Revised RA Implementation Staff Proposals

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Table of Contents

1. Combined Heat and Power (CHP) resources procured Outside of the IOUs' TAC Areas....................3

2. Schedule Outage Replacement Rule for Cost Allocation Mechanism (CAM) Resources and Combined Heat and Power (CHP)....................5

3. Process for Allocating Committed Flexible Capacity Associated with CAM and CHP Resources.........7

4. Local RA Proposals....................9

Proposal 4.1: Aggregation of Local Areas by IOU Service Area....................11

Proposal 4.2: Altering Timing of Incremental Local RA Adjustments....................11

Proposal 4.3: Quarterly CAM/RMR Allocations Rather Than Monthly CAM/RMR Allocations............. 13

1. Combined Heat and Power (CHP) resources procured Outside of the IOUs' TAC Areas

Background:

California Public Utilities Commission Decision D.07-06-029 recognized the need to address zonal Resource Adequacy (RA) requirements due to the concerns that Path 26 could be collectively over-relied on by LSEs for RA compliance. To address this concern, a Path 26 counting constraint for system RA was adopted in lieu of specific zonal RA requirements. The Path 26 counting constraint is an annual five step process, conducted by the CAISO that limits the amount of capacity each LSE can use to cross Path 26 in connection with their system RA compliance filing. Step three of the Path 26 counting constraint allows for the optional submission of existing RA commitments that need to use Path 26 for delivery to the LSE's loads. This step of the process nets the north-to-south and south-to-north Path 26 counting impacts associated with the existing RA commitments. The benefit of this netting are then allocated, in step four, to all LSEs based on load-ratio share.[1]

The Long-Term Procurement Plan (LTPP) proceeding assesses the long-term resource needs for each IOU service territory every two years and, when there is a need, authorizes the IOUs to procure additional resources. This need determination is specific to each IOU Transmission Access Charge (TAC) area (a region roughly equivalent to the IOU service territory).

Decision (D.)06-07-029 of the LTPP proceeding (LTPP Rulemaking 06-02-013) adopted a process known as the Cost Allocation Mechanism (CAM). CAM allows the investor-owned utilities (IOUs) to allocate the capacity costs and benefits of certain new generation resources to all benefiting customers within their TAC areas.[2] These benefiting customers are bundled-utility customers, Direct Access (DA) customers and Community Choice Aggregator (CCA) customers. The capacity cost of CAM resources are allocated to all benefiting customers and collected through a non-bypassable charge that includes only the cost of the capacity (i.e., total cost less energy revenues). The benefits of CAM resources are allocated as a Resource Adequacy (RA) credit. This credit is allocated to Load Serving Entities (LSEs) serving benefiting customers, and reduces each LSE's RA requirement. In most cases, the RA benefits associated with each CAM resource are easily allocated, since the customers paying for the CAM resource are located in the same TAC area as the LSEs receiving the RA benefits.

Parallel to the CAM process, the qualifying facility (QF)/combined heat and power (CHP) settlement, which was adopted in D.10-12-035, established a cost allocation mechanism to be used to share the benefits and costs associated with meeting the CHP and greenhouse gas (GHG) goals. This cost allocation mechanism is almost identical to what was adopted in the LTPP decision for CAM resources.

[1] D.07-06-029 page13-14

[2] The types of resources eligible for CAM treatment are not the subject of this proposal. However, CAM resources are typically resources that get authorized through the LTPP process for system or local reliability (Marsh Landing, Walnut Creek, El Segundo, etc.).

Under the CHP settlement framework, the costs and the RA benefits are also allocated to all benefiting customers. However, the mechanism adopted by the CHP settlement does not require that the CHP facility be located in the IOU's service territory.

