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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009

ADMINISTRATIVE LAW JUDGE'S RULING ON ENERGY DIVISION'S PROPOSAL

Pursuant to the Track 2 schedule set forth in the Assigned Commissioner's Scoping Memo and Ruling, attached to this ruling are Energy Division's Track 2 proposals.

IT IS RULED that the Commission's Energy Division's Track 2 proposals are attached to this ruling as Appendix A.

Dated February 21, 2020, at San Francisco, California.

/s/ DEBBIE CHIV
Debbie Chiv
Administrative Law Judge

327195291

APPENDIX A

California Public Utilities Commission

February 21, 2020

Energy Division Proposals for Proceeding R.19-11-009

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Proposal A: Reaggregate PG&E Other Local Area for RA Compliance

I. Background

In Decision (D.) 06-06-064, the Commission aggregated six of the local reliability areas in the PG&E service area (Humboldt, Fresno, Kern, Sierra, Stockton, North Coast/North Bay) for Resource Adequacy (RA) because of concerns about local market power. The combined local area was known as "PG&E Other."

D.19-02-022, acknowledged the ongoing tension between the desire to mitigate market power in constrained areas and the desire to minimize backstop procurement given that the California Independent System Operator (CAISO) makes backstop decisions based on sub-local needs and collective deficiencies. In the decision, the California Public Utilities Commission (CPUC) declined to disaggregate to the sub-local area as CAISO had advocated, but did disaggregate the "PG&E Other" area to the local area level stating that it was "a necessary first step towards addressing inefficient procurement that may lead to backstop procurement"[1] in light of the decision to adopt a load service entity (LSE)-based multi-year requirement for local resource adequacy.

Of the 42 LSEs that had 2020-2023 local RA requirements, 20 requested local waivers for the 2020 year ahead RA filing. This was a significant increase in waiver requests over prior years.[2] While, on the whole, adequate resources were shown to CAISO so that no year ahead backstop procurement was needed for 2020, many LSEs were unable to procure adequate capacity to meet requirements for all applicable local areas.

As noted by PG&E in its Local waiver request Advice Letter submission, the total level of generating capacity available in the Kern, Sierra, and Stockton local areas is very close to the 2020 local requirement for those areas. This is true, the 2020 requirements for these areas were approximately 96% percent of total supply for Stockton, 100% for Kern, and 82% for Sierra and that is before reduced load carrying capability (ELCC) values (adopted for 2020) are taken into consideration.[3]

Another issue, also raised by PG&E, is the issue of unequal application of the disaggregated requirements since they do not apply to non-CPUC jurisdictional LSEs. Municipal utilities own 20% of capacity in Stockton and 54% of capacity in Sierra.[4] However, since these LSEs are not subject to disaggregated requirements, they have no incentive to sell capacity they hold in the PG&E Other local areas.[5]

II. Proposal

When the Commission decided to delay designation of a central procurement entity, it also disaggregated the PG&E Other local area in order to prevent leaning and ensure that adequate capacity was procured in all ten CAISO-identified local areas. However, LSEs had trouble meeting the

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[1] D.19-02-022 at 33
[2] There were 8 local waiver requests for 2018 and 10 for 2019.
[3] See http://www.caiso.com/Documents/Final2020LocalCapacityTechnicalReport.pdf
[4] See http://www.caiso.com/Documents/Final2020LocalCapacityTechnicalReport.pdf
[5] See Petition for Modification of Decision 19-02-022 by Pacific Gas and Electric Company, p.8-9

disaggregated requirements and it appears that given that there are 26 LSEs serving load in the PG&E service territory, supply is very tight is some local areas, and non-jurisdictional LSEs are not subject to disaggregated requirements, it may not be feasible for all LSEs to meet all local requirements in the PG&E Other areas. More granular requirements may also have exacerbated market power concerns. In light of these challenges, Energy Division staff propose that the local areas comprising the PG&E Other area be reaggregated for compliance purposes until a central procurement entity is in place.

Proposal B: Demand Response Minimum Testing and Dispatch Requirements

I. Background

All resource adequacy resources are required to be able to dispatch for four hours on three consecutive days. D.05-10-042, Ordering Paragraph 16, restated the minimum requirements for a resource to qualify for the resource adequacy requirement (RAR):

> The Commission's determination in D.04-10-035 that to qualify for RAR, a resource must (1) be able to operate for a minimum of four hours per day for three consecutive days and (2) be able to run a minimum aggregate number of hours per month based on the number of hours that loads in the CAISO control area exceed 90% of peak demand in that month is affirmed as to the summer months; for the non-summer months, the second prong of that test is waived.

This requirement was extended to demand response resources in D.11-06-022.

D.14-06-050 considered testing requirements for demand response resources. It found that, "any Load Serving Entity (LSE) which seeks to show a supply-side demand response resource in its RA compliance filings shall provide evidence of resource performance at least once per calendar year. If the resource is dispatched by the California Independent System Operator (CAISO) for at least two consecutive hours, the dispatch will meet this requirement. Otherwise, the LSE must provide test results."

