment which includes consistent resource valuation methodologies to avoid unintentional double counting of resources and leaning that creates potential reliability concerns.
	California Municipal Utilities Association (CMUA)	CMUA does not see, at this time, a compelling need to make other changes to counting conventions or other rules that would place more procurement determinations within the authority of the ISO, and thus subject to FERC jurisdiction.	The ISO believes that consistent counting methodologies are necessary to avoid potentially inconsistent counting of resources that results in inequitable treatment between LSEs.
	California Public Utilities Commission Staff (CPUC)	CPUC staff would not likely be supportive of new capacity valuation mechanisms that would apply to the CPUC's RA program and resources procured by CPUC-jurisdictional LSEs in CPUC approved contracts. The CPUC currently determines the RA counting conventions and qualifying capacity methodology for many types of resources. Conventions and counting rules are adopted through CPUC decisions. Therefore, CPUC Staff would not support adopting a standardized approach applicable to all jurisdictions within a regional ISO.	The ISO is proposing to conduct a reliability assessment that uses consistent counting methodologies. The ISO believes that consistent counting methodologies are necessary to avoid potentially inconsistent counting of resources that results in inequitable treatment between LSEs or potentially could jeopardize reliability. The ISO stresses that it is not proposing to require that LRAs to utilize the ISO counting methodologies for their RA programs. The ISO is only proposing to use consistent counting methodologies for the reliability assessment, which will inform the ISO regarding the potential need for any backstop procurement.
	AWEA and CalWEA	AWEA and CalWEA wish to promote the Effective Load Carrying Capability (ELCC) approach for determining the QC of generation resources. The widespread adoption of the ELCC approach is due to the accuracy with which the ELCC approach reflects the contribution of a resource to supply capacity adequacy needs in a BAA.	The ISO is proposing to adopt resource counting methodologies that accurately capture the extent that a resource is capable of meeting the ISO's reliability needs. The ISO will consider the extent that different methodology could

Topic	Stakeholder	Question/Comment	ISO Response
		Importantly, this ELCC calculation should be updated following an expansion of the ISO footprint, to properly account for the impact of geographic diversity in electricity supply and demand on the capacity value contribution of all resources. This is particularly important for variable renewable resources, which see significant increases in their capacity value contribution over larger balancing areas due to the geographic diversity of their output.	be utilized to accurately measure this, including the ELCC approach.
	California Department of Water Resources (CDWR)	ISO contemplates adding new default tariff provisions to determine capacity of resources that can count toward meeting RA obligation. ISO provides example on wind and solar resources where there is a need for reevaluation and indicates that calculations method does not exist for storage resources. If there is further need of such provisions beyond the existing provisions, they should only be added as the default provisions. LRA's own criteria should not be impacted.	LRAs will still be able to procure resources based upon counting conventions they choose. The ISO's proposed reliability assessment will utilize consistent counting methodologies to assess the level of resources provided to meet reliability needs.
	Western Power Trading Forum (WPTF)	WPTF asks the ISO to consider a local, system, and flexible qualifying capacity standardized value for all resources. In the future, particularly with renewable resources, allowing resources to qualify as different amounts of RA may lead to additional complications and inequitable treatment between LSEs. Creating standardized QC values will also simplify contracting for resources that contract with multiple LRAs and simplify the ISO's internal RA processes. WPTF supports consistent values, even if this requires a separate stakeholder initiative due to the technical and potentially contentious nature of developing these values.	The ISO's proposed reliability assessment will utilize consistent counting methodologies to assess the level of resources provided to meet reliability needs. The ISO agrees with this suggestion by WPTF as well as the reasons why consistent counting methodologies are necessary.
	PG&E	PG&E recommends that ISO views simplification as a priority throughout this initiative, as complications to this basic framework could arise if requirements, resource counting conventions and must offer obligations are inconsistent between LRAs or LSEs. If there are significant differences in RA programs across LRAs, transacting capacity to meet RA requirements across states will be difficult, which will prevent significant RA cost savings for all LSEs in the ISO footprint.	The ISO agrees with the suggestion to prioritize simplification and the reasons that PG&E explains.

Topic	Stakeholder	Question/Comment	ISO Response
	"Six Cities" (Cities of Anaheim, Azusa, Banning, Colton, Pasadena & Riverside)	The application of consistent rules throughout the integrated BAA will be necessary (1) where zonal or local variations would impair overall system reliability, or (2) where the economic impacts of zonal or local variations cannot be confined to the zone or local area in which a variation in policy or practice applies.	The ISO agrees with the Six Cities explanation of instances where it may be necessary to apply consistent rules.
Maximum Import Capability ("MIC")	California Office of Ratepayer Advocates (ORA)	Currently, the ISO's import methodology counts power flowing from resources outside of the ISO BAA through interties into the ISO BAA. Following the potential integration of the ISO and PacifiCorp, power flowing between the ISO and PacifiCorp would no longer fit the current tariff definition of imports into California. The power flowing within an enlarged BAA, as well as power imported from outside a new BAA, would need to be studied by the ISO. The ISO may need to address potential problems that could hinder RA compliance if the current ISO MIC methodology is utilized. For example, will congestion issues within areas of the BAA require changes to import classifications and a new methodology for calculating imports?	The ISO agrees with these comments. The ISO is conducting analysis to determine what changes may be necessary. At this time, the ISO believes that only minor modification to the MIC methodology may be required to reflect the different peak time periods in which non-coincident peaking areas without commonly known constraints experience their maximum non-simultaneous imports to achieve unconstrained and reliable maximum amount of import capability that can be relied upon for RA purposes in an expanded BAA.
	Western Power Trading Forum (WPTF)	WPTF asks the following as the ISO moves forward with a methodology to determine maximum import capability: 1. Will all the new interties points be eligible as RA points, as is currently? 2. How much new RA intertie capacity will there be with PacifiCorp integration? 3. Does having a large increments of new RA intertie space create any new reliability issues? 4. Will the space for the new interties be allocated in the same manner as today? 5. How much, if any, of the RA intertie capacity is going to be grandfathered to the joining entity, and what are the market impacts of such grandfathering?	The answers to WPTF's questions are provided below. 1. Yes. 2. Historical data needs to be provided and a technical deliverability analysis needs to be performed in order to establish the new RA intertie capacity, which generally should follow historical highest values of imports at peak periods. 3. See answer #2 above. 4. Yes, the ISO is not currently proposing enhancements to the MIC allocation process. This would only be changed through a separate, open stakeholder process. 5. Generally, all existing transmission ownership rights are respected, all existing transmission