In the last year, the IOUs' CHP requests for offers (RFOs) have resulted in procurement outside the IOUs' TAC areas; as a result, the RA benefits to the TAC area are limited by Path-26 constraints. Allocating CHP RA credit to LSEs in one TAC area for resources procured in another TAC area can be problematic for the following reasons: 1) It does not consider the Path-26 system constraint, 2) Local costs are not equitably allocated, in that customers in one TAC area (that of the IOU conducting the RFP) are paying for reliability benefits in another area (the TAC area in which the CHP is located), and 3) It creates another level of complexity in procurement planning that is not transparent to LSEs that service DA and CCA load.

Currently a total of 309 MW of CHP resources (CAM allocated) located in the south are paid by PG&E TAC customers and approximately 200 MW of CHP resources (CAM allocated) located in the north are paid by SCE TAC customers. These numbers continue to increase as the IOUs CHP goals are met.

Staff Proposal:

In conjunction with staff proposal 2 (see below), staff proposes that CAM and CHP resources procured outside of the IOUs north or south zone be required to be included in the Path 26 netting process. The IOU responsible for the procurement of the CHP resource must submit the resource/contract information to the CAISO as an existing contract in step three of the Path 26 netting process adopted in D.07-06-029[3].

These submitted CHP contracts will net against each other, and the overlapping amounts will supplement the "available" transfer capacity of Path 26, since in reality no actual flows will occur. The additional available Path 26 capacity created by netting of these CHP contracts should be allocated to all LSEs based on the LSEs netting participation-ratio share and no longer on LSEs load-ratio. Specifically, staff proposes that step four of the Path 26 counting constraint adopted in D.07-06-029, be modified to read:

> "Step 4. The CAISO will allocate the additional Path 26 RA counting capacity that was made available due to netting of existing commitments. The additional counting capacity will be allocated to LSEs that participated in the netting process based on each LSEs participation-ratio share, and will be additive to the LSEs' baseline allocations. "

The IOU responsible for procuring the CHP resource(s) would receive the netting Path 26 benefit associated with CHP resource(s) and therefore be able to use that benefit to aid in showing the resource on the RA plans for compliance. Other LSEs paying for the costs of the CHP resource(s) would be allocated the RA system benefit of the CHP resource consistent with the zone/TAC they serve load in.

[3] D.07-06-029 page13

By requiring the CHP resources to go through the Path26 netting process while also implementing staff proposal 2, the Path 26 counting issue is resolved. Additionally, the level of complexity in procurement planning for LSEs that service DA and CCA load is reduced. However, the local benefits of the CHP resources are not given to the TAC area customers paying for the resource. Instead these benefits are bundled with the local area the resource resides in.

2. Schedule Outage Replacement Rule for Cost Allocation Mechanism (CAM) Resources and Combined Heat and Power (CHP)

Background:

Decision (D.)11-06-022 eliminated the California Public Utilities Commission (CPUC) administered scheduled outage replacement rule beginning with the 2013 RA compliance year. The CPUC's replacement rule was superseded by the ISO's scheduled outage replacement rule in January 2013. The ISO's scheduled outage replacement rule requires the Scheduling Coordinators (SC) for both the Load Service Entity (LSE) and the Resources to manage scheduled outages if the ISO determines replacement capacity is needed. The replacement obligation falls on the SC for the LSE if a approved/pending maintenance outage is submitted to the ISO 45 days prior to the compliance month. The replacement obligation falls on the SC of the Resource if an approved maintenance outage is submitted after 45 days prior to the compliance month.[4]

SCs for LSEs are able to manage scheduled outages through the RA plan submittal to the ISO (i.e., LSEs include the replacement resource in their RA plans). The CAISO Interface for Resource Adequacy application (CIRA) alerts the SC for the LSE if a unit is on planned outage and if replacement capacity is needed. If the SC for the LSE does not manage the outage, and the ISO determines that it needs replacement capacity for system reliability, the ISO has the authority to procure backstop capacity through its Capacity Procurement Mechanism (CPM) and to recover the procurement costs from the SC for the LSE that did not provide replacement[5]. Currently, CAM and CHP resources are not subject to the CAISO's entire scheduled outage replacement rule because these resources are treated as a credit towards meeting RA requirements (i.e., they are not listed as physical resources on RA plans) and there is no mechanism in place that requires the SCs for the LSEs to provide replacement capacity if needed.