Separate from these RA performance testing requirements, all RA resources must also receive qualifying capacity values from the CPUC in order to participate in the RA program. D.09-06-028 adopted the load impact protocols (LIPs) for determination of the qualifying capacity of demand response resources. These protocols rely on results of historical dispatches (including historical test dispatches, if necessary) during the RA measurement hours, which are currently 4-9 PM, to predict future load drop. Currently, only Demand Response Auction Mechanism (DRAM) resources are exempt from the LIPs.

Unlike all other resource types – which cannot obtain a qualifying capacity value or begin generating until they are tested by CAISO and do not regularly gain or lose generating capability – DR resources are not subject to CAISO testing and routinely gain and lose customers. In addition, past experience with DR suggests that customer response is generally not uniform over a four-hour dispatch period or over repeated dispatches. Of even greater and more immediate concern, CAISO's Department of Market Monitoring recently reported that in aggregate, third party demand response RA resources participating in the CAISO market do not have the load to support shown capacity.[6] As more DR resources come online that are subject to LIPs, it will be important to accurately evaluate the capacity they can reliably provide. It is also important that DR resources demonstrate that they can meet the minimum capabilities required of all other RA resources, regardless of whether they are subject to LIPs. Without

[6] Q3 Report on Market Issues and Performance, P.90-2, http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf.

minimum testing or dispatch requirements, it is not possible to assess the true amount of available DR capacity.

II. Proposal

In order to improve accuracy of LIP evaluations and ensure that DR resources can reliably provide RA capacity, Energy Division staff propose that all non-emergency demand response, with the exception of DRAM resources, be required to dispatch for a four-hour period during the RA measurement hours on three days during the peak summer months of July-September. This requirement would apply to each resource ID. Dispatches could occur through the CAISO market or as test events. In addition, Energy Division staff propose that minimum dispatch requirements be consistent with dispatch assumptions associated with the MCC DR bucket. That is, third party DR be required to dispatch at least 12 hours per month (proposed) or consistent with whatever MCC DR assumptions are adopted by the Commission. DRAM resources would be exempt from these requirements during the pilot, as they have their own dispatch and QC methodologies.

Proposal C: Qualifying Capacity of Demand Response Resources

I. Background

In April 2008 the Commission established the Load Impact Protocols (LIPs) and required that the Investor Owned Utilities (IOUs) use the LIPs for their DR programs.[7] In 2015 and 2016 with the introduction of the Demand Response Auction mechanism (DRAM), the Commission exempted DR resources contracted in the 2016-2019 DRAM pilot years from performing load impact protocols and permitted DRAM resources to receive Qualifying Capacity (QC) and Effective Flexible Capacity (EFC) values based on the contracted quantities.[8]

In June 2009, the Commission adopted LIPs for RA QC valuation purposes.[9] In June 2016, the Commission exempted third-party DR resources from LIPs until the end of 2019.[10] In June 2019, D.19-06-026 in the Resource Adequacy proceeding reaffirmed that both third-party and IOU-managed DR resources receive QC values based on the application of the LIPs moving forward. However, resources procured in the 2020-2023 DRAM were given an exemption to this requirement.[11] In July 2019, D.19-07-009 in DR proceeding established QC guidelines specific to DR resources procured in DRAM for deliveries in 2020 through 2023.[12]

II. Challenges

In Fall 2019, in accordance with D.19-06-026, Commission Staff conducted the first round of Load Impact analysis for a 3rd party DR Provider offering non-DRAM DR resources in the 2020 RA market. Staff acknowledges that there were many challenges in applying the LIPs as currently defined in terms of conducting a robust, rigorous and transparent analysis.

Going forward, many more 3rd Party DR Providers (DRPs) are expected to participate in the LIP process to seek QC values for non-DRAM DR resources offered to the RA market, leading to a much higher volume of LIP filings submitted to Energy Division. Stakeholders and Staff are greatly concerned about the administrative complexity and the workload implications of processing the LIP filings as well as the quality and rigor of the analysis itself due to the technical challenges of applying several of the protocols to 3rd party DR resources.

During the recent RA Track 2 working group sessions, parties identified additional issues and challenges in applying the LIPs specifically to 3rd party DRP resources that were generally not encountered in applying LIPs to IOU DR programs. These issues include (some identified by Staff):

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7 D.08-04-050
8 D.15-06-063, D.16-06-045
9 D.09-06-028
10 D.16-06-45
11 D.19-06-026
12 D.19-07-009

1. The customer mix of 3rd party DR resources may be less stable (new business models, marketing efforts, etc.) than the IOU programs. Hence past year ex-post results for DRP resources may not be a good representation of next year ex-ante estimates.
2. There may be challenges in assessing reasonableness of the forecasted customer enrollment level for DRP resources. The marketing budget for IOU DR programs is fixed and known to Staff via CPUC approved budgets. However, Staff lacks insight into 3rd party DRP marketing effort/budgets.
3. In handling newly formed resources with no historical performance, the Protocols allow broad flexibility to the DR provider in how statistical analysis is performed, potentially leading to widely inconsistent results depending on the discretion applied by the DR provider. In the case of IOU DR programs, Staff has the benefit of DRMEC IOU members (who are experts in EM&V issues related to DR resources) expertise and advice in its analysis. Such assistance is not expected to be available to Staff in evaluating DRP LIP filings as these filings are expected to be filed as confidential reports and not accessible by DRMEC IOU representatives advising Staff. This may be remedied by non-disclosure agreements for DRMEC members.
4. High upfront expense in conducting the extensive statistical analysis required for a LIP filing with little assurance that the DR provider succeed in obtaining an LSE contract for its DR resource in order to offset the expense.