Topic	Stakeholder	Question/Comment	ISO Response
			contracts are respected until they expire, Pre-RA Import Commitments (resource contracts) are grandfathered from the point of integration until they expire unless PacifiCorp, ISO and possibly other stakeholder negotiations are undertaken for a different arrangement. Since RA is a bilateral market the impact to that market is unknown, and there will be no direct impacts to the energy markets because the RA contracts do not have scheduling priority in day-ahead or real-time markets.)
Intra-BAA Transfer Counting Constraints (Zonal RA Concept)	Bay Area Municipal Transmission (BAMx)	Zonal constraints should be respected in supplying resources to meet RA requirements (e.g. Path 26 or paths between California and PacifiCorp, or within PacifiCorp); however, as the use of zones expands, the benefits and risks of alternate counting mechanisms need to be vetted among stakeholders (e.g. should zonal limits apply to the cumulative designated resources using the path in each direction to reach its contracted load, or should the limits be applied to the net transfers in each direction? Or if southern California LSEs are contracting with resources in NP15 and northern California LSEs are contracting with resources in SP15, should the zonal limits be enforced on the gross contracts in each direction or the net?).	The ISO proposes to extend the current Path 26 Counting Constraint methodology to an expanded BAA. The details of exactly how this methodology might work or need to be revised for use in an expanded BAA are still under consideration. The ISO will continue to analyze the issue and will work with stakeholders to identify these issues and develop this aspect of the proposal further.
Resource Showings and Compliance	California Municipal Utilities Association (CMUA)	It should be recognized the current regime is not completely uniform and it still works well. While the CPUC is the LRA for a bulk of the LSEs within California, there are many prudently planning POUs' LRAs that adopt RA policies, balancing cost and procurement risk, along with the host of other procurement obligations inherent to serving load in California, such as renewable resource requirements. Despite such diversity of procurement policies, to our knowledge the ISO has never indicated when it reviews the annual showings, that there has been an overall shortfall or that reliability is compromised.	The ISO agrees with this characterization of the current processes and intends to continue to defer to LRA and LSE procurement decisions and RA programs in the first instance. The ISO will need to continue to assess system reliability.
Bidding and Scheduling Requirements / MOO	California Municipal Utilities	Unless the ISO is going to revisit the must-offer obligation ("MOO") requirement in its entirety, CMUA strongly believes that the MOO must	The ISO agrees.

Topic	Stakeholder	Question/Comment	ISO Response
	Association (CMUA)	apply equally across the consolidated and expanded BAA.	
Standardized RA Requirements	California Department of Water Resources (CDWR)	If there is a need for higher PRM (than the current 15%) that is to be adopted by all, such needs should be demonstrated. As such, the guiding principle, as stated, should not alter the LRA RA programs (which set PRM and counting criteria) that are working fine. Standardization should instead be limited to default provisions, applicable to entities choosing to adopt ISO default provisions.	The ISO agrees about PRM and continued deference to LRA and LSE procurement and RA programs. The ISO will need to perform a system reliability assessment that will be based upon consistent methodologies.
	Western Power Trading Forum (WPTF)	WPTF supports the ISO developing a standardized methodology or principles (e.g. 1 in 10) for all LRAs.	The ISO agrees there is a need to establish some consistent methodologies for purposes of evaluating system reliability.
	California Office of Ratepayer Advocates (ORA)	The ISO notes that a PRM and system RA capacity requirements may need to be standardized to fairly assess RA needs across the region. Variation in reserve margins amongst LRAs would result in unequal contribution to regional reliability. Currently, PRMs vary between California and other states. The appropriate PRM, which balances reliability and loss of load events, along with associated ratepayer costs and impacts, becomes a key topic for discussion in a potential regional BAA.	The ISO agrees with this comment. The ISO must ensure that reliability is maintained and the proposed reliability assessment would help to ensure that there are not unequal levels of reliability in different areas of an expanded ISO BAA.
	California Office of Ratepayer Advocates (ORA)	ORA does not endorse a standardized regional approach for counting rules as suggested by the ISO in its Issue Paper. Currently in California, the LRAs have the ability to determine the QC of resources to meet RA requirements. ORA requests that the ISO provide information on QC methodologies used by entities in the proposed new BAA. Although ORA shares the ISO's concerns regarding "capacity leaning" if QC rules created by various LRAs fail to provide equivalent levels of reliability, a standardized regional approach may not be an optimal solution given many questions that will need to be addressed. For example, it is unclear how capacity values for solar may vary between LRAs if California adopts an ELCC methodology which will produce lower QCs for solar resources as the penetration increases. Should the QC of solar resources be lowered in all states due to increased solar penetration in California? Is the grid value of an intermittent renewable resource in Wyoming the	The ISO believes these comments and questions raise important issues to consider in this stakeholder initiative and under the ISOs proposed framework for the reliability assessment, which contemplates the need for consistent counting methodologies for resources capacity values.

Topic	Stakeholder	Question/Comment	ISO Response
		same as a similar resource built in California? Should the rules for distributed resources in California be the same as those in other states? What will be the QC value of resources whose MWs are moved among states? If regional RA is adopted, ORA recommends allowing each LRA to create its own QC methodology. However, the regional RA initiative would need to address and potentially mitigate any imbalances related to QC calculation variations amongst LRAs.	
	Northern California Power Agency (NCPA)	LRAs have the need and the right to establish unique RA programs that address the particular needs and responsibilities of their respective LSEs. LSEs often have unique operational characteristics that necessitate planning and procurement strategies tailored to the needs of their customers, the characteristics of their resources and the need to satisfy legal requirements, such as environmental mandates. For example, it is important for LRAs to retain the ability to set the rules and requirements used to establish the type of resources their respective LSEs may use to meet their planning reserve needs. While NCPA supports ISO's effort to ensure that RA requirements are enforced in a comparable manner across a potentially expanded ISO footprint, a single, standardized RA requirement for all LSEs (an idea floated at the December 16 stakeholder meeting) is the wrong solution. NCPA strongly believes that the current deference to LRAs to establish programs for their respective LSEs is a key element to the success of the overall program.	The ISO agrees about the need for continued deference to LRA and LSE procurement and RA programs. However, the ISO will need to perform a reliability assessment that will be based upon consistent methodologies, so it can ensure that reliability is maintained and determine whether any backstop procurement is required to maintain such reliability. The ISO believes that the reliability assessment would need to utilize some consistent requirements and counting methodologies in order accurately assess reliability.
Potential Future LSE List	SDG&E	ISO and PacifiCorp should work together to prepare a summary of the LRAs that have authority over LSEs within a merged balancing authority, were that to occur, identifying which LRAs have authority over which LSEs and should describe the basic planning and decision processes that each LRA uses to oversee and direct the generation and demand side management planning activities of their respective LSEs (such as load forecasting responsibilities and techniques, minimum PRM, methodologies for determining the dependable capacity of generating units and demand side management programs, and descriptions of any "local" generation requirements and how those requirements are set). Other BAAs, for example	The ISO provides information in Appendix 2 to this straw proposal on PacifiCorp's load forecasting process and methodology. The ISO also provides information in Appendix 3 on PacifiCorp's LSEs and the BAA in which each resides and an internet link to a posted map of PacifiCorp's transmission system.

Topic	Stakeholder	Question/Comment	ISO Response
		NV Energy and Arizona Public Service, should be invited to contribute to this summary.	
Updating ISO Default Tariff Provisions	Bay Area Municipal Transmission (BAMx)	Any such updates should be limited to those necessary for the regionalization effort—other modifications to bring the tariff up to date should be addressed in separate, focused stakeholder processes.	The ISO agrees with the comment.
	California Department of Water Resources (CDWR)	Any necessary changes should not alter the LRA's RA provisions and should instead be made to facilitate other LRAs to join ISO rather than to alter existing LRA RA programs.	The ISO agrees with the comment.
	Western Power Trading Forum (WPTF)	WPTF supports going a step further than the ISO's goal [of creating default provisions to set forth criteria for LRAs that have not established or provided certain criteria to the ISO] and establishing standardized ranges or values for this criteria to ensure that LRA's cannot create criteria that enables their LSEs to lean on other areas to provide grid reliability.	The ISO agrees that some consistent methodologies will be necessary to perform reliability assessments.
	California Office of Ratepayer Advocates (ORA)	Regional RA would require regular updates as needed to keep the ISO tariff and its LRA default program current. The CPUC conducts an annual RA proceeding, which regularly revises the RA program to add improvements and respond to procurement changes and grid impacts. The regional RA effort may require a similar annual process on a multistate basis to keep the ISO tariff current.	The ISO agrees with the comment that regular updates to the RA provisions may be necessary to maintain the most up to date methodologies and processes.
	PG&E	It is appropriate to update the ISO Default Qualifying Capacity Criteria provisions. The ISO should outline each update to the ISO's default resource counting provisions in the ISO Straw Proposal.	The ISO agrees but believes that the proposed reliability assessment will mitigate the need for continued use of default provisions.
Backstop Provisions	Bay Area Municipal Transmission (BAMx)	Backstop resource procurement costs should flow to the beneficiaries of such procurement. If procured to address local or zonal needs, those not benefiting should not be assigned any costs associated with such procurement. For entities within the benefitting area, consideration should be given for differentials in planning margins maintained by individual LSEs.	The ISO agrees with these principles when considering backstop procurement cost allocation.
	California Municipal Utilities	Tariff attempts to track cost causation by placing backstop procurement risk with entities that are shown to be short are appropriate and should be	The ISO agrees with this suggestion.