[4] CAISO Business Practice Manual for Reliability Requirements 4.5.1.2.1 page 42

[5] http://www.caiso.com/Documents/Dec11_2013_OrderAcceptingAmendment-Multi-StageResourceAdequacyBidsER14-93.pdf

[6] Total June 2014 allocated CAM allocation RA credits distributed

Currently there are 5,352 MW[6] of CAM and CHP RA credits being allocated for use towards monthly RA requirements. These numbers are expected to grow as each IOU fulfills its CHP procurement targets[7] and its Capacity authorizations from the Long Term Procurement decisions identified in D.13-02-006 and D.14-03-004[8].

Staff Proposal:

Staff proposes that the utility responsible for procuring the CAM and CHP resource(s), be the **SC for the LSE** of the CAM and CHP resources. This would require the IOU to be responsible for showing CAM and CHP resources on its RA plans. This is possible due to the abolition of the energy auction mechanism earlier this year in D.1402040. Therefore if scheduled outage replacement falls on the SC for the LSE (the scheduled outage was submitted to the CAISO 45 days prior to the compliance month) the IOU would also be responsible for that replacement, if needed.

Additionally, the IOUs will be given the authority to recover scheduled outage replacement costs, associated with replacement that falls on responsibility of the SC for the LSE, through a balancing account mechanism. For scheduled outages that are approved after the compliance filing due date, the SC of the resource will still be responsible for outage replacement as specified in the CAISOs replacement rule.[9]

In order to minimize the costs associated with replacement capacity, staff proposes that the IOUs be required to use a least cost-best fit evaluation for the replacement process of scheduled outages for CAM and CHP resources. In the least cost-best-fit evaluation the cost of capacity from the IOUs portfolio will be determined using the average capacity price from the most recent RA report.

For CAM and CHP resources where the **SC for the resource** is not the IOU nothing changes, with regards to replacement. The same can be said for CAM and CHP resources where the SC for the resource is the IOU. Currently the SCs for all CAM and CHP resources are subject to the Scheduled outage replacement rules if the outage is submitted after 45 days prior to the compliance month.

In order to facilitate this proposal and ensure that the scheduled outage replacement rule is extended to CAM and CHP resources, the IOUs responsible for procuring CAM and CHP resources will be required to include the full capacity of those CAM and CHP resources in their RA plans (either the CAM units or the replacement units). The IOUs will be required, to the extent specified by the terms of their Purchase Power Agreement, to bid the facilities as Flexible RA, meaning submission of economic bids into the ISO

[6] Total June 2014 allocated CAM allocation RA credits distributed

[7] http://www.cpuc.ca.gov/PUC/energy/CHP/

[8] SCE's Local Capacity Need and San Onofre Nuclear Generation Station (SONGS) replacement needs

[9] Section 4.5.1 of CAISO Business Practice Manual for Reliability requirements
http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements

market..[10]

For non-IOU LSEs, the CAM and CHP allocation process will not change. The CPUC will still provide those LSEs with a CAM and CHP credit that will count towards their System RA requirements. However, the CPUC will also provide the IOUs with a CAM and CHP debit. The CAM and CHP debit will be a negative value (meaning addition to the IOU's RA obligation) equal to the amount of CAM and CHP credits provided to non-utility LSEs serving load in each TAC area. For example, assume that an IOU has a 90% load ratio share in its TAC and has procured a CAM resource with a NQC of 100MW. The IOU would show the 100 MW CAM resource (or a replacement if the resource is on a planned outage) in its RA showing, all LSEs serving load in the TAC area would get a total of 10 MW RA CAM credit, and the IOU would get a 10 MW CAM debit (negative value). In this case, the IOU would receive a higher RA requirement equal to the credit the other LSEs are receiving. The CAM resource, or replacement, would be shown in the IOU's RA filing as a physical resource which would count for a 100MW towards its RA requirement (higher by 10 MW).