III. Proposal

To address the above listed challenges in expanding the application of LIPs to non-IOU DR resources, Staff proposes that an alternative pathway to LIPs be created by the Commission to establish QC values of 3rd party DR resource to ensure that the offered capacity is real and reliable when dispatched. The 3rd party DR Providers would have the option to pursue either the LIPs or opt for the alternative performance contract approach after development of such a mechanism.

Instead of the LIPs' reliance on upfront (ex-ante) validation of a DR resource capability, the alternative approach would rely on strict back-end (ex-post) performance and testing requirements enforced via a performance contract between the LSE and the 3rd Party DR provider. With the execution of the contract, the QC value of the subject DR resource would be set equal to the contracted quantity

The performance contract approach is modeled on the existing construct of the IOU Local Capacity Requirement (LCR) contracts for DR resources. The LCR contracts are subject to IOU least Cost Dispatch requirements because the IOU is the scheduling coordinator. For resources bid into the CAISO market by other scheduling coordinators, similar bidding requirements would need to be developed in order to ensure that these 3rd party resources have similar characteristics and usefulness.

The Commission should establish a standardized, model template of a performance contract to be executed between the 3rd Party DR Provider and an LSE that includes specified elements for 1) testing, dispatch and performance requirements, 2) payments and penalties for non-performance, and terms &

conditions including bidding requirements. The specific elements would be determined via a stakeholder process in the RA proceeding and approved by the Commission.

It should be noted that until the Commission approves a new process, Energy Division will continue to utilize the LIP process to determine QC values for 3rd party DR resources.

Proposal D: Qualifying Capacity of Hybrid Resources

I. Background

In D.20-01-004, the CPUC adopted an interim qualifying capacity (QC) counting methodology for hybrid resources. The decision defined hybrid resources as "a generating resource co-located with a storage project and with a single point of interconnection" where the storage resource has charging restrictions related to the Investment Tax Credit.

The adopted methodology states that:

> Where a hybrid resource has charging restrictions related to the Investment Tax Credit, the qualifying capacity value shall be based on the greater of either: (i) the effective load carrying capacity-based qualifying capacity (QC) of the intermittent resource or the QC of the dispatchable resource, whichever applies, or (ii) a modified QC of the co-located storage device capped at the maximum amount of expected energy available to charge the storage device.[13]

In comments to the proposed decision, parties raised two issues that were incorporated into the adopted decision. First, a hybrid resource may choose to operate in the CAISO market with either one or multiple resource IDs. The decision affirms that since the resources will have identical charging restrictions, the adopted QC methodology would apply no matter regardless of resource ID configuration.

Second, in comments on the PD, SCE raised the issue of how to count a hybrid resource when the storage component was sized such that it could not be reasonably expected to fully charge in one day. The decision stated that "it is reasonable to cap the monthly QC of the charging device at the capacity value that can reasonably be expected to be charge on a daily basis,"[14] but did not prescribe a method for determining what the cap should be.

II. Proposal

Staff support the adopted methodology and believe that the changes made from the PD to the final decision were reasonable. A renewable generator co-located with a storage device that is seeking the Federal tax credit will have similar (if not identical) physical characteristics and ITC charging restrictions whether the resources participate in the CAISO market through one or multiple resource IDs. Since the resources can be expected to operate similarly, these hybrid or co-located resources should be subject to the same QC counting conventions. Staff support continuing to apply the adopted counting methodology to all hybrid and co-located resources subject to ITC charging restrictions.

D.20-01-004 did not define how the cap on the monthly QC would be determined. Staff propose the following in order to determine the amount of energy that the renewable generator can reasonably be expected to generate in one day. Staff propose calculating the average daily generation of the renewable resources resource at each hybrid facility for each month based on three years of settlement data. In cases where the renewable generator has been online for three years, the average value for the

[13] D.20-01-004 Ordering Paragraph 1

[14] D.20-01-004 Finding of Fact 6

three years will be used to determine expected monthly generation. A tech factor will be generated based on average production of the fleet of solar and wind generators. For months where a resource does not have three years of settlement data, the tech factor will be applied to calculate expected generation.

Finally, since resources may qualify for the ITC while charging from the grid 25% of the time, Staff propose to calculate the cap based on the assumption that expected renewable generation will charge 75% of the storage device and 25% will be charged from the grid. Therefore, the cap would equal expected monthly generation of the renewable generator divided by 0.75.