Topic	Stakeholder	Question/Comment	ISO Response
	Association (CMUA)	used as a tool to ensure that default procurement that is triggered due to the lack of uniform procurement results in cost attribution that tracks cost causation.	
	Northwest Intermountain Power Producers Coalition (NIPPC)	NIPPC recognizes ISO must have some authority to respond when an LSE proves to be deficient in meeting RA requirements. The ISO should consider whether there may be alternatives to backstop procurement of generation resources. Although NIPPC recognizes that the ISO has never exercised its backstop authority to acquire RA on behalf of an LSE, LRAs considering whether to allow their PTO to participate in an expanded regional energy market may perceive backstop procurement of resources by the ISO as interfering with their regulatory responsibilities. The ISO's use of backstop procurement authority in any expanded footprint must be reviewed in the overall context of how the existing RA requirements in the new jurisdictions work. How the ISO's backstop authority would apply in an expanded footprint is an issue that requires careful consideration to ensure that it is modified as necessary to work well with existing RA programs in the expanded footprint area.	The ISO agrees that the issue of how backstop authority would apply in an expanded footprint requires careful consideration to ensure that it works well with existing RA programs in the expanded footprint area. The ISO will also need to ensure that its backstop authority provisions are updated to reflect any RA requirements established for use under the reliability assessment.
	SDG&E	The imposition of backstop procurement costs would undermine the ability of LRAs to effectively oversee and direct generation and demand-side management planning activities of their jurisdictional LSEs.	The ISO believes that current LRA and LSE procurement has worked well, and the ISO has not had to exercise its backstop authority to cure RA deficiencies to date. That being said, the ISO still needs to ensure that adequate resources have been procured to maintain reliability. If the ISO identifies any insufficiency there will be a chance for LSEs to cure any identified needs before the ISO undertakes any backstop procurement.

Topic	Stakeholder	Question/Comment	ISO Response
	Western Power Trading Forum (WPTF)	ISO should consider backstop RA provisions that determine cumulative shortages by LRA or newly created zones. As the ISO expands, having a structure that innately allows leaning between LSEs and LRAs will likely reduce efficiencies and provide incentives for LSEs to not fully demonstrate RA sufficiency each month. From WPTF's perspective, it is extremely important for planning requirements to be strictly enforced by the ISO in order to provide LSEs and LRAs the correct incentives to build and contract the optimal resource set in the short- and long-term.	The ISO agrees that backstop procurement provisions should be based on cumulative shortages and proposes that any backstop procurement costs be allocated to entities that have not met the minimum requirements established for the ISOs proposed reliability assessment.
Initiative Schedule	Bay Area Municipal Transmission (BAMx)	BAMX supports CMUA's concern that ISO's proposed timeline is inadequate for addressing the complex issues and supporting a robust stakeholder engagement.	The ISO will evaluate the schedule following the March 2 stakeholder meeting and written stakeholder comments have been submitted on March 16.
	California Municipal Utilities Association (CMUA)	CMUA does not believe ISO's proposed RA timeline to discuss and address issues associated an expanded BAA is adequate or prudent. While the TAC initiative has complex questions associated with balancing cost causation and equitable concerns about cost shifting, RA has those issues, plus the added complexity of difficult technical questions.	The ISO will evaluate the schedule following the March 2 stakeholder meeting and written stakeholder comments have been submitted on March 16.
	SDG&E	The ISO should allow sufficient time for the above activities to take place. ISO board-approval in June, 2016 may be premature.	The ISO will evaluate the schedule following the March 2 stakeholder meeting and written stakeholder comments have been submitted on March 16.
	Western Power Trading Forum (WPTF)	WPTF questions the feasibility of this schedule even under the circumstance that stakeholders agree there are no changes needed to the RA program. Given the proposed scope – which includes worthwhile and comprehensive changes to the RA program – WPTF is mostly just confused about the reasoning behind the June BOG deadline.	The ISO will evaluate the schedule following the March 2 stakeholder meeting and written stakeholder comments have been submitted on March 16. This straw proposal discusses in some detail why the schedule is currently targeted for the June Board meeting.
Deliverability	AWEA and CalWEA	CalWEA, as well as other California stakeholders, have had ongoing objections to the ISO's transmission deliverability assessment approach, citing its overly restrictive nature which severely discounts a resource's ability to meet system-RA	The ISO has developed and reviewed its deliverability methodology through several open stakeholder processes. Based on input from all

Topic	Stakeholder	Question/Comment	ISO Response
		capacity needs. This is because, according to the ISO's transmission deliverability assessment methodology, the availability of sufficient transmission capacity for a resource is determined based on available transmission capacity between that resource and the load centers in ISO footprint under an unrealistic and overly restrictive system dispatch condition that also assumes the two worst transmission contingencies in the system. AWEA's and CalWEA's main objection to the ISO's transmission deliverability assessment approach is not necessarily with its assumption that transmission capacity should be available between the resource and load centers in the ISO's footprint, but rather with the assumption of unreasonable operating conditions. In that regard, we propose the following reforms for the ISO's transmission deliverability assessment approach: • The system dispatch used in the transmission deliverability assessment should be consistent with typical operating practices for the ISO; and • Transmission capacity availability should be considered under normal operating conditions and not an N-2 outage condition.	participating stakeholders, the ISO does not believe that changes to its deliverability methodology are necessary and is not proposing to consider changes to the methodology under this initiative.
	Northwest Intermountain Power Producers Coalition (NIPPC)	In its Issue Paper, the ISO describes how it currently establishes deliverability, but the ISO does not describe how the rules establishing deliverability might need to change with expansion. Future papers and presentations should highlight any impact an expanded footprint might have on the ISO's deliverability rules. The ISO deliverability rules recognize internal constraints within the current ISO footprint. As the Issue Paper notes, an expanded footprint will likely have transmission transfer constraints between the ISO and PacifiCorp. However, further expansion including, for example, Nevada Energy joining as a PTO could increase transmission capacity between the ISO and intermountain West. Future stakeholder meetings should discuss how internal constraints are currently managed, and explore to what extent this approach to constraint management can be applied to an expanded footprint as well as what new complexities -- and opportunities -- need to be considered in establishing deliverability of resources across an expanded	The ISO has developed its deliverability methodology to effectively assess and ensure reliability. The ISO is not proposing to consider further changes to the methodology under this initiative. The existing deliverability methodology ensures that major intra BAA transfer path transfer capability (e.g. Path 26) is not degraded below the existing transfer capability. The ISO expects to utilize a similar approach for new major intra BAA transfer paths introduced when the BAA is expanded.