The process of allocating the Local RA benefit associated with the CAM and CHP resources will also be modified. For non-IOU LSEs the process will not change: the RA requirement for each local area will first be reduced by the RA value of all the CAM and CHP resources in the local area. LSEs will then be assigned their Local RA requirements net of all CAM and CHP local benefits. However, for the IOUs the process of allocating local benefits will change. The IOU, responsible for the CAM or CHP procurement, will be allocated its portion of the local requirements, **NOT** considering the RA benefit of CAM and CHP resources. Instead, the IOUs will be given a higher local RA requirement equal to the amount of local CAM and CHP benefits subtracted off the non-utility LSEs serving load in each TAC. The IOUs will then show the whole local value of the CAM and CHP resource or that of replacement units on its RA showing, to meet its Local RA requirement

3. Process for Allocating Committed Flexible Capacity Associated with CAM and CHP Resources

Background:

Decision (D.)06-07-029 adopted a cost allocation methodology, stating that,

> The LSEs in the IOUs' service territory will be allocated rights to the capacity that can be applied toward each LSE's resource adequacy (RA) requirements. The LSEs' customers receiving the benefit of this additional capacity pay only for the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract.[11]

[10] http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx

[11] D.06-07-029 OP1: http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/58268.htm

LSEs receive CAM credit based on their proportionate share of service area peak load. D.07-09-044[12] adopted a settlement that allowed for the quarterly reallocation of the CAM capacity credits. The quarterly allocation was then modified in D.09-06-028, which adopted a monthly allocation for service areas with two or more CAM contracts, as follows:

> For service territories with one operational Cost Allocation Mechanism contract, Energy Division shall perform quarterly reallocations of Cost Allocation Methodology credits. For service territories with two or more operational Cost Allocation Methodology contracts, Energy Division shall perform monthly reallocations of Cost Allocation Methodology credits. If, for any month, a reallocation would result in no change greater than 0.5 megawatts for any load-serving entity, Cost Allocation Methodology credits would not be reallocated that month.[13]

Energy Division began monthly reallocation of system CAM capacity credits in 2010 and this practice continues. The monthly allocation of system CAM and CHP capacity credits occurs approximately 45 days prior to the compliance filing due date associated with the CAM and CHP capacity. Allocation of CAM and CHP capacity credits is based on the most current revised load forecast ratios. For example, January CAM and CHP credit allocations are based on revised December load ratio shares.

Historically Energy Division has allocated the local benefits of CAM and CHP resources annually. The annual allocation is done by reducing the Local RA requirement(s) by the amount of Local RA benefit provided by each CAM and CHP resource. The annual allocation is initially done in July and then again in September. Starting with the 2011 Compliance year, Energy Division began implementing a local true-up process (adopted in D.10-12-038). The true-up methodology allowed for the reallocation of the local benefits of CAM twice during the compliance year.

To allocate the Local RA benefit of CAM and CHP resources, Energy Division subtracts the total August CAM and CHP resource RA values in each local area from the total CPUC-jurisdictional requirement in each local area. Currently this process is completed four times per year: once in July with the initial year-ahead allocations and again in September with the final year-ahead allocations. There are also two true-ups during the RA compliance year.

CAM and CHP resources may also be eligible for Flexible RA; however, there is currently no allocation methodology for this Flexible RA CAM benefit.

Staff Proposal:

Staff proposes that only CAM and CHP resources contractually able to provide committed flexible capacity be made available for flexible allocation.

