TRACK 2 ENERGY DIVISION STAFF PROPOSALS: MULTI-YEAR RA REQUIREMENTS

I. Introduction

This Staff proposal builds off elements of the "Solution 1" multi-year resource adequacy (RA) proposal released on February 16, 2018[1] and also incorporates the directives adopted in in the Track 1 decision (D.18-06-030). The document first provides relevant background information, followed by a high-level analysis of the most recent contract data. The final section describes two proposals: (1) Multi-Year Local RA Framework with a Single Service Area Procurement Entity and (2) Study to Guide Preferred Local Procurement.

II. Background

On February 16, 2018, Staff issued a paper titled *Current Trends in California's Resource Adequacy Market* (*Current Trends*). This paper identified several emerging issues in the RA program, including growth of community choice aggregation, increases in local deficiencies, more frequent CAISO backstop procurement through Reliability Must Run (RMR) designations and the Capacity Procurement Mechanism (CPM), and a notable decline in forward procurement. Since the issuance of that report, Staff has continued to document and observe issues in the bilateral RA market.

As discussed in *Current Trends*, stakeholders expected a large amount of load migration was expected to occur in 2018. This expectation derived from CCA implementation plans rather than from year-ahead RA forecasts, which at the time did not account for all CCAs who intended to serve load in 2018. In the July 2018 month-ahead RA load forecast, Staff observed approximately 3,300 MW of load migration across all load serving entities (LSEs), including roughly 2,600 MW in the PG&E transmission access charge (TAC) area, roughly 600 MW in the SCE TAC area, and roughly 60 MW in the SDG&E TAC area. This level of load migration entails a significant amount of procurement by load gaining LSEs in the intra-year procurement time frame. Several LSEs filed local waivers for July and August 2018, and Staff has also observed individual system deficiencies during those months.

Several local resources have also indicated their intent to retire. On February 28, 2018, GenOn/NRG filed retirement notices with the Commission – pursuant to General Order 167 – for three of its generation resources: Ellwood Generating Station (a 54 MW resource located in the Moorpark sub-local area), Ormond Beach Generating Station (a 1,516 MW resource located in the Moorpark sub-local area), and Etiwanda Generating Station (a 640 MW resource located in the LA Basin Local

[1] See the Energy Division staff report *Current Trends in California's Resource Adequacy Program*, available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457193.

Area). These retirements, in conjunction with observed deficiencies and local waiver requests, have signaled the potential for additional backstop procurement in 2019.

On May 15, 2018, CAISO filed its Final Local Capacity Technical Report[2] in the RA proceeding (R.17-09-020). The report identified the need for Ellwood and one unit of Ormond Beach for reliability purposes.[3] Specifically, CAISO stated the following in its filing:

> *The Final Local Capacity Technical Analysis identifies a local capacity need to retain the Ellwood Generating Station (Ellwood) and one of the generating units at Ormond Beach (Ormond Beach). On February 28, 2018, NRG California South LP, the owner of both Ellwood and Ormond Beach, submitted notices to shut down and retire these generating facilities prior to the 2019 resource adequacy year. [Footnote Omitted] As a result, the CAISO intends to seek a reliability-must run (RMR) designation for Ellwood and one of the Ormond Beach units at the CAISO's July Board of Governors meeting. The CAISO's intention to seek an RMR designation for these units does not bar load-serving entities from entering into bilateral contracts with the Ellwood or Ormond Units.*[4]

In an attempt to address the potential backstop procurement of these resources for 2019 and 2020, the Commission directed Southern California Edison (in D.18-06-030) to attempt to negotiate contracts with these generators at lower costs than would be expected through the backstop mechanism process employed by the CAISO.[5] The cost of these contracts would go through the Cost Allocation Mechanism (CAM). In addition, the Commission concluded that a three- to five-year local RA requirement would be initiated for 2020.[6] This decision did not specify details of a multi-year procurement framework but instead issued guidance for related proposals in Track 2 of R.17-09-020. Staff addresses this guidance within its proposals below.

Section III below reviews findings from the most recent multi-year contract data collection effort. Staff's proposals follow in Sections IV and V.

III. Contract Data Analysis

a. Data Collection and Methodology

On April 4, 2018, Staff distributed a data request to thirty-five LSEs that were in existence at the time and which were expected to serve load in 2018. This number included community choice

[2] California ISO, "California Independent System Operator Corporation 2019 Annual Resource Adequacy Related Analyses," available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M215/K367/215367280.PDF
[3] California ISO, *2019 Local Capacity Technical Analysis: Final Report and Study Results*, May 15, 2018, p. 3, available at http://www.caiso.com/Documents/Final2019LocalCapacityTechnicalReport.pdf.
[4] California ISO, "2019 Annual Resource Adequacy Related Analyses," at 1-2
[5] D.18-06-030 at 31, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M216/K634/216634123.PDF.
[6] Ibid. at 28

aggregators (CCAs) whose implementation plans had been approved as of December 8, 2017.[7] The number did not include three new CCAs which the Commission had authorized to serve load in 2018 under the Resolution E-4907 waiver process,[8] as Energy Division had not granted waivers to these CCAs by the time data collection began.

The request asked LSEs to report all contracts they held for system, local, or flexible resource adequacy – including utility-owned generation and capacity that IOUs had procured under the cost allocation mechanism (CAM) – with terms covering any portion of the January 2018 through December 2028 time period. Specifically, Energy Division asked LSEs to provide the following information regarding each RA contract: resource ID and name, contract ID, contract start and end date, CAM designation (if applicable), unit type and fuel type, balancing area, Path 26 designation, local area (if applicable), nameplate capacity, and contracted capacity. The request expanded upon similar initiatives in 2014, 2016, and 2017[9] and was intended to meet the Commission's direction that Energy Division periodically report on multiyear contracting activity.[10]

Energy Division requested that LSEs respond by April 27, 2018, or just over three weeks after receiving the request. Thirty-one LSEs responded to the data request, two of which indicated that they did not hold any resource adequacy contracts with terms extending beyond December 31, 2018. Four electric service providers (ESPs), representing roughly 4% of the expected coincident peak load for CPUC-jurisdictional LSEs in August 2018, did not respond to the data request. For 2018 only, Energy Division included data from these LSEs' August month-ahead filings, as well as from the filings of the two respondents that indicated they did not hold any multiyear contracts.

During and after the response window, Staff analyzed responses to ensure consistency with the request and to identify potential double-counting or other issues. Staff contacted respondents to resolve any issues in the data. In early June, three LSEs asked Energy Division to accept data regarding additional contracts that had been under negotiation – but were not concluded – during the response period. Energy Division accepted the additional data, given that the contracts were under negotiation during the response window and given the purpose of the research effort, which is to understand LSEs' forward contracting activity.

As in *Current Trends*, Staff focused the analysis below on system and local capacity under contract. All requirements, available capacity, and contracted capacity are for August of a given year. System capacity requirements for 2018 are the actual month-ahead August requirements, and system capacity requirements for 2019 are 115% of the initial year-ahead August 2019 load forecast. System requirements for 2020 through 2028 represent 115% of the coincident-adjusted, mid-range

[7] See Resolution E-4907 at 11, available at
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M210/K016/210016662.PDF
[8] Ibid. at 11
[9] For a detailed description of these requests, see the Energy Division staff report *Current Trends in California's Resource Adequacy Program*, available at
http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457193
[10] See D.17-06-027 at 18, available at
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K027/192027253.PDF

2018-2030 California Energy Demand Forecast for CPUC-jurisdictional LSEs, with mid-range assumptions for additionally achievable energy efficiency savings and additionally achievable solar PV (the 2017 IEPR forecast).[11] Local and sub-local capacity requirements for 2018 and 2019 similarly reflect the actual requirements in those years, whereas local requirements for 2020 through 2023 come from CAISO's one-year-ahead Local Capacity Technical Reports for 2018[12] and 2019 and from CAISO's five-year-ahead reports for 2020,[13] 2021,[14] 2022,[15] and 2023.[16] Available capacity in 2018 comes from the 2018 Net Qualifying Capacity list,[17] modified to exclude resources that retired or mothballed prior to 2018. Available capacity for 2019 through 2028 derives from the RESOLVE baseline assumptions, which Staff similarly modified (1) to remove any conventional generating units, including once-through cooling units, after the year in which they are scheduled to retire and (2) to ensure that baselines for renewables, storage, and demand response reflect the actual capacity available from those resource categories in 2018. Finally, "contracted capacity"[18] derives from the data submitted by LSEs. Staff augmented contracted capacity for 2018 to include (1) allocations of utility-run demand response programs, which Staff also added to available capacity in 2018, and (2) August 2018 capacity contracts reported in month-ahead resource adequacy filings by the six LSEs that did not provide data or indicated that they did not hold contracts with multiyear terms. Inasmuch as demand response programs (DRAM and utility-run programs) are mandated, Staff assumed that all demand response capacity from the RESOLVE baseline would also be under contract from 2019 through 2028, while taking care not to double-count any DR reported by LSEs in those years.

b. System Capacity

The following section discusses actual projected system load for CPUC-jurisdictional LSEs, actual and projected system capacity requirements, available capacity, and capacity under contract for 2018 through 2028. In each figure, the height of the stacked bar represents total available capacity in the

[11] California Energy Commission, "Form 1.5b – Statewide: California Energy Demand Forecast 2018-2030, Mid Demand Baseline Case, Mid AAEE and AAPV Savings," February 16, 2018, available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=222582.
[12] California ISO, *2018 Local Capacity Technical Analysis: Final Report and Study Results*, May 1, 2017, available at http://www.caiso.com/Documents/Final2018LocalCapacityTechnicalReport.pdf.
[13] California ISO, *2020 Local Capacity Technical Analysis: Final Report and Study Results*, April 30, 2015, available at http://www.caiso.com/Documents/Final2020Long-TermLocalCapacityTechnicalReportApr302015.pdf.
[14] California ISO, *2021 Local Capacity Technical Analysis: Updated Final Report and Study Results*, March 14, 2017, available at http://www.caiso.com/Documents/Final2021Long-TermLocalCapacityTechnicalReport.pdf.
[15] California ISO, *2022 Local Capacity Technical Analysis: Final Report and Study Results*, May 3, 2017, available at http://www.caiso.com/Documents/Final2022Long-TermLocalCapacityTechnicalReport.pdf.
[16] California ISO, *2023 Local Capacity Technical Analysis: Final Report and Study Results*, May 15, 2018, available at http://www.caiso.com/Documents/Final2023Long-TermLocalCapacityTechnicalReport.pdf.
[17] The most recent NQC list is available on the CAISO website at http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx
[18] "Contracted capacity" refers to the sum of (1) utility-owned generation, (2) capacity contracts between LSEs and generators or between LSEs and other LSEs, including contracts for capacity at interties, and (3) capacity that IOUs have procured under CAM.

relevant area. Imports – which LSEs may use to meet system capacity requirements – are represented as a hollow rectangle, indicating that they are not a portion of available capacity in the relevant area but nevertheless count towards meeting system requirements. "Centralized procurement" represents the sum of (1) CAM, (2) the demand response auction mechanism (DRAM), (3) supply-side demand response programs run by the IOUs but for which LSEs in a given IOU service territory receive capacity credits, and (4) behind-the-meter local capacity resources (BTM LCR) in Southern California for which LSEs in Southern California Edison's service territory receive capacity credits. Centralized procurement does not include capacity that is under RMR or CPM designation in 2018, which equals roughly 1,720 MW. Except in the case of BTM LCR, available and contracted demand response capacity was increased by 15% in accordance with how these resources are treated for RA compliance. "Unspecified capacity" represents capacity that CCAs and ESPs have contracted from IOUs but for which the IOUs have not yet specified the resources that will appear on RA filings and supply plans. This category appears separately to avoid double-counting of capacity that IOUs have under contract but which they will provide to ESPs or CCAs in the future. Staff assumed that contracts for unspecified capacity would be met with physical resources in the CAISO area rather than with imports. Finally, all numbers are for August of the given year.