Topic	Stakeholder	Question/Comment	ISO Response
		footprint. In the earliest stages of an expanded geographic footprint, transmission transfer capability between the ISO and PacifiCorp will be limited. Accordingly, NIPPC recommends that the ISO outline the formal process it will use to establish the local RA requirements in consultation with LRAs. NIPPC also recommends that the ISO describe its process for conferring with LRAs and LSEs to establish local RA requirements upon expansion of the ISO footprint. The description of the process should include a list of topics for resolution along with a timeline, and as discussed below, the respective roles of the ISO and the LRA in enforcing RA requirements.	
	Bay Area Municipal Transmission (BAMx)	ISO's current deliverability methodology, built around delivering generation to the "aggregate of load" may need adjustment, as this concept becomes less clear for a large region (e.g. wind in Wyoming may be deliverable to load in Utah and wind in the Tehachapi Area may be deliverable to California—however, should wind in Wyoming or the Tehachapi Area be required to be deliverable to the other sub-areas?). It may no longer be reasonable to have the determination of Area Deliverability Network Upgrades (ADNU) be agnostic to the load being served. Therefore, such adjustments to ISO's deliverability methodology, possibly coupled with the expansion of Zonal Transfer Constraints, will need to consider the regional topology and loads being served.	The ISO believes this issue is important when considering an expanded BAA with areas that may not experience simultaneous transfer constraints that coincide with those identified for the current BAA footprint. As described in the response above, at this time, the ISO believes this probably can be reflected accurately through the annual deliverability studies without requiring any enhancements to the ISO tariff or BPMs. The ISO will continue to assess this situation.
	Western Grid Group, Western Resource Advocates, Natural Resources Defense Council, Interwest Energy Alliance and Vote Solar (NGOs)	We have concerns that the current implementation of RA process at ISO, through its deliverability assessment, is overly restricting various resources to meet system's resource adequacy needs, leading to unneeded construction of deliverability transmission projects. We also believe that growing move toward using an ELCC methodology that fairly and appropriately reflects the performance capabilities for each resource for determining qualifying capacity should be accelerated. An evaluation of the experience with the ISO deliverability assessment process including the flexible capacity and "must offer" requirements should be undertaken and reforms adopted as part of expanding the RA program to the expanded ISO footprint.	The ISO has developed its deliverability methodology to meet its deliverability evaluation needs in order to assess and ensure reliability. At this time, ISO does not believe that changes to its deliverability methodology are necessary and is not proposing to consider changes to the general methodology under this initiative. Changes that may be necessary to the deliverability methodology related to ELCC methodology, flexible capacity, etc. are beyond the scope of this initiative.

Topic	Stakeholder	Question/Comment	ISO Response
Major Revisions to ISO RA Construct	Powerex Corp.	Rather than focusing on narrow wording changes, ISO should engage with its stakeholders in the broader discussion of whether the existing construct should be extended in the first place, or whether an alternative RA framework would be better suited to meeting the needs of a broader regional market. [Instead,] a properly designed centralized forward capacity market would enable voluntary participation by all suppliers capable of meeting the technical requirements for RA capacity—including suppliers located outside the ISO footprint—allowing them to compete to meet these needs and thus ensuring ISO's RA. Additionally, a centralized forward capacity market would provide much-needed price transparency, which is vital to ensuring new capacity investments are made at the right time and in the right locations. ISO should [therefore] explore substantive changes to its existing RA framework that could be made to remove existing barriers to entry, encourage greater participation by external resources, and promote the transparent pricing of capacity. Ultimately, ensuring equal competitive opportunities for all resources capable of meeting RA needs will confer broad reliability and economic benefits, both within any expanded CAISO footprint and throughout the west. Centralized forward capacity markets have not yet been developed in the west, and ISO's proposal in this initiative to merely extend ISO's current bilateral RA framework, which is based on a procurement process that is not centralized, liquid, or transparent, does not advance ISO's broader efforts to build markets that achieve the cost-saving benefits of centralized procurement. Because the actual selection, negotiation, and execution of RA contracts [under ISO's current system] is generally left to the subjective judgment of each individual LSE, there is no assurance that such a framework will lead to least-cost outcomes that are free of undue discrimination and not adversely affected by barriers to entry to new or external resources. In fact, the limited information that exists on RA procurement activities shows a very broad range of prices and suggests that RA requirements were not satisfied at least cost. Additionally, since the pricing of RA capacity is left to the individual negotiations between an LSE and a supplier, the existing RA	The ISO does not intend to change the current RA program significantly. The current RA program, which is based on a bilateral procurement framework overseen by the CPUC and LRAs, has worked well and provided many benefits. The ISO does not intend to move away from this construct. The RA framework will continue to rely on the RA programs and bilateral procurement processes overseen by state regulatory commissions and LRAs. The ISO intends to only change those tariff provisions where modification is appropriate to make RA work more effectively in the context of an expanded ISO BAA. This stakeholder initiative is focused on "need to have" items for a more regional ISO, and the ISO does not intend for this initiative to explore broader changes to the general RA construct.

Topic	Stakeholder	Question/Comment	ISO Response
		construct fails to produce transparent price signals regarding the value of RA capacity that could create long-term incentives for additional market entry where it is most needed.	
RA Rules	Northwest Intermountain Power Producers Coalition (NIPPC)	NIPPC believes that RA rules must not discriminate between independently owned generation and generation owned by LSEs. In the current ISO market structure, generation resources owned by LSEs are able to recover the fixed costs of that generation through their retail rates - and need to recover only their operating costs through the energy market. Independently owned generators that do not have contracts with the regulated utilities for the output of their generation, however, must recover both their fixed and variable costs through their energy bids into the market. This difference in the treatment of fixed costs threatens the long-term viability of independent power to participate in the marketplace and provide low cost/low risk generation resources to loads across the West. This issue of procuring adequate capacity on fair and reasonable terms is a challenge in organized markets across the country. But this has also been an issue in the bilateral markets in the West. For example, in the Pacific NW, the NW Power and Conservation Council has struggled with how to account for the seasonal availability of independently owned generation that is installed in the region but not under contract. While NIPPC recognizes that this process is not the appropriate one in which to undertake a wholesale review of the ISO's RA mechanisms, these issues will need to be revisited in the future.	The ISO does not intend to change the current RA program significantly. The current RA program, which is based on a bilateral procurement framework overseen by the CPUC and LRAs, has worked well and provided many benefits. The ISO does not intend to move away from this construct. The RA framework will continue to rely on the RA programs and bilateral procurement processes overseen by state regulatory commissions and LRAs. In this initiative, the ISO only intends to change those tariff provisions where modification is appropriate to make RA work more effectively in the context of an expanded ISO BAA. This stakeholder initiative is focused on "need to have" items for a multi-state ISO, and the ISO does not intend for this initiative to explore broader changes to the general RA construct. The ISO notes that it annually seeks stakeholder input regarding the initiatives the ISO should consider as part of the ISO's development of a stakeholder initiatives catalog The ISO encourages NIPPC to actively participate in that process.

Appendix 2 - Load Forecasting Review

This appendix compares the load forecasting process that is currently used for the ISO's current BAA to the processes used by PacifiCorp and the Midcontinent Independent System Operator ("MISO"). The purpose of this comparison is to provide background for discussion surrounding the potential issues and opportunities associated with the different load forecasting structures.