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12 D.07-09-044 http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/73043.htm

13 D.09-06-028 OP 3b: http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/102755.htm

Additionally staff proposes that the same allocation methodology currently used for the allocation of Local RA CAM benefits be extended to the allocation of Flexible RA CAM benefits. The allocation timeline would follow the same timeline proposed in staff proposal 4.2, which includes an initial annual allocation in July, a final annual allocation in September and one true up allocation in April (for compliance from July-December). In order to ensure accurate allocation of Flexible RA capacity to all benefiting customers, the IOUs will need to provide Energy Division with a complete list of all their procured flexible CAM resources prior to the July RA allocations. The Effective Flexible Capacity (EFC) associated with each eligible flexible resource will be allocated to the TAC area paying for the resource.

Finally, if proposal 2 is adopted then the Flexible RA for CAM resources would be allocated in the same manner detailed for Local RA benefits in proposal 2. This would mean that non-IOU LSE receive a reduction in their Flexible RA requirements and IOUs receive an increase equal to that decrease, while also being required to show the whole resource, or replacement resource, on its RA showings.

4. Local RA Proposals

Background:

In D.06-06-064, the CPUC adopted local RA obligations, which require LSEs under CPUC jurisdiction to procure and commit to the ISO sufficient generation in Local Areas to meet their Local RA needs. The CPUC has adopted obligations on an annual basis ever since this 2006 Decision, and the Local RA program has evolved with policy development and revisions to procurement rules each year.

D.06-06-064 also aggregated several Local Areas in PG&E's service territory into one Local Area, with only the Greater Bay Area remaining separate, in order to protect LSEs from market power and to promote administrative simplicity.[14] This aggregation was made permanent in D.11-06-022.[15]

Aggregation into less granular Local Areas represents a tradeoff, however. If LSEs procure sufficient MW totals of Local RA resources, but the portfolio of Local RA resources procured does not meet reliability concerns due to subarea constraints or resource use limitations, there will be residual unmet local reliability needs. To ensure that the aggregated procurement adequately satisfies local reliability concerns, the ISO analyzes procurement by the LSEs (as shown in their RA filings), running a power flow model using the procurement committed by LSEs. The ISO then publishes a report which lists any residual procurement required to remedy local reliability conditions and decides whether to procure more Local RA resources via backstop procurement. Aggregation into less granular Local Areas to prevent market power and promote simplicity thus trades off against the possibility of inefficient and untargeted procurement by LSEs and need for backstop procurement by the ISO.

[14] D.06-06-064 – section 3.3.4

[15] D.11-06-022 section 3.2.12

LSEs receive an allocation of Local RA obligations in July, which give LSEs separate Local RA obligations in five Local Areas; two in PG&E's service territory, two in SCE's service territory, and one that covers the entirety of SDG&E's service territory. Because of a decision to partially reopen direct access in several "tranches" in 2010,[16] the CPUC has also created a process to reallocate Local RA obligations twice a year, based on the schedule of direct access "tranches" included in the direct access process.[17] The Local RA reallocation process adopted in 2010 created a process whereby each LSE receives an incremental adjustment to Local RA procurement obligations, which adjusts that LSE's previously-allocated year-ahead obligation. The incremental Local RA amounts can be either positive (if the LSE received load since the year-ahead allocation process) or negative (if the LSE lost load or if additional CAM resources came online) since the year-ahead allocations.

To simplify marginal procurement and mitigate market power, these adjustments may be aggregated to an LSE's overall service territory. For example, adjustments in LA Basin and Big Creek/Ventura, which are both in SCE service territory, may be aggregated; the resulting adjustment could be procured in either of the two Local Areas. LSEs receive Local RA adjustments twice each year, once in February for the May and June compliance months, and again in April. LSEs use adjustments received in April for the remainder of the compliance year (June through December).

However, despite efforts to simplify this process, it remains confusing to LSEs, particularly for small LSEs who receive small (1 or 2 MW for example) adjustments in each Local Area. In addition, aggregation may lead to excessive or more costly procurement, since small MW amounts may not be readily available for purchase. The procurement process is further complicated by allocations of Demand Response and CAM capacity, which offset LSEs' Local RA obligations.