For example, a rough daily solar production per MW of installed capacity by month is shown as MWh/MW below. Therefore, the cap would apply to any storage beyond the MWh/MW/.75 value.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MWh/MW	3.84	5.60	6.37	7.46	8.45	8.98	8.43	8.08	7.62	6.30	4.76	3.86
MWh/MW /.75	5.12	7.47	8.49	9.95	11.27	11.98	11.23	10.77	10.16	8.40	6.34	5.15

Proposal E: Effective Flexible Capacity of Storage

I. Background

D.14-06-050 adopted qualifying capacity (QC) and effective flexible capacity (EFC) value for storage resources. For storage resources, the qualifying capacity value is defined as the MW at which the resource can discharge for four hours. D.14-06-050 defined the QC value as PmaxRA.

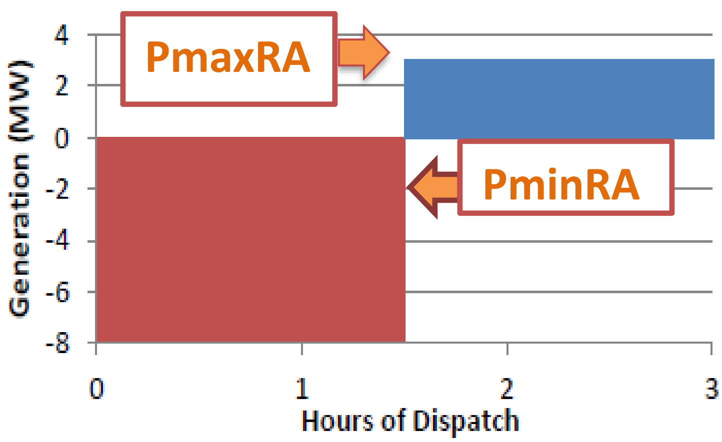
The adopted EFC value for bidirectional storage was capped at the greater of the net qualifying capacity (NQC) value or (NQC-PminRA) where PminRA was defined as the height of a rectangle where the base is 1.5 hours of discharge and the area is the battery's available energy for dispatch in MWh.

Two options were adopted for calculating the EFC, the sustainable output option and the upward ramping option.

Figure 1, below depicts the QC and EFC calculation for a 3MW/12MWh bi-directional storage resource opting for the sustainable output option. Here:

- PmaxRA (height of blue rectangle)= 12 MWh (area)/4h (base)= 3 MW
- PminRA (height of red rectangle)= -12 MWh (area)/1.5h (base)= -8 MW
- EFC= PmaxRA – PminRA= 3 MW – (-8 MW)= 11 MW

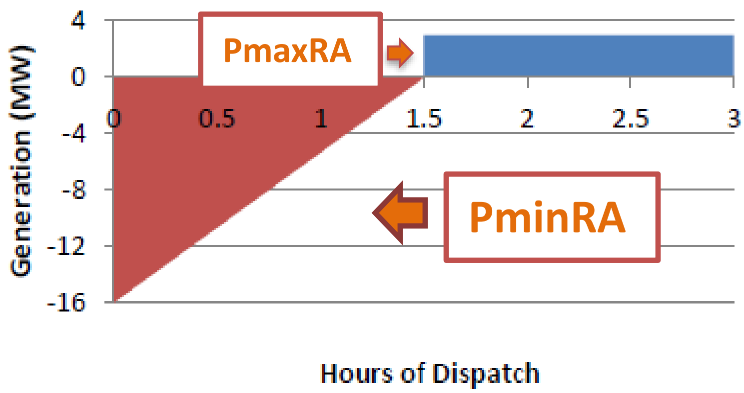
Figure 1: Sustainable Output Option for EFC Calculation



Under the upward ramping option Pmax RA remains the same while PminRA is defined as the height of a triangle (Figure 2). Here:

- PmaxRA = 12 MWh (area)/4h (base)= 3 MW
- PminRA = 2 * [-12 MWh (area)/1.5h (base)]= -16 MW
- EFC= PmaxRA – PminRA= 3 MW – (-16 MW)= 19 MW

Figure 2: Upward Ramping Option for EFC Calculation



This results in an EFC value of 19 MW which is over six times the battery's total capacity.

II. Proposal

Given that the current CPUC methodology assigns a 3 MW bi-directional battery and EFC of either 11 MW or 19 MW, Staff views this methodology as significantly over-valuing the flexible capacity of bi-directional storage. Staff proposes to cap both PminRA and PmaxRA at the QC value of a 4-hour dispatch. This would equate to an EFC value of twice the QC value. This assumes that the device fully charges over 1.5 hours and fully discharges over 1.5 hours.

The cap of two times QC would apply to bi-directional storage resources with both a Pdemandmin and Psupplymin of zero meaning they can ramp continuously up to and down from 0 MW. In cases where the storage device cannot ramp continuously over the full range of the device's capacity, the cap in either direction would be the difference between PminRA or PmaxRA and Pdemandmin or Psupplymin respectively.