Summary

Key features of the three processes are summarized in the table below.

Table 1 - Comparison of Load Forecasting ISO, PacifiCorp and MISO

Element	ISO	PacifiCorp	MISO
Load Forecast Used	System: 1 in 2 years Local: 1 in 10 years Flexibility: 1 in 2 months	1 in 20 years	1 in 10 years
Coincidence Adjustment	Yes	Yes	Yes
Defined Areas	Load Pockets LCR Areas	States	Local Resource Zones (LRZs)
Independent Forecasts	Yes (CEC)	No	Yes (Third Party)
Plans/Filed	Integrated Energy Policy Report/Biennial & CEC Load Forecast annually	Integrated Resource Plan/Biennial	N/A
PRM	15-17%	13%	14.8% (determined annually)
RRA Allocation	System: allocated to LSEs by coincident peak load based on LSEs load share Local: subset of system RA requirements Flexible: allocated to LRAs based on their LSEs' contribution to net load ramp	N/A	Local Reliability Requirement: LRZs must yield 1 in 10-year Loss of Load Expectation1 (LOLE) with no assistance from resources outside the respective zone

California Energy Commission Load Forecasting

The ISO's current RA program is a planning and procurement process consisting of one-year-ahead and one-month-ahead resource showings of each Load Serving Entity's (LSE's) capacity to meet its expected load, plus a 15-17% Planning Reserve Margin (PRM). The ISO, CEC, CPUC, and other Local Regulatory Authorities (LRAs), including publicly-owned utilities, work together under unified planning assumptions to preserve grid reliability and ensure adequate resources satisfy demand. The CEC independently prepares load forecasts every year through its Integrated Energy Policy Report (IEPR) to determine LSE procurement requirements. This forecast spans ten years and covers all load within California.

[1] LOLE: A count on the expected (mean) number of reliability events over the course of a year. A LOLE event equates to one event in 10 years and is a common reliability target in the industry.

In parallel, each April, the CPUC's LSEs submit the preceding year's historical sales and hourly load data, the upcoming year's monthly peak demand forecasts, and monthly and year-ahead load forecasts (which may be resubmitted by August to account for load migrations or revised assumptions).

The CEC annually assesses the reasonableness of demand forecasts by comparing LSEs' load forecasts to their historic load and recent monthly forecasts. The CEC may make monthly "plausibility" adjustments to LSE forecasts if the forecast diverges unreasonably from the LSE's actual peak loads or historical usage taking into account load migration patterns. The CEC aggregates the adjusted load forecast and provides these estimates to the CPUC. The CPUC then uses these to determine annual and monthly System RA obligations. In addition, the CEC reports peak electricity demand for all of California and five utility planning areas: Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, Sacramento Municipal Utility District, and Los Angeles Department of Water and Power. After CP and plausibility adjustments are applied, the CEC allocates credit for energy efficiency (EE), demand response (DR), and distributed generation (DG) programs in each of its three IOU service areas.

Additional detail on the CEC load forecasting process is provided at the end of this document.

PacifiCorp Load Forecasting

PacifiCorp's Integrated Resource Plan (IRP) utilizes a load forecast that estimates energy sales and peak demand over a 20-year period within the six states that it serves. PacifiCorp prepares its IRP on a biennial schedule, filing its plan with state utility commissions during each odd numbered year. For even-numbered years, PacifiCorp updates its preferred resource portfolio and action plan by considering the most recent resource cost, load forecast, regulatory, and market information. PacifiCorp uses three load forecast sensitivities—Low Load Forecast Sensitivity reflecting low economic growth, High Load Forecast Sensitivity reflecting high economic growth, and a 1-in-20 Extreme Load Scenario in which the peak has the chance of occurring once in 20 years. PacifiCorp also divides its forecasts into classes that use energy for similar purposes (residential, commercial, industrial, and irrigation and street lighting), each being uniquely forecast using monthly sales by class in each jurisdiction and variables specific to their usage patterns.

Jurisdictional Peak Load Forecasts are modeled at the state level, using econometric equations that relate observed monthly peak loads, peak load producing weather and the weather-sensitive loads for all classes. To develop state-level hourly load forecasts, PacifiCorp uses hourly load models that include state-specific hourly load data, daily weather variables, 20-year average temperatures, historical weather patterns, and day type variables. These hourly forecasts, adjusted to match monthly peaks, are aggregated to the total system level to identify coincidence levels and each jurisdiction's contribution to the PacifiCorp system monthly peaks.

Additional detail on the PacifiCorp load forecasting process is provided at the end of this document.

MISO Load Forecasting

MISO conducts load forecasting using reporting by Local Balancing Authorities (LBA) and LSEs with real-time and historical input data. For each LBA, MISO provides a short term load forecast (STLF) that produces a five-minute integrated forecast load, and a medium term load forecast (MTLF) that provides a seven-day hourly load forecast. LSEs are then required to submit Non-Coincident Peak (NCP) demand and energy bids for load forecasts, as well as CP demand forecasts to determine each LSE's PRM requirement. MISO requires LSEs with demand and energy not subject to retail choice switching to provide a forecast on November 1st for the following planning year, whereas LSEs subject to retail choice switching must report their share within Electric Distribution Companies' forecasts.

In addition, an unbiased third party conducts an Independent Load Forecast utilizing state-level forecasts to construct ten-year, annual, energy, and seasonal peak demand forecasts for the MISO System and for each Local Resource Zone (LRZ). MISO consists of nine LRZs, developed to reflect the need for adequate Planned Resources within specific physical locations. Through these LRZ forecasts, an Independent System Forecast offers additional outlook on future demand from a regional perspective, in addition to LSEs' forecasts. MISO determines each LRZ's forecast using an allocation method based on the fraction of each states load within a specific LRZ.

Additional detail on the MISO load forecasting process is provided at the end of this document.

CEC Load Forecasting
Resource Adequacy 2016 Load Forecast Adjustment Methodology

Miguel Cerrutti
Demand Analysis Office – California Energy Commission
Donald Brooks
Energy Division – California Public Utilities Commission

October 2015

This report documents the methodology used by the Demand Analysis Office (DAO) of the California Energy Commission (CEC) to implement the process defined by the California Public Utility Commission's (CPUC's) Decision (D.) 05-10-042 for the 2016 compliance year. The process consists of adjusting CPUC jurisdictional load-serving entities (LSEs) peak load forecasts to be used for year-ahead and month-ahead CPUC Resource Adequacy (RA) program compliance. The program requires LSEs to submit monthly and annual compliance fillings to ensure they have adequate capacity commitments to satisfy peak demand plus reserves. The methodology the CEC applies to LSE compliance information includes five distinct adjustments: forecast, coincidence, plausibility, demand side management, and prorating to the overall CEC demand forecast.

(1) Development of IOU Service Area Forecasts

CEC's peak-load forecast for each investor owned utility (IOU) service area is derived from short-term weather normalized peak-load forecasts for each transmission access charge (TAC) area[2]. Weather normalization factors out the variations in weather allowing for comparison of peak loads over time under different weather conditions. Weather normalization consists of regressing daily peak loads on weather and calendar effects and using the regression estimates with historical weather patterns in a Monte Carlo simulation to produce a distribution of peak loads of which the median, the one-in-two, represents the weather normalized peak loads. To better capture peak load's weather sensitivity and adequately represent the latest weather patterns, weather normalization requires four years (2011 – 2014) of CAISO's Energy Management System (EMS) data to estimate correlation between peak load and recent weather patterns and 30 years (1985 – 2014) of weather data to define normal weather conditions.