Figure 1: System RA Capacity and Obligations for CPUC Jurisdictional LSEs, 2018-2028

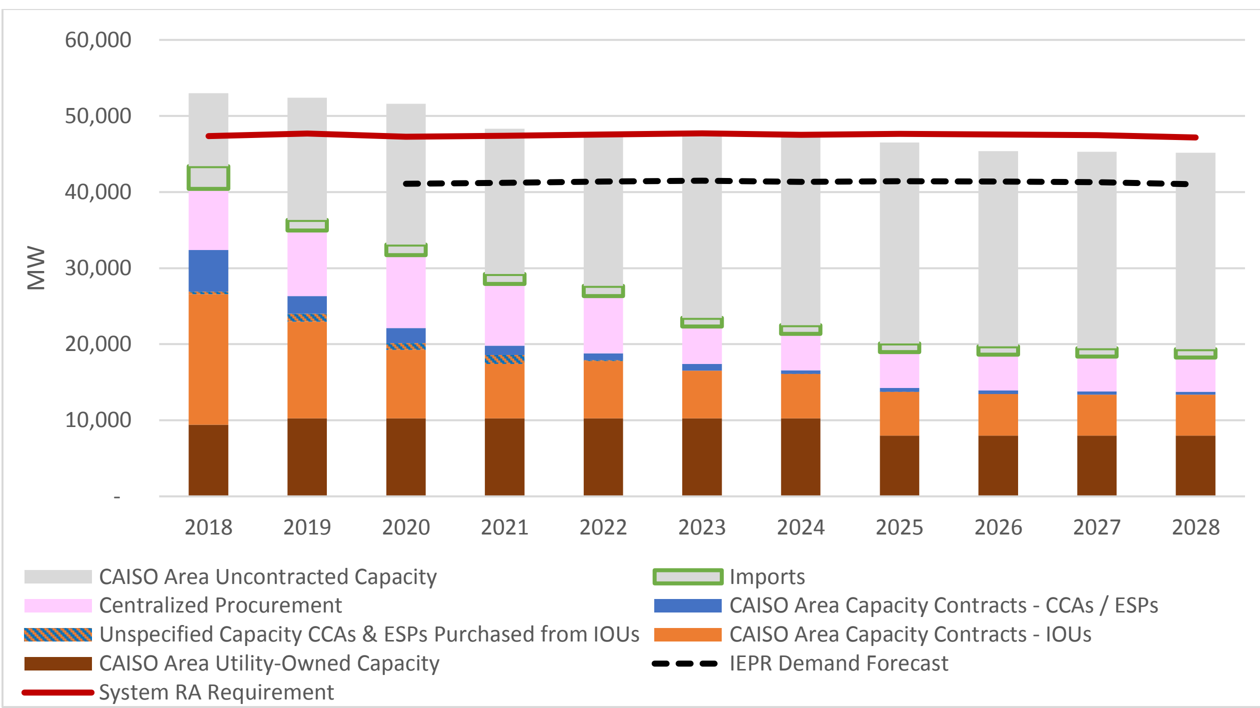


Figure 1 presents system capacity information for CPUC-jurisdictional LSEs across California. Total available capacity in the CAISO area in each year is similar to the total capacity reported in the *Current Trends* report, except that Staff made the modifications noted in the methodology section above. Differences in available supply between the *Current Trends* report and this analysis derive almost exclusively from these methodology changes, namely removing retired and mothballed resources and updating the RESOLVE baselines to match capacity that was actually available as of 2018. In addition, the 2017 IEPR forecast for CPUC-jurisdictional LSEs that Staff used in this analysis is between 1,000 MW and 1,900 MW higher in each year than the 2016 IEPR forecast used in the *Current Trends* report.

The percentage of each year's system requirement that was under contract as of April 2018 is also similar to the percentage reported in the February 2018 report: LSEs had procured 76% of the estimated 2019 requirement (one year out), which declines to 41% of the requirement ten years out. LSEs had procured 92% of the August 2018 requirement as of April 2018, which reflects both the fact that LSEs need not show 100% procurement until forty-five days before the compliance month and the fact that RMR and CPM capacity do not appear in the data. If we add RMR and CPM capacity to the 2018 contract data, roughly 95% of the August 2018 requirement was "under contract" as of April 2018. Table A.1 in the Appendix indicates the percentage of each year's August requirement that is currently under contract by the various LSE types or is that part of a centralized procurement mechanism (again, excluding RMR and CPM).

Figure 2: System RA Capacity and Obligations for CPUC Jurisdictional LSEs North of Path 26, 2018-2028

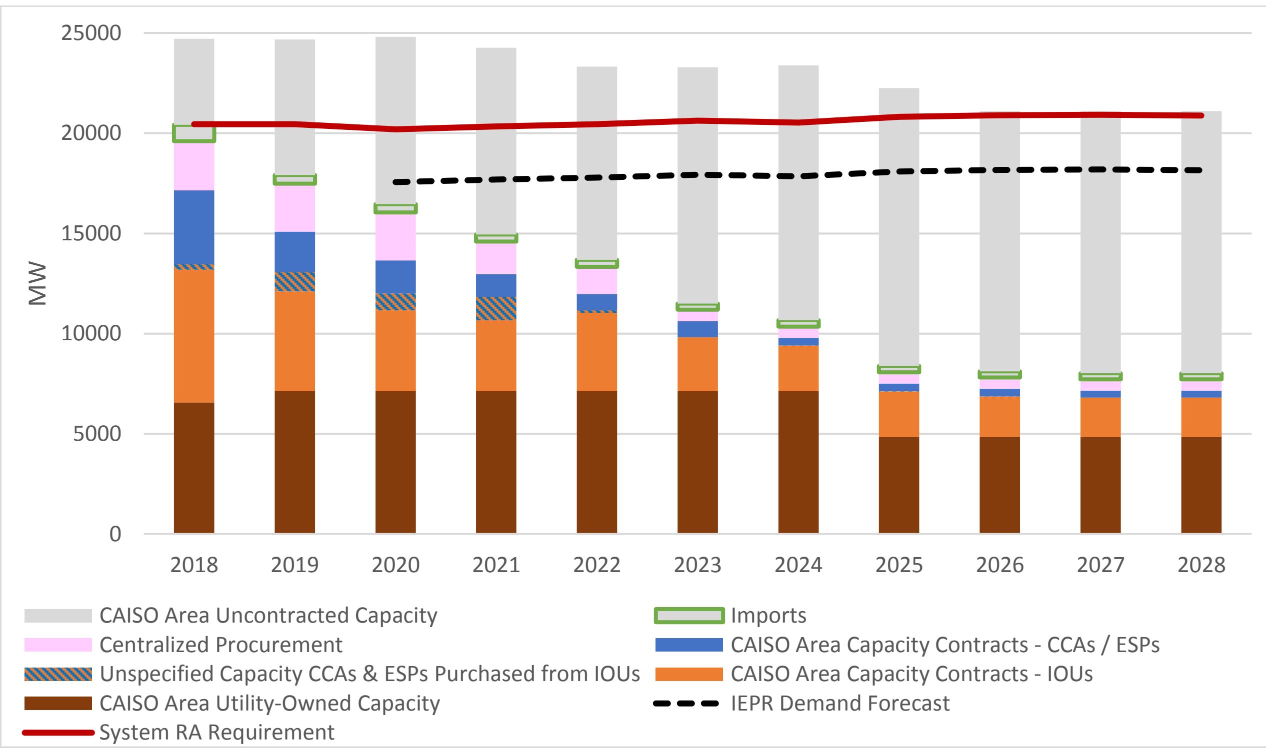
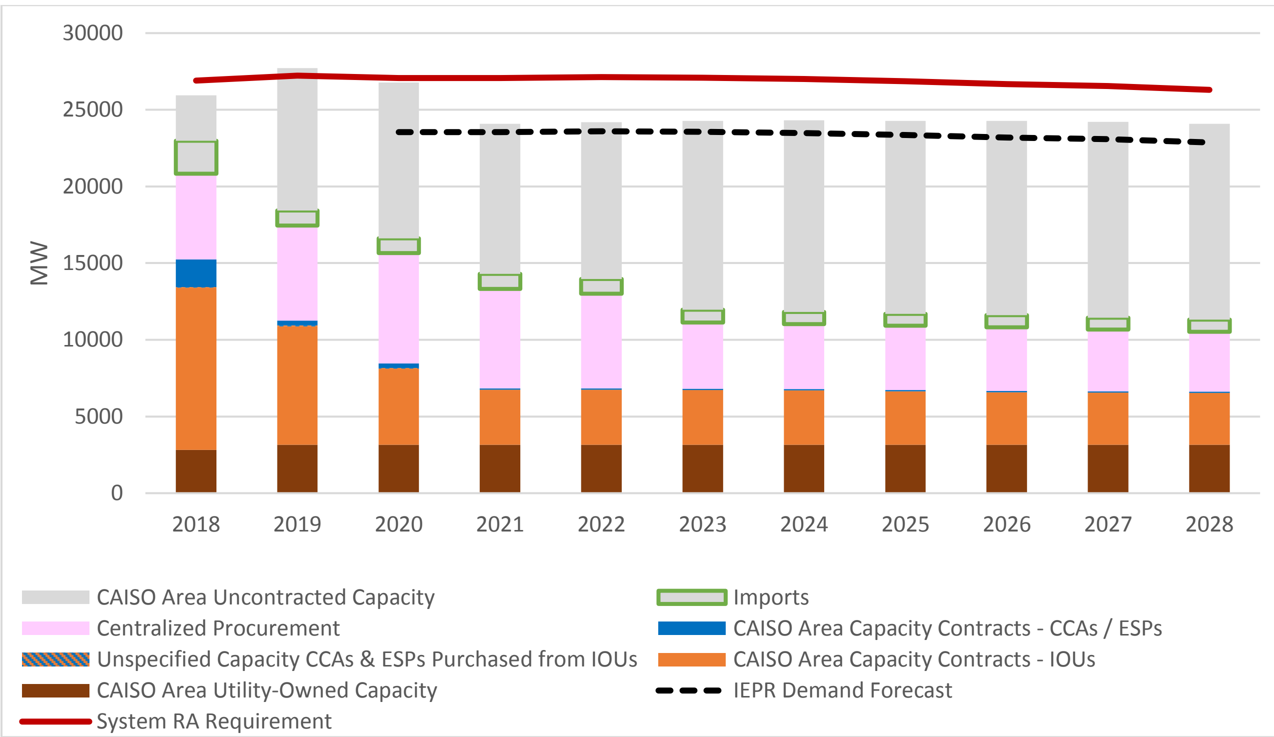


Figure 2 presents the same type of information as Figure 1, except that the data are limited to capacity (and system requirements) north of Path 26. Table A.2 in the Appendix indicates the percentage of each year's requirement that is under contract by LSE type. Note that the percentages are somewhat less informative in this instance, as capacity north of Path 26 can be used to meet requirements south of Path 26, or vice versa. The primary objective is to show how much of the capacity on either side of Path 26 is under contract, regardless of which requirement it will ultimately meet. Figure 3 below (and Table A.3 in the Appendix) gives analogous information for areas south of Path 26.

Because the RESOLVE baselines do not indicate the zonal (north or south of Path 26) location for new renewable or storage resources, Staff assumed that new renewable and storage resources would be sited north or south of Path 26 in proportion to the zonal location of capacity from each resource category in 2018. For example, if 40% of wind capacity was located north of Path 26 in 2018 and 60% was located south of Path 26 in 2018, then Staff assumed 40% of incremental wind capacity in every future year of the RESOLVE baseline would be north of Path 26 and 60% would be south of Path 26.