Proposal F: The Planning Reserve Margin and DR Capacity Values

I: Background

Resource adequacy system requirements are based on a monthly load forecast plus a 15% planning reserve margin (PRM), while local and flexible RA requirements are adopted by the Commission based on CAISO studies. Local and flexible RA requirements have no associated PRM. Theoretically, demand response lowers peak load and, thus, should also reduce the PRM. For that reason, the Commission has adopted a 15% PRM adder for demand response. Peak load reduction would not result in a similar reduction in flexible or local RA requirements.

As described in the 2020 Filing Guide, "[t]he 15% planning reserve margin is added to the DR capacity in the Summary tabs to reflect that DR programs directly reduce the load that the system is required to support, and thus that load does not need planning reserves."[15] In Decision D.10-06-036, the Commission adopted a method to "gross up" the qualifying capacity (QC) of dispatchable demand response (DR) resources for line losses. Specifically, the Commission adopted the following formula:

> DR RA Value = 1.15 * DR Load Impact * (1.00/(1.00 – T&D Line Loss Rate)) *where*, T&D Line Loss Rate = 3% + [Investor Owned Utility (IOU)]-specific Distribution Loss Factors.[16]

The Commission subsequently adopted the current IOU-specific Distribution Loss Factors in D.15-06-063.[17]

It has recently come to Staff's attention that some DR providers may be selling DR capacity to LSEs at values that include not only the DR Load Impact and T&D line losses – which together constitute the qualifying capacity of a resource[18] - but which also include the 15% planning reserve margin. This is not necessarily a problem for DR capacity that meets system requirements. As discussed above, the RA Filing templates automatically adjust reported DR values upwards by 15% to account for the planning reserve margin, which Energy Division and CEC staff use to calculate LSE's Year Ahead and Month Ahead system RA requirements.

However, including the planning reserve margin in DR sales for local capacity is a problem. The planning reserve margin does not apply to local capacity requirements, and DR capacity therefore does not avoid a planning reserve margin when meeting local RA requirements. For that reason, the RA Filing templates do not add the planning reserve margin on top of local DR capacity when comparing that capacity against local requirements. Whereas D.10-06-036 does include the planning reserve margin in defining "DR RA Value," the context for this definition is system RA requirements. Furthermore, D.15-06-063 and the "Qualifying Capacity Methodology Manual Adopted 2017" do not include the planning reserve

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[15] "2020 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings" at 31, available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442462872.

[16] D.10-06-036 at 40, available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/119856.PDF.

[17] D.15-06-063 at 14-15, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K977/152977475.PDF.

[18] See D.15-06-063 at 12 and the "Qualifying Capacity Methodology Manual Adopted 2017" at 18, available at file:///C:/Users/Co6d1ok/Downloads/Adopted_QC_methodologymanual_2017.pdf.

margin in the definition of (net) qualifying capacity, which is the value that appears in the CPUC Net Qualifying Capacity List and which LSEs enter into the RA Filing templates.[19]

II: Proposal

Staff believes it would be helpful for the Commission to clarify that qualifying capacity values do not include the planning reserve margin, that the planning reserve margin does not apply to local or flexible capacity requirements, and that Energy Division will not augment the qualifying capacity of local or flexible DR resources with the planning reserve margin when determining the contribution of those resources towards meeting RA requirements.

[19] The Filing Guide (at 30) also states that "[t]he DR allocations – and other DR capacity values entered manually into the DR tab – do not include the 15% planning reserve margin."

Proposal G: Transparency of Load Impact Protocol Results

I: Background

Qualifying capacity of all generating resources besides demand response is publicly available on the Net Qualifying Capacity list posted by the CPUC and CAISO. When load impact protocols (LIPs) were adopted for purposes of demand response qualifying capacity counting in D.09-06-028, the Commission found that results of the evaluations should be made public to the maximum extent possible. However, since at that time the only existing DR was operated by the investor owned utilities, it addressed, transparency in terms of capacity that would be allocated to all LSES. In this decision the Commission determines that "to promote fairness and confidence in the RA program, the DR capacity credit allocation process should be transparent to the maximum extent consistent with Commission policy regarding confidentiality of electric procurement data made in D.06-06-066 and subsequent decisions in the underlying rulemaking (R.05-06-040)."[20]

D.09-06-028 did not address transparency of load impact results that were not subject to allocation as there were none at that time. However, with the growth of third-party demand response providers, qualifying capacity of non-IOU DR resources is beginning to be determined through application of the LIPs.

Demand response is not considered a supply-side resource. Without transparency regarding the amount of available DR capacity, it will not be possible to accurately assess the size of the supply stack. In an era of short supply where the Commission has just authorized procurement of 3,300 MW of new capacity in the Integrated Resources Plan proceeding to address supply shortages, it is important that we can accurately assess existing capacity and system needs.

II: Proposal

In order to promote transparency and treat all demand response resources equally regardless of provider, Staff propose that all LIP results be posted publicly to the maximum extent allowable, <u>while protecting customer privacy and market sensitive information of DR providers by adhering to existing Commission policy regarding confidentiality</u>. We anticipate that data would be redacted in cases where there are few customers in an area. Some providers have raised concerns that sharing capacity figures would put them at the competitive disadvantage. If parties, feel this is the case, they should explain why it would be problematic in comments given that capacity values would not reveal the number or identity of customers comprising the resource or the amount of capacity that remains available for purchase.

[20] D.09-06-028 p.25

Proposal H: Reporting System Capacity When Showing Local or Flexible Capacity

I: Background

Decision D.13-06-024 clarified that the "flexible" and "generic" (i.e., "non-flexible") attributes of a megawatt are bundled and cannot be sold separately.[21] Therefore, flexible resources provide both flexible and system capacity simultaneously, and an LSE should list a flexible megawatt both as flexible capacity and as system capacity in an RA Filing to Energy Division. Note that because the monthly NQC and monthly EFC of a resource generally differ, the total system capacity reported may exceed the total flexible capacity reported in a given filing. However, because a flexible megawatt is also a system megawatt, the system capacity reported in an RA Filing should be at least equal to the flexible capacity reported. Similarly, resources that provide local capacity also provide system capacity,[22] and if an LSE reports local capacity from a particular resource in an RA Filing to Energy Division, it should also report the associated system capacity from that resource.

The CPUC uses monthly NQC values to assess system RA compliance and uses August NQC values to assess local RA compliance. Many resources – but particularly wind and solar resources – have system NQC values that differ by month. Therefore, if an LSE has secured the entire capacity of a local resource whose NQC differs by month, then the only month in which the system capacity and local capacity that the LSE reports would certainly be equal is August. In all other months, the system and local capacity values that the LSE reports may differ. Furthermore, if the LSE has only secured a portion of the capacity of a local resource whose NQC differs by month, then the LSE must prorate the local capacity it shows in each month accordingly, to ensure that the local capacity of that resource is not overcommitted. In other words, whereas a local resource is also a system resource, a local megawatt is not necessarily equal to a system megawatt because monthly NQCs can vary for system compliance, whereas only the August NQC is applicable for local compliance. For that reason, RA filings have separate columns for local and system capacity values.

See the examples in the table below, and note that whereas the table is intended to illustrate various scenarios, the progression of monthly NQC values is not necessarily representative of a particular existing resource.

[21] D.13-06-024, Appendix A at A5, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K423/70423172.PDF.
[22] D.06-06-064 at 38-39.

Examples of How to Report Local Capacity Under Various Scenarios

	Monthly NQC of Resource	August NQC of Resource	System Capacity LSE Has Under Contract	System Capacity LSE Should Show in Filing	Local Capacity LSE Should Show in Filing
Month 1	200 MW	150 MW	200 MW	200 MW	150*(200/200) = 150 MW
Month 2	200 MW	150 MW	150 MW	150 MW	150*(150/200) = 112.5 MW
Month 3	150 MW	150 MW	150 MW	150 MW	150 MW
Month 4	100 MW	150 MW	100 MW	100 MW	150*(100/100) = 150 MW
Month 5	100 MW	150 MW	80 MW	80 MW	150*(80/100) = 120 MW
Month 6	50 MW	150 MW	50 MW	50 MW	150*(50/50) = 150 MW
Month 7	50 MW	150 MW	25 MW	25 MW	150*(25/50) = 75 MW
Month 8	0 MW	150 MW	0 MW	0 MW	150 MW or 0 MW^

^The LSE should only show the full August NQC if it has the resource fully under contract for the entire year. Otherwise, it is impossible to tell how much of the August NQC should be shown, and the LSE cannot report this resource against its monthly local RA requirement.

The system capacity of this resource varies each month, as does the amount of system capacity the LSE has under contract. In each case, the LSE prorates the amount of local capacity it shows based on how much of the total monthly NQC the LSE has under contract. For example, in Month 2, it would be incorrect for the LSE to report 150 MW of system capacity and 150 MW of local capacity – even though the August NQC is 150 MW and the LSE has 150 MW of system capacity under contract in that month – because the LSE does not have the entire monthly NQC under contract. If another LSE has the remaining 50 MW of system capacity under contract in Month 2 and reports the equivalent local capacity value, but the LSE in the table reports 150 MW of local capacity, then the two will have collectively over-reported the local capacity available from this resource. (This is a consequence of the current accounting method.) The system and local capacity values in the table are only equal in Month 3, when the LSE has the entire monthly capacity under contract, and it so happens that the NQC equals the August NQC.

II: Proposal

For the most part, the system, flexible, and local capacity reporting rules outlined above appear in the 2020 Filing Guide. It also appears that most LSEs are reporting capacity correctly. However, Staff believe it would be beneficial if the Commission affirmed these rules, namely that in their RA Filings to Energy Division, (1) LSEs should report any flexible capacity as system capacity, as well, (2) LSEs should report the local and system capacity of any local resources they show towards their compliance obligations, adjusting the local capacity accordingly based on how much system capacity is under contract in the given month, and (3) if the monthly NQC for a resource is 0 MW, the LSE should report the full August NQC value as the local capacity value for the resource if the LSE has the entire capacity of the resource under contract for the full year, or if not, the LSE should report 0 MW as the local capacity value in that month.

Proposal I: Deficiency Notices for Violations Other Than Insufficient Capacity

I: Background

The 2020 Filing Guide describes two types of issues that may be present in an RA Filing. The first is a "substantive error" or "procurement deficiency," which the 2020 Filing Guide describes as follows:

> Procurement deficiencies occur when LSEs do not make sufficient RA capacity available to the CAISO via an RA Filing or supply plan confirmation by the RA Filing due date. If additional RA capacity is made available to the CAISO on behalf of the LSE by suppliers, that amount will be debited against any deficiency even if the LSE does not list it in their RA filing.[23]

The second is "minor typographical or numerical errors," which the 2020 Filing Guide describes as "simple typographical or numerical errors that do not affect compliance or do not invalidate resources sufficient to drop the LSE below [the Resource Adequacy Requirement]."[24] Energy Division generally issues a "deficiency notice" to alert an LSE about one or more procurement deficiencies, whereas Energy Division generally issues a "correction notice" to alert an LSE about one or more minor typographical or numerical errors. If an LSE's filing contains both procurement deficiencies and minor typographical or numerical errors, Energy Division generally issues a deficiency notice that describes both.

II: Proposal

Energy Division Staff believe there is sometimes confusion among LSEs regarding what each of these notices means for compliance, and in particular, whether penalties may apply. In addition, staff notes that there are certain issues that are neither procurement deficiencies nor typographical and numerical errors, such as the "Specified Violations" identified in Resolution E-4195,[25] as modified by D.11-06-022.[26] As a result, Staff believe it may be useful to standardize and clarify the use of each type of notice to a greater extent.

Staff proposes that it will issue a "deficiency notice" whenever it identifies a "procurement deficiency" (as defined in the 2020 Filing Guide) or believes that the LSE may have made a "Specified Violation." Energy Division would issue a deficiency notice if at least one error falls in this category, even if other errors in the notice fall in the categories proposed for a "correction notice" below. Note that Energy Division does not issue penalties, so a deficiency notice does not automatically mean a the CPUC will issue a penalty, but it would signify that an error that could result in penalties has occurred. Staff proposes that it will issue a "correction notice" whenever it identifies a "minor typographical or numerical error" (as defined in the 2020 Filing Guide) or requires additional information that the LSE has not necessarily failed to provide in violation of Commission rules, but which Energy Division requires in order to complete the compliance process.

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[23] "2020 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings" at 44, available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442462872.
[24] Ibid. at 44.
[25] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_RESOLUTION/93662.PDF.
[26] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/138375.PDF.

Proposal J: Revise the RA Penalty Structure

I: Background

Public Utilities Code Section 380 requires the Commission to establish and enforce a resource adequacy program.

D.05-10-042 and D.06-06-064 established penalties for System and Local RA procurement deficiencies. D.05-10-042 determined that setting the penalty at three times the cost of new generation was an appropriate sanction for an LSE's failure to procure the capacity needed to meet its system RA obligations. D.06-06-064 determined that 100% of the cost of new generation was reasonable as a penalty for LSEs who fail to procure the capacity needed to meet its local RA obligation.

The penalty structure is provided in the table below:

Penalty Structure Adopted in D.05-10-042 and D.06-06-064

	Small Procurement Deficiency	System Procurement Deficiency	Local Procurement Deficiency
Replaced within five business days of the date of notification	$1,500/incident	$9.99/kW-month	$3.33/kW-month

In 2006, Resolution E-4017 established a citation program to enforce the Commission's Resource Adequacy program for specific violations and in specific amounts and delegated to Energy Division the authority to issue citations. In 2008, Resolution E-4195 supplemented and replaced E-4017; it transfers authority to draft and issue citations from Energy Division to Commission Staff as a whole, broadens the scope of the Resolution to encompass all Load Serving Entities (LSEs) that are potentially subject to Resource Adequacy obligations, and adds a Specified Violation for failure to make timely filings in the manner required and for small procurement deficiencies, defined as up to 1% of an LSE's RA requirement and not more than 5 MW, and authorized Commission staff to impose a penalty on LSEs that violated the requirement.

The penalty structure was revised in D.10-06-036 to provide LSEs an incentive to cure deficiencies in a timely manner. Specifically, it created a penalty structure for deficiencies cured within five business days and those that are not. The penalty structure is provided in the table below:

Penalty Structure Adopted in D.10-06-036

	Small Procurement Deficiency	System Procurement Deficiency	Local Procurement Deficiency
Replaced within five business days of the date of notification	$1,500 first incident in calendar year; $3,000 for each incident thereafter in a calendar year	$3.33/kW-month	$3.33/kW-month
Replaced after five business days from the date of notification or not replaced	LSE pays the applicable System or Local RA penalty for the deficiency	$6.66/kW-month	$3.33/kW-month

In 2011, the Commission modified the penalty structure once again, lessening the penalties for deficiencies cured within five business days. Specifically, D.11-06-022 eliminated the penalty for small procurement deficiencies and instead created a Specified Violation for any procurement deficiency remedied within five business days. D.11-06-022 modified Appendix A to Resolution E-4195 to create a new Specified Violation with a $5,000 or $10,000 penalty for LSEs (depending upon the size of the deficiency) that remedy deficiencies within five business days after the initial notification by Energy Division. It also doubled the penalty to $10,000 or $20,000 if Energy Division finds that an LSE has a second deficiency. This new Specified Violation replaced in total the Specified Violation for Small Procurement Deficiencies. Other Specified Violations from Appendix A remain and continue to be used.

The Specified Violation is as follows:

D.11-06-022 New Specified Violation for Deficiency Cured Within Five Business Days

Specified Violation	Deficiency in either System or Local RA Filing (Modifying Appendix A in Resolution E-4195)
Deficiency cured within five business days from the date of notification by the Energy Division	$5,000 per incident if the deficiency is 10MW or smaller, $10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be $10,000 per incident if the deficiency is 10 MW or smaller, $20,000 for a deficiency larger than 10 MW.

For those deficiencies not cured within five business days, the other penalties adopted in D.10-06-036 continue to apply. The table below shows the penalties retained for deficiencies <u>not</u> remedied within five business days.

Penalty Structure Adopted in D.11-06-022

	System Procurement Deficiency (modifying D.10-06-036 Ordering Paragraph 6g)	Local Procurement Deficiency (modifying D.10-06-036 Ordering Paragraph 6g)
Deficiency remedied after five business days from the date of Energy Division notification or not remedied at all	$6.66/kilowatt-month	$3.33/kilowatt-month

D.14-06-050 extended the Local RA penalty structure to Flexible RA deficiencies, and D.19-02-022 extended the Local RA penalty structure to multiyear Local RA requirements. D.19-06-026 raised the local RA penalty price of $3.33/kW-month to the equivalent value of the newly-adopted local RA trigger price, or $4.25/kW-month.

The current RA penalty structure is as follows:

Current Penalty Structure

	Deficiency in either System, Local or Flexible RA Filing		
	System RA Penalty	**Local RA Penalty**	**Flexible RA Penalty**
Deficiency cured within five business days from the date of notification by the Energy Division	$5,000 per incident if the deficiency is 10MW or smaller, $10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be $10,000 per incident if the deficiency is 10 MW or smaller, $20,000 for a deficiency larger than 10 MW.	$5,000 per incident if the deficiency is 10MW or smaller, $10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be $10,000 per incident if the deficiency is 10 MW or smaller, $20,000 for a deficiency larger than 10 MW	$5,000 per incident if the deficiency is 10MW or smaller, $10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be $10,000 per incident if the deficiency is 10 MW or smaller, $20,000 for a deficiency larger than 10 MW
Replaced after five-business days from the date of notification or not replaced	$6.66/kW-month	$4.25/kW-month	$3.33/kW-month

Currently, the penalty price for system RA deficiency is $6.66/kW-month for all twelve months. However, capacity prices in the summer months can be much higher than the current system penalty price of $6.66/kW-month. (The RA price analysis in the 2018 RA Report[27] indicates that summer RA prices are almost twice as high as non-summer RA prices.) Staff believes that if the penalty price for the summer months is below the capacity prices, there is a perverse incentive for LSEs to pay the penalty price rather than cure their deficiencies. Staff would also like to ensure that there is an incentive to actually procure capacity by the time of the Month Ahead filing when an LSE was deficient in the Year Ahead filing. Finally, staff believes it may be appropriate to institute a form of penalty escalation so that LSEs who consistently fail to procure sufficient capacity are not able to simply pay penalties, lean on other LSEs to actually procure the remaining needed capacity (particularly if there is no CPM designation from CAISO), and yet continue to operate in the RA program.

II: Proposal(s)

Staff proposes the following revisions to the penalty structure to address the identified concerns.

1. Set the penalty for system capacity deficiencies to be twice as high in the five summer months (May to September) as the non-summer months (January to April, October to December). Currently, the penalty for system deficiencies is $6.66/kW-month for all twelve months. Staff proposes to revise the penalty such that it would be $9.40/kW-month in the five summer months and $4.70/kW-month in the non-summer months. This proposal would shape the annual penalty prices so that non-summer month penalties are half of summer month penalties.

2. Staff seeks comments on how to ensure that LSEs have an incentive to cure any deficiencies between the Year Ahead and Month Ahead filings. Is it appropriate to penalize LSEs for the portion of a Month Ahead deficiency that is redundant to (and already penalized as a result of) a Year Ahead deficiency but that was not cured in the interim? How else might to the CPUC incent LSEs to both meet their 90% Year Ahead requirements (which the penalty on Year Ahead deficiencies accomplishes) and cure any deficiencies from the Year Ahead process when meeting their 100% Month Ahead requirements (which there is no incentive to cure without a second, separate Month Ahead penalty for these same deficiencies)?

3. Staff is also seeking comments from parties on whether Energy Division should establish a process to remove from the market LSEs who consistently cannot procure sufficient capacity to meet their RA requirements. For instance, should the penalty for the LSEs' inability to procure capacity escalate each time the LSEs fail to procure sufficient capacity to meet their RA requirements?

[27] Available at https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/2018%20RA%20Report%20rev.pdf.