Local RA adjustments were historically driven by two factors: large blocks of customers migrating from one LSE to another pursuant to the partial opening of direct access during 2011 and 2012, and the addition of large new power plants and CHP procurement that occurred largely in 2013. In the near future, however, there are no new power plants that are set to come online and be allocated via CAM. Additionally, all tranches of direct access reopening were filled up prior to the 2014 year; it is reasonable to assume that migration will no longer follow the timetable outlined in D.10-03-022. As a result, it is uncertain what the timing for adjustments ought to be and what the scale of adjustments is likely to be going forward.

Proposal 4.1: Aggregation of Local Areas by IOU Service Area

The impacts of aggregation depend on the MW size of the procurement obligations (and indirectly on the size of the LSE, since Local RA allocations are based on peak load); thus it may be reasonable to allow further aggregation of Local RA year-ahead procurement obligations for smaller LSEs (5 MW of Local RA in one service territory for example) and not for larger LSEs. Aggregation of local RA obligations

[16] D.10-03-022

[17] D.10-12-038

for larger LSEs would likely result in greater chance of procurement that was too heavily weighted in one Local Area and did not resolve local reliability concerns.

D.06-06-064 created a process whereby Local RA obligations less than 1 MW would be rounded down to zero and effectively waived, in light of the small reliability benefit produced by the effort of procuring the small MW volumes. Energy Division proposes to retain that rounding convention, and to aggregate on a small scale for 2015 RA compliance year. Energy Division suggests a threshold at 5 MW of total Local RA obligation net of CAM capacity in a utility service territory. Energy Division proposes that an LSE may aggregate Local RA obligations totaling 5 MW or less in any one service territory and procure all of the necessary Local RA in only one Local Area. One key motive for this proposed rule is to limit administrative obligations where LSEs need to procure small quantities of Local RA resources in two Local Areas, when they could instead procure a larger amount in one single area. For smaller LSEs, the costs of procuring in both Local Areas in a service territory may outweigh the reliability benefits of the procurement. Another key reason is to provide additional local market power mitigation. Allowing the aggregation of local area requirements for LSEs that serve a small amount of load (LSEs that have less than a 5 MW local requirement in the local area) will give generation owners in local areas less market power over small LSEs.

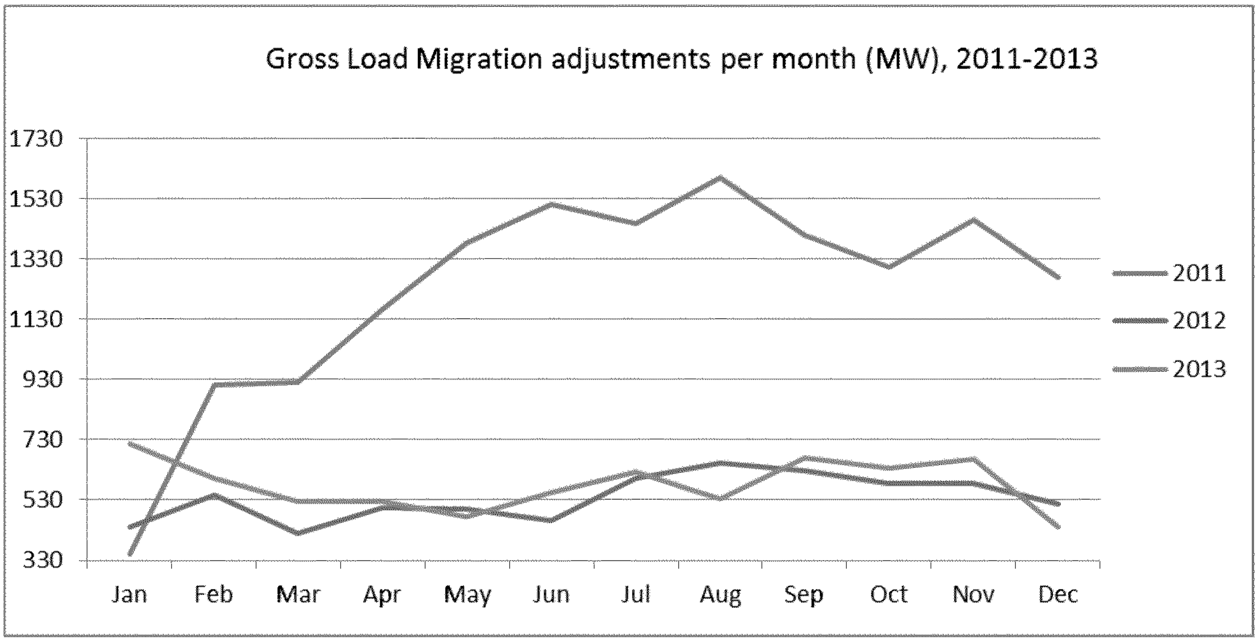
Energy Division encourages comments as to whether the proposed threshold is the correct amount or not, and encourages additional input from parties and the ISO regarding the possible increase in reliability risk balanced against the decrease in administrative obligations for small-LSE, small-MW Local RA obligations.