Figure 3: System RA Capacity and Obligations for CPUC Jurisdictional LSEs South of Path 26, 2018-2028



c. Local Capacity

Figures 4 and 5 below present the sum of CPUC-jurisdictional[19] local area requirements north and south of Path 26, respectively, as well as capacity under contract to meet those requirements. Except for imports, which do not appear here because imports do not count towards local capacity requirements, the capacity categories in Figures 4 and 5 are the same as in the system analysis. Staff

[19] Staff calculated CPUC-jurisdictional local area requirements by multiplying each requirement against the 2018 load share for CPUC-jurisdictional LSEs in the relevant TAC area (PG&E, SCE, or SDG&E).

did not augment demand response capacity by 15% in the local analysis because there is no planning reserve margin embedded in local requirements, and therefore demand response does not offset a planning reserve margin for local RA compliance. Tables A.4 and A.5 in the Appendix indicate the percentage of aggregate local requirements north and south of Path 26, respectively, that are currently under contract by the various LSE types or that are part of a centralized procurement mechanism (excluding RMR and CPM capacity).

Figure 4: Local RA Capacity and Obligations for CPUC Jurisdictional LSEs North of Path 26, 2018-2023

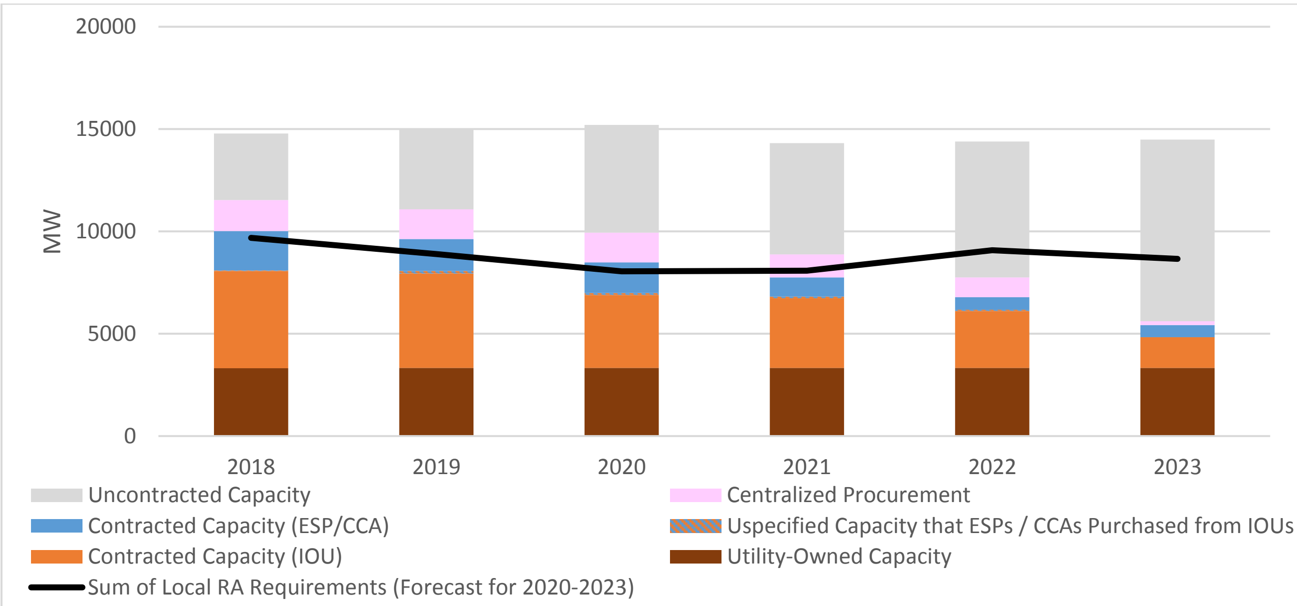
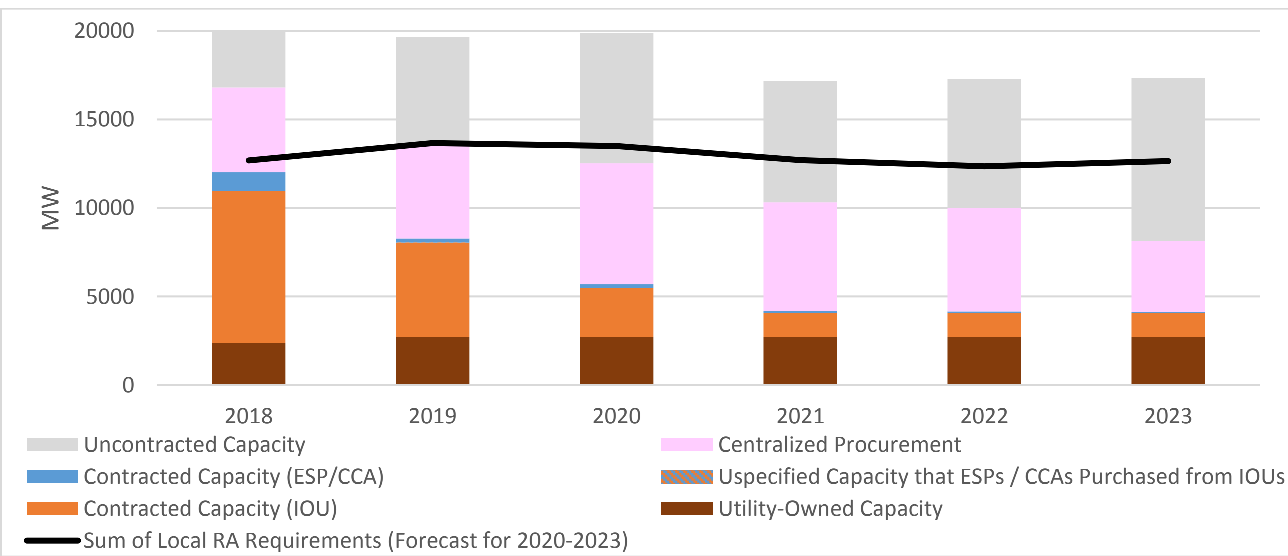


Figure 5: Local RA Capacity and Obligations for CPUC Jurisdictional LSEs South of Path 26, 2018-2023



We present Figures 4 and 5 here to be consistent with past reports on multiyear contracting. Although Figures 4 and 5 give a sense of how much capacity is under contract in local areas, they do not indicate whether individual local and sub-local requirements are met, since they sum all capacity and all local requirements. To illustrate, assume a scenario in which California has only two locally constrained areas: Local Area A and Local Area B. If the requirement in Local Area A were 100 MW and the requirement in Local Area B were 50 MW, and if LSEs procured 150 MW in Local Area A and 0 MW in Local Area B, then the summation inherent in Figures 4 and 5 would suggest that local requirements were 100% met in California. In reality, 150% of Local Area A's requirement would be met, and 0% of Local Area B's requirement would be met. This is a suboptimal situation that could lead to over procurement in Local Area A backstop procurement in Local Area B.

To understand the true extent of multiyear contracting for local capacity, it is necessary to examine contracting at the local and sub-local levels. Local area requirements are driven by constraints in sub-local areas, and collective deficiencies may arise when procurement does not address certain sub-local constraints, even if all LSEs meet their individual local requirements. Staff provides supplemental Tables A.6 and A.7 in the Appendix, which present CPUC-jurisdictional local and sub-local requirements in several years, as well as the percentage of those requirements that was met by existing contracts as of April 2018 (excluding RMR and CPM capacity from what is "under contract"). As the tables show, although the Bay Area's 2019 requirement has already been met by LSE procurement, the sub-local requirements in Oakland and South Bay-Moss Landing had not been met as of April 2018. If unaddressed, situations such as this could lead to further backstop procurement in 2019 and beyond.

Staff's proposals below seek to address local procurement needs with an eye to the sub-local requirements that drive local deficiencies. Staff provides additional data in these proposals and in the Appendix that highlight the interaction between sub-local and local requirements, as well as changes in those requirements over time.

IV. Proposal 1: Multi-Year Local RA Framework with a Single Service Area Procurement Entity

a. Establishing a Multi-Year Local RA Requirement:

In D.18-06-030, the Commission adopted a multi-year RA framework for implementation in 2020. The Commission concluded the following:

> *The existing Local Capacity Requirement Technical Studies will be a primary input to the Commission's determination of multi-year local needs. However, if we adopt a three or four-year local RA program in Track 2, it may be helpful if the CAISO were to add a study that matches this new timeframe, and not just the current one and five year studies.*[20]

[20] D.18-06-030 at 33

CAISO currently produces one-year-ahead and five-year-ahead local capacity technical studies. Staff proposes that the Commission use the one-year-ahead study to develop the two-year requirement and use the five-year-ahead study to develop the three-, four-, and five- year requirements. Staff proposes that for years two, three, and four, CAISO utilize engineer managed adjustments to revise the power flow results to account for approved transmission upgrades that are scheduled to be in service for the associated year. These engineer managed adjustments would allow transmission planning assumptions to flow into the local requirements and would minimize the risk of over procurement in years following year one.

The inputs and assumptions used in the one-year-ahead and five-year-ahead studies would go through the annual CAISO stakeholder process, wherein parties could file comments on the appropriate inputs and assumptions. Staff proposes that the inputs and assumptions of the one-year-ahead and five-year-ahead studies also be vetted in the CPUC's annual RA proceeding. Thus, parties would file comments on the inputs and assumptions in Track 3 of the current RA proceeding. See Section III(e) below for a narrative timeline of how this would work for 2020. As part of the process to study and develop local requirements for 2020 thorough 2025, it would also be necessary to include any projects that have been identified as economical in the 2018 Transmission Planning Process (TPP) LCR reduction study. Section III(c), below, addresses this coordination.

Finally, Staff proposes that the Commission only adopt and allocate the CPUC-jurisdictional portion of the total multi-year local requirement, as is done today for the annual local requirements. Municipal utilities would procure the non-jurisdictional share, as is done today.

b. Percentages and Duration

In addition to proposing a multi-year local RA requirement in D.18-06-030, the Commission found that a 100% local procurement requirement for the first year and a 95% requirement for the second year was appropriate. Parties were directed to propose multi-year local RA requirements with three- to five-year durations as part of their Track 2 testimony. For year three (and beyond, if adopted), parties were directed to propose a reasonable amount of local procurement based on data such as that presented in the *Current Trends* report.[21]

The voluntary levels of procurement shown in Table 1 below were taken from the most recent contract data analysis (including CAM resources, BTM LCR resources in Southern California, and modified RESOLVE assumptions for DRAM and utility-run DR). The numbers represent procurement in each local area as a percentage of the total local requirement for that area. The table illustrates that some local areas are over procured, and some are under procured.

[21] D.18-06-030 at OP 10 and at pp. 29-30

Table 1: Contracted Local Procurement as a Percentage of Local Requirements, 2019-2023

Local Area	2019	2020	2021	2022	2023
Bay Area	134%	119%	84%	71%	40%
Big Creek-Ventura	105%	101%	70%	65%	60%
Fresno	172%	150%	231%	143%	144%
Humboldt	131%	126%	127%	111%	111%
Kern	117%	409%	363%	177%	125%
LA Basin	99%	90%	100%	108%	66%
North Coast/North Bay	102%	137%	147%	97%	72%
San Diego-Imperial Valley	99%	95%	60%	57%	63%
Sierra	71%	70%	63%	47%	47%
Stockton	131%	167%	154%	133%	55%

In order to arrive at a voluntary local percentage that could guide a sufficient level of procurement, Staff capped the total procurement in each local area at 100% of the requirement and then summed all local procurement and all local requirements. Capping procurement at the local requirement avoids the local area summation problem described in relation to Figures 4 and 5 in the analysis section, namely that summation causes over procurement in one local area to "count towards" under procured requirements in other areas.

Table 2 below lists the amount of capped procurement by local area. The second-to-last line of the table describes this procurement as a percentage of aggregate local capacity requirements for CPUC-jurisdictional LSEs across the entire state. These values establish the current voluntary levels of local procurement, which are 97% in year 1, 93% in year two, 82% in year three, 76% in year four, and 61% in year five. These levels are significantly lower than they would be if a cap were not applied at the respective LCR requirements. For comparative purposes, the last line of the Table 2 shows total (uncapped) procurement as a percentage of aggregate local requirements.

Staff also analyzed procurement in sub-local areas for the years 2019 and 2023, capped at sub-local area requirements (these numbers do not appear in Table 2). As of April 2018, capped sub-local procurement met 87% of aggregate 2019 sub-local requirements and 43% of the aggregate 2023 sub-local requirements. These numbers are clearly lower than capped procurement for local areas overall. Tables A.6 and A.7 in the Appendix provide additional information regarding sub-local areas, including the percentage of each sub-local requirement in 2018, 2019, 2022, and 2023 that was met by procurement as of April 2018.

Table 2: Procurement by Local Area Capped at Local Area Requirement (MW), 2019-2023

	Year 1	Year 2	Year 3	Year 4	Year 5
	2019	**2020**	**2021**	**2022**	**2023**
Bay Area	4,030	3,786	3,933	3,303	1,701
Big Creek-Ventura	2,350	2,335	1,519	1,529	1,461
Fresno	1,509	1,687	1,048	1,680	1,525
Humboldt	149	154	153	153	153
Kern	426	122	95	111	157
LA Basin	7,186	7,475	6,171	5,413	4,057
North Coast/North Bay	622	460	434	387	362
San Diego-Imperial Valley	3,998	2,710	2,635	2,632	2,622
Sierra	1,261	1,077	836	813	813
Stockton	386	304	329	367	166
Total Contracted Capped at LCR	**21,917**	**20,109**	**17,152**	**16,387**	**13,016**
Total LCR	**22,567**	**21,548**	**20,795**	**21,441**	**21,321**
Contracted Capacity (Capped at LCR)/LCR	**97%**	**93%**	**82%**	**76%**	**61%**
Contracted Capacity (not Capped)/LCR	**110%**	**104%**	**92%**	**83%**	**64%**

Local and sub-local RA requirements are driven by two key inputs: (1) load forecasts and (2) the transfer limits into the constrained area. Therefore, the risk of over procurement can be narrowed to decreases in the load forecast and uncertainty in the timing of transmission upgrades to the constrained area. Transmission upgrade assumptions will continue to flow into the LCR studies through the annual TPP. Load forecast assumptions will continue to come from the approved Integrated Energy Policy Report (IEPR) demand forecast process.

The next issue is managing uncertainty between year one and year five, given that additional local studies do not currently exist. As noted above, Staff proposes that requirements for years two, three, and four be established using engineer managed adjustments to address the changes in transmission assumptions from year to year. A similar adjustment may be possible for the load forecast used in the studies. Staff proposes that parties explore this through vetting the LCR assumptions in the CAISO's LCR process.

It is also important to examine the uncertainty inherent in differences between the five-year-ahead and one-year-ahead local study results. Tables 7 and 8 in Section V provide the results of recent one-year-ahead five-year-ahead studies, respectively. Table 3 below presents the difference between the one-year-ahead and five-year-ahead requirements (one-year-ahead minus five-year-ahead) for each local area in 2017, 2018, and 2019 as a percentage of the original five-year-ahead requirement. Positive percentages reflect an increase in the requirements from year five to year one, indicating a need for additional procurement, whereas negative percentages reflect a decrease, indicating a risk of over procurement.

Table 3: Change from Five-Year-Ahead to One-Year-Ahead Local Requirement (as a Percentage of Five-Year-Ahead Local Requirement)

	2017	2018	2019
Humboldt	-5%	-14%	-5%
North Coast/North Bay	62%	50%	34%
Sierra	4%	83%	104%
Stockton	69%	72%	121%
Bay Area	31%	15%	6%
Fresno	-16%	-1%	5%
Kern	13%	-4%	148%
LA Basin	-26%	-32%	-11%
Big Creek-Ventura	-19%	-14%	0%
San Diego-Imperial Valley	13%	20%	22%
Total	**-4%**	**-4%**	**9%**

Table 4 below presents Staff's recommendation for minimum levels of procurement in each local area and each year. These procurement levels are greater than the current voluntary levels of aggregate local procurement (see the second-to-last line in Table 2). They are also greater than current voluntary procurement in some individual local areas (see Table 1) and in sub-local areas overall (see discussion above). Thus, Staff expects these levels will help to balance reliability needs with some degree of over procurement risk.

Given Staff's proposed procurement levels, over procurement could potentially occur if the requirement in a local area dropped more than 25% between the five-year-ahead and one-year-ahead studies. Table 3 indicates that whereas the requirements for several local areas dropped between the two studies in recent years, only the LA basin experienced drops of more than 25%. Staff therefore concludes that the proposed procurement levels address most of the over procurement risk based on recent study results. Staff further notes that whereas the risk of over procurement does exist, even if it were to occur, excess capacity could still be applied towards system and flexible RA needs and thus would still have value in contributing to grid reliability.

Table 4: Staff Recommendation for Forward Local Procurement, Year 1 – Year 5

Year 1	Year 2	Year 3	Year 4	Year 5
100%	**95%**	**90%**	**80%**	**75%**

c. Coordination with CAISO's LCR reduction study in the Transmission Planning Process:

CAISO's 2018-2019 TPP Study Scope includes an LCR reduction study that aims to *identify potential transmission upgrades that would economically lower gas-fired generation capacity requirements in local capacity areas or sub-areas. . . . The local capacity areas and sub-areas to be studied will be prioritized based on the attributes of the gas-fired generation to provide other system benefits and on the gas-fired generation being located in disadvantaged communities.*[22]

On April 18, 2018, CAISO presented its "Local Capacity Requirement Potential Reduction Study"[23] as part of its 2018-2019 TPP Study Scope. In its presentation, CAISO asserted that the number of distinct local and sub-local areas will decrease from 53 areas in 2018 to 41 in 2026, as a result of newly approved transmission projects. This will result in the elimination of the following 12 sub-local areas:[24]

Sierra: Placerville, Placer, Bogue, Drum-Rio Oso, and South of Palermo sub-local areas
Stockton: Lockeford sub-local area
LA Basin: West of Devers, Valley-Devers, and Valley sub-local areas
Big Creek/Ventura: Moorpark sub-local area
San Diego/Imperial Valley: Mission and Miramar sub-local areas

In its current LCR potential reduction study, CAISO has identified 21 local and sub-local areas to be studied. These areas represent approximately fifty percent of the local needs forecasted for 2026.[25]

The 21 distinct areas under study include the following:[26]

Humboldt: Overall and any sub-local areas (if needed)
North Coast/North Bay: None
Sierra: Pease and South of Rio Oso sub-local areas, as well as overall (if needed)
Stockton: None
Bay Area: Llagas, San Jose, and South Bay-Moss Landing sub-local areas, as well as overall (if required)
Fresno: Hanford, Herndon, and Reedley sub-local areas
Kern: Overall and all sub-local areas
LA Basin: Eastern sub-local area
Big Creek/Ventura: Santa Clara sub-local area
San Diego/Imperial Valley: El Cajon, Pala, Border, Esco, and San Diego sub-local areas, as well as overall

CAISO is scheduled to present the preliminary results of the LCR assessment and potential transmission upgrades or preferred resource alternatives on November 16, 2018. The results would not be final until the TPP receives approval from CAISO management in February 2019 and from the

[22] California ISO, *2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan*, March 30, 2018, p. 49, available at http://www.caiso.com/Documents/Final2018-2019StudyPlan.pdf
[23] California ISO, "Local Capacity Requirements Potential Reduction Study," April 18, 2018, available at http://www.caiso.com/Documents/Presentation-LocalCapacityRequirementReductionStudy.pdf
[24] Ibid. at 6
[25] Ibid. at 14
[26] Ibid. at 11

CAISO Board of Governors in March 2019. This timeline makes coordinating any approved projects difficult for the first multi-year LCR study. However, Staff proposes that if CAISO management approves any projects, they should be included in the five-year-ahead study and incorporated via engineer managed adjustments for the years they are expected to be in service.

d. Single Service Area Procurement Entity

D.18-06-030 directs parties to include implementable central buyer structures as part of their Track 2 proposals. Additionally, the Commission states that "[w]eighing both the concerns and the potential benefits of moving to a central buyer system, we believe that a central buyer system – for at least some portion of local RA – is the solution most likely to provide cost efficiency, market certainty, reliability, administrative efficiency, and customer protection."[27] Additionally, the decision states that

> *all proposals must address how the central buyer structure would balance economic procurement criteria with other essential state policies, such as greenhouse gas emissions reductions targets and consideration of impacts on disadvantaged communities. In particular, we remain concerned that a centralized capacity market may not meet these objectives.*[28]

Staff proposes that the distribution utility act as the local procurement entity for its service area (the Single Service Area Procurement Entity). In order to mitigate anti-competitive concerns, Staff proposes that the distribution utility develop an independent arm to manage this local procurement within its service area. This separate arm would be required to follow competitive neutrality rules, ensuring anti-competitive concerns are mitigated.

Staff proposes that the RA program utilize the established competitive neutrality rules adopted in D.13-12-029,[29] or else rules similar to these. In addition to being subject to competitive neutrality rules, the Single Service Area Procurement Entity's local procurement management arm would be subject to a stakeholder monitoring committee similar to the CAM procurement review groups (PRG) today. Staff proposes that this monitoring committee possibly be merged with the CAM group. Finally, Staff proposes that an independent evaluator be involved in all local solicitations and transactions undertaken by the Single Service Area Procurement Entity. The independent evaluator would provide a public report following each solicitation that would analyze local procurement, market power, and aggregate pricing.

Staff proposes that on an annual basis following the adoption of local RA requirements, each Single Service Area Procurement Entity would hold a competitive solicitation for multi-year local RA procurement. Any existing or potential new resources without a contract would bid into the solicitation, and LSEs or third parties holding RA contracts would similarly bid those resources into the solicitation. The solicitation would therefore include all LSEs (IOUs, CCA, and ESPs) with existing

[27] D.18-06-030 at 32
[28] Ibid. at 33
[29] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M082/K904/82904047.PDF

contracts, third party marketers with existing contracts, traditional generation resources, and preferred resources. The most effective, efficient, and economical resources would be awarded contracts by the Single Service Area Procurement Entity. Resources that did not get picked in the solicitation (because they were not the most effective, efficient, and economical resources) could still be used by individual LSEs to meet system, and possibly flexible, requirements.

The Single Service Area Procurement Entity would procure local, system, and flexible products, as well as well as dispatch rights, which would help ensure that the local resource fleet is subject to the CPUC's least cost dispatch rules (ensuring locational price stability). RA attributes would remain bundled, so a resource could not sell just local RA and not any associated flexible RA. The Single Service Area Procurement Entity would use a least-cost best-fit approach to determine the best portfolio of resources to procure, given that not all resources would have the same attributes.

e. Multi-year Local Procurement Timeline

Figures 6 and 7 below illustrate Staff's proposed timeline for implementation of multi-year RA in 2020. The process begins in 2018 with CAISO's annual local capacity requirement stakeholder process. In mid-October 2018, CAISO will publish its draft Local Capacity Area Technical Study Manual. This will be followed by a stakeholder meeting in late October, and comments will be due in mid-November. Staff proposes that in addition to filing comments on the inputs and assumptions in CAISO's stakeholder process, parties should file comments in the annual RA proceeding (Track 3 for 2020 through 2025 studies).