The two-step time-series regressive analysis based on peak-producing days and Monte Carlo simulation produces one-in-two weather normalized peak loads for summer and for each month, which are compared and adjusted with historic peak loads and load shapes of each service area. Weather normalized peak loads are projected two years ahead (2016), i.e. locked two years out, using the latest economic and demographic information. The one-in-two weather normalized peak loads for summer form the base to develop Integrated Energy Policy Report (IEPR) peak loads at the IOUs service areas after they have been adjusted downward by critical peak pricing, peak time rebate and non-event based demand program impacts (real time or time of use pricing and permanent load shifting). The one-in-two weather normalized monthly peak loads for each month are used by the CEC to reconcile the aggregate LSEs year-ahead forecasts in each IOU area for RA compliance.

CPUC jurisdictional LSEs submit peak demand forecasts each year by following the "best estimate approach". LSEs use reasonable assumptions for monthly demand growth and load migration and create a forecast of their individual non-coincident peak load. These monthly forecasts are checked to ensure that transmission, distribution, and unaccounted for energy losses are properly included. Adjustments to IOU forecasts typically reflect differences in forecast assumptions compared to the CEC forecasts while adjustments to energy service provides (ESPs) forecasts reflect uncertainty in load migration assumptions.

[2] For details, see Resource Adequacy Forecast Adjustment(s) Allocation Methodology. R.14-10-010 Workshop PUC February 9, 2015.

(2) Coincident Factor Adjustment

The CEC evaluates each LSE load forecast individually and performs an adjustment to reflect the LSE's load contribution to the coincident CAISO's system peak in that month. CEC staff developed a methodology to calculate LSE-specific monthly coincidence factors[3]. CEC staff began by collecting LSE hourly load data and CAISO settlement loads from the EMS database for the immediately preceding year (i.e. 2014). The coincident factor reflects each LSE's forecast contribution to hourly load at the time of CAISO's peak load. The coincidence factor is calculated as the ratio of each LSE's load at the time and hour of the five highest monthly CAISO system peak loads to the specific LSE's actual non-coincident peak load in any given month. This step results in five factor values for each month; the median represents the LSE-specific monthly coincidence factor for the coming compliance year (i.e., 2016). The median is better suited as an indicator of central tendency due to the skewed nature of the peak load values. The LSE-specific coincidence adjustment factor is used in setting the LSE's RA obligation. The RA obligations are also used in calculating the load factors used to allocate RA capacity credit and import transfer rights.

CPUC staff in coordination with CEC staff based the coincidence adjustments on the previous three years of load information, due to concerns about the disproportionate impact of outlier events due to small sample size. Greater sample sizes better approximate historical trends across all months of the year. Annual variability is more related to weather than to load composition. For that reason, factors were estimated using a longer time interval, using data from 2012 through 2014.

Although a greater sample size from three years of data eliminated most of the observed variability and outlier results, inter-year variability persisted for some LSE forecasts and produced unreasonable results. Atypically extreme weather events unreasonably bias results with small sample sizes, but larger sample sizes obscure changing trends in load composition that are more reflective of the future than past load trends. A median based on a three-year interval captures simultaneously central tendency and variability in the recent load composition and latest weather effects. This step results in the median of fifteen factor values representing the LSE-specific monthly coincidence factor for the coming compliance year.

Table 1 shows the date, time, and load of the five highest monthly system peak loads in CAISO by month and year. Since CAISO's EMS contains confidential information, Table 1 presents the information based on CAISO Open Access Same-Time Information System (OASIS), which is considered a proxy for EMS.

Table 1 2012-2014 CAISO OASIS Coincident Peaks

2012	5	1	31	17	36327	
2012	5	2	31	18	36152	
2012	5	3	31	16	35868	
2012	5	4	31	19	35472	
2012	5	5	31	15	35047	
2012	6	1	1	17	36810	
2012	6	2	1	16	36712	
2012	6	3	1	15	36169	
2012	6	4	20	17	36189	
2012	6	5	12	17	36075	

(3) Plausibility Adjustment

As provided by CPUC Decision (D.) 04-10-035, CEC staff determines whether an LSE's forecast is plausible by comparing preliminary LSE coincidence adjusted submitted forecasts with CEC's adopted IOU service area forecasts. CEC staff

[3] LSE specific coincidence adjustments were adopted in D. 12-06-025.

performs a plausibility comparison for individual LSE forecasts to the most recent month-ahead load forecasts, August, and adjusts them if the difference is greater than a tolerance threshold. An estimate of current monthly peak demand is calculated from monthly load profiles and recent LSE-specific month-ahead peak demand forecasts. If an LSE's monthly forecast exceeds the tolerance threshold, then CEC staff evaluates the reasonableness of the forecast and will adjust the forecast to make it more plausible. CEC staff allows LSE forecasts to be up to five percent divergent from CEC estimates before the forecast is considered implausible.

(4) Demand side Management Allocation Adjustment

After the coincidence adjustments and plausibility adjustments are applied, CEC staff allocates credit for energy efficiency (EE), demand response (DR), and distributed generation (DG) programs in each of the three IOU service areas[4]. The allocation accounts for the proportion of the load impacts accruing to each LSE due to a portion of the distribution charge paid by their customers. CEC staff allocates the impacts of the programs to LSEs proportionate to their share of load and so the decrease to their loads equals to the sum of the EE/DR/DG credit. Consistent with the direction in CPUC Decision (D.) D.05-10-042, depending on whether all customers or only bundled customers participate, program impacts are allocated to each LSE based on its share of total load or to IOUs only.

Finally adjustments are then made to LSE forecasts to account for Demand Response (DR) programs that are paid for through distribution charges. Time of Use, Permanent Load Shifting, Critical Peak Pricing, and Peak Time Rebate programs all decrease the CEC load forecast and are listed as downwards adjustments as part of the DR adjustment. The downwards effects of these programs impact IOU forecasts only or load forecasts for all bundled and non-bundled customers depending on how the costs of the program are recovered.

(5) Prorated Adjustment to Conform to Overall CEC Forecast

As established in CPUC Decision (D.) 05-10-042, after making the above adjustments CEC staff compares the aggregate of LSE's adjusted load forecasts to CEC's adopted load forecasts and reconciles them if they differ by more than one percent in a given month by applying the pro-rata adjustment to bring the total of the forecasts within one percent of the CEC's monthly weather normalized forecasts for IOUs service areas. CEC staff evaluates the reasonableness of the pro-rata adjustment for each LSE and service area.

From the aggregate LSE forecasts, CEC calculates monthly load shares for each TAC area that are used to allocate DR, cost-allocation methodology (CAM), and reliability must-run (RMR) RA credits. The forecasts and load shares for August are also used to allocate Local RA obligations. The forecasts and the allocations together determine the system annual and monthly RA obligations.

[4] These adjustments are directed by CPUC Decision (D.) 05-10-042.

PacifiCorp: Load Forecasting

Purpose:

Review of PacifiCorp load forecasting may be useful for discussion of the incorporation of PacifiCorp into the ISO BAA. This review provides a high level overview of the methodology that PacifiCorp has adopted for its load forecast. Appendix A of PacifiCorp's 2015 IRP contains additional detail related to PacifiCorp's load forecast and can be found at http://www.pacificorp.com/es/irp.html, under 2015 IRP (March 31, 2015) – 2015 Integrated Resource Plan – Volume II, Appendices.

PacifiCorp Load Forecasting Overview:

PacifiCorp's Integrated Resource Plan conducts load forecasts using estimates of energy sales and peak demand over a 20 year period. The Integrated Resource Plan is prepared and filed at its six state utility commissions every other year. PacifiCorp uses three load forecast sensitivities including Low Load Forecast Sensitivity, High Load Forecast Sensitivity, and a 1-in-20 Extreme Load Scenario.

PacifiCorp's forecast is divided by class based on how each class uses its energy. These include the residential, commercial, irrigation and street lighting, and industrial classes. Each class is modeled separately then used to develop hourly load forecasts.

The hourly load forecasts for each jurisdiction are aggregated to the total system level, which allows PacifiCorp to determine coincidence levels and the contribution of each jurisdiction to the monthly peak.

PacifiCorp Load Forecasting:

Introduction

The load forecast used in the IRP is an estimate of the energy sales, and peak demand over a 20-year period. The 20-year horizon is important to anticipate electricity demand in order to develop timely response of resources.

In the development of its load forecast PacifiCorp employs econometric models that use historical data and inputs such as regional and national economic growth, weather, seasonality, and other customer usage and behavior changes. The forecast is divided into classes that use energy for similar purposes and at comparable retail rates. The classes are modeled separately using variables specific to their usage patterns. For residential customers, typical energy uses include space heating, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, televisions and various other end use appliances. Commercial and industrial customers use energy for production and manufacturing processes, space heating, air conditioning, lighting, computers and other office equipment.

Jurisdictional peak load forecasts are developed using econometric equations that relate observed monthly peak loads, peak load producing weather and the weather-sensitive loads for all classes. The system coincident peak forecast, which is used in portfolio development, is the maximum load required on the system in any hourly period and is extracted from the hourly forecast model.

Regional Economy by Jurisdiction

The PacifiCorp electric service territory is comprised of six states and within these states the Company serves a total of 90 counties.

The level of retail sales for each state and county is correlated with economic conditions and population statistics in each state. The Company uses both economic data, such as employment, and population information, such as household data, to forecast its retail sales.

Weather

The Company's load forecast is based on normal weather defined by the 20-year time period of 1994-2013. The Company updated its temperature spline models to the five-year time period of 2009-2013. The Company's spline models are used to model the commercial and residential class temperature sensitivity at varying temperatures.

Statistically Adjusted End-Use ("SAE")

The Company models sales per customer for the residential class using the SAE model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are heating and cooling related variables, equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price. The Company uses ITRON for its load forecasting software and services, as well as SAE. To predict future changes in the efficiency of the various end uses for the residential class, an excel spreadsheet model obtained from ITRON was utilized; the model includes appliance efficiency trends based on appliance life as well as past and future efficiency standards. The model embeds all currently applicable laws and regulations regarding appliance efficiency, along with life cycle models of each appliance. The life cycle models, based on the decay and replacement rate are necessary to estimate how fast the existing stock of any given appliance turns over, i.e. newer more efficient equipment replacing older less efficient equipment. The underlying efficiency data is based on estimates of energy efficiency from the US Department of Energy's Energy Information Administration (EIA). The EIA estimates the efficiency of appliance stocks and the saturation of appliances at the national level and for individual Census Regions.

Individual Customer Forecast

The Company updates its load forecast for a select group of large industrial customers, self-generation facilities of large industrial customers, and data center forecasts within the respective jurisdictions. Customer forecasts are provided by the customer to the Company through a customer account manager ("CAM").

Class 2 Demand-side Management (DSM) Resources in the Load Forecast

PacifiCorp modeled Class 2 DSM as a resource option to be selected as part of a cost-effective portfolio resource mix using the Company's capacity expansion optimization model, System Optimizer. The load forecast used for IRP portfolio development excluded forecasted load reductions from Class 2 DSM; System Optimizer then determines the amount of Class 2 DSM—expressed as supply curves that relate incremental DSM quantities with their costs—given the other resource options and inputs included in the model. The use of Class 2 DSM supply curves, along with the economic screening provided by System Optimizer, determines the cost-effective mix of Class 2 DSM for a given scenario.

Modeling Overview

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential sales forecast is developed as a use-per-customer forecast multiplied by the forecast number of customers.

The customer forecasts are based on a combination of regression analysis and exponential smoothing techniques using historical data from January 2000 to February 2014. For the residential class, the Company forecasts the number of customers using IHS Global Insight's forecast of each state's number of households as the major driver.

The Company models sales per customer for the residential class using the SAE model discussed above, which combines the end-use modeling concepts with traditional regression analysis techniques.

For the commercial class, the Company forecasts sales using regression analysis techniques with non-manufacturing employment designated as the major economic driver, in addition to weather-related variables. Monthly sales for the commercial class are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers. The development of the forecast of monthly commercial sales involves an additional step; to reflect the addition of a large “lumpy” change in sales such as a new data center, monthly commercial sales are increased based on input from the Company’s CAM’s. Although the scale is much smaller, the treatment of large commercial additions is similar to the methodology for large industrial customer sales, which is discussed below.

Monthly sales for irrigation and street lighting are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers.

The majority of industrial sales are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver. For a small number of the very largest industrial customers, the Company prepares individual forecasts based on input from the customer and information provided by the CAM’s.

After the Company develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps. First, monthly peak forecasts are developed for each state. The monthly peak model uses historical peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. The weather variables include the average temperature on the peak day and lagged average temperatures from up to two days before the day of the forecast. The peak forecast is based on average monthly historical peak-producing weather for the 20-year period, 1994 through 2013. Second, the Company develops hourly load forecasts for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures as identified above, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly peaks from the first step above. Hourly loads are then adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified, as well as the contribution of each jurisdiction to those monthly peaks.

Alternative Load Forecast Scenarios

The purpose of providing alternative load forecast cases is to determine the resource type and timing impacts resulting from a change in the economy or system peaks as a result of higher than normal temperatures.

The September 2014 forecast is the baseline scenario. For the high and low economic growth scenarios assumptions from IHS Global Insight were applied to the economic drivers in the Company’s load forecasting models. These growth assumptions were extended for the entire forecast horizon.

Recognizing the volatility associated with the oil and gas extraction industries, PacifiCorp applied additional assumptions for the Utah and Wyoming industrial class load forecasts in the high and low scenario. Specifically, the Company focused on the increased uncertainty of the industrial load forecast as it moves further out in time. In order to capture this increased uncertainty the Company modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The 1,000 load values are then ranked and the Company selected the 95th percentile and 5th percentile of the Utah and Wyoming industrial loads for both the low and high growth scenarios.

MISO Load Forecasting

Purpose:

Review of MISO's load forecasting may be useful for discussion due to the geographic and regulatory framework of the MISO region, which is multi-state. This review provides a high level overview of the methodologies and requirements that MISO has adopted for its load forecasting.

MISO Load Forecasting Overview:

MISO conducts load forecasts in the short term and medium term. MISO provides short term load forecast (STLF) for use in the Real-Time Energy and Operating Reserve Market that produces the 5 minute integrated forecast load for each LBA in MISO. The medium term load forecast (MTLF) provides an hourly load forecast for seven days for use in the Reliability Assessment Commitment process for the Real-Time Energy and Operating Reserve Market.

In order to develop their load forecasts, MISO requires Load Forecast reporting by Local Balancing Authorities (LBA) and individual LSEs. To produce a STLF, MISO requires real-time input data provided at a fixed interval. For the MTLF, LBAs and LSEs are required to submit a seven day hourly load forecast twice daily.

MISO employs various Peak Forecasting methodologies for use in resource adequacy. LSEs are required to submit Non-Coincident Peak (NCP) demand and energy for load forecasts as well as Coincident Peak (CP) Demand Forecasts to determine each LSE's Planning Reserve Margin Requirement.

In addition to Load Forecasts by LSEs, MISO has instituted an Independent Load Forecast developed by an unbiased, third-party vendor, State Utility Forecasting Group. This Forecast is used as an additional outlook on future demand.

MISO Load Forecasting:

1. **Short Term Load Forecasting (STLF)**
    a. Forecast Granularity: 5 minute interval updated every 5 minutes up to 6 hours out
    b. Obtained by summing up the forecasts for the LBAs that are in the market footprint
    c. Inputs of the STLF
        i. Real time input data:
            1. The total LBA ICCP load submitted to MISO via ICCP at 2 second frequency
        ii. Historical input data:
            1. The historical LBA load going back to at least 1 year at 1 minute granularity
            2. Similar day information
                a. Day of the week
                b. Special events
                c. Day light saving time changes
                d. Holidays
    d. ICCP Data Requirements
        i. Each LBA within MISO is required to send valid ICCP data to MISO at a fixed interval
    e. LBA Data Validation Checks
        i. Total ICCP load should not exceed the defined load min/max limits for the LBA
        ii. Total ICCP should not exceed the defined hourly rate-of-change for the LBA
        iii. If the ICCP data violated the above checks, the state estimator solved value for the LBA load is used in place of the total LBA load
2. **Medium Term Load Forecasting (MTLF)**
    a. Forecast Granularity:
        i. Hourly intervals for the current day plus 6 following days, updated every 15 minutes

        ii. The peak for each day following the 7 day period covered by the hourly load forecast for 31 days
    b. Inputs of MTLF
        i. Weather forecast information downloaded every 30 minutes
        ii. At least 3 years' worth of historical load for each LBA
        iii. Real time load profile from current day operations for each LBA
        iv. Calendar information
    c. MTLF Requirements
        i. Each LBA is required to send at least 7-day hourly load forecasts to MISO
        ii. Each LBA is required to update and submit MTLF data at least twice daily
        iii. Whenever applicable, MISO requires the LBA to submit their pump load schedules and update when necessary
    d. LBA Data Validation Checks
        i. Forecast data should not:
            1. Exceed the defined load min/max limits for the LBA
            2. Exceed the defined hourly rate-of-change for the LBA
            3. Be older than 24 hours
            4. Contain any blank value
        ii. If violated, the LBA forecast will be replaced by the MISO generated load forecast

3. Peak Forecasting
    a. Methodologies
        i. End-Use:
            1. An enumeration of end-uses and specification of the level of each use
            2. Critiques: under-forecasting
        ii. Econometric:
            1. Based on statistically estimated forecasting equations linking electricity use to key variables
            2. Critiques: inability to directly account for specific activities or requirements
            3. MISO uses this to forecast load
        iii. Hybrid:
            1. End-use structure embedded in an overall model with econometric estimations
    b. Non-Coincident Peak (NCP) Demand Forecasts
        i. Reported on monthly basis for forecast years 1 and 2 and on a seasonal basis for years 3-10
    c. Coincident Peak (CP) Demand Forecasts
        i. Used to determine each LSE's Planning Reserve Margin Requirement
        ii. Based on historical weather conditions, economic conditions, and expected load changes
        iii. CPD forecasts are required by MISO's settlements process
        iv. NCP Forecast * Coincidence Factor = CP Forecast
            1. Where Coincidence Factor is defined as the relationship between CP and NCP
    d. Forecast Reporting
        i. LSEs with demand and energy not subject to retail choice switching:
            1. Must provide MISO with demand and energy forecast on Nov. 1st for the following planning year
        ii. LSEs with demand and energy subject to retail choice switching:
            1. Not required to provide MISO with demand and energy forecasts but must work with Electric Distribution Companies to report their share of EDC's forecasts
            2. Electric Distribution Companies are responsible for submitting forecasts in areas of retail choice switching

4. Independent Load Forecasting

a. MISO hired the State Utility Forecasting Group to develop 10 year demand and energy forecasts annually for the next three years.
b. Its Purpose:
    i. To gather an independent view of future demand in MISO
    ii. To provide transparency into the process and assumptions
    iii. To provide additional data for stakeholder discussions
c. Independent Load Forecasting Methodology
    i. Step 1: State Forecasting Models: Develop an econometric model for each state in the MISO footprint
        1. Inputs:
            a. Weather
            b. Population
            c. Employment
            d. Income
            e. Gross State Product
            f. Electricity Price
            g. Natural Gas Price
    ii. Step 2: Annual State Retail Sales: Use the State Forecasting Model from Step 1 to forecast retail sales for a 10 year period
        1. Inputs:
            a. State Forecasting Models
            b. Projections of Forecast Drivers
            c. State Energy Efficiency (EE) Standards
    iii. Step 3: Local Resource Zone (LRZ) Annual Energy: Use the statewide energy forecasts to construct a forecast for each LRZ
        1. The allocation method is based on the fraction of each state's load that is in a specific LRZ
        2. Inputs:
            a. Annual State Retail Sales with and without EE adjustments
            b. Allocation factors
    iv. Step 4: LRZ Seasonal Peak Demands: Use the LRZ annual energy forecast to develop seasonal non-coincident peak demand projections for each LRZ
        1. Inputs:
            a. LRZ Annual Energy Forecasts
            b. MISO LBA hourly loads
            c. Weather
            d. Coincident Factors
    v. Step 5: MISO System Forecasts: Use the LRZ Annual Energy Forecasts from Step 3 to project the Coincident Peak demand for the MISO
        1. Inputs:
            a. Coincidence Factors
d. How it works with LSE Forecasting
    i. Not done to replace LSE and TO Forecasting
    ii. Independent Load Forecasting is a top-down approach while LSE and TO forecasting is a bottom up approach
    iii. Represents MISO from a regional perspective
    iv. Offers additional outlook on future demand

Appendix 3 - PacifiCorp Load Serving Entities and Transmission System Map

Load Serving Entities

February 18, 2016

Name	BAA
Basin Electric Power Cooperative	PACE
Black Hills Power, Inc.	PACE
Bonneville Power Administration - Power Services	PACE, PACW
Deseret Power	PACE
Exelon Generation Company, LLC	PACW
Iberdrola Renewables, Inc.	PACW
Noble Americas Energy Solutions LLC	PACW
PacifiCorp Market Function	PACE, PACW
Portland General Electric Company	PACW
Shell Energy North America (US), L.P.	PACE
South Columbia Basin Irrigation District	PACW
Tri-State G & T Power Marketing	PACE
United States Bureau of Reclamation	PACW
Utah Associated Municipal Power Systems	PACE
Utah Municipal Power Agency	PACE
Western Area Power Administration	PACE, PACW

Transmission System Map

February 4, 2016

A map of PacifiCorp's transmission system is posted to the ISO website for this stakeholder initiative at the following link: http://www.caiso.com/Documents/PacifiCorpTransmissionSystemMap-PathRatings.pdf. This map is from PacifiCorp's OASIS site and is public information. The map shows some of the internal path ratings and WECC path ratings, as well as resource types, capacity and a general location of facilities.