Clarifications to the Reliability Must Run Designation Process

Final Proposal

November 1, 2021

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1. Introduction

The purpose of this initiative is to clarify the Reliability Must Run (RMR) designation type (local or system) when more than one reliability reason for designation exists.

Per ISO Tariff – Appendix A, Reliability Must-Run Generation (RMR Generation) is defined as the "Generation that the ISO determines is required to be on line to meet Applicable Reliability Criteria requirements. This includes i) Generation constrained on line to meet NERC and WECC reliability criteria for interconnected systems operation; ii) Generation needed to meet Load demand in constrained areas; and iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area."

Tariff section 41.2 "Reliability Studies and Determination of RMR Status" specifies that in addition to the Local Capacity Technical Study under 40.3.1, the ISO may perform additional technical studies, as necessary, to ensure generators are retained for compliance with Reliability Criteria. Stakeholders have requested the ISO clarify the order and type of designation when more than one RMR designation need (local and system) exists.

1.1. Background

A Reliability Must-Run Contract is a contract entered into by the ISO with a resource owner that operates a Generating Unit or other resource giving the ISO the right to call on the Generating Unit or Resource to generate Energy, provide Ancillary Services, Black Start, Voltage Support or similar services to maintain the reliability of the ISO Controlled Grid.

The Reliability Must Run contract is in existence since ISO start-up and it evolved through time from being the main source of procuring local resources across the ISO footprint into being the back stop against resource retirement and/or mothball for those resources that are required in order to maintain reliability and compliance of the ISO controlled grid with all NERC, WECC and ISO reliability standards (local and system).

Since start-up the ISO always had resources under Reliability Must Run contract to maintain compliance with reliability standards in different local areas across its footprint. It was only starting this year when ISO denied retirement/mothball requests for system wide reliability needs. These needs include maintaining contingency reserve requirements per the BAL-002 reliability standards as well as unloaded capacity to meet operating needs per BAL-001 and BAL-003 reliability standards.

Reference for Tariff and business practice manual (BPM) as follows:

1. ISO Tariff section 41: http://www.caiso.com/Documents/Section41-Procurement-RMRResources-asof-Sep28-2019.pdf

2. Reliability Requirements BPM sections 12.1:
https://bpmcm.caiso.com/BPM%20Document%20Library/Reliability%20Requirements/BPM%20for%20Reliability%20Requirements%20Version%2059.docx

2. Issue Paper: Clarifications to the Reliability Must Run Designation Process

Per ISO Tariff section 41.2 the ISO has the right at any time based upon ISO Controlled Grid technical analyses and studies to designate a Generating Unit or other resource as a Reliability Must-Run Resource. These ISO Controlled Grid technical analyses and studies include the need to provide Ancillary Services or other system wide reliability services.

The reliability need triggers the cost allocation as well as the resource adequacy credits allocation of the Reliability Must Run contract. Per ISO Tariff section 41.9 "the ISO will allocate Reliability Must-Run costs not recovered through market revenues to the Scheduling Coordinators for Load-Serving Entities that serve load in the TAC Area(s) in which the need for the RMR Contract arose". Also per ISO Tariff section 41.8 "the ISO will provide Resource Adequacy credits to the Scheduling Coordinators of Load-Serving Entities that serve load in the applicable TAC Area(s) in which the need for the RMR Contract arose equal to the Load-Serving Entity's pro rata share of the eligible net qualifying capacity of the RMR Resource".

2.1. Primary reliability need

If there are multiple reliability needs, for example local and system, than the ISO must pick one as the primary reliability need that will trigger the designation and the Reliability Must Run contract.

Issues to consider when choosing the primary reliability need:

1. Historically, since start-up, the ISO only designated resources for local reliability needs and it currently considers it the primary reliability need any time it is binding.

2. The responsible utility, within the TAC areas bearing the RMR local costs, has the incentive to invest in the needed infrastructure to eliminate the local reliability need. The incentive to invest in infrastructure to address local issues that drive local designations can be maintained if local designation continues to be the primary reliability need. If the system need is considered the primary reliability need then the incentive to invest in infrastructure to address local issues is lost until the system reliability need is mitigated.

3. Once under a Reliability Must Run contract the resource can be used to mitigate all reliability needs both local and system and therefore all customers benefit from the resource. However, the customers located in the TAC areas where the local reliability need exists will benefit the most because the unit is required to meet local needs in their TAC areas as well as system needs and the customers outside of the TAC areas where the local reliability need exists do not get the local benefit.

4. Generally, per all CPUC Resource Adequacy reports, there is a premium paid for local resources. The "local" Resource Adequacy credits, given in the TAC areas where the local reliability problem exists, to any LSE paying for the Reliability Must Run contract, are more valuable to the LSEs with load in the same TAC areas where the local reliability exists. The same local credits will not be valuable for LSEs with load in other TAC areas (Example an LSE with load in SCE TAC area will have little to no use of local credits in PG&E TAC area).

5. If a system wide need is considered the primary need then all current local Reliability Must Run contracts will have to be designated and converted to system wide Reliability Must Run contracts (including cost and Resource Adequacy credit allocations) for as long as the system reliability need exists.

Other stakeholder proposed changes and improvements:

Please provide other suggestions related to the designation of a resource as Reliability Must Run.

Stakeholder Input

The CAISO has received comments from Cal-CCA, PG&E, SCE, Six Cities, Vistra and WPTF.

Stakeholder have generally provided mixed responses to the main issues raised.

Most stakeholders would like additional details regarding the RMR designation process.

3. Straw Proposal: Clarifications to the Reliability Must Run Designation Process

The ISO will move forward with clarifications to the Reliability Must Run designation process in order to provide transparency and consistency in RMR designation when more than one reliability needs exist.

3.1. Primary reliability need

Principles:

Cost-Causation

The ISO can designate a resource as reliability must run for any single reliability need, either for local or on system wide basis. When both local and system reliability needs are present one of them can be considered primary without distorting the cost-causation principle.

Generally the numbers of hours of expected need, in meeting mandatory standards and implicit ratepayer benefit, is high for local reliability requirements, in the range of tens-hundreds-thousands of hours per year, and generally low for system wide reliability needs, in the range of tens of hours per year.

Allocate costs in a manner that reflects benefits received

Load Serving Entities (LSEs) paying for the RMR contract receive RA credits (local, system and flex – if applicable) that go along with the intrinsic value given by the number of hours of expected usage in order to assure reliability of their load by mitigating the mandatory reliability standards.

The system and flex RA credits can be useful to all LSEs, however the local RA credits are only useful to the LSEs with load in the TAC where the resource is located. As such if local is considered the primary reliability need (when more than one need exists) then all RA credits are useful to all paying LSEs. If system is considered as the primary reliability need or if a hybrid methodology (where both local and system needs are accounted for in some predetermined percentage) is applied than the majority of the LSEs will have no use for the local RA credit given. (Example: An LSE with load in SCE, SDG&E or VEA TAC has no use of local RA credits in the PG&E TAC).

All public data available in the CPUC provided yearly RA reports, shows that local RA capacity is generally at a premium cost over system wide RA capacity cost. The RA value of the local RA credits is the highest among all types of RA credits provided and it can only be fully utilized when local is considered the primary reliability need. In any other situation the majority of the LSEs will be unable to use the local RA credits which are the most valuable type of RA credit.

Incentives:

Participating Transmission Owner incentive to build transmission in order to eliminate the local need

The responsible utility, within the TAC areas bearing the RMR costs, has the incentive to invest in the needed infrastructure in order to eliminate the local reliability need. The incentive to invest in infrastructure to address local issues that drive local designations is the highest when local designation is considered primary reliability need because the RMR costs are divided only among their ratepayers. This incentive is reduced for a hybrid cost allocation and is even lower when the system need is considered the primary reliability need.

Load Serving Entities incentive to procure the needed resource under an RA contract

Load Serving Entities (LSEs) have the highest incentive to procure the resource under an RA contract when their share of the cost allocation is the highest. Therefore the LSEs that pay for the RMR contract have the highest incentive to sign the resource under an RA contract when local is considered the primary reliability need. This incentive is highly diminished under hybrid cost allocation and even lower when the system need is considered the primary reliability need.

Other issues to consider:

Existing Reliability Must Run contract conversions

There is no need to change the RMR cost allocation or to convert the Oakland legacy RMR contract to a new RMR contract if local is considered the primary reliability need.

For a hybrid cost allocation or if system is considered the primary reliability need there is a need to change the cost allocations for certain existing RMR contracts. Also the Oakland legacy RMR contract needs to be converted to a new type of RMR contract because its costs are currently recouped by the PTO in the TAC area where the local need exists and therefore the PTO cannot recoup or allocate costs to LSEs outside its territory (for system wide reliability reasons).

Certain stakeholders have suggested, during the stakeholder call and in their comments, that the ISO should leave intact all old RMR contracts and only use the hybrid or system first designation for new RMR contracts. ISO disagrees with these views because that would result in discriminatory treatment based on the start date of the RMR contract and its original designation and would not reflect the reliability needs of the current system. The ISO has to run the evaluation of need (local and system) every year in order to evaluate if extension of the RMR contract is necessary and for what reasons; ignoring new reliability needs for some but not all needed resources would result in an unfair cost and RA credit allocation.

Expected mitigation time in order to eliminate the need

In order to eliminate (or reduce) local reliability problems generally new transmission projects are required. On average new transmission projects require long lead times in range of 5-10 years before they become operational. This includes time for ISO and PTO approval, CPUC environmental review and approval as well as time for construction.

In order to eliminate system wide reliability needs generally new resources are required. On average resources can become operational in 2-3 years from the time the system reliability need has been identified. ISO has a high number of resources in the ISO queue with studies complete that can be built in a few years after procurement contracts are signed.

ISO implementation costs and timelines

Implementation of either the local or system as being the primary reliability need can be accomplished rather quickly and at low cost because current ISO software is already configured to accept such designations.

Implementation of the hybrid allocation methodology will take longer and will have a higher cost because not only a new methodology needs to be approved however ISO software modifications need to be completed in order to implement such hybrid allocation.

Timing and complexity of hybrid designations

The topic of how to arrive at the appropriate split between local and system needs is complex and will require further stakeholder discussion, input and justification. A few examples are: split 50/50, split based on the number of mandatory standards, split based on number of contingencies, split based on expected number of hours of local need vs. system need etc.

The ISO is willing to conduct further stakeholder meetings to address such details however timing may become an impediment. The ISO has never had a system wide reliability need before 2021 and does not expect that to happen again after system reliability margin is restored. The ISO expects that the system wide reliability need will be eliminated in a short time. The current stakeholder process will not affect the year 2022 extensions for current RMR resources and any new Tariff and BPM may be in effect for year 2023 designation at the earliest. Depending on the amount and complexity of the software modifications required for hybrid designation it may further defer its implementation until 2024. The ISO would like to avoid the risk of building a new complex and complicated RMR cost allocation type and new software that based on past performance and current analysis has low chance of significantly impacting RMR designations in the foreseeable future.

Straw Proposal:

By looking at all the above listed principles, incentives and other issues, the ISO is proposing that local be designated as the primary reliability need when more than one need exists and that RMR cost allocation and RA credit allocation follow the same principle.

This type of designation is consistent with cost-causation principle and it is the only alternative that allows all paying LSEs to fully utilize their RMR provided RA credits including the most valuable, the local RA credits. It provides the highest level of incentives to the PTO in building new local transmission in order to eliminate the local need and also provides the highest level of incentives to LSEs in order to procure this resource under an RA contract. It is the only alternative that does not require either RA cost allocation change or the conversion of the legacy RMR contract for Oakland into the new type of RMR contract. It is simple, can be implemented by the ISO quickly and at low costs.

Other stakeholder proposed changes and improvements:

The ISO has a current process in order to allow resources (gas or otherwise) to convert to storage however the existing resource or its replacement must be available at the time of the expected reliability need. The ISO is working directly with resource owners to allow repowers in stages or under seasons (parts of the year) when reliability of the grid is not in jeopardy from either a local or a system need. The ISO may codify its existing process in the appropriate BPMs after further evaluation; however the ISO does not consider that significant changes are necessary or required.

Please provide other suggestions related to the designation of a resource as Reliability Must Run.

Stakeholder Input

The CAISO has received comments from Cal-CCA, PG&E and SCE.

The stakeholder process has low stakeholder involvement. Generally the stakeholders involved provided mixed responses to the main issues raised.

4. Final Proposal: Clarifications to the Reliability Must Run Designation Process

The ISO will move forward with clarifications to the Reliability Must Run designation process in order to provide transparency and consistency in RMR designation when more than one reliability needs exist.

4.1. Primary reliability need

Principles:

Cost-Causation

The ISO can designate a resource as reliability must run for any single reliability need, either for local or on system wide basis. When both local and system reliability needs are present one of them can be considered primary without distorting the cost-causation principle.

A few stakeholders suggested that the RMR contract represents RA capacity. The ISO wants to be clear that the RMR contract is a rate based contract for all costs incurred by the resource (including energy) and that the ISO is precluded from using the RMR contract to back-stop RA. The RMR contract is to be used exclusively to meet reliability standards and its main benefit is to prevent outages to firm load.

Generally the numbers of hours of expected need, in meeting mandatory standards and implicit ratepayer benefit, is high for local reliability requirements, in the range of tens-hundreds-thousands of hours per year, and generally low for system wide reliability needs, in the range of tens of hours per year.

Allocate costs in a manner that reflects benefits received

Load Serving Entities (LSEs) paying for the RMR contract receive, as a secondary benefit, RA credits (local, system and flex – if applicable) that go along with the main benefit given by the number of hours of expected usage in order to assure firm load reliability in mitigating mandatory reliability standards.

The system and flex RA credits can be useful to all LSEs, however the local RA credits are only useful to the LSEs with load in the TAC where the resource is located. As such if local is considered the primary reliability need (when more than one need exists) then all RA credits are useful to all paying LSEs. If system is considered as the primary reliability need or if a hybrid methodology (where both local and system needs are accounted for in some predetermined percentage) is applied then the majority of the LSEs will have no use for the local RA credit given. (Example: An LSE with load in SCE, SDG&E or VEA TAC has no use of local RA credits in the PG&E TAC).

All public data available in the CPUC provided yearly RA reports, shows that local RA capacity is generally at a premium cost over system wide RA capacity cost. The RA value of the local RA credits is the highest among all types of RA credits provided and it can only be fully utilized when local is considered the primary reliability need. In any other situation the majority of the LSEs will be unable to use the local RA credits which are the most valuable type of RA credit.

Incentives:

Participating Transmission Owner incentive to build transmission in order to eliminate the local need

The responsible utility, within the TAC areas bearing the RMR costs, has the incentive to invest in the needed infrastructure in order to eliminate the local reliability need. The incentive to invest in infrastructure to address local issues that drive local designations is the highest when local designation is considered primary reliability need because the RMR costs are divided only among their ratepayers. This incentive is reduced for a hybrid cost allocation and is even lower when the system need is considered the primary reliability need.

Load Serving Entities incentive to procure the needed resource under an RA contract

Load Serving Entities (LSEs) have the highest incentive to procure the resource under an RA contract when their share of the cost allocation is the highest. Therefore the LSEs that pay for the RMR contract have the highest incentive to sign the resource under an RA contract when local is considered the primary reliability need. This incentive is highly diminished under hybrid cost allocation and even lower when the system need is considered the primary reliability need.

Other issues to consider:

Existing Reliability Must Run contract conversions

There is no need to change the RMR cost allocation or to convert the Oakland legacy RMR contract to a new RMR contract if local is considered the primary reliability need.

For a hybrid cost allocation or if system is considered the primary reliability need there is a need to change the cost allocations for certain existing RMR contracts. Also the Oakland legacy RMR contract needs to be converted to a new type of RMR contract because its costs are currently recouped by the PTO in the TAC area where the local need exists and therefore the PTO cannot recoup or allocate costs to LSEs outside its territory (for system wide reliability reasons).

Certain stakeholders have suggested, during the stakeholder call and in their comments, that the ISO should leave intact all old RMR contracts and only use the hybrid or system first designation for new RMR contracts. The ISO disagrees with these views because that would result in discriminatory treatment based on the start date of the RMR contract and its original designation and would not reflect the reliability needs of the current system. The ISO has to run the evaluation of need (local and system) every year in order to evaluate if extension of the RMR contract is necessary and for what reasons; ignoring new reliability needs for some but not all needed resources would result in an unfair cost and RA credit allocation.

Expected mitigation time in order to eliminate the need

In order to eliminate (or reduce) local reliability problems generally new transmission projects are required. On average new transmission projects require long lead times in range of 5-10 years before they become operational. This includes time for the ISO and PTO approval, the CPUC environmental review and approval as well as time for construction.

In order to eliminate system wide reliability needs generally new resources are required. On average resources can become operational in 2-3 years from the time the system reliability need has been identified. The ISO has a high number of resources in the ISO queue with studies complete that can be built in a few years after procurement contracts are signed.

ISO implementation costs and timelines

Implementation of either the local or system as being the primary reliability need can be accomplished rather quickly and at low cost because current ISO software is already configured to accept such designations.

Implementation of the hybrid allocation methodology will take longer and will have a higher cost because not only a new methodology needs to be approved however ISO software modifications need to be completed in order to implement such hybrid allocation.

Timing and complexity of hybrid designations

The topic of how to arrive at the appropriate split between local and system needs is complex and will require further stakeholder discussion, input and justification. A few examples are: split 50/50, split based on the number of mandatory standards, split based on number of contingencies, split based on expected number of hours of local need vs. system need etc.

The ISO is willing to conduct further stakeholder meetings to address such details however timing may become an impediment. The ISO has never had a system wide reliability need before 2021 and does not expect that to happen again after system reliability margin is restored. The ISO expects that the system wide reliability need will be eliminated in a short time. The current stakeholder process will not affect the year 2022 extensions for current RMR resources and any new Tariff and BPM may be in effect for year 2023 designation at the earliest. Depending on the amount and complexity of the software modifications required for hybrid designation it may further defer its implementation until 2024. The ISO would like to avoid the risk of building a new complex and complicated RMR cost allocation type and new software that based on past performance and current analysis has low chance of significantly impacting RMR designations in the foreseeable future.

Final Proposal:

By looking at all the above listed principles, incentives and other issues, the ISO is proposing that local be designated as the primary reliability need when more than one need exists and that RMR cost allocation and RA credit allocation follow the same principle.

Table 1: Comparison among alternatives

Principle (P) Incentive (I) Other (O)	Local as primary	System as primary	Hybrid method
Cost-Causation (P)	Second best	Third best	Best
RA credits (local, system and flex) (P)	Best	Third best	Second best
Building transmission (I)	Best	Third best	Second best
Procuring resource as RA (I)	Best	Third best	Second best
Conversion of current RMR contracts (O)	Best	Second best	Second best
Assumed mitigation time (O)	Best	Second best	Second best
Implementation cost (O)	Best	Second best	Third best
Complexity and timeline (O)	Best	Second best	Third best

The "local as primary" type of designation is consistent with cost-causation principle and it is the only alternative that allows all paying LSEs to fully utilize their RMR provided RA credits including the most valuable, the local RA credits. It provides the highest level of incentives to the PTO in building new local transmission in order to eliminate the local need and also provides the highest level of incentives to LSEs in order to procure this resource under an RA contract. It is the only alternative that does not require either RA cost allocation change or the conversion of the legacy RMR contract for Oakland into the new type of RMR contract. It is simple, can be implemented by the ISO quickly and at low costs.

Other stakeholder proposed changes and improvements:

The ISO has a current process in order to allow resources (gas or otherwise) to convert to storage however the existing resource or its replacement must be available at the time of the expected reliability need. The ISO is working directly with resource owners to allow repowers in stages or under seasons (parts of the year) when reliability of the grid is not in jeopardy from either a local or a system need. The ISO may codify its existing process in the appropriate BPMs after further evaluation; however the ISO does not consider that significant changes are necessary or required.

5. Stakeholder Engagement and EIM Governing Body Role

Stakeholder input is required in order to clarify the Reliability Must Run designation process. The schedule proposed below allows opportunity for stakeholder involvement and feedback.

This initiative will consider clarifications to the Reliability Must Run designation process. The ISO staff believes that the EIM Governing Body would not have any role with respect to the proposed clarifications to the RMR designation process, which will go to the Board of Governors for decision in December 2021, before changes to the ISO Tariff need to be approved by the Federal Energy Regulatory Commission (FERC).

The role of the EIM Governing Body with respect to policy initiatives changed on September 23, 2021, when the Board of Governors adopted revisions to the corporate bylaws and the Charter for EIM Governance to implement the Governance Review Committee's Part Two Proposal. Under the new rules, the Board and the EIM Governing Body have joint authority over any

> proposal to change or establish any ISO tariff rule(s) applicable to the EIM Entity balancing authority areas, EIM Entities, or other market participants within the EIM Entity balancing authority areas, in their capacity as participants in EIM. This scope excludes from joint authority, without limitation, any proposals to change or establish tariff rule(s) applicable only to the ISO balancing authority area or to the ISO-controlled grid.

Charter for EIM Governance § 2.2.1 None of the clarifications to the RMR designation process, and the associated tariff amendments, would be "applicable to EIM Entity balancing authority areas, EIM Entities, or other market participants within EIM Entity balancing authority areas, in their capacity as participants in EIM." Instead, the proposed tariff rules would be applicable "only to the ISO balancing authority area or to the ISO-controlled grid." Accordingly, the proposed tariff changes fall outside the scope of joint authority.

The "EIM Governing Body may provide advisory input over proposals to change or establish tariff rules that would apply to the real-time market but are not within the scope of joint authority." Id. The proposed tariff revisions, however, also fall outside this advisory role, because they not apply to the real-time market. Rather, the clarifications to the RMR designation process applies only to procurement of resources internal to the ISO with an executed Participating Generator Agreement (PGA) and a Generator Interconnection Agreement (GIA) (either 2-party of 3-party GIA), if they are needed to meet the mandatory reliability standards.

Stakeholders are encouraged to submit a response to the EIM classification of this initiative as described above in their written comments, particularly if they have concerns or questions.

5.1. Schedule

Table 3 lists the proposed schedule for the updates to the Clarification to the Reliability Must Run designation process.

Table 2: Schedule for Clarification to the Reliability Must Run designation process

Item	Date
Post Issue Paper	August 10, 2021
Stakeholder Call	August 17, 2021
Stakeholder Comments Due	August 31, 2021
Post Straw Proposal	September 21, 2021
Stakeholder Meeting	September 29, 2021
Stakeholder Comments Due	October 13, 2021
Post Final Proposal and Draft Tariff/BPM Language	November 1, 2021
Stakeholder Call	November 8, 2021
Stakeholder Comments Due	November 22, 2021
CAISO Board of Governors Meeting	December 14-15, 2021

The ISO proposes to present its proposal to the ISO Board of Governors on December 2021. The ISO is committed to providing many opportunities for stakeholder input into its market design, policy development, and implementation activities. Stakeholders should submit written comments through the ISO's commenting tool.

5.2. Next Steps

The ISO will discuss the Final Proposal during the stakeholder call on November 8, 2021. The ISO requests stakeholders submit written comments in response to the Clarification to the Reliability Must Run designation process final proposal and stakeholder call by November 22, 2021.