To the extent that the TPP LCR reduction study finds economical projects, these will receive approval from CAISO management in late January 2019 and from the Board of Governors in March 2019. Approved projects will then flow into the LCR studies. The CAISO will file the draft and final LCR studies into the Track 3 RA proceeding in April and May. These studies will include engineer managed adjustments for the year 2, year 3, and year 4 requirements.

The multi-year local requirements for years 2020-2025 will be adopted in June 2019. LSEs will receive their initial RA allocations in July, including CAM credits towards system and flexible requirements. Under this proposal, LSEs would no longer be sent a local requirement. Instead, the Single Service Area Procurement Entities would receive the total jurisdictional share of the multi-year local requirements and run an all-source solicitation beginning in July and concluding in September. The Single Service Area Procurement Entities would be required to make a showing to the CPUC and the CAISO in mid-to-late September. The CAISO would use this information to determine if any backstop procurement (RMR or CPM) were needed for the coming year. Additionally, LSEs would be allocated credits (based on coincident load shares) for any system and flexible capacity that was procured during the local RA procurement or backstop processes. LSEs would still be required to make their system and flexible RA showing on or around October 31.

Figure 6: Proposed RA Timeline, 2018-2020

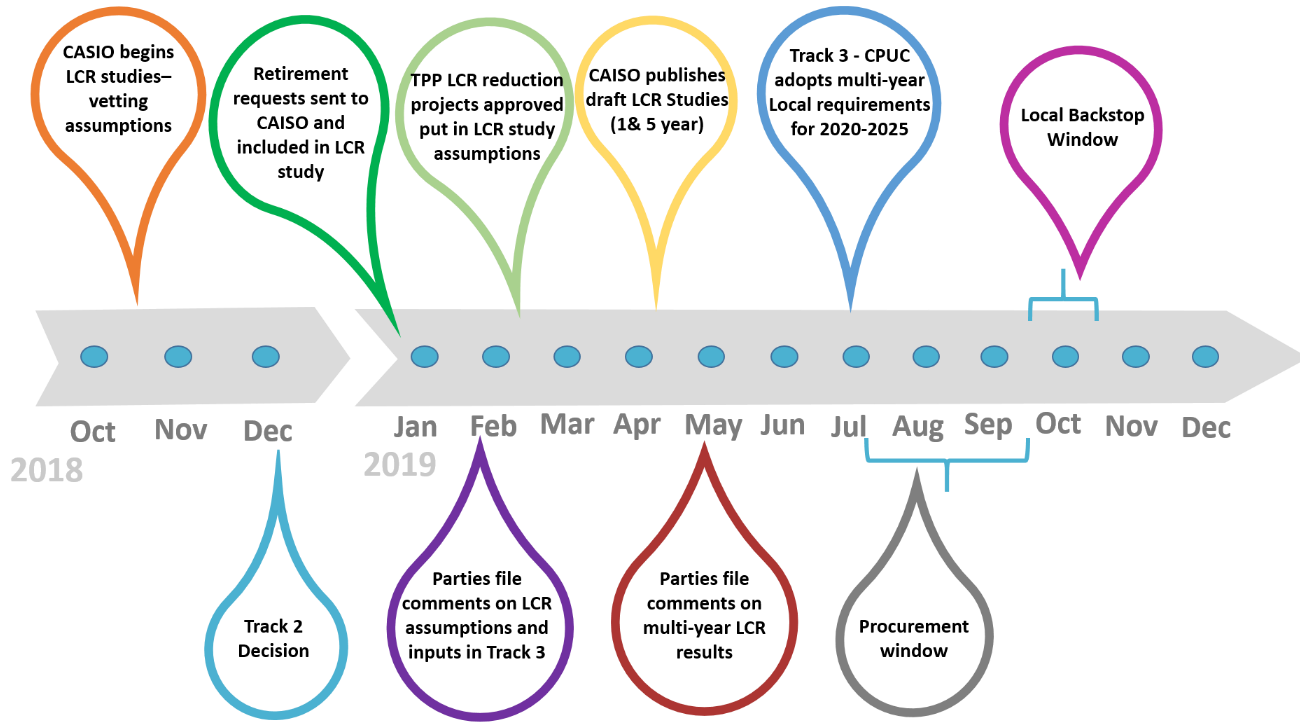
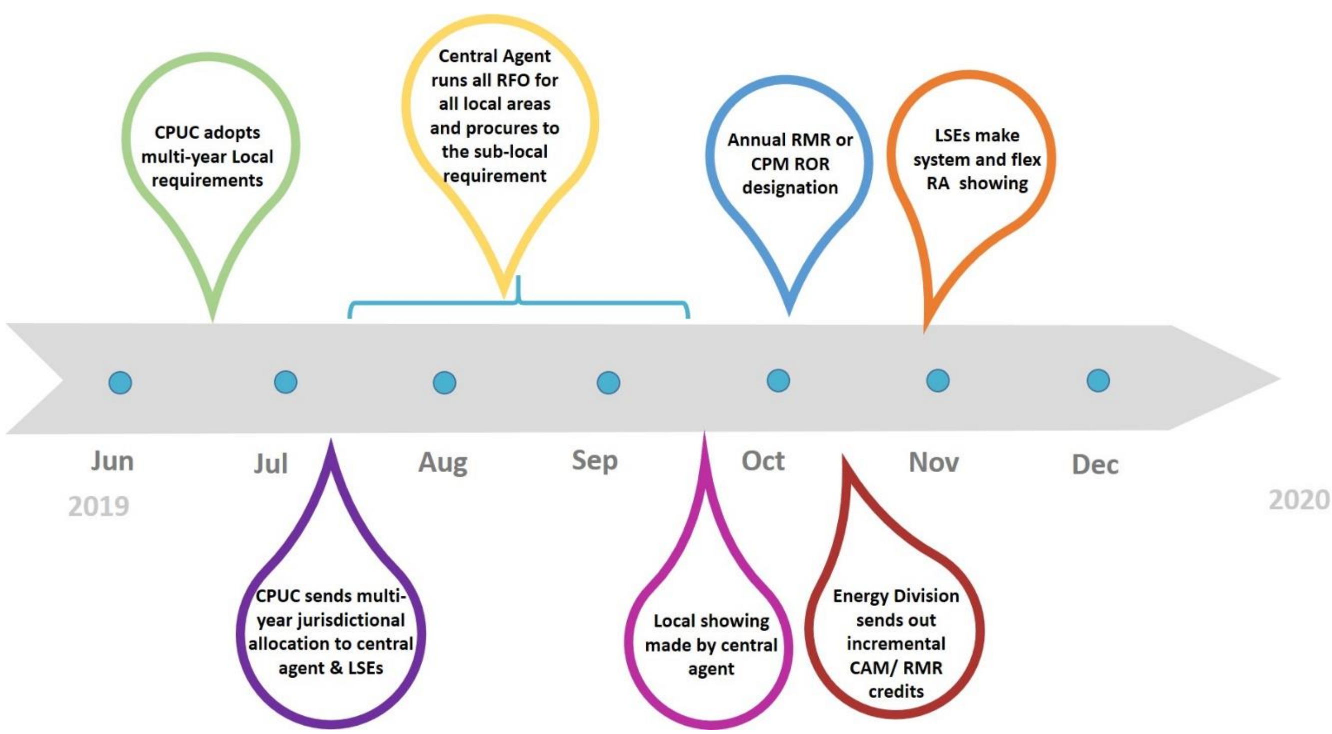


Figure 7: Proposed RA Timeline, 2019 Detail



f. Compliance and Market Power Mitigation

Staff proposes that there be no local compliance penalties for the Single Service Area Procurement Entity. The entity would be required to make all reasonable attempts to procure the capacity through its solicitation. If this resulted in a necessary resource not being procured, the resource might still be procured in the following year's solicitation. If the resource continues to not be procured, CAISO's current backstop authority could be utilized to retain the resource in the year-ahead timeframe. The cost of the backstop procurement would provide sufficient incentive to comply with local requirements. In addition, the independent evaluator would report on any market power issues that resulted in the distribution utility not being able to meet the requirements.

Staff recognizes the potential for considerable market power, given that resource procurement will be for transmission-constrained sub-local areas, where competition largely does not exist. To mitigate the risk of generators exercising this market power in the competitive solicitation process, Staff proposes that the Single Service Area Procurement Entity exercise its judgment to decide when it would be better for the resource to be procured through the annual backstop mechanisms, which are limited to one year and capped at the soft offer price of $6.31 kW-month (for RMR, the costs are limited to a resource's cost of service and must receive FERC approval). Additionally, Staff expects the expansion to a five-year solicitation timeframe to increase competition and mitigate market power, as it provides enough lead time for potential new resources to also submit bids.

Finally**,** Staff recommends that the annual CPM process remain annual and not be expanded to include the multi-year RA framework. This will help incentivize generators to pursue multi-year contracts through the bilateral solicitation process rather than single-year contracts through a backstop process. Additionally, it is consistent with the purpose of backstop procurement, which is to provide operational reliability, whereas the multi-year RA process will serve as a longer-term planning mechanism.

g. Cost Allocation

Since multi-year local procurement would benefit all customers in the distribution utilities' service territories, the total net capacity costs would be allocated to all benefiting customers. Staff proposes using the Commission's CAM methodology, which was originally adopted in D.06-07-029 and later modified in D.07-09-044, D.11-05-005, and D.14-02-040. The Commission has relevant statutory authority under Public Utilities Code (PUC) Section 365.1(c)(2), which provides that the Commission will:

> *(A) Ensure that, in the event that the commission authorizes, in the situation of a contract with a third party, or orders, in the situation of utility-owned generation, an electrical corporation to obtain generation resources that the commission determines are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution*

service territory, the net capacity costs of those generation resources are allocated on a fully nonbypassable basis consistent with departing load provisions . . .

(C) The resource adequacy benefits acquired by an electrical corporation pursuant to subparagraph (A) shall be allocated to all customers who pay their net capacity costs. Net capacity costs shall be determined by subtracting the energy and ancillary services value of the resource from the total costs paid by the electrical corporation pursuant to a contract with a third party or the annual revenue requirement for the resource if the electrical corporation directly owns the resource. . . .

h. IRP Coordination

The 2018 Integrated Resource Planning (IRP) decision (D.18-02-018) adopts a reference system plan that guides procurement planning efforts necessary to achieve SB 350 greenhouse gas reduction goals. This reference system plan will be refreshed every two years, and LSEs are required to submit individual plans that adhere to the reference system plan:

Each LSE will be required to plan toward adherence to the reference system portfolio, with specific justification given when its plan deviates from the reference portfolio. When it comes to actual procurement, we expect that LSEs will choose the most appropriate and effective resources offered to them that meet their customers' needs, when analyzing cost, reliability, and disadvantaged communities impacts, among other considerations.[30]

Staff recognizes that all multi-year RA procurement would need to be coordinated with the IRP planning efforts. Local capacity procured by LSEs under the IRP framework must flow into the Single Service Area Procurement Entity's annual solicitations. Similarly, resources selected by the Single Service Area Procurement Entity must flow back into the IRP planning process and be included in all IRP analysis and determinations. Staff proposes that local capacity (and associated system capacity) obtained by the Single Service Area Procurement be allocated to LSEs in IRP based on the LSE load ratio shares currently utilized in IRP. Staff invites parties' comments on how to ensure that two-way communication between IRP and local RA capacity procurement equitably meets the requirements of both programs.

V. Proposal 2: Study to Guide Preferred Resource Procurement

In D.18-06-030, the Commission stated as follows:

In addition to a study that is used in setting requirements, we also see the need to study the characteristics of the current resource fleet and potentially identify quantitative or qualitative

[30] D.18-02-018 at 91, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K771/209771632.PDF.

criteria that consider additional local resource attributes (such as flexibility, locational effectiveness, efficiency, emissions and impacts on disadvantaged communities). Energy Division may propose such a study in Track 2, where it can be considered in more detail and coordinated with any IRP planning necessary to meet the state's 2030 greenhouse gas reduction goals.[31]

This section discusses the criteria that should be considered as the Single Service Area Procurement Entities select local and sub-local resources for procurement. The section first provides background on the local capacity study process, how the local capacity requirements for local areas and sub-local areas have changed over time (to provide some indication of past variability, which could affect procurement objectives), the CAISO's most recent one-year-ahead and five-year-ahead studies for 2019 and 2023 (which could affect procurement in 2020), the available generation in each of the local and sub-local areas, and the criteria that Staff expects would need to be considered in selecting resources to meet local needs.

a. Local Criteria and CAISO's Process

Each year, CAISO publishes the local capacity technical analyses for one and five years forward. CAISO's study process begins in October of the year before the study is adopted, and the study is relevant to the year after which it is adopted (e.g., the study for 2019 and 2023 local requirements began in October 2017).

To conduct its local study, CAISO uses the 1-in-10 summer peak load forecast developed by the California Energy Commission for each local capacity area, with the exception of the Humboldt area, where the winter peak is used for the assessment. CAISO assesses service reliability using an N-1-1 standard, which CAISO explains this as follows:

> *This is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation after considering all reasonable and feasible operating solutions (involving customer load interruption) developed and approved by the ISO, in consultation with the PTOs. Under this option, there is no expected load interruption to end-use customers as the ISO operators prepare for the second contingency. However, the customer load may be interrupted after the second contingency occurs.*[32]

CAISO publishes the local resource requirements for each of the ten local areas and over 40 sub-local areas within those local areas. The CPUC aggregates six local areas in PG&E's service area for purposes of RA compliance.

[31] D.18-06-030 at 34

[32] California ISO, *Final Manual: 2019 Local Capacity Area Technical Study*, December 2017, p. 19, available at https://www.caiso.com/Documents/2019LocalCapacityRequirementsFinalStudyManualdocx.pdf.

b. 1-in-10 Load Forecasts Over Time

The 1-in-10 load forecasts for the local areas have changed over time. The forecasts used in the one-year-ahead and five-year-ahead studies for several years are shown in Tables 5 and 6 below. The one-year-ahead forecasts have mostly remained steady or decreased over time in each of the local areas. For example, the one-year-ahead 1-in-10 forecast for the LA Basin was 19,931 MW in 2012, decreased to 18,466 MW by 2018, and increased to 19,266 MW for 2019. The five-year-forward 1-in-10 loads have exhibited similar patterns.

Table 5: One-Year-Ahead Local Forecasts in MW (1-in-10), 2012-2019

	2012	2013	2014	2015	2016	2017	2018	2019
Humboldt	210	210	195	195	196	188	187	187
North Coast/North Bay	1,420	1,479	1,465	1,458	1,433	1,311	1,333	1,465
Sierra	1,816	1,738	1,958	1,961	1,906	1,757	1,818	1,758
Stockton	1,086	1,109	1,163	1,105	1,186	1,157	1,169	1,174
Bay Area	9,954	10,233	10,419	10,229	10,083	10,477	10,247	10,230
Fresno	3,120	3,032	3,246	3,217	3,331	2,964	3,290	3,070
Kern	1,110	1,311	1,281	731	851	1,139	867	1,088
LA Basin	19,931	19,460	19,694	19,970	20,168	18,890	18,466	19,266
Big Creek-Ventura	4,693	4,596	4,580	4,807	4,806	4,719	4,802	5,162
San Diego/Imperial Valley	4,844	5,114	5,200	5,407	5,283	4,840	4,924	4,412
Total	**48,184**	**48,282**	**49,201**	**49,080**	**49,243**	**47,442**	**47,103**	**47,812**

Table 6: Five-Year-Ahead Local Forecasts in MW (1-in-10), 2017-2023

	2017	2018	2019	2020	2021	2022	2023
Humboldt	206	208	204	200	195	190	188
North Coast/North Bay	1,538	1,561	1,484	1,476	1,318	1,249	1,524
Sierra	2,144	2,176	2,076	1,994	1,822	1,814	1,822
Stockton	967	1,224	1,136	1,230	1,186	1,035	1,227
Bay Area	10,497	10,936	10,330	10,131	9,644	10,180	10,441
Fresno	3,364	3,401	3,258	3,512	3,240	3,352	3,231
Kern	1,307	1,324	745	279	216	885	1,140
LA Basin	20,599	20,705	20,506	20,764	19,506	19,020	20,072
Big Creek-Ventura	4,632	5,207	4,889	4,845	3,849	5,020	5,169
San Diego/Imperial Valley	5,506	5,663	5,538	5,412	4,980	5,053	4,554
Total	**50,760**	**52,405**	**50,166**	**49,843**	**45,956**	**47,798**	**49,368**

c. Local Requirements Over Time

The one-year-ahead and five-year-ahead local requirements for several years – which are based on peak load conditions, the topology of the system (including transmission upgrades), and the availability and effectiveness of the generation in each of the local and sub-local areas – are shown in Tables 7 and 8 below. As these tables demonstrate, local generation requirements vary from year to year in each local area, and overall needs have declined somewhat over time, from a total of 26,778 MW in 2012 to 25,244 MW for 2019.

For the purposes of multi-year contracting, the 2019 and 2023 local requirements are the most relevant, with overall requirements of 25,244 MW for 2019 and 23,424 MW for 2023. The largest (anticipated) nominal decrease between the one-year-ahead 2019 requirements and the five-year-ahead 2023 requirements is in the LA Basin local area, and the largest nominal increase is in the Bay Area local area.

Table 7. One-Year-Ahead Local Capacity Requirements in MW, 2012-2019

	2012	2013	2014	2015	2016	2017	2018	2019
Humboldt	212	212	195	166	167	157	169	165
North Coast/North Bay	613	629	623	550	611	721	634	689
Sierra	1,974	1,930	2,088	2,200	2,018	2,043	2,113	2,247
Stockton	567	567	701	707	808	745	719	777
Bay Area	4,278	4,502	4,638	4,367	4,349	5,617	5,160	4,461
Fresno	1,907	1,786	1,857	2,439	2,519	1,779	2,081	1,671
Kern	325	525	462	437	400	492	453	478
LA Basin	10,865	10,295	10,430	9,097	8,887	7,368	7,525	8,116
Big Creek-Ventura	3,093	2,241	2,250	2,270	2,398	2,057	2,321	2,614
San Diego-Imperial Valley	2,944	3,082	4,063	4,112	3,184	3,570	4,032	4,026
TOTAL	**26,778**	**25,769**	**27,307**	**26,345**	**25,341**	**24,549**	**25,207**	**25,244**

Table 8. Five-Year-Ahead Local Capacity Requirements in MW, 2017-2023

	2017	2018	2019	2020	2021	2022	2023
Humboldt	165	197	173	170	169	169	169
North Coast/North Bay	446	424	516	509	480	440	553
Sierra	1,969	1,153	1,102	1,703	1,686	1,967	1,924
Stockton	440	418	351	403	404	702	439
Bay Area	4,281	4,486	4,224	4,191	5,194	5,315	4,752
Fresno	2,110	2,110	1,589	1,888	1,160	1,860	1,688
Kern	434	474	193	135	105	123	182
LA Basin	10,019	11,071	9,119	9,229	6,898	6,022	6,793
Big Creek-Ventura	2,537	2,688	2,619	2,598	2,398	2,597	2,792
San Diego-Imperial Valley	3,156	3,362	3,290	2,878	4,357	4,643	4,132
TOTAL	**25,557**	**26,383**	**23,176**	**23,704**	**22,851**	**23,838**	**23,424**

d. Sub-Local Needs Over Time

Whereas the local RA program is based on the overall local requirements, CAISO also assesses generation needs for sub-local areas and may engage in backstop procurement if a sub-local area has a significant deficiency. Like the local requirements, the sub-local needs change over time, with most decreasing somewhat between 2019 and 2023, according to the most recent studies. Tables A.8 and A.9 in the Appendix present the total (not only CPUC-jurisdictional) local and sub-local requirements in 2019 and 2023, as well as the expected generation available in each of the local areas and sub-local areas. Unlike in Figures 4 and 5, which depict Staff's estimate of available capacity in 2019 and future years based on RESOLVE assumptions, Tables A.8 and A.9 show the physical capacity (including mothballed units) included in the 2019 and 2023 CAISO local studies. To arrive at the list of included physical resources, CAISO begins with the current NQC list, removes planned retirements, and adds approved new generation (e.g. Carlsbad Energy Center and Alamitos Energy Center).

As Tables A.8 and A.9 show, generation in some sub-local areas will be needed, whereas other areas are less constrained. Furthermore, a large portion of the capacity in some sub-local areas comes from qualifying facilities (QF) or is owned by IOUs or municipal utilities. In those areas, the capacity available for bilateral contracting ("market capacity") and whose absence could drive sub-local deficiencies is sometimes small, which illustrates the potential existence of market power and the need to identify holistic procurement criteria.

e. Criteria for Assessing Which Resources Should be Procured

This section discusses the criteria that would need to be considered to determine which local resources should be procured in each local and sub-local area. These criteria include at least the following:

Future Needs in the Local Areas and Sub-Local Areas: One important consideration will be the needs in the sub-local areas in future years. For example, if a transmission upgrade reduces or eliminates the need for generation in a sub-local area, it may not make sense to sign contracts with resources in that sub-local area, unless the resource or resources also contribute to the sub-local needs in an overlapping sub-local area (in some cases, sub-local areas are entirely contained within other sub-local areas).

Effectiveness Factors: One of the most important factors to consider is the effectiveness of the resource in meeting the contingency identified by the CAISO studies. It would be inefficient and unnecessarily expensive to procure resources that are not effective in meeting the contingency, as this would mean additional resources, likely over and above the requirement, would be necessary to fully meet the local generation requirement.

CAISO publishes the effectiveness factors for each of the local areas and sub-local areas in its local studies, but to complicate matters, CAISO indicates that these effectiveness factors may not be able to guide procurement. CAISO's recent description of needs for the Western LA Basin serve as an example:

> *There are other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area and have less LCR need. As such, anyone [sic] of them (combination of contingencies) could become binding for any set of procured resources. As a result, effectiveness factors may not be the best indicator towards informed procurement.*[33]

There are also other considerations – including cost, efficiency, operational flexibility, and location – that could argue for procuring less effective resources, as discussed below.

Cost: Cost is an important factor but is not necessarily an overriding factor. A resource could be less expensive, but it could also be less effective, less efficient, and less flexible. This is particularly important given the current fragmented and aggregated local capacity procurement requirements. Entities might have an incentive to buy the least expensive resource, but not the most effective, efficient, or flexible resource, which could potentially be needed in the future to meet California's greenhouse gas reduction goals.

Operational Characteristics (including Age, Efficiency, Flexibility, and Facility Type): Other factors to consider include the operational characteristics of the facility, such as age, efficiency, flexibility, and facility type. It may not make sense to contract for older, less efficient, and potentially less

[33] California ISO, *2019 Local Capacity Technical Analysis: Final Report and Study Results* at 54.

flexible resources if newer, more efficient, and more flexible resources are available and are expected to be needed at some point in the future.

Location of Facility: Another important issue is the location of the facility and the potential burden on disadvantaged communities that pollution from different types of facilities imposes. This must be considered in on-going and future procurement decisions, as is currently the case for the Oakland and Moorpark areas.

Cost of Potential Alternatives: In addition to assessing which existing resources to procure to meet local needs, it may also make sense to consider cost-effective transmission upgrades that obviate the need for local procurement and reduce potential market power. Procurement exercises should also consider cost-effective new generation resources.

In summary, decisions regarding which resources to procure to meet local needs must consider numerous quantitative and qualitative criteria. The Single Service Area Procurement Entity will need to work with CAISO, the CPUC, and others to ensure that the local procurement not only meets California's reliability goals, but also effectively addresses the state's greenhouse gas and environmental justice goals. The procurement monitoring group and independent evaluator will also serve an important advisory role as they consider procurement alternatives, and the independent evaluator will provide both public accountability and confidential reporting to the CPUC to ensure that the Single Service Area Procurement Entity reasonably balances the above criteria.

VI. Appendix

Tables A.1 through A.3 below present the percentage of each year's August requirement that was under contract by the various LSE types or was part of a centralized procurement mechanism as of April 2018 (excluding RMR and CPM capacity). The tables correspond to Figures 1, 2, and 3 in the main discussion, respectively.

Table A.1: Percent of System RA Requirement Procured by LSE Type, Including Imports, 2018-2028

Metric	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Percent of Req. Met by IOU Procurement	60%	51%	44%	39%	40%	37%	36%	31%	31%	30%	31%
Percent of Req. Met by CCA Procurement*	7%	7%	6%	5%	2%	2%	1%	1%	1%	1%	1%
Percent of Req. Met by ESP Procurement*	7%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Percent of Req. Met by Centralized Procurement	17%	18%	20%	17%	16%	10%	10%	10%	10%	10%	9%
TOTAL	**92%**	**76%**	**70%**	**62%**	**58%**	**49%**	**47%**	**42%**	**41%**	**41%**	**41%**

*Includes unspecified capacity

Table A.2: Percent of System RA Requirement North of Path 26 Procured by LSE Type, Including Imports, 2018-2028

Metric	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Percent of Req. Met by IOU Procurement	67%	61%	57%	54%	56%	49%	47%	36%	34%	34%	34%
Percent of Req. Met by CCA Procurement*	14%	14%	12%	11%	4%	4%	2%	2%	2%	1%	1%
Percent of Req. Met by ESP Procurement*	7%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Percent of Req. Met by Centralized Procurement	12%	12%	12%	8%	7%	3%	3%	3%	3%	3%	3%
TOTAL	**100%**	**88%**	**82%**	**73%**	**67%**	**56%**	**52%**	**40%**	**39%**	**38%**	**38%**

*Includes unspecified capacity

Table A.3: Percent of System RA Requirement South of Path 26 Procured by LSE Type, Including Imports, 2018-2028

Metric	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Percent of Req. Met by IOU Procurement	56%	44%	34%	28%	28%	28%	28%	28%	28%	28%	28%
Percent of Req. Met by CCA Procurement*	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%
Percent of Req. Met by ESP Procurement*	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Percent of Req. Met by Centralized Procurement	21%	23%	27%	24%	23%	16%	16%	16%	16%	15%	15%
TOTAL	**85%**	**68%**	**61%**	**53%**	**51%**	**44%**	**44%**	**44%**	**44%**	**43%**	**43%**

*Includes unspecified capacity

Tables A.4 and A.5 below indicate the percentage of aggregate local requirements north and south of Path 26, respectively, that under contract by the various LSE types or were part of a centralized procurement mechanism as of April 2018 (excluding RMR and CPM capacity). The tables correspond directly to Figures 4 and 5 in the main discussion.

Table A.4: Percent of Aggregate Local RA Requirements North of Path 26 Procured by LSE Type, 2018-2023

Metric	2018	2019	2020	2021	2022	2023
Percent of Req. Met by IOU Procurement	83%	89%	86%	83%	67%	56%
Percent of Req. Met by CCA Procurement*	14%	18%	20%	12%	7%	6%
Percent of Req. Met by ESP Procurement*	6%	1%	0%	0%	0%	0%
Percent of Req. Met by Centralized Procurement	16%	16%	18%	14%	11%	2%
TOTAL	**119%**	**125%**	**123%**	**110%**	**85%**	**65%**

*Includes unspecified capacity

Table A.5: Percent of Aggregate Local RA Requirements South of Path 26 Procured by LSE Type, 2018-2023

Metric	2018	2019	2020	2021	2022	2023
Percent of Req. Met by IOU Procurement	86%	59%	41%	32%	33%	32%
Percent of Req. Met by CCA Procurement*	1%	1%	1%	1%	1%	1%
Percent of Req. Met by ESP Procurement*	7%	1%	1%	0%	0%	0%
Percent of Req. Met by Centralized Procurement	38%	39%	51%	48%	47%	32%
TOTAL	**133%**	**100%**	**93%**	**81%**	**81%**	**64%**

*Includes unspecified capacity

Tables A.6 and A.7 below presents local and sub-local requirements for CPUC-jurisdictional LSEs[34] in 2018, 2019, 2022, and 2023, as well as how much of each requirement was under contract as of April 2018 (excluding RMR and CPM capacity). Staff removed any sub-local areas for which there is no requirement in any of the four years, and Staff also removed (and marked as "confidential") data for sub-local areas in which there were fewer than three contracts for capacity. As the NQC list and respondent data do not identify DR resources by sub-local area, DR resources are not included in the sub-local percentages in Tables A.6 and A.7. For comparison, the information for local areas includes corresponding percentages including with and excluding DR.

Table A.6: Percent of CPUC-Jurisdictional 2018 and 2019 Local and Sub-Local Requirements Under Contract as of April 2018

	2018		2019	
Local or Sub-Local Area	**CPUC-Jurisd. Requirement (MW)**	**% Req. Under Contract *[% Without DR]***	**CPUC-Jurisd. Requirement (MW)**	**% Req. Under Contract *[% Without DR]***
Bay Area	**4661.34**	**114% *[113%]***	**4029.89**	**134% *[133%]***
Ames/Pittsburg/Oakland Comb.	-	-	1572.75	133%
Contra Costa	960.27	202%	963.88	200%
Llagas	94.85	212%	69.56	(confidential)
Oakland	50.59	0%	18.07	0%
San Jose	440.84	85%	159.89	202%
South Bay-Moss Landing	2006.36	53%	1493.25	88%
Big Creek-Ventura	**2086.17**	**212% *[203%]***	**2349.52**	**105% *[97%]***
Moorpark	453.01	379%	389.19	44%
Rector	462.89	133%	-	-
S. Clara	224.71	97%	213.02	77%
Vestal	762.20	90%	558.17	191%
Fresno	**1879.89**	**146% *[145%]***	**1508.61**	**172% *[170%]***
Borden	16.26	164%	0.90	2956%
Coalinga	25.29	91%	16.26	142%
Hanford	135.50	126%	50.59	336%
Herndon	794.96	123%	715.46	114%
Reedley	17.16	0%	4.52	0%
Wilson	1879.89	153%	1508.61	170%
Humboldt	**152.67**	**153% *[148%]***	**149.05**	**131% *[127%]***
Kern	**409.22**	**120% *[108%]***	**426.39**	**117% *[106%]***
Kern Oil	120.15	74%	104.79	123%

[34] As stated in the main analysis, Staff calculated CPUC-jurisdictional local and sub-local requirements by multiplying each requirement against the 2018 load share for CPUC-jurisdictional LSEs in the relevant TAC area (PG&E, SCE, or SDG&E).

	2018		2019	
Local or Sub-Local Area	**CPUC-Jurisd. Requirement (MW)**	**% Req. Under Contract *[% Without DR]***	**CPUC-Jurisd. Requirement (MW)**	**% Req. Under Contract *[% Without DR]***
South Kern PP	-	-	426.39	106%
Westpark	-	-	46.07	98%
LA Basin	**6763.63**	**123% *[112%]***	**7294.84**	**99% *[89%]***
Eastern	2122.12	116%	2656.92	90%
El Nido	204.03	264%	207.63	259%
Western	3254.63	156%	3589.00	117%
North Coast/North Bay	**572.73**	**129% *[127%]***	**622.41**	**102% *[100%]***
Eagle Rock	188.80	52%	205.97	42%
Fulton	388.44	96%	474.26	71%
Lakeville	572.73	134%	622.41	103%
San Diego-Imperial Valley	**3833.00**	**106% *[105%]***	**4026.00**	**99% *[98%]***
Border	50.00	329%	100.00	0%
El Cajon	75.00	135%	88.00	115%
Esco	8.00	2039%	-	-
Miramar	-	(confidential)	-	(confidential)
Mission	28.00	(confidential)	-	(confidential)
Pala	23.00	435%	10.00	1000%
San Diego	2157.00	105%	2417.00	111%
Sierra	**1649.53**	**92% *[91%]***	**1774.20**	**71% *[70%]***
Drum-Rio Oso	519.43	118%	457.10	123%
Pease	91.24	95%	83.11	105%
Placer	76.79	172%	69.56	190%
Placerville	70.46	34%	-	-
South of Palermo	1467.96	74%	1537.52	66%
South of Rio Oso	710.94	56%	750.69	44%
South of Table Mountain	1649.53	96%	1774.20	70%
Stockton	**359.54**	**142% *[136%]***	**385.73**	**131% *[126%]***
Lockeford	61.43	0%	74.98	0%
Stanislaus	142.73	83%	137.31	86%
Tesla-Bellota	560.08	80%	607.96	73%
Weber	28.00	(confidential)	18.97	(confidential)

Table A.7: Percent of CPUC-Jurisdictional 2022 and 2023 Local and Sub-Local Requirements Under Contract as of April 2018

	2022		2023	
Local or Sub-Local Area	**CPUC-Jurisd. Requirement (MW)**	**% Req. Under Contract *[% Without DR]***	**CPUC-Jurisd. Requirement (MW)**	**% Req. Under Contract *[% Without DR]***
Bay Area	**4655.01**	**71% *[70%]***	**4292.76**	**40% *[39%]***
Ames/Pittsburg/Oakland Comb.	-	-	1472.48	41%
Contra Costa	942.20	184%	1034.35	72%
Llagas	21.68	0%	11.74	0%
Oakland	45.17	0%	-	-
San Jose	100.27	(confidential)	264.68	(confidential)
South Bay-Moss Landing	2119.28	(confidential)	1785.94	(confidential)
Big Creek-Ventura	**2334.24**	**65% *[58%]***	**2417.83**	**60% *[53%]***
Moorpark	497.95	17%	-	-
Rector	455.70	219%	-	-
S. Clara	259.76	32%	265.15	25%
Vestal	762.20	140%	558.17	183%
Fresno	**1680.25**	**143% *[141%]***	**1524.87**	**144% *[142%]***
Borden	17.16	156%	7.23	369%
Coalinga	28.91	80%	14.45	160%
Hanford	133.70	101%	96.66	38%
Herndon	769.66	86%	741.66	76%
Reedley	-	-	10.84	0%
Wilson	1680.25	138%	1524.87	140%
Humboldt	**152.67**	**111% *[107%]***	**152.67**	**111% *[107%]***
Kern	**111.11**	**177% *[135%]***	**157.18**	**125% *[95%]***
Kern Oil	111.11	63%	118.34	59%
South Kern PP	-	-	-	-
Westpark	-	-	46.07	0%
LA Basin	**5412.70**	**108% *[95%]***	**6105.70**	**66% *[55%]***
Eastern	1893.82	105%	2428.62	50%
El Nido	-	-	47.64	(confidential)
Western	3418.22	42%	3568.32	11%
North Coast/North Bay	**397.48**	**97% *[95%]***	**499.56**	**72% *[70%]***
Eagle Rock	210.48	41%	232.16	37%
Fulton	371.28	49%	499.56	36%
Lakeville	397.48	94%	-	-
San Diego-Imperial Valley	**4610.00**	**57% *[56%]***	**4132.00**	**63% *[62%]***

	2022		2023	
Local or Sub-Local Area	**CPUC-Jurisd. Requirement (MW)**	**% Req. Under Contract *[% Without DR]***	**CPUC-Jurisd. Requirement (MW)**	**% Req. Under Contract *[% Without DR]***
Border	62.00	0%	108.00	0%
El Cajon	40.00	253%	35.00	289%
Esco	30.00	384%	20.00	576%
Miramar	42.00	(confidential)	-	(confidential)
Mission	-	(confidential)	-	-
Pala	28.00	357%	10.00	1000%
San Diego	2502.00	56%	2731.00	51%
Sierra	**1720.90**	**47% *[46%]***	**1738.06**	**47% *[46%]***
Drum-Rio Oso	-	-	-	-
Pease	77.69	(confidential)	67.75	(confidential)
Placer	69.56	158%	80.40	137%
Placerville	-	(confidential)	-	(confidential)
South of Palermo	-	-	-	-
South of Rio Oso	695.59	18%	500.46	25%
South of Table Mountain	1720.90	46%	1738.06	46%
Stockton	**366.76**	**133% *[128%]***	**300.82**	**55% *[48%]***
Lockeford	28.00	0%	93.05	0%
Stanislaus	130.08	79%	132.79	77%
Tesla-Bellota	580.86	73%	288.17	36%
Weber	25.29	(confidential)	15.36	(confidential)

Tables A.8 and A.9 below present the capacity requirements – and capacity available by type, as defined in the physical resource lists from the CAISO LCR studies[35] – for each local and sub-local area in 2019 and 2023. (As these available capacity numbers come from the physical resource lists, they do not include DR.) Capacity requirements are for the entire local or sub-local area and are not adjusted to represent CPUC-jurisdictional requirements. The tables also present the capacity requirement in each local and sub-local area as a percentage of the total available capacity.

Note that in instances where a resource is located in more than one sub-local area, Staff included the resource's entire capacity as available in each relevant sub-local area. Thus, the available capacity in a local area may not equal the sum of available capacity in that local area's sub-local areas.

[35] See the discussion in Section V(d).

Table A.8: Capacity Needs and Available Capacity by Category for Local and Sub-Local Areas, 2019

		2019 Total Resources Available (MW)					2019 LCR Need	
Local Area	**Sub-Local Area**	**QF/Muni Resource Capacity (MW)**	**Non-UOG Market Capacity (MW)**	**Utility-owned (UOG) Capacity (MW)**	**Battery/ Net Seller/ Wind Capacity (MW)**	**TOTAL Capacity (MW)**	**LCR Need (MW)**	**Need as Percentage of Total Available MW**
Humboldt		**0**	**0**	**163**	**39**	**202**	**165**	**81%**
NCNB		**119**	**768**	**2**	**1**	**890**	**689**	**77%**
	Eagle Rock	2	280	2	1	285	228	80%
	Fulton	60	517	2	1	580	525	91%
	Lakeville	119	768	2	1	890	689	77%
Sierra		**1,146**	**227**	**689**	**88**	**2,150**	**1,964**	**91%**
	Bogue	0	97	0	0	97	-	-
	Drum-Rio Oso	235	199	196	88	717	506	71%
	Pease	36	48	0	50	135	92	68%
	Placer	42	24	66	0	132	77	58%
	Placerville	0	24	0	0	25	-	-
	South of Palermo	646	58	677	38	1,419	1,702	120%
	South of Rio Oso	598	50	66	13	727	831	114%
	South of Table Mountain	1,146	227	689	88	2,150	1,964	91%
	Weimer	20	0	1	0	20	-	-
Stockton		**144**	**328**	**99**	**62**	**633**	**427**	**67%**
	Lockeford	24	0	0	0	24	83	349%
	Stanislaus	104	3	99	0	207	152	74%
	Tesla-Bellota	118	324	99	19	561	673	120%
	Weber	2	4	0	42	48	21	44%
Bay Area		**627**	**5,504**	**564**	**359**	**7,054**	**4,461**	**63%**
	Ames	0	630	0	0	630	see Pitts	-
	Contra Costa	127	1,159	564	321	2,171	1,067	49%
	Llagas	0	247	0	0	247	77	31%
	Oakland	49	165	0	0	214	20	9%
	Pittsburg (& Ames, Oak)	243	1,383	0	10	1,636	1,741	106%
	San Jose	202	322	0	0	524	177	34%
	South Bay-Moss Landing	202	2,159	0	0	2,361	1,653	70%
Fresno		**340**	**1,209**	**1,807**	**82**	**3,438**	**1,670**	**49%**
	Borden	0	0	27	10	36	1	3%

Local Area	Sub-Local Area	2019 Total Resources Available (MW)					2019 LCR Need	
		QF/Muni Resource Capacity (MW)	Non-UOG Market Capacity (MW)	Utility-owned (UOG) Capacity (MW)	Battery/ Net Seller/ Wind Capacity (MW)	TOTAL Capacity (MW)	LCR Need (MW)	Need as Percentage of Total Available MW
	Coalinga	3	0	21	35	58	18	31%
	Hanford	0	156	0	35	190	56	29%
	Herndon	210	471	521	37	1,239	792	64%
	Reedley	0	4	0	0	4	5	127%
	Wilson	340	1,209	1,807	82	3,438	1,670	49%
Kern		**13**	**162**	**3**	**297**	**475**	**472**	**99%**
	Kern Oil	13	7	3	106	129	116	90%
	South Kern PP	13	162	3	297	475	472	99%
	Westpark	0	0	0	45	45	51	113%
LA Basin		**1,443**	**6,553**	**1,199**	**462**	**9,657**	**8,116**	**84%**
	Eastern	756	1,710	1,105	124	3,696	2,956	80%
	Eastern Metro	691	160	1,102	0	1,953	-	-
	El Nido	0	527	0	11	538	231	43%
	Valley	66	1,550	3	124	1,743	-	-
	Valley-Devers	66	1,550	3	124	1,743	-	-
	West of Devers	1	80	976	0	1,057	-	-
	Western	687	4,541	386	338	5,951	3,993	67%
Big Creek-Ventura		**424**	**2,804**	**1,060**	**681**	**4,969**	**2,614**	**53%**
	Big Creek	380	1,136	1,000	681	3,198	-	-
	Moorpark	44	1,680	47	0	1,771	433	24%
	Rector	0	0	1,000	0	1,000	-	-
	S. Clara	44	156	47	0	247	237	96%
	Ventura	44	1,680	47	0	1,771	-	-
	Vestal	2	114	1,000	0	1,116	621	56%
San Diego-Imperial Valley		**106**	**3,212**	**744**	**277**	**4,339**	**4,026**	**93%**
	Border	2	178	0	0	179	100	56%
	El Cajon	0	41	53	8	101	88	87%
	Encina	0	558	0	0	558	-	-
	Esco	0	67	30	106	203	0	-
	Miramar	0	0	96	0	96	0	-
	Mission	0	4	0	0	4	0	-
	Pala	0	100	0	0	100	10	10%
	San Diego	106	1,881	744	130	2,862	2,417	84%

Table A.9: Capacity Needs and Available Capacity by Category for Local and Sub-Local Areas, 2023

		2023 Total Resources Available (MW)					2023 LCR Need	
Local Area	Sub-Local Area	QF/Muni Resource Capacity (MW)	Non-UOG Market Capacity (MW)	Utility-owned (UOG) Capacity (MW)	Battery/ Net Seller/ Wind Capacity (MW)	TOTAL Capacity (MW)	LCR Need (MW)	Need as Percentage of Total Available MW
Humboldt		**0**	**39**	**163**	**39**	**241**	**169**	**70%**
NCNB		**119**	**768**	**2**	**1**	**889**	**553**	**62%**
	Eagle Rock	2	280	2	1	285	257	**90%**
	Fulton	60	517	2	1	580	553	**95%**
	Lakeville	119	768	2	1	890	-	-
Sierra		**1,146**	**227**	**689**	**88**	**2,150**	**1,924**	**89%**
	Bogue	0	97	0	0	97	0	-
	Drum-Rio Oso	235	199	196	88	717	-	-
	Pease	36	48	0	50	135	75	56%
	Placer	42	24	66	0	132	89	67%
	Placerville	0	24	0	0	25	0	
	South of Palermo	646	58	677	38	1,419	-	-
	South of Rio Oso	598	50	66	13	727	554	76%
	South of Table Mountain	1,146	227	689	88	2,150	1,924	89%
	Weimer	20	0	1	0	20	-	-
Stockton		**144**	**374**	**99**	**66**	**683**	**333**	**49%**
	Lockeford	24	0	0	0	24	103	433%
	Stanislaus	104	3	99	0	207	147	71%
	Tesla-Bellota	118	370	99	24	612	319	52%
	Weber	2	4	0	42	48	17	35%
Bay Area		**627**	**5,504**	**564**	**359**	**7,054**	**4,752**	**67%**
	Ames	0	630	0	0	630	see Pitts	**-**
	Contra Costa	127	1,159	564	321	2,171	1,145	53%
	Llagas	0	247	0	0	247	13	5%
	Oakland	49	165	0	0	214	0	-
	Pittsburg (& Ames, Oak)	243	1,383	0	10	1,636	1,630	100%
	San Jose	202	322	0	0	524	293	56%
	South Bay-Moss Landing	202	2,159	0	0	2,361	1,977	**84%**
Fresno		**340**	**1,280**	**1,807**	**82**	**3,509**	**1,688**	**48%**
	Borden	0	21	27	10	57	8	14%

		2023 Total Resources Available (MW)					2023 LCR Need	
Local Area	**Sub-Local Area**	**QF/Muni Resource Capacity (MW)**	**Non-UOG Market Capacity (MW)**	**Utility-owned (UOG) Capacity (MW)**	**Battery/ Net Seller/ Wind Capacity (MW)**	**TOTAL Capacity (MW)**	**LCR Need (MW)**	**Need as Percentage of Total Available MW**
	Coalinga	3	0	21	35	58	16	28%
	Hanford	0	156	0	35	190	107	56%
	Herndon	210	471	521	37	1,239	821	66%
	Reedley	0	4	0	0	4	12	305%
	Wilson	340	1,280	1,807	82	3,509	1,688	48%
Kern		**13**	**162**	**3**	**297**	**475**	**174**	**37%**
	Kern Oil	13	10	0	106	129	131	101%
	South Kern PP	13	162	3	297	475	-	-
	Westpark	0	0	0	45	45	51	113%
LA Basin		**1,443**	**4,454**	**1,199**	**462**	**7,558**	**6,793**	**90%**
	Eastern	756	1,710	1,105	124	3,696	2,702	73%
	Eastern Metro	691	160	1,102	0	1,953	-	-
	El Nido	0	527	0	11	538	53	10%
	Valley	66	1,550	3	124	1,743	0	-
	Valley-Devers	66	1,550	3	124	1,743	0	-
	West of Devers	1	80	976	0	1,057	0	-
	Western	687	2,443	385	338	3,852	3,970	103%
Big Creek-Ventura		**424**	**1,233**	**1,060**	**681**	**3,398**	**2,690**	**79%**
	Big Creek	380	1,136	1,000	681	3,198	-	**-**
	Moorpark	44	110	47	0	201	-	-
	Rector	0	0	1,000	0	1,000	-	-
	S.Clara	44	102	47	0	193	295	153%
	Ventura	44	110	47	0	201	-	
	Vestal	2	114	1,000	0	1,116	621	56%
San Diego-Imperial Valley		**106**	**3,316**	**744**	**303**	**4,469**	**4,132**	**92%**
	Border	2	178	0	0	179	108	60%
	El Cajon	0	41	53	8	101	35	35%
	Encina	0	558	0	0	558	-	-
	Esco	0	67	30	106	203	20	10%
	Miramar	0	0	96	0	96	0	-
	Mission	0	4	0	0	4	0	-
	Pala	0	100	0	0	100	10	10%
	San Diego	106	1,881	744	130	2,862	2,731	95%