Proposal 4.2: Altering Timing of Incremental Local RA Adjustments

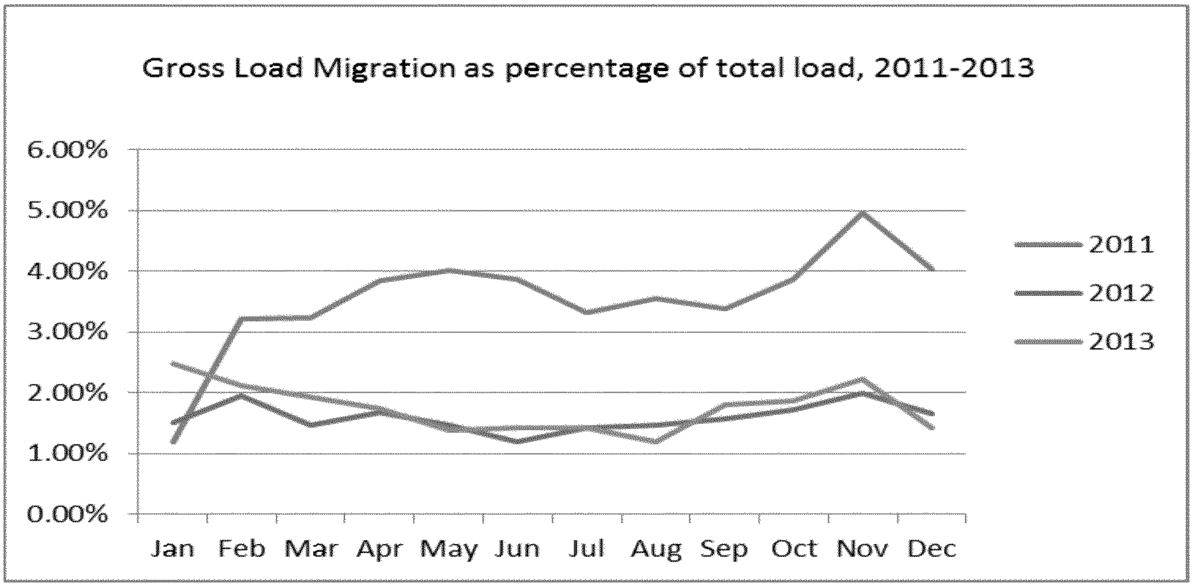
Energy Division proposes that since the direct access "tranches" have been filled, there is no reason to maintain the current twice yearly timing of Local RA adjustments. Energy Division proposes to move to one annual readjustment, in the middle of the year. Currently, there is a process to allocate Local RA obligations in July of the year before, an additional opportunity to reallocate in September, and two opportunities very near each other during the compliance year. Energy Division is concerned that the work it takes, both from Energy Division staff and LSE staff, to perform two adjustments that are so near each other is not warranted given that the tranches are filled and it is not clear that there will be any common time for migration in large numbers to occur.

The chart below shows total load migration by month for 2011 through 2013. These graphs are different from the similar information presented in the annual RA reports; the RA reports sum net load migration, meaning 1 MW moving from one LSE to another would net to zero since one LSE would gain a MW and another LSE would lose a MW. The graphs below represent gross load migration, as staff calculated the absolute value of load migration by LSE per month, meaning if one LSE gained 1 MW and another LSE lost 1 MW, that would total 2 MW of load migration. Load migration is determined by calculating the delta between the year-ahead forecasts and the updated coincident forecasts that each LSE uses for month-ahead RA filings on an LSE-specific basis, then summing by month.

While these graphs potentially double count migration, and it is possible (but not certain) that all migration would in fact net to a much lower amount (as shown in the annual RA reports). The purpose of the chart below is to track the monthly pattern to find a breakpoint or month when load migration is significantly higher than other months, or when trends change. It appears from the chart below that the magnitude of load migration is significantly decreased from 2011; there does not appear to be a clear trend or pattern to support continuing two adjustments per year or for specifying which month in particular is best for the adjustments to occur.



By way of comparison, gross load migration as a percentage of peak load also fails to show much of a pattern; migration forms a much smaller percentage of peak load after 2011, and there is no particular trend to support two adjustments per year. Currently, gross load migration amounts to between one and two percent of total load each month, with percentages lowest in the middle of year as load levels are highest.



Energy Division proposes to retain the second adjustment, and eliminate the first one; Energy Division proposes to adjust Local RA obligations once during the compliance year, with forecasts submitted by LSEs in March and adjustments sent by Energy Division in April, for use in all RA Filings from July to December. Parties are welcome to suggest alternatives as to timing, and Energy Division welcomes comments and input from direct access customers or LSEs.

Proposal 4.3: Quarterly CAM/RMR Allocations Rather Than Monthly CAM/RMR Allocations

Energy Division staff currently reallocates System RA credit for CAM and Reliability Must Run ("RMR") capacity on a monthly basis, in keeping with D.09-06-028. While RMR capacity has decreased to nearly zero (there is just one 165 MW RMR contract left for allocation), CAM capacity has increased drastically, to about 5,000 MW. These resources represent approximately 11 percent of the nearly 46,000 MW of peak load under CPUC jurisdiction.

Although the amount of CAM capacity is significant and expected to grow substantially, the amount of CAM and RMR capacity being reallocated each month is much smaller than it was in prior years, and is expected to remain so for the next few years, since all large CAM resources have finished construction. Currently, CAM capacity reallocation is primarily due to load migration. As shown in the previous proposal, the amount of load that migrates each month amounts to under two percent of total load. That two percent is served by Direct Access ("DA") and Community Choice Aggregators ("CCAs") and represents around 12% to 24% of total DA and CCA load.[18] Because CAM/RMR credit amounts to 11% of total load, only about one to two and half percent of DA and CCA RA resources are exposed to uncertainty due to load migration each month ((11% of RA obligation met via CAM times 12-24% of load

[18] According to 2014 RA obligations and forecasts used for RA compliance, DA and CCA load amounts to between nine and twelve percent of total load per month of 2014.

migrating each month, equaling 1.3-2.6% of their RA obligation may be uncertain each month due to CAM resource allocations).

Some LSEs are currently confused by the CAM and RMR allocations each month, and do not respond to small changes in allocations or adjust their System RA filings accordingly. Thus there are some LSEs that fail to take advantage of up to date allocations. There is some confusion about what numbers are the most up to date, despite good faith efforts to be accurate and responsive. Energy Division is concerned that LSEs are not fully able to keep up with all the information currently presented to them.

Thus Energy Division proposes that System RA from CAM and RMR resources be reallocated quarterly going forward. As a result, DA and CCA LSEs' CAM and RMR allocations would respond less frequently to load migration. This would result in less overall uncertainty related to System RA capacity allocations for DA and CCA LSEs.