CALIFORNIA PUBLIC UTILITIES COMMISSION

# Current Trends in California's Resource Adequacy Program

## Energy Division Working Draft Staff Proposal

Energy Division Staff

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## Figures and Tables

## List of Acronyms

| | |
|---|---|
| AAEE | Additional Achievable Energy Efficiency |
| ALJ | Administrative Law Judge |
| BTM | Behind-the-Meter |
| CAISO | California Independent System Operator |
| CAM | Cost Allocation Mechanism |
| CCA | Community Choice Aggregator |
| CEC | California Energy Commission |
| CHP | Combined Heat and Power |
| CPM | Capacity Procurement Mechanism |
| CPUC | California Public Utilities Commission |
| D. | Decision |
| DR | Demand Response |
| ELCC | Effective Load Carrying Capability |
| ESP | Energy Service Provider |
| FERC | Federal Energy Regulatory Commission |
| GHG | Greenhouse Gas |
| IEPR | Integrated Energy Policy Report |
| IOU | Investor-Owned Utility |
| IRP | Integrated Resource Plan |
| LCR | Local Capacity Requirement |
| LESR | Limited Energy Storage Resource |
| LSE | Load Serving Entity |
| LTPP | Long Term Procurement Planning |
| NQC | Net Qualifying Capacity |
| PUC | (California) Public Utilities Code |
| PV | Photovoltaic |
| QF | Qualifying Facility |
| R. | Rulemaking |
| RA | Resource Adequacy |
| RAR | Resource Adequacy Requirement |
| RMR | Reliability Must Run |
| Staff | Energy Division Staff |
| TAC | Transmission Access Charge |
| UOG | Utility-Owned Generation |
| WECC | Western Electricity Coordinating Council |

# 1. INTRODUCTION AND SUMMARY

California's hybrid electric system involves numerous direct participants and other stakeholders. Privately-owned electric generators, investor-owned utilities (IOU), municipal utilities, community choice aggregators (CCA), and electric service providers (ESP) constitute the fundamental infrastructure of generation, transmission, and distribution. The California Public Utilities Commission (CPUC) and California Energy Commission regulate various aspects of system construction, operation, maintenance, and financing and implement overarching state policy goals. The nonprofit California Independent System Operator (CAISO) operates transmission infrastructure and oversees wholesale electric markets that serve the vast majority of Californians, ultimately under the guidelines of the Federal Energy Regulatory Commission (FERC). In addition, numerous academic, for-profit, and nonprofit stakeholders participate in planning and regulating the state's electric system, as do millions of ratepaying California residents.

Prior to the deregulation of California's electric sector, vertically-integrated IOUs owned and operated the majority of generating units within the state. Pursuant to the deregulation provisions of Assembly Bill (AB) 1890 (Brulte, 1996), IOUs were forced to divest a large percentage of their generation fleet but retained most of their hydropower and nuclear assets. Deregulation was suspended in 2001 in the wake of the California energy crisis; since this time, both IOUs and independent companies have built and operated generation infrastructure throughout the state.

In response to the energy crisis, the Legislature enacted AB 1X-1 (Keeley, 2001),[1] which authorized the California Department of Water Resources (DWR) to enter into long term-contracts with power suppliers for the purpose of selling electricity to utility retail customers. This was necessary, for at the time, the utilities were not financially able to meet their net short needs. Following AB 1X-1, the Legislature enacted AB 57 (Wright, 2002)[2], which added Public Utilities Code (PUC) section 454.5. This section of the code directed the IOUs to file procurement plans with the Commission that included:

> (1) An assessment of the price risk associated with the electrical corporation's portfolio, including any utility retained generation, existing power purchase and exchange contracts, and proposed contracts under which the electrical corporation will procure electricity, electricity demand reductions, and electricity related products and the remaining open position to be served by spot market transactions. ...
>
> (10) The electrical corporation's risk management policy, strategy, and practices, including specific measures of price stability.[3]

Additionally, the statute required that the procurement plan show that the IOU would "create and maintain a diversified procurement portfolio consisting of both short-term and long-term electricity and electricity related and demand reduction products."[4]

In implementing AB 57, D.02-10-062[5] adopted a regulatory framework that directed the three large IOUs to resume full procurement responsibilities on January 1, 2003. The framework contained requirements

[1] http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200120021AB1
[2] http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200120020AB57
[3] PUC Section 454.5(b.1), & (b.10)
[4] PUC Section 454.5(b.9.B)

for an expedited review process and timely cost recovery that conformed with the legislation's statutory requirements.

The Legislature went even further to avoid another energy crisis by passing AB 380 (Nunez, 2005),[6] which was codified as PUC Section 380. This section required the CPUC to establish Resource Adequacy (RA) requirements for CPUC jurisdictional load serving entities (LSE),[7] in consultation with CAISO. Under the RA program, each LSE must commit its own generators – or contract with generators owned by other entities – to ensure reliability of the electric system. Section 380 also requires LSEs to meet the minimum reliability and planning criteria specified by the Western Electricity Coordinating Council (WECC). The first filings under the Commission's RA program were due in 2006; the program has since grown to include annual and monthly capacity requirements on the IOU system level, within locally constrained areas, and for flexible ramping capability.

Over the last ten years, California has maintained adequate reserves under the Commission's RA program to ensure reliable grid operation. Yet California's electric system is undergoing – and planning for – significant structural changes that include integrating greater numbers of intermittent renewable resources, repowering or retiring over 16 gigawatts of gas-fired power plants that rely on once-thorough cooling (OTC) technology, and an increasing number of resources that will surpass their design life in the coming years. In addition to these changes, the California electric system is also witnessing rapid expansion of CCAs.

## 1.1 Purpose and Outline

These trends present challenges that, in the absence of action by the CPUC and industry stakeholders, will increasingly strain the electric system's ability to maintain reliability. The current Staff Proposal attempts to describe these and other challenges facing California's electric system and to offer solutions that would ensure reliability and minimize cost to ratepayers.

This section provides an overview of the report, including high-level analytical results. The next section describes the history of California's RA program in more detail, including several centralized and backstop procurement mechanisms that have coexisted and interacted with the RA program over time. The third section analyzes data submitted by CPUC jurisdictional LSEs regarding the system and local capacity contracts they have executed as of April 2017. These contracts cover the eleven years from 2017 through 2027, and the report compares contracted capacity against current and future resource adequacy requirements to evaluate the contours of contracting activity by IOUs and other LSEs. The fourth section of this report discusses emerging issues that have begun to challenge the current RA paradigm and, therefore, the dual mandates of reliability and least-cost procurement. The fifth section proposes potential multi-year frameworks to address these issues in light of the RA program's history and the findings of contract data analysis. These solutions include (1) multi-year local RA requirements with the distribution utility as the central buyer and (2) multi-year local RA requirements with no central buyer.

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[5] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/20249.PDF

[6] http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB380

[7] CPUC jurisdictional LSEs are subject to CPUC RA requirements. They include the three large IOUs, CCAs, and ESPs that serve load within the CAISO market area.

## 1.2 Summary of Analytical Findings

In March and April of 2017, Energy Division staff requested data from twenty-four LSEs regarding the RA contracts they had executed for any portion of the January 2017 to December 2027 timeframe. The term "contract" covered both actual contracts between LSEs and suppliers (generators or interties) and the portion of LSE-owned capacity that would be committed for RA purposes. Twenty LSEs responded to the data request and reported a total of 1,010 contracts. Staff augmented the dataset with known contracts for 2017 DRAM resources that responding LSEs had not reported; this brought the total number of contracts to 1,039.

As of April 2017, responding LSEs had contracted for 97% of the total August 2017 system capacity requirement. When considering the year ahead filings for the four LSEs that did not respond to the data request, this percentage changes to over 99% of the total August requirement. Responding LSEs had also secured 75% of the August 2018 system requirement. When compared with the results of the 2014 *Joint Reliability Track One Staff Report*,[8] this reflects an approximate 15 percentage point drop[9] in forward procurement roughly one year before the August compliance month.

Changes to the qualifying capacity methodology for wind and solar impact the amount of available resources under contract. Beginning in 2018, the qualifying capacity of wind and solar resources is based on a new effective load carrying capability (ELCC) methodology. In applying ELCC methodology to the 2018 through 2027 contract data, we observe a reduction of approximately 5.3 percentage points in the percentage of each year's August system requirement that is currently under contract.

Contracts for imports into the CAISO area account for 6.5% of the system requirement in August 2017, which declines to 3.5% of the requirement in August 2027. Natural gas resources represent the majority of available capacity within the CAISO area across all years, though only 24% of projected natural gas capacity in 2027 was under contract as of April 2017. The majority of capacity from projected solar, wind, and hydro resources in 2027 was under contract as of April 2017.

Local resource contracts are analyzed against local RA requirements (adopted and forecasted) and are broken down by resource type. The data show that as of April 2017, LSEs had procured 150% of aggregate 2017 local requirements, as well as 99% of aggregate 2018 requirements and 81% of aggregate 2019 requirements. Nevertheless, procurement in sub-local areas has recently fallen short of sub-local needs, as highlighted in the recent RMR and CPM designations.[10]

[8] Available at http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9107

[9] This is after accounting for the effects of switching to an "effective load carrying capability" methodology for determining the net qualifying capacity of wind and solar resources, as described below.

[10] Procurement in individual local and sub-local areas cannot be reported due to confidentiality requirements.

## 2. History of the Resource Adequacy Program

Following the California energy crisis of 2000-2001, the California Legislature acted to implement a planning scheme that would prevent similar issues in the future. Through Public Utilities Code (PUC) 380, as amended,[11] the Legislature directed that the Commission, "in consultation with the Independent System Operator, shall establish resource adequacy requirements for all load-serving entities." Section 380 further states that in setting these requirements, the following objectives must be achieved:

> *(1) Facilitate development of new generating capacity and retention of existing generating capacity that is economic and needed.*
>
> *(2) Establish new or maintain existing demand response products and tariffs that facilitate the economic dispatch and use of demand response that can either meet or reduce an electrical corporation's resource adequacy requirements, as determined by the commission.*
>
> *(3) Equitably allocate the cost of generating capacity and demand response in a manner that prevents the shifting of costs between customer classes.*
>
> *(4) Minimize enforcement requirements and costs.*
>
> *(5) Maximize the ability of community choice aggregators to determine the generation resources used to serve their customers.*

PUC Section 380 also sets the following requirements for the Commission's resource adequacy program:

> *(h) The commission shall determine and authorize the most efficient and equitable means for achieving all of the following:*
>
> *(1) Meeting the objectives of this section.*
>
> *(2) Ensuring that investment is made in new generating capacity.*
>
> *(3) Ensuring that existing generating capacity that is economic is retained.*
>
> *(4) Ensuring that the cost of generating capacity and demand response is allocated equitably.*
>
> *(5) Ensuring that community choice aggregators can determine the generation resources used to serve their customers.*

[11] PUC Section 380 is available at http://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=1.&chapter=2.3.&article=6.

*(6) Ensuring that investments are made in new and existing demand response resources that are cost effective and help to achieve electrical grid reliability and the state's goals for reducing emissions of greenhouse gases.*

*(i) In making the determination pursuant to subdivision (h), the commission may consider a centralized resource adequacy mechanism among other options.*

The Commission subsequently adopted an RA framework for system resource capacity in D.04-10-035[12] and in D.05-10-042.[13] The Commission added local capacity requirements to this framework in D.06-06-064[14] and instituted an interim flexible resource adequacy product in D.14-06-050.[15]

Thus, the current RA program consists of system, local, and flexible RA requirements for each month of a compliance year.[16] In October, CPUC jurisdictional LSEs must demonstrate that they have procured 90% of their system RA obligations for the five summer months (May – September) of the following year, as well as 100% of their local requirements and 90% of their flexible requirements for each month of the coming compliance year. Following this year-ahead showing, the RA program requires that LSEs demonstrate procurement of 100% of their system and flexible RA requirements on a month-ahead basis.

Monthly and annual system RA requirements are derived from load forecasts that LSEs submit to the CPUC and CEC annually.[17] The adopted forecast methodology is known as the "best estimate approach" and requires jurisdictional and non-jurisdictional LSEs to submit historical hourly peak load data for the preceding year, as well as monthly energy and peak demand forecasts for the coming compliance year that are based on reasonable assumptions for load growth and customer retention. Following this annual submission, the CEC makes a series of adjustments[18] to the LSE load forecasts, which are then aggregated to form the total load forecast used for year-ahead RA compliance. Throughout the compliance year, LSEs must also submit monthly load forecasts to the CEC that account for load migration. These monthly forecasts are used to calculate monthly RA requirements.

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[12] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/41416.PDF
[13] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/50731.PDF
[14] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/57644.PDF
[15] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M097/K619/97619935.PDF
[16] For a detailed description of current RA program requirements, see the *2018 Final RA Guide* at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454920.
[17] For a detailed description of current RA program requirements, see the *2018 Final RA Guide* at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454920.
[18] The process by which CEC adjusts LSE load forecasts to arrive at annual (and monthly) system resource adequacy requirements is described in *Resource Adequacy 2016 Load Forecast Adjustment Methodology – Revised* at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11366.

Local RA requirements are developed though the CAISO's annual Local Capacity Requirement stakeholder process. In this process, the CAISO conducts a *Local Capacity Technical Analysis*[19] to identify the minimum local resource capacity required in each local area to meet energy needs using a 1-in-10 weather year and an N-1-1 contingency.[20] As part of this study process, the ISO obtains input from stakeholders on the criteria, methodology and assumptions used as inputs into the studies, and feedback on the study results. It is worth noting that the CAISO also uses the final results of this study for assisting in the allocation of costs of any backstop capacity procurement needed for reliability.

The study results are provided to the CPUC (in its RA proceeding) for consideration in its annual RA program. A decision adopting the local capacity requirements is voted on in June of each year. Following the annual decision, the CPUC allocates the adopted local RA requirements to each jurisdictional LSE in each Transmission Access Charge (TAC) area using the ratio of the LSE's peak load in the TAC area to total peak load in the TAC area in August of the compliance year (as indicated in annual LSE peak load forecasts).

The current local RA framework includes 45 local sub-areas that form ten local capacity areas across California. These include Humboldt, North Coast/North Bay, Sierra, Stockton, Greater Fresno, Kern, Greater Bay Area, LA Basin, Big Creek/Ventura, and San Diego/Imperial Valley. Each Local Capacity Area's overall requirement is determined by achieving each sub-area requirement. Because these areas are a part of the interconnected electric system, the total for each Local Capacity Area is not simply a summation of the sub-area needs. Appendix 4 documents the 2018 and 2022 local sub-area requirements in relation to the amount of available capacity located each local sub-area. This illustrates there are a number of local sub- areas (9 of 45) where the requirement exceeds the available capacity, reflecting local constraints. In addition, some local sub-areas have only one or two generators available. For more information on resources located in each specific area see the CAISO's list of physical resources accounted for in the 2018 and 2022 Local Capacity Technical Studies.[21]

In the development of the Local Capacity requirement framework, the Commission chose to aggregate six of the local capacity areas in PG&E's TAC area, to mitigate local market power concerns. D.06-06-064 states:

> *Market power issues can arise when procurement obligations are established for small local areas, and aggregation of such areas for the purpose of establishing local procurement obligations can mitigate market power; however, aggregation of local areas could possibly lead to over-procurement in some areas and under-procurement (with CAISO backstop procurement required) in others.*[22]

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[19] The most recent technical analysis is available at http://www.caiso.com/Documents/Final2018LocalCapacityTechnicalReport.pdf.

[20] An N-1-1 contingency is a scenario in which the transmission system loses a single major component, adjusts to the new operational situation, and then loses a second component. Adequate planning for this scenario requires the system to remain energized even after the second component fails.

[21] Available at Physical Resource List Used During 2018 and 2022 Local Capacity Technical Studies

[22] D.06-06-064 FOF 23

In conclusion to this finding, D.06-06-064 found that "[a]ggregation of local areas as set forth in the foregoing discussion appropriately balances concerns about backstop procurement, administrative complexity, and market power mitigation, and should therefore be adopted."[23]

Pursuant to SB 695 (Kehoe, 2009),[24] the Commission reopened direct access (DA) in 2010 through D.10-03-022.[25] As part of SB 695's directive, the Commission was required to ensure that other providers of electricity in California were subject to the same procurement-related requirements that applied to the IOUs, including resource adequacy requirements, renewable portfolio standards, and greenhouse gas emission reductions.[26] Following the limited reopening of DA,[27] the CPUC adopted a local true-up process in D.10-12-038[28] to ensure equitable allocation of local costs as load migrated between LSEs. The decision stated that, "with the reopening of DA, the expected load migration between LSEs throughout the year will have some effect on the local obligation of participating LSEs. In order to track the local RA obligation and ensure that all service providers are subject to the same RA treatment, a mechanism for local true-ups was established for 2010."[29]

Prior to the local true-up process, LSEs were allocated local requirements once annually. If an LSE lost load to another LSE during the compliance year, the local requirements were stranded with them for the entire compliance year. The adopted local-true up process provides LSEs with a mid-year local requirement adjustment that accounts for load migration. In order to provide the mid-year adjustment, LSEs are required to submit updated load forecasts in March of the compliance year, which the CPUC uses to adjust local RA requirements for July through December. LSEs must demonstrate procurement of any incremental local requirements in their monthly filings for these months. The incremental local obligations are currently aggregated by TAC area to mitigate market power.

An interim flexible capacity requirement was implemented in 2015 to address ramping needs associated with integration of variable energy resources. The interim product is defined as the largest three-hour net load ramp of the month plus 3.5% of peak load. Resources are counted as flexible capacity if they can be economically dispatched to ramp up or sustain output for three hours. The total flexible need is broken down into three categories of flexible capacity, each of which has a defined must offer obligation into the CAISO markets, as well as certain criteria for energy limits and number of starts which resources must meet to qualify in that category.

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[23] D.06-06-064 COL 15
[24] Available at http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100SB695
[25] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/114976.PDF
[26] PU Code 365.1c.1
[27] D.10-03-022 reopened direct access but capped load migration at a GWh amount for each IOU which roughly equates to 1000 MW of peak load.
[28] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/128572.PDF. This process replaced the prior mechanism adopted in D.10-03-022.
[29] D.10-12-038 at 4

Each year, the CAISO conducts a *Flexible Capacity Needs Assessment*[30] to determine the quantity of economically dispatched capacity needed by CAISO to manage grid reliability during the largest three-hour continuous ramp in each month. This study is submitted to the CPUC for consideration. Flexible requirements are allocated once annually and then revised in April, alongside the local RA requirements.

While the interim flexible product was originally intended to be in place for only three years, development of a durable flexible product has proven to be challenging, as parties have failed to reach consensus on what the key elements of a flexible product should be. Currently, elements such as shorter duration ramps, eligibility of imports, and the need for related market reforms are being discussed in the CAISO's FRAC MOO 2 initiative.

In the past, the RA program worked in close coordination with the Long Term Procurement Planning (LTPP) process, which identifies and authorizes new generation to meet long-term reliability needs.[31] Historically, the Commission has directed the investor owned utilities (IOUs) to procure the new generation for long-term reliability in each IOU's service area. In doing so, the Commission adopted a cost sharing mechanism (CAM), where all benefiting customers share the costs and benefits of the new generation. The CAM is addressed in more detail in the "Central Procurement Mechanisms" section below.

In 2016, D.16-06-042[32] transferred LTPP functions to the joint Integrated Resource Planning and Long Term Procurement Planning (IRP-LTPP)) proceeding, R.16-02-007. IRP-LTPP is an "umbrella" proceeding that will consider all of the Commission's electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply. R.16-02-007 is also the primary proceeding for implementation of the IRP requirements of Senate Bill (SB) 350 (de León, 2015),[33] which are codified in PUC Sections 454.51 and 454.52. In the order instituting rulemaking, the Commission states, "these new Legislative requirements represent a logical evolution that builds on our work in previous long-term procurement planning (LTPP) proceedings and evolves and refines the implementation of the decade-long procurement 'loading order' policy."[34] Throughout the remainder of this report, staff refers to the IRP-LTPP proceeding simply as "IRP."

SB 350 requires the CPUC to focus energy procurement decisions on reducing greenhouse gas (GHG) emissions by 40 percent by 2030. This includes efforts to achieve at least 50 percent renewable energy procurement, doubling of energy efficiency, and promoting transportation electrification. This legislation requires the Commission's integrated resource planning process to ensure that LSEs meet targets that allow the electricity sector to contribute to California's economy-wide greenhouse gas emissions reduction goals.

[30] The most recent flexible capacity assessment is available at http://www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2017.pdf.
[31] Needs are assessed over a 10 year planning horizon.
[32] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K022/164022041.PDF
[33] For more information on SB 350, see the Commission's related webpage at http://www.cpuc.ca.gov/sb350/.
[34] R.16-02-007 OIR at 2

The following subsections review two policy debates that have arisen frequently within the Commission's RA program. The first is the topic of whether to establish multi-year RA requirements. The second topic is central capacity procurement, examples of which currently exist and interact with the RA program. Activity in both policy areas affects emerging issues in the RA program, and both are therefore relevant to the discussion in subsequent sections of the report.

## 2.1 Multi-Year Resource Adequacy

The CPUC has previously considered multi-year RA requirements in three different rulemakings. The first was through Track 2 of R.05-12-013, which concluded that there were "significant reasons not to proceed with a multi-year forward procurement mandate" because new programs such as the RA program, the renewable portfolio standard, and the Locational Marginal Pricing component of CAISO's Market Redesign and Technology Upgrade were "expected to encourage new development."[35] The Commission also noted that "[t]he RA program is new, and we should recognize the possibility that the year-ahead procurement obligation will provide adequate incentive for merchant development."[36]

In addition to considering multi-year RA requirements, R.05-12-013 considered whether to adopt a policy for a centralized capacity auction mechanism administered by CAISO, or to continue the resource adequacy program's reliance on bilateral contracting for capacity. D.10-06-018 found that the bilateral approach best met the current RA programs objectives, stating:

> *Proponents of the centralized capacity auction mechanism did not persuasively demonstrate how such a system could be structured to prioritize renewable resources and otherwise support the Commission's environmental goals. We therefore decide to preserve the current the bilateral contracting approach for the time being.*[37]

The second rulemaking, R.14-02-001, was opened in February 2014 "to consider policy proposals to refine California's existing reliability framework for electricity procurement…[and] to ensure that California's electric reliability framework continues to adapt as needed to meet the changing requirements of the electric grid."[38] This rulemaking resulted from the Joint Reliability Plan agreed to between the CPUC and the CAISO Board of Governors in 2013. The scoping ruling for this proceeding laid out three tracks:

- Track 1, which considered two and three-year RA procurement requirements,
- Track 2, which considered a long term joint reliability planning assessment with CAISO and the CEC,[39] and

[35] D.10-06-018 at 33. Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/118990.PDF.
[36] Id. at 33
[37] D.10-06-018 at 3.
[38] R.14-02-001 OIR at 2. Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M087/K779/87779434.PDF.
[39] Under Track 2, Staff released a concept paper in March 2015 and held a workshop in April 2015. The concept paper is available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9085.

- Track 3, which considered CAISO's development of a market-based backstop mechanism to replace its Capacity Procurement Mechanism.[40]

In October 2014, the Assigned Commissioner and Administrative Law Judge (ALJ) for R.14-02-001 issued a ruling releasing a *Joint Reliability Plan Track One Staff Report*.[41] This report aimed at supporting the Commission's goal of determining whether procurement policies should change in response to uncertainty around the sufficiency of the present reliability framework. The report identified four pivotal issues that must be understood before a decision supporting multi-year RA could be made. The report then addressed each of these issues and concluded that multi-year requirements, imposed on all load serving entities, were not necessary at that time, in part because sufficient forward procurement was taking place. The pivotal issues, and staff's conclusions, are summarized below:

1. **Whether the current reliability framework is sufficient to ensure reliability:** The report concluded that the present reliability framework may or may not be sufficient to ensure reliability. Staff proposed that the reliability framework be assessed by determining: (a) if the interrelated parts of the framework, as developed and/or authorized by the Commission, the CAISO and the FERC were working as designed; and (b) whether the framework provided adequate assurance that the system could adapt to future needs and that generation resources would be available to meet those needs.
2. **Whether the availability of flexible capacity, at that time, was uncertain:** The report concluded that it was not yet possible to analyze the effects of the recent RA decision on flexible procurement to conclude if further regulatory action was warranted. There was no evidence to suggest that the current generation fleet could not meet the system's highest anticipated demand for flexibility.
3. **Whether the Commission should be concerned about the potential for inefficient resource retirements:** The report concluded that the Commission may choose to establish a new terminology as well as a factor test for "inefficient retirements" to help discern whether there may be resource retirements at any point in the next five years that create reliability risks, and if so, this knowledge may justify new procurement policies such as multi-year RA.
4. **Whether the observable pattern of LSE forward procurement justified concern:** The report concluded that data collection and analysis conducted by staff showed that CPUC jurisdictional LSEs were conducting a significant quantity of forward procurement. If annual updates to this data continued to demonstrate similar procurement patterns, it would suggest that multi-year RA requirements may have minimal effects.

In reviewing forward procurement practices, the report analyzed contracts that CPUC jurisdictional LSEs had executed as of May 2014 for any portion of the timeframe between January 2014 and December

[40] Policy development related to issues within the scope of Track 3 occurred through the CAISO's stakeholder initiative on the CPM. On November 4, 2015, the assigned Commissioner and Administrative Law Judge issued a ruling closing Track 3 of the JRP proceeding. CAISO filed its proposed tariff at FERC with widespread stakeholder support. The tariff was approved on October 1, 2015.
[41] Available at http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9107

2024. This analysis indicated that system capacity for CPUC jurisdictional LSEs was nearly 95% contracted one year ahead and that flexible capacity was more than 100% contracted one year ahead. The report did not examine contracts for local capacity.

In reply comments filed during the proceeding, CAISO suggested that "the most appropriate path forward is for the Commission to defer consideration of all multi-year requirements until after the ISO performs the studies necessary to develop a more durable flexible capacity definition."[42] On January 16, 2015, the Assigned Commissioner and ALJ issued a ruling that suspended Track 1 of the R.14-02-001 until further notice. In their ruling, the Assigned Commissioner and ALJ noted that multi-year RA might be examined alongside the flexible capacity requirement under consideration in the RA proceeding.[43] The Commission subsequently closed Track 1 of R.14-02-001 in January 2016, offering the following justification:

> *Due to ED staffing and budget constraints, it is likely that staff will not be able to provide a study allowing for comments and a Commission decision by May 2016. Given the uncertainty of when and/or if this work or other JRP work will be completed, there is no compelling reason to keep Track 1 or Track 2 open via an amended scoping memo or order extending deadline. Any remaining work pertaining to Track 1 or Track 2 should be assumed by other ongoing Commission Long-Term Procurement Planning (LTPP) or RA proceedings.*[44]

In this decision, the Commission also stated that "the RA proceeding has the permanent flexible capacity issue scoped, and that effort needs to be finalized before a two- or three-year RA requirement can be determined."[45]

On January 29, 2016, the Independent Energy Producers Association (IEP) filed and served a Motion[46] to Amend the Phase 2 Scoping Memo and Ruling of the RA proceeding, R.14-10-010. IEP argued that the proceeding should consider multi-year RA requirements, in the form of either a reporting requirement or a procurement requirement. On February 16, 2016, CAISO submitted a reply in support of IEP's motion. CAISO clarified their earlier comments in R.14-02-001, noting as follows:

> *CAISO continues to believe that development of the flexible capacity mechanism should precede instituting multi-year RA* procurement *requirements, but there is merit in addressing certain fundamental multi-year RA issues in this proceeding such as whether multi-year RA obligations are needed and the benefits of multi-year RA* reporting *requirements.*[47]

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[42] CAISO Reply Comments in R.14-02-001, Filed November 12, 2014, at 2. Available at http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=140045406.
[43] R.14-02-001, AC and ALJ Ruling of January 16, 2015 at 1. Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M144/K897/144897286.PDF.
[44] D.16-01-033 at 6. Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K111/158111350.PDF
[45] Id., OP 4 at 9
[46] Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M158/K122/158122389.PDF.
[47] CAISO Response in R.14-10-010, Filed February 16, 2016, at 2. Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K671/159671213.PDF. Emphasis in original.

The September 13, 2016 Scoping Ruling granted IEP's motion in part and directed Energy Division Staff to issue a report addressing the status of forward capacity procurement to help inform the parties and the record of the proceeding.[48]

Staff distributed its subsequent report – *An Assessment of Capacity Under Contract*[49] – to the R.14-10-010 service list on December 22, 2016. The report served as a follow up to the 2014 *Joint Reliability Plan Track One Staff Report*. Like the prior report, it examined capacity contracts executed by CPUC jurisdictional LSEs over a ten-year timeframe. The contract data were collected in October 2015 and covered any portion of the January 2016 to December 2025 timeframe.

The 2016 report found that LSEs had collectively procured their entire system and local capacity requirements for the 2016 compliance year and over half of their requirements for the 2017 compliance year. The report noted that the level of system and local capacity under contract declined in the years (2017 and 2018) immediately following the RA compliance year (2016). Following the immediate decline, the amount of system capacity under contract declined slightly over the remainder of the study period, with 44% or more of forecast need under contract through 2025. Local capacity under contract varied by area but followed the same declining trend. Similarly, flexible capacity contracts collectively exceeded the established RA requirements for 2016 and 2017 but decreased to roughly three-fifths of the 2016 requirement in 2025. The report also concluded that a significant amount of capacity from non-cogeneration combined cycle gas turbines was not under long-term contracts.[50] Finally, the report concluded that the analysis demonstrated that forward contracting practices had remained stable since the prior 2014 *Joint Reliability Plan Track One Staff Report*.

As described above, the 2016 report did not highlight any urgent need to adopt multi-year contracting. The Commission ultimately did not adopt multi-year capacity requirements in R.14-10-010, due in part to the fact that R.14-10-010 did not adopt a durable flexible capacity product, which the Commission still considered to be a necessary precursor to any multi-year requirements. Instead, the Commission opted for an interim flexible capacity requirement until such a time as a durable requirement were adopted, offering the following explanation:

> *Since we are not adopting a durable FCR program at this time (which, according to the Scoping Memo in this proceeding, is a prerequisite for a multi-year RA requirement), we do not adopt a multi-year RA requirement here, nor do we address the substantive issues relating to such a requirement. In future RA proceedings the Commission may re-examine whether a durable FCR program should continue to be a prerequisite to adoption of a multi-year RA requirement.*[51]

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[48] R.14.10-010, Scoping Ruling of September 13, 2016 at 7. Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M166/K987/166987422.PDF.
[49] Available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451994
[50] California Public Utilities Commission, *An Assessment of Capacity Under Contract*, December 22, 2016, pp. 19-20, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451994.
[51] D.17-06-027 at 17. Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K027/192027253.PDF.

This decision also encouraged Energy Division to continue monitoring and report on multi-year contracting activity.[52] The current report is a response to the Commission's direction.

Parties to R.14-10-010 offered numerous comments on the 2016 report. One request was that future studies provide more granularity regarding resource location and operational characteristics, as well as information on LSE response rates and on the proportion of total contracting activity that respondents represent. Parties also noted a significant drop in forward procurement activity between the 2014 and 2016 reports and requested an analysis of this finding. Other requests included analyses of CCA activity and unit risk of retirement; a discussion of the specific components of contracts for flexible capacity; and inclusion of a range of possible outcomes based on projected contract renewals, time of use rates, weather, and the availability of natural gas storage infrastructure. Although the scope of the current report extends beyond simply examining multi-year contracting activity, staff has attempted to address as many party comments as possible and will continue to do so in any future analyses.

## 2.2 Central Procurement Mechanisms

### 2.2.1 IOU Procurement for System Reliability and Other Policy Goals

To support the development of new generation resources to ensure electric reliability, the Commission adopted the cost allocation mechanism (CAM), which allows the costs and benefits of new generation to be shared by all benefiting customers in an IOU's service territory. The Commission designated IOUs to procure the new generation through long-term power purchase agreements, and the rights to the capacity were allocated among all LSEs in the IOU's service territory. The allocated capacity rights can be applied toward each LSE's RA requirements. In exchange for those benefits, the LSEs' customers – termed "benefitting customers" – pay for the net cost of the capacity.[53] The Commission described the need for CAM as follows:

> *We have found that long-term contracts are necessary to solicit investment in new generation in California, and both the ESPs and the IOUs are unwilling to sign long-term contracts. The ESPs' customers are on short-term contracts and the ESPs cannot recruit new customers with the suspension of DA. The IOUs are concerned that without some cost allocation provision to assure that their bundled customers are not left paying for new generation in the face of departing load, that long-term contracts are too risky.*[54]

Additionally, D.06-07-29 states that "Pub. Util. Code § 380 allows the costs an IOU incurs to sustain system reliability and local area reliability to be fully recovered from all customers on whose behalf the costs are incurred. It is consistent with AB 380 for the Commission to adopt the cost-allocation

[52] Id. at 18

[53] The energy and capacity components of the newly acquired generation are disaggregated. The net capacity cost is calculated as the total cost of the contract minus the energy revenues associated with the dispatch of the contract. The non-bypassable charge levied is for the net capacity cost only, and the non-IOU LSEs maintain the ability to manage their energy purchases.

[54] D.06-07-029 COL 3 Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/58268.PDF

methodology set forth herein so that the IOUs' bundled customers are not alone responsible for the cost of new generation to retain system reliability."[55]

System and Local reliability needs identified in LTPP proceedings are specific to the TAC area of each IOU, and as such, CAM allows an IOU to allocate the net capacity costs and benefits of certain new generation resources to all customers of CPUC jurisdictional LSEs who are located within the IOU's TAC area. In 2011, the Commission eliminated the authority of IOUs to determine which new generation resources would be covered by CAM. The decision also permitted CAM for utility-owned generation and allowed CAM to match the duration of the contract.[56]

In D.10-12-035,[57] the Commission adopted a settlement that resolved numerous disagreements and other challenges concerning qualifying facilities (QFs). The Settlement established the QF/Combined Heat and Power (CHP) Program, which requires IOUs to procure a minimum of 3,000 MW of CHP capacity over the program period and to reduce GHG emissions consistent with the California Air Resources Board's *AB 32 Climate Change Scoping Plan*.[58] The Settlement also established a method of cost allocation that was intended to distribute the benefits and costs of meeting the state's CHP goals and GHG reduction goals equitably. The mechanism itself is nearly identical to the CAM adopted for LTPP contracts in D.06-07-029 and applies to all bundled customers, direct access customers, and CCA customers within a given TAC area. As with CAM, the RA benefits associated with QC/CHP contracts are allocated to all LSEs serving customers who pay for those contracts.[59]

Aside from the procurement of CHP and other new resources described above, the Commission extended the CAM mechanism to include storage resources procured to address the 2015 Aliso Canyon gas shortage reliability issue.[60] This resulted in approximately 70 MW of storage resource procurement. In addition, demand response resource costs are allocated to ratepayers through the distribution rate component of electric bills, and the benefits of these resources are allocated to LSEs as a demand response credit that is very similar to CAM.[61] Centralized procurement of demand response resources is addressed further in the "Demand Response Programs" subsection below.

Figure 1 below illustrates the growth in resources covered by the CAM mechanism, as well as the slightly declining procurement of demand response resources over time. Approximately 6,400 MW of capacity (including DRAM) will enter the RA program through the CAM mechanism by August 2018; this will increase to just over 8,500 MW by August 2020. For utility run demand response programs, more than 1,700 MWs of capacity have been procured to meet 2018 system RA requirements (this does not include

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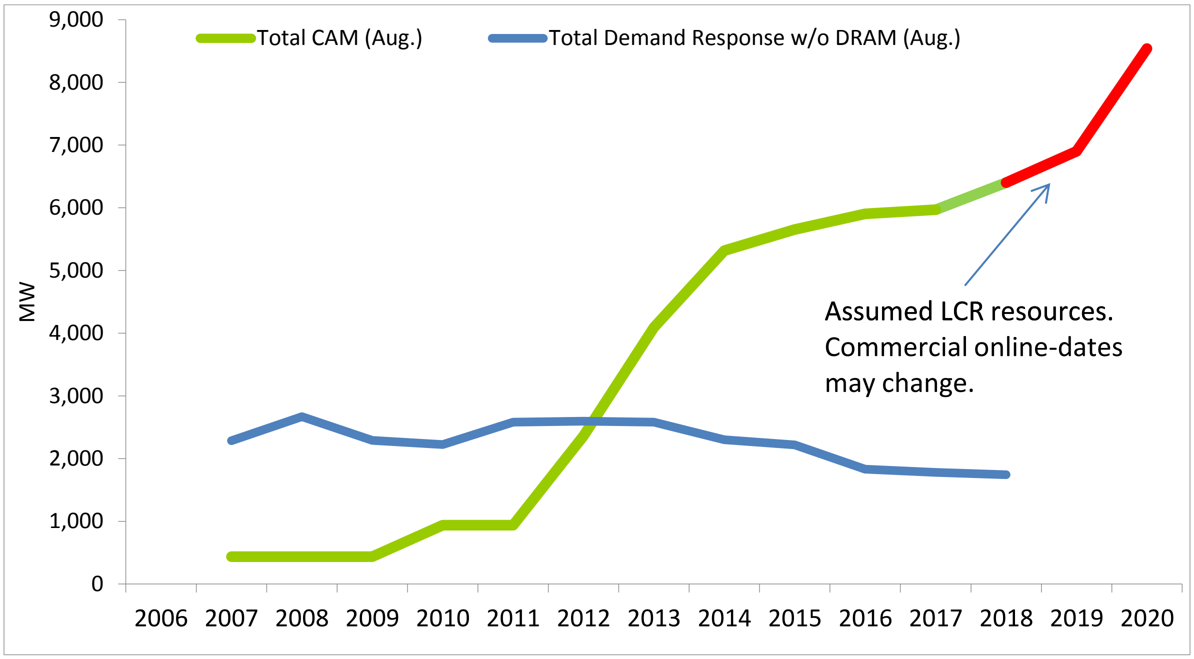
[55] D.06-07-029 COL 2 Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/58268.PDF
[56]D.11-05-005, OP 1-3 at 19. Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/134983.PDF
[57] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/128624.PDF
[58] Available at https://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm
[59] *CHP Program Settlement Agreement Term Sheet*, Section 13.1.2.2 at 56. Available at http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF.
[60] See Resolution E-4791 (available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M162/K850/162850315.PDF) and Resolution E-4798 (available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M166/K269/166269958.PDF).
[61] This does not include DRAM resources. Currently DRAM resources are being allocated through CAM.

load modifying DR resources, which lower the load forecasts used for RA compliance). The IOUs act as central buyers of CAM capacity and demand response resources within their service areas and run competitive solicitations to select the "least cost, best fit" resources that meet the procurement authority criteria directed by the Commission. The RA benefits associated with this procurement are allocated to all benefiting ESPs and CCAs as a credit that counts towards meeting their RA requirements.

**FIGURE 1: CAM AND DEMAND RESPONSE RESOURCE PROCUREMENT, 2007-2020**




Recent growth in CAM is largely connected with replacement of conventional generation assets that provide local capacity services but have either recently retired or will retire in the next few years. Whereas units that have retired in recent years were not covered by CAM, their replacements are entering the RA framework through CAM. One significant example is the 2,246 MW San Onofre nuclear generating station, which was located in the San Diego/Imperial Valley local reliability area and closed in 2013. A second example is the retirement of several older, natural gas-fired steam generators in compliance with the State Water Board's "Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling," otherwise known as the "Once-Through Cooling (OTC) Policy."[62] The OTC Policy prescribes two potential tracks to reduce cooling water intake at affected units: (1) flat reduction of water intake or, if this is not feasible, (2) installation of infrastructure that would reduce entrainment and impingement mortality of marine life. Many generators have instead opted to retire the affected units and to replace their capacity with resources that do not use once-through cooling. The CPUC and CEC have authorized several combined-cycle natural gas facilities – which are more efficient and release fewer greenhouse gases per unit energy produced – as well as energy storage, energy efficiency, and demand response resources to replace the capacity of San Onofre and OTC natural gas units.

[62] Available at https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/policy100110.pdf

Table 1 below lists the major remaining CAISO jurisdictional OTC facilities, their net dependable capacity prior to OTC compliance, and their current offline dates.[63] Several units have already retired – the most recent information regarding retirement and replacement schedules is available in the *Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) 2017 Report*.[64] An updated version of this report will be available in March 2018.

### TABLE 1: REMAINING CAISO JURISDICTIONAL OTC UNITS[65]

| Resource Name | Capacity (MW) | Offline Date |
|---|---|---|
| Alamitos Units 1, 2, 6 | 844 | December 31, 2019 |
| Alamitos Units 3-5 | 1,165 | December 31, 2020 |
| Encina Units 2-5 | 844 | December 31, 2018 |
| Huntington Beach Unit 1 | 225 | December 31, 2019 |
| Huntington Beach Unit 2 | 225 | December 31, 2020 |
| Moss Landing Units 1-2 | 1,020 | December 31, 2020 |
| Ormond Beach | 1,516 | December 31, 2020 |
| Redondo Beach Unit 7 | 343 | October 31, 2019 |
| Redondo Beach Units 5, 6, 8 | 577 | December 31, 2020 |
| **TOTAL** | **7,189** | |

Table 2 below lists specific large scale projects that the CPUC has authorized to date as replacements for both OTC capacity and the capacity of the San Onofre nuclear generating station in Southern California.

### TABLE 2: LARGE SCALE REPLACEMENTS FOR CAISO JURISDICTIONAL OTC UNITS AND SAN ONOFRE

| Resource Name | Capacity (MW) | Location | Commercial Online Date | Contract Duration (Years) |
|---|---|---|---|---|
| Alamitos Energy Center | 640 | LA Basin | 2020 | 20 |
| Alamitos Energy Storage | 100 | LA Basin | 2021 | 20 |
| Barre Wellhead | 98 | LA Basin | 2020 | 20 |
| Carlsbad Energy Center | 500 | San Diego | 2018 | 20 |
| Huntington Beach Energy Center | 644 | LA Basin | 2020 | 20 |
| Pio Pico Energy Center | 300 | San Diego | 2017 | 25 |

[63] The offline dates for some units are earlier than their official OTC compliance dates, as construction of replacement units will require early depowering.

[64] Available at https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/05042017_saccwis_an_rpt.pdf

[65] Several units located in the Los Angeles Department of Water and Power (LADWP) service territory are subject to OTC compliance. These units do not appear here because the LADWP territory is outside the CAISO area. The 2,280 MW Diablo Canyon nuclear generating station also uses once-through cooling technology; both units at Diablo Canyon will have retired by December 31, 2025. Finally, Table 1 does not include Mandalay, which retired all three of its units (including two units subject to OTC compliance) on February 6, 2018.

In addition to the resources listed in Table 2, the Commission has also approved approximately 340 MW of new preferred resources in the LA Basin and and Big-Creek Ventura local areas to replace OTC and San Onofre Nuclear Generating station.[66] These preferred resources include distributed generation, energy storage, energy efficiency, and demand response, and they will come online slowly from 2017 through 2021. The costs and benefits for these resources are being shared by all customers through a mechanism similar to the adopted CAM.

### 2.2.2 Reliability Must Run (RMR) Designations

Reliability Must Run (RMR) is a centralized backstop procurement mechanism that CAISO uses to ensure reliability. A resource receiving an RMR designation must continue to operate and is compensated at its cost of service. Historically, CAISO has also aimed to mitigate market power through RMR designations. Prior to the implementation of a local reliability program, CAISO relied on an annual process known as the Local Area Reliability Service (LARS) to designate facilities for RMR. CAISO's *2004 Reliability Must-Run Technical Study of the ISO-Controlled Grid* describes the LARS process as follows:

> *The LARS initiative is the process by which the ISO determines how to mitigate local area reliability problems. To initiate the LARS process, the ISO staff conducts a technical study to determine which specific areas within the ISO controlled grid exhibit local reliability problems and the technical requirements necessary to mitigate identified local reliability problems. The ISO then issues a Request for Proposal (RFP) that can satisfy the requirements. Market Participants are encouraged to submit alternatives to RMR generation to satisfy the LARS MW requirement for each identified LARS area. The ISO considers generation, transmission and demand-side related proposals. ISO staff then evaluates the alternatives and compares them on a cost-effectiveness basis, subject to certain constraints such as operating characteristics, among others. The ISO also considers transmission projects submitted by the Participating Transmission Owners (PTOs) through their annual transmission assessments. Based on these considerations, ISO management presents the list of preferred alternatives to the ISO Board for approval. [...] Units on the Unit Eligibility list are then compared to other generation, transmission and demand side proposals in the LARS RFP process. The LARS RFP process is the final step in selecting and presenting the preferred RMR mitigation alternatives to the ISO Board for approval.*[67]

In 2004, the Commission expressed its intention to limit reliance on RMR contracts for resource adequacy, noting the following:

> *Although we expect that RMR contracts will remain available as, at a minimum, a backstop mechanism to mitigate local market power in the future, RMR contracts are relatively expensive, especially considering their limited operating parameters. Moreover, they fragment a more*

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[66] Approved in D.15-11-041 and D.16-05-050

[67] California ISO, *2004 Reliability Must-Run Technical Study of the ISO-Controlled Grid*, May 2003, pp. 4-5, http://www.caiso.com/Documents/2004ReliabilityMust-RunTechnicalStudy-ISO-ControlledGrid.pdf.

*comprehensive planning approach from the perspectives both of transmission and overall procurement.*[68]

Addressing the local reliability challenges posed by constrained transmission limits, D.04-07-028 stated that "a utility scheduling practice or procurement plan that focuses solely on least cost energy, without regard to deliverability of the procured energy to load or to local reliability, is not in compliance with our prior decisions, approved short-term procurement plans, and Assembly Bill 57."[69] The Commission also stated that "it is our intention to minimize the use of RMR contracts, and that the utilities should include local reliability in their long-term procurement plans for the purpose of reducing the need for RMR contracts."[70]

Concerns about local reliability and CAISO's reliance on RMR contracts led to consideration of localized RAR for all LSEs. D.04-10-035 determined that adding a local component to the RAR program would be consistent with the Commission's prior decisions in which it had held that LSEs are responsible for procuring the resources needed to meet their customers' needs.[71] The Commission determined that the benefits of local RAR – including the effects of longer term contracts on generators' financial stability, the ability for LSEs to identify cheaper and cleaner alternatives to RMR contracts, and possible incentives for transmission upgrades – would likely outweigh the costs (which include higher procurement and forecasting costs, program complexity, and possible market power).[72]

In a 2005 straw proposal on local capacity requirements, CAISO indicated that it was its "intent and long-term objective to phase out RMR Generation," although it expected this to occur prudently and over an appropriate timeframe.[73] The Commission subsequently implemented its local RA program in D.06-06-064, and local RA requirements began to supplant RMR contracting in the 2007 compliance year. As Figure 2 below shows, this resulted in a significant reduction in RMR designations. Between 2011 and 2017, only a single resource (the Oakland Power Plant) received annual RMR designations. In 2018, CAISO designated three resources – Feather River, Yuba City, and Metcalf – as RMR, marking the first increase in RMR capacity designations since the RA program began. The "Emerging Issues" section of this report discusses this recent RMR activity in more detail.

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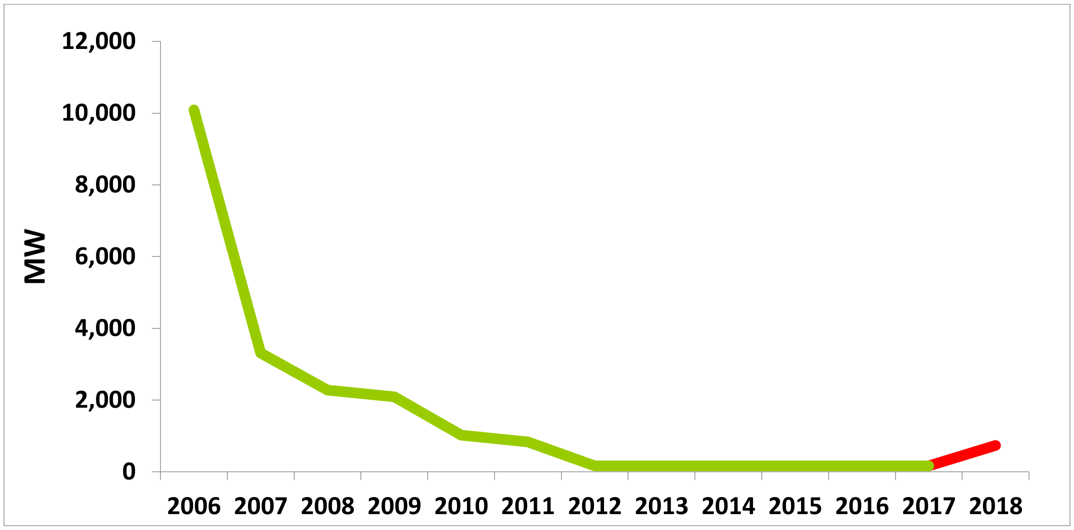
[68] D.04-07-028 at 14. Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/38094.PDF.
[69] Id. at 9-10
[70] Id. at 13
[71] D.04-10-035 at 33. Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/41416.PDF.
[72] Id. at 33-34
[73] California ISO, *First Revised Straw Proposal: CPUC Resource Adequacy Requirements – Local Capacity*, January 25, 2005, p. 1, http://www.caiso.com/docs/2005/06/22/2005062214371421107.pdf.

**FIGURE 2: RMR DESIGNATIONS, 2006-2018**




### 2.2.3 Capacity Procurement Mechanism (CPM)

In addition to RMR, CAISO has a voluntary backstop procurement mechanism known as the Capacity Procurement Mechanism (CPM). Like RMR, this is a type of centralized capacity procurement performed by the CAISO for reliability. Under its CPM tariff authority, CAISO can offer specific resources a contract to provide capacity services in the following circumstances:

1. Insufficient Local Capacity Area Resources in an annual or monthly Resource Adequacy Plan;
2. Collective deficiency in Local Capacity Area Resources;
3. Insufficient Resource Adequacy Resources in an LSE's annual or monthly Resource Adequacy Plan;
4. A CPM Significant Event;
5. A reliability or operational need for an Exceptional Dispatch CPM;
6. Capacity at risk of retirement within the current RA Compliance Year that will be needed for reliability by the end of the calendar year following the current RA Compliance Year; and
7. A cumulative deficiency in the total Flexible RA Capacity included in the annual or monthly Flexible RA Capacity Plans, or in a Flexible Capacity Category in the monthly Flexible RA Capacity Plans.[74]

Beginning in November 2016, CAISO transitioned CPM payments from a flat, administratively determined rate ($70.88/kW-year as of October 31, 2017) to unit-specific rates based on a competitive bidding process and subject to a Soft Offer Cap of $75.68/kW-year. Units may only receive compensation above the Soft Offer Cap through an affirmative ruling by the Federal Energy Regulatory Commission.[75] In December 2017, CAISO procured unit 2 at Moss Landing (510 MW) and units 4 and 5 at Encina (545 MW total) under its first ever annual CPM designation, which will run from January 1, 2018 through December 31, 2018.

[74] See CAISO Tariff Section 43A.2, available at https://www.caiso.com/Documents/Section43A_CapacityProcurementMechanism_asof_Sep25_2016.pdf.

[75] See CAISO Tariff Sections 43A.4.1.1 and 43A.7.1, available at link in supra note 41.

### 2.2.4 Demand Response Programs

Demand response (DR) programs are administered centrally by the IOUs, and the capacity benefits of DR extend to all ratepayers located within an IOU's service territory, regardless of whether those customers receive retail service from the IOU or from another LSE. Accordingly, all ratepayers pay for DR through their distribution rates, and the CPUC allocates RA capacity credits for each DR program to the LSEs whose customers pay for that program.

There are three categories of DR programs for which IOUs manage procurement and which enter the RA compliance process via different pathways. The first is "nondispatchable" or "demand side" DR, which the three large IOUs include in their annual load forecasts to CPUC and which are removed from the final load forecasts that feed into RA requirements. The second is utility-run programs, also referred to as "event based" or "supply side" DR. The following excerpt from the *2016 Resource Adequacy Report* explains how these programs are treated for RA compliance:

> *The costs for most DR programs are allocated through the distribution charge which means that most DR programs, other than SCE's Save Power Day (SPD) and Critical Peak Pricing (CPP) programs, are paid for by bundled, direct access, and community choice aggregator customers. The RA credit associated with DR is calculated using the CPUC-adopted Load Impact Protocols. On about April 1 of each year, the IOUs/DR providers submit the ex-ante load impact values associated with each DR program for the coming RA compliance year. Energy Division verifies and evaluates the ex-ante load impact values using the ex-post performance load impacts from the previous year and the programs' forecast assumptions. When the values are determined to be final, the DR RA credits are posted on the CPUC's RA compliance website and then allocated to all LSEs for the coming compliance year.*[76]

The final category of DR is the Demand Response Auction Mechanism (DRAM). DRAM is a pilot program under which the three IOUs contract with third parties for capacity that is subsequently bid into the CAISO day-ahead and real-time markets. DRAM resources do not currently have local designations on the net qualifying capacity (NQC) lists, though CAISO intends to begin crediting these resources toward local capacity requirements beginning in 2018. The CPUC currently allows DRAM capacity within local areas to count towards LSEs' local RA requirements by allocating capacity through the CAM mechanism.

[76] California Public Utilities Commission, *The 2016 Resource Adequacy Report*, June 2017, p. 37, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942.

# 3. Analysis of 2017-2027 Contract Data

## 3.1 Data Collection and Time Frame

On March 1, 2017, staff sent a data request to all 24 CPUC jurisdictional LSEs that were serving load at that time. The request asked LSEs to report system, local, and flexible capacity contract data by month for contracts covering any portion of the period from January 2017 through December 2027. As in the past, LSEs were instructed to report all resources – including conventional generation, wind, solar, DR, or storage resources – that are owned, in whole or in part, by the LSE or were under contractual commitment to the LSE for all or a portion of their capacity. LSEs were given just over 30 days (until April 3, 2017) to respond to the data request, after which staff reviewed submissions and clarified inconsistencies. Twenty LSEs responded to the data request, of which 3 were IOUs, 11 were ESPs, and 6 were CCAs. These 20 LSEs represented 97% of the overall August 2017 system resource adequacy requirement.

## 3.2 Data Validation

Staff took extensive measures to ensure that reported data were consistent with the data request and with the purpose of this research effort. The data reported here do not include contracts that will be concluded closer to the monthly deadlines for resource adequacy showings. Therefore, this report represents only a snapshot of contracted capacity for resource adequacy as of April 2017 and should be considered "in progress." In addition, as staff did not request data from California LSEs that are outside CPUC jurisdiction, those entities' resource adequacy plans do not appear here. Appendix 1 outlines the data request, and Appendix 2 provides a detailed description of data handling procedures for specific issues that arose during analysis.

Staff initially validated data against the CAISO's 2017 NQC List[77] and, once it became available, against the 2018 NQC List.[78] A resource's NQC value represents the maximum amount of capacity it can provide towards meeting system and local RA requirements and reflects reductions to rated (nameplate) capacity based on testing and verification, application of performance criteria, and deliverability restrictions. Resource Adequacy program rules specify the process for determining a resource's NQC value.[79] Staff also validated data against the most recent CAISO Master Control Area Generating Capability List,[80] which includes all active generating resources in the CAISO balancing authority area. To assess general consistency with RA filings, staff compared information for contracts covering some portion of 2017 against filings for August 2017. Finally, staff supplemented incomplete filings with known capacity from DRAM, from utility-run demand response programs, and from behind-the-meter (BTM) solar photovoltaic and DR capacity authorized in D.15-11-041[81] to replace retiring OTC units and

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[77] Available at http://www.caiso.com/Documents/NetQualifyingCapacityReport_ComplianceYear2017.xlsx
[78] Available at http://www.caiso.com/Documents/NetQualifyingCapacityReport_ComplianceYear-2018.xlsx
[79] See *Qualifying Capacity Methodology Manual Adopted 2017*, available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455533
[80] Available at www.caiso.com/Documents/GeneratingCapabilityList.xls
[81] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K064/156064924.PDF

the San Onofre nuclear generating station.[82] See the "Assumptions" section below and Appendix 2 for more detailed information on treatment of these supplemental data.

Given the expanded purpose of this effort relative to the 2014 *Joint Reliability Plan Track One Staff Report* and the 2016 report *An Assessment of Capacity Under Contract*, staff focused the analysis on system and local capacity. This report does not consider requirements or contracts for flexible capacity.

## 3.3 Assumptions

### 3.3.1 Load Forecasts and Capacity Requirements

Load forecasts for 2019 through 2027 in this report derive from data tables provided in the *California Energy Demand Update Forecast 2015 - 2027, Mid Demand Baseline Case, Mid AAEE Savings*,[83] which was filed in the CEC's 2016 Integrated Energy Policy Report (IEPR) docket 16-IEPR-05.[84] Staff summed the CEC noncoincident load forecasts for CPUC jurisdictional LSEs in each year and estimated coincident load by multiplying this total against the year-specific ratio of total CAISO coincident load to total CAISO noncoincident load. Staff then estimated system RA requirements for CPUC jurisdictional LSEs from 2019 to 2027 by adding a 15% planning reserve margin to estimated coincident load in each of these years. System RA requirements for August 2017 and August 2018 were already available from the August 2017 month ahead RA process and the 2018 year ahead RA process, respectively.

### 3.3.2 Available Capacity

Staff consulted several resources to estimate the set of supply-side and demand-side resources available for resource adequacy during the study period. The initial estimate of local and system capacity available in 2017 came from the 2017 NQC List. Although DRAM resources appear on the NQC list, they do not currently have local designations. In order to incorporate DRAM in the analysis of local capacity, staff excluded these resources and instead used demand response CAM allocations from the 2017 year ahead RA process to reincorporate DRAM capacity into the available supply stack.[85] Next, staff added the capacity of utility-run demand response programs[86] to total available capacity, since these resources are counted towards system and local RA compliance requirements. Utility-run DR capacity was taken from August 2017 month-ahead RA compliance filings. Next, staff added the capacity of preferred resources in the Western LA Basin that were approved in D.15-11-041 but were not reported in the

[82] Behind-the-meter storage contracts agreed under D.15-11-041 were included in LSEs' data responses, and it was therefore unnecessary to add them to the data set.

[83] California Energy Commission, *California Energy Demand Update Forecast 2015 - 2027, Mid Demand Baseline Case, Mid AAEE Savings*, February 2017, http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN216264_20170227T144018_Corrected_LSE_and_BA_Tables_Mid_Baseline__Mid_AAEE.xlsx.

[84] Available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05

[85] As noted previously, CPUC allows DRAM resources to apply towards local capacity requirements through CAM, and CAISO intends to begin crediting DRAM resources toward local capacity requirements beginning in 2018.

[86] These include the Base Interruptible Program (BIP), capacity bidding programs, air conditioning cycling programs, and agricultural pumping programs. For the purposes of RA compliance, the capacity of utility-run DR programs is applied against LSE RA requirements on a pro rata basis rather than being subtracted from CEC load forecasts.

initial data response. For the analysis of available system capacity, all DR capacity – including DRAM – was augmented by 15% to account for the fact that DR resources used to meet RA capacity requirements are allowed to claim the 15% planning reserve margin that they offset. This adjustment was not made for the analysis of available local capacity, as there is no planning reserve margin in local RA requirements. Finally, although LSEs may secure imports from outside the CAISO area to help meet their system RA requirements, the analysis of available system capacity only considers resources physically located within the CAISO area. The purpose of this distinction is to highlight the capacity available solely within the CAISO area.

The same adjustments were made for available supply in 2018, except that the 2018 NQC list and August 2018 year ahead compliance filings (in the case of utility-run DR) were the starting points for that year. For 2019 through 2027, staff used IRP baseline assumptions for conventional generation – including future build and expected retirements of once-through cooling and other units – renewable generation, demand response, and storage resources from the IRP proceeding (R.16-02-007).[87] 2018 NQC values were used for conventional generation in the IRP baseline data,[88] and baseline wind and solar capacity was adjusted using August ELCC factors.[89] Again, DR capacity was adjusted upwards by 15% in the analysis of available system capacity, and contracts approved under D.15-11-041 were added to the supply stack because they did not appear in the IRP baseline. Appendix 2 describes these data handling processes in more detail.

### 3.3.3 Contracted Capacity

Throughout the following analysis, the term “contracted capacity” refers to the sum of (1) “capacity contracts,” which are actual contracts for RA capacity that LSEs execute with third party owners of generation, and (2) “utility-owned capacity,” which is the capacity of generators owned by LSEs themselves and which LSEs also apply towards their RA requirements. Since LSEs may secure imports to meet their system RA requirements, “contracted capacity” includes imports in the analysis of system capacity below.

### 3.3.4 Effective Load Carrying Capability

Pursuant to Public Utilities Code Section 399.26(d), Commission decision D.17-06-027[90] adopted a methodology for calculating the effective load carrying capability (ELCC) of wind and solar resources. This methodology will inform qualifying capacity values for resource adequacy showings by wind and

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[87] Baseline inputs to the RESOLVE model used in the IRP proceeding are available at http://www.cpuc.ca.gov/General.aspx?id=6442453965.

[88] Installed capacity was used for conventional generators scheduled to replace retiring OTC units, as these units have not yet received NQC values. The NQC value for dispatchable conventional generation is capped at a unit’s maximum deliverable capacity, which is generally close to installed capacity. For more information, see the *Qualifying Capacity Methodology Manual Adopted 2017*, available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455533.

[89] The August ELCC factor for solar resources is 41.0% of nameplate capacity, and the August ELCC factor for wind resources is 26.5% of nameplate capacity. For the full list of monthly ELCC factors, see Energy Division’s second proposal in D.17-06-027, Table 1 at A3.

[90] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K027/192027253.PDF

solar resources beginning in 2018. As the data collection for this research effort occurred in 2017, reported capacity values for wind and solar resources were based on the exceedance methodology for qualifying capacity that was used in 2017 and prior years.[91] Staff therefore modified the values for available capacity (supply stack) and the contracted capacity of wind and solar resources from 2018 onward by applying the August ELCC factors to nameplate capacity values. In the handful of cases where nameplate capacity was not reported by a respondent and was not available in the CAISO Master Generating Capability List (for example, in the case of resources that have not yet received CAISO identifiers), staff used the highest monthly contracted capacity value reported by the respondent as a proxy for nameplate capacity. These contracted capacity values are based on the former exceedance methodology, and they are therefore an underrepresentation of nameplate capacity. In turn, staff's subsequent ELCC calculations underreport the capacity from these few resources. The estimates in this report of available and contracted capacity from wind and solar resources from 2018 on should therefore be treated as conservative. Since the exceedance methodology was used for RA compliance throughout 2017, the available and contracted capacity values for wind and solar resources in 2017 reflect the exceedance methodology instead of the ELCC methodology.

## 3.4 Results

### 3.4.1 Contract Landscape

LSEs reported 1,010 unique, existing contracts covering portions of the January 2017 – December 2027 timeframe. As discussed above and in Appendix 2, staff consulted August 2017 month ahead RA filings to incorporate an additional 29 existing 2017 DRAM contracts for the two IOUs that did not identify these contracts in their initial data submissions. Thus, this report considers a total of 1,039 unique contracts, of which 885 involve resources that are not owned by the contracting LSE. Note that multiple unique contracts may exist between a given LSE and a given resource for the same timeframe. This usually occurs if an LSE must secure additional capacity to meet its RA requirement or if the contract terms are staggered.

### 3.4.2 System Capacity

This section describes capacity that is available to CPUC jurisdictional LSEs to meet system resource adequacy requirements between 2017 and 2027, as well as which resources are currently under contract for that time period. As noted previously, the results below provide a snapshot of contracting activity as of April 2017. All annual values reflect resource adequacy requirements, available capacity, and contracted capacity in August of the given year, as the CAISO system typically experiences peak annual demand in August, and system resource adequacy requirements are therefore highest in that month. Furthermore, capacity values represent the capacity that qualifies to meet system requirements rather than installed capacity.

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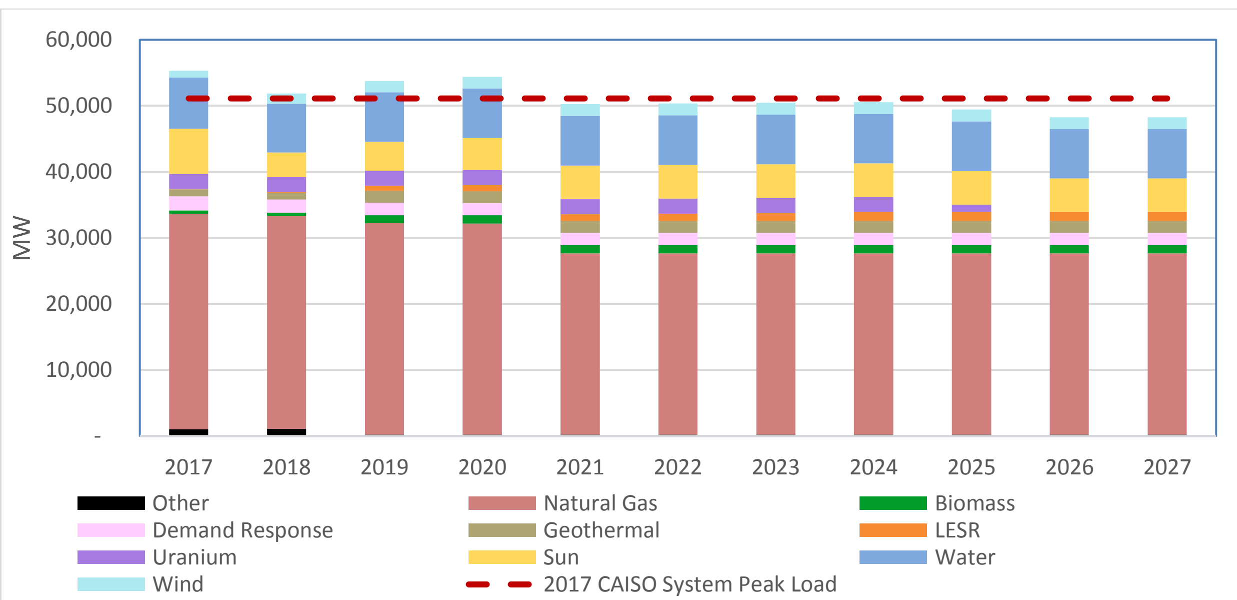
[91] For more information on the exceedance methodology, see the *Qualifying Capacity Manual Adopted 2015* at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9187.

Figure 3 presents available capacity in the CAISO area from 2017 through 2027 by fuel type.[92] Available capacity declines overall across the research timeframe, from just under 55.3 GW in 2017 to 50.1 GW in 2027. There are several dips and jumps, however, that follow planned retirements, onboarding of new generation, and other factors. First, the effect of the new ELCC calculation methodology for wind and solar is immediately discernible between 2017 and 2018: despite the addition of several new medium-capacity solar generators in 2018, overall available solar capacity declines from about 6.8 GW in 2017 to 3.7 GW in 2018 before rebounding to about 5.1 GW by 2027. On the other hand, wind capacity increases from 1.0 GW in 2017 to just over 1.5 GW in 2018 and climbs to just under 1.8 GW by 2020.

The full effect of natural gas OTC unit retirement is visible in 2021, by which time natural gas capacity drops to roughly 27.5 GW (from a peak of 32.6 GW in 2017). Capacity from limited energy storage resources (LESR) ordered by Decision D.13-10-040 begins to come online in 2019, and the retirement of Diablo Canyon nuclear generating station is apparent in 2025 and 2026. Available demand response capacity – which only includes DRAM and programs run by IOUs[93] – remains around 2 GW through 2027.

Figure 3 also indicates the 2017 CAISO system peak load of 51,118 MW, which occurred on September 1. As noted in the "Assumptions" section, LSEs may secure import capacity to apply towards meeting their system RA requirements; the RA program does not depend solely on generators located within the CAISO area. Nevertheless, assuming no drastic departures from RESOLVE baseline estimates, this quick comparison suggests that there will be enough capacity within the CAISO area alone to meet this level of demand through at least 2020.

**FIGURE 3: AVAILABLE SYSTEM CAPACITY BY FUEL TYPE, 2017-2027**

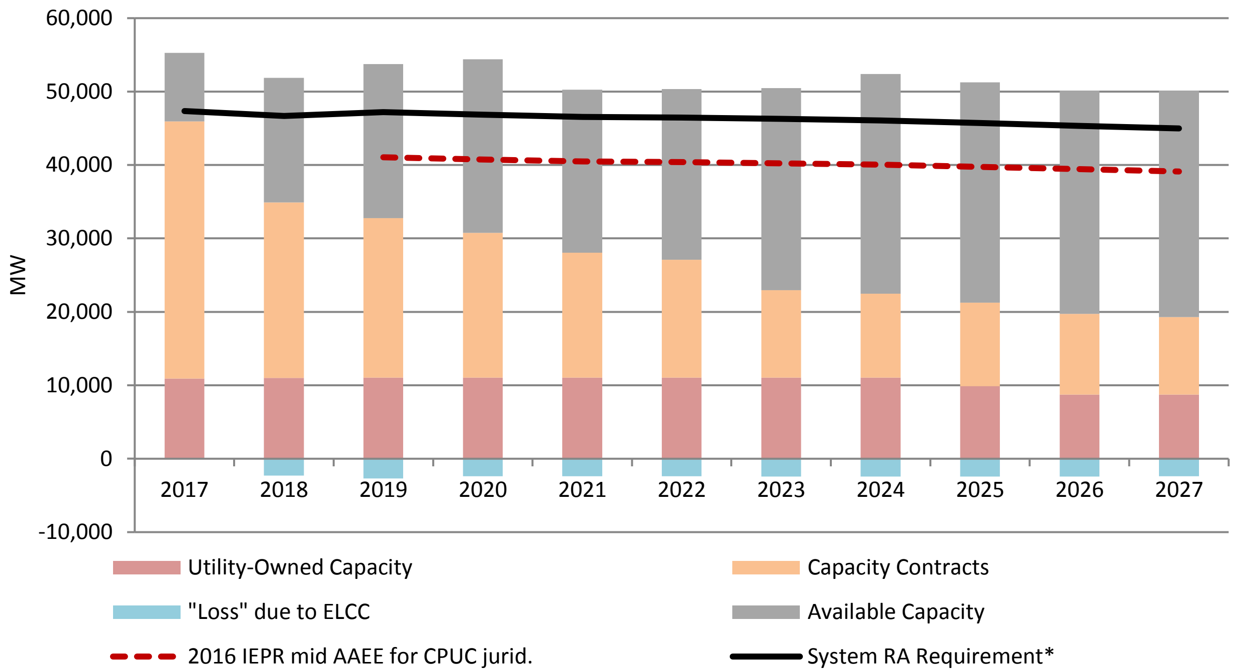



[92] Available capacity for wind and solar resources in 2017 is based on the exceedance methodology, whereas available capacity for these resources from 2018 through 2027 is based on the ELCC methodology. See Appendix 2 for more details.

[93] As of 2018, demand response programs run by IOUs ("utility-run programs") include critical peak pricing, peak time rebate, real time pricing, and peak load shifting offerings.

Figure 4, below, compares total available capacity[94] in each year against the total capacity of IOU-owned generators and the capacity that LSEs have contracted from independently-owned generators as of April 2017. Figure 4 also presents the 2016 IEPR mid-range demand forecast (with mid-range additional achievable energy efficiency, or AAEE) for CPUC jurisdictional LSEs from 2019 to 2027, as well as total system capacity requirements for these LSEs, which from 2019 on represent 115% of the forecasted load. Again, all values are for August of a given year.

**FIGURE 4: SYSTEM RA CAPACITY AND OBLIGATIONS FOR CPUC JURISDICTIONAL LSES, 2017-2027**




* System RA requirement is final month ahead requirement (with RMR removed) in 2017, sum of year ahead forecasts in 2018, and IEPR forecasted requirement from 2019 to 2027

Although available capacity declines overall during the study timeframe, this trend roughly tracks a decline in projected monthly peak load in the CAISO area from 40.9 GW in August 2017 to 39.1 GW in August 2027. (These projected peaks are based on forecasts for 1-in-2 weather years and are therefore lower than the extreme 2017 peak identified in Figure 3, which occurred during a heat wave.) Available capacity also consistently exceeds the forecasted system RA requirement for CPUC jurisdictional LSEs,[95] as well as the 2016 IEPR mid AAEE projections for CAISO system coincident peak (not shown), which are between 700 MW and 1,500 MW lower than the forecasted CPUC jurisdictional system RA requirement in each year. Note that available capacity only includes resources that are physically located within the

[94] Available capacity for each year in Figures 3 and 4 is about 10 GW lower than available capacity in Figure 8 of the 2016 Staff working paper *An Assessment of Capacity Under Contract*. This is due to a calculation error in the 2016 working paper.

[95] This is intended as a "back of the envelope" comparison. As noted previously, system RA requirements can be met by imports, which are not shown in "Available Capacity" in Figure 1. Depending on system conditions, CAISO also exports electricity to LSEs outside the CAISO area (and outside CPUC jurisdiction).

CAISO area and thus excludes roughly 1.6 GW of capacity from resources that are located outside of the CAISO area but are regularly scheduled into CAISO markets.[96] Imports from units outside the CAISO area are included in "contracted capacity," however, since they contribute to meeting RA requirements.

"Contracted capacity" – the sum of utility-owned capacity and system capacity contracts – for August 2017 represented roughly 97% of that month's system RA requirement. Contracted capacity does not exceed the requirement for two reasons. First, the system requirement represents all CPUC jurisdictional LSEs, whereas contracted capacity only represents twenty of the twenty-four LSEs in operation at the time of data collection. Year ahead filings for 2017 indicate that the remaining LSEs had procured 1,196 MW of physical and demand response capacity for August. Together, contracted capacity in Figure 3 and this additional procurement represent 99.6% of the August 2017 system RA requirement. Second, LSEs are only required to procure 90% of their monthly system RA requirements (for May through September) during the year ahead RA process and are not required to show 100% procurement until forty-five days prior to the first day of the compliance month. Staff collected data in April 2017, which means LSEs still had roughly two months to cure any net short positions for August. By the month ahead deadline for August 2017 RA filings, LSEs had procured 100.55% of the system requirement.

Contracted capacity drops sharply between 2017 and 2018, representing 75% of the August system requirement in the latter year. Contracted capacity then declines steadily through 2027, when it represents 43% of the August system requirement. This trend is consistent with the findings of staff's 2016 working paper, *An Assessment of Capacity Under Contract*, and likely reflects the requirement that LSEs only show 90% of necessary capacity up to the beginning of the compliance year. As noted previously, another factor contributing to this drop in 2018 is the switch from an exceedance methodology to an ELCC methodology in calculating the net qualifying capacity of wind and solar resources. Figure 4 indicates the capacity "lost" due to the new ELCC calculation in each year. This loss ranges from 5.0% of the RA system capacity requirement in 2018 to 5.4% of the forecasted requirement in 2027. Alternatively, this loss ranges from 6.3% of the total capacity that would be contracted in 2018 were the exceedance methodology still in place (contracted capacity plus the ELCC loss) to 11.2% of this exceedance capacity in 2027.[97]

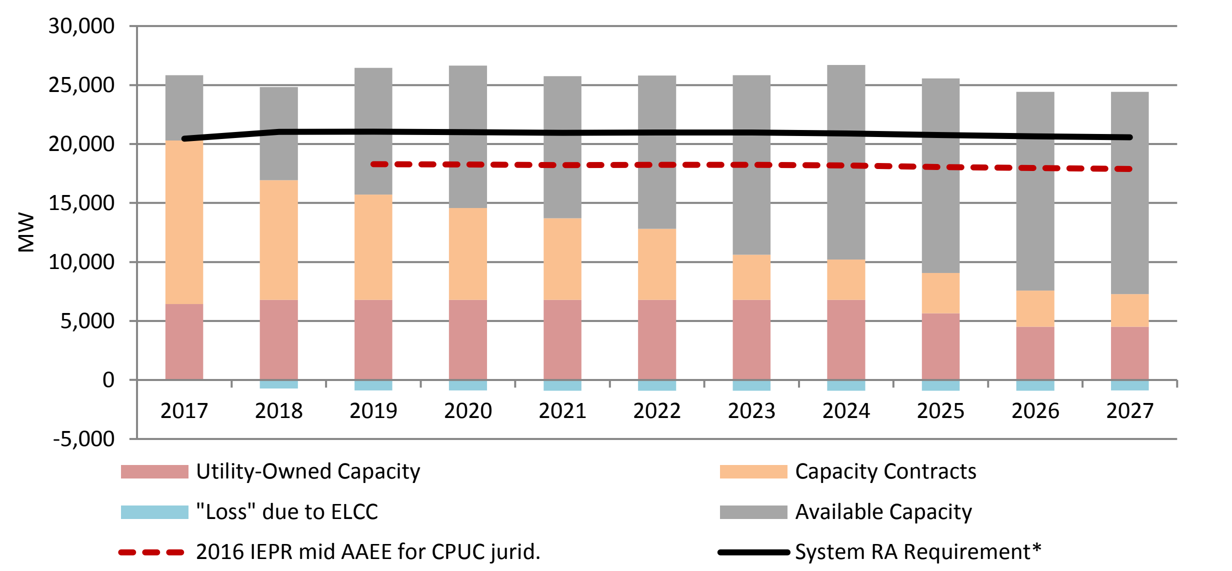
Path 26 is a 1500 kV transmission corridor between northwestern Los Angeles County and western Kern County that serves as a primary link between the PG&E transmission grid to the north and the SCE (and SDG&E) transmission grid to the south. CAISO determines maximum capacity allocations along Path 26 for each jurisdictional LSE to ensure that LSEs do not obtain more system capacity on the opposite side

[96] Excluded units include the Hoover Dam in Arizona and Nevada (of which CAISO receives a designated output share), the Palo Verde nuclear generating station in Arizona (of which SCE is a partial owner), and the Mexicali combined cycle gas plant in Baja California.

[97] The ELCC loss represents a drop in capacity for resources that were under contract as of April 2017. It does not include the drop in available capacity for any resources that were not under contract at that time. In any year, contracted capacity based on the exceedance methodology is the equivalent of contracted capacity in Figure 4 plus the ELCC loss. Total available capacity based on the exceedance methodology is available capacity in Figure 4, plus the ELCC loss, plus any loss in uncontracted available capacity due to the methodology switch (not shown in Figure 4).

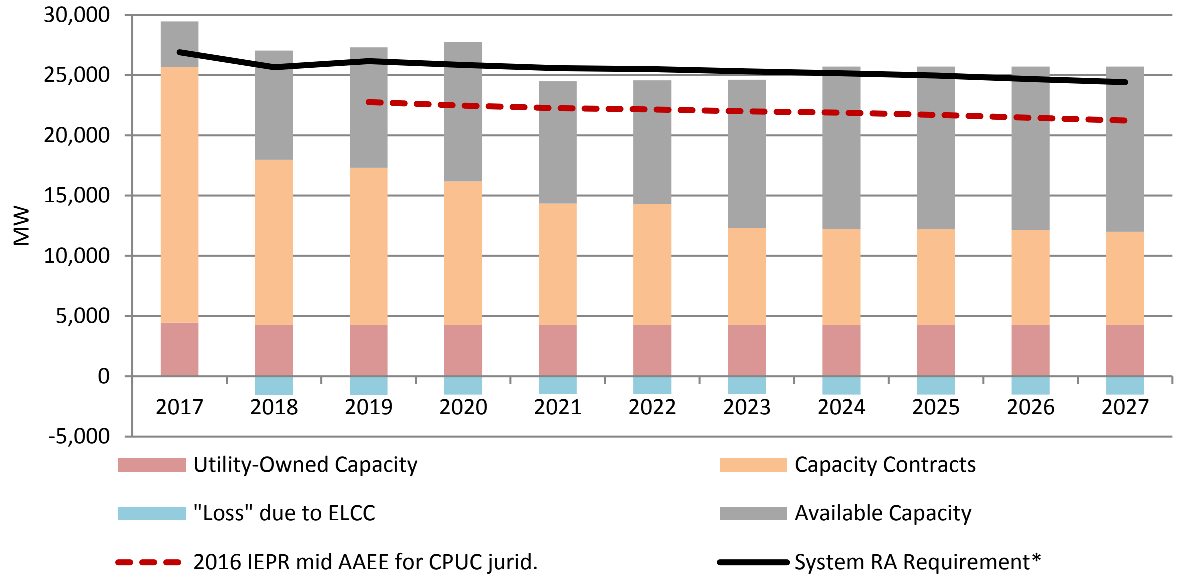
of the path than could be delivered during normal system operation. Figures 5 and 6 present the same information as is shown in Figure 4, split, respectively, into the regions north of Path 26 ("NP 26") and south of Path 26 ("SP 26"). The figures do not indicate how much capacity from resources on a given side of Path 26 have been contracted to meet system obligations on that same side, since capacity on one side may be used to meet obligations on the other, subject to LSEs' Path 26 allocations. Instead, the figures aim to highlight any differences in contracting activity on either side, with regional load forecasts and system capacity requirements as a backdrop.

**FIGURE 5: SYSTEM RA CAPACITY AND OBLIGATIONS FOR CPUC JURISDICTIONAL LSES NORTH OF PATH 26, 2017-2027**




* System RA requirement is final month ahead requirement (with RMR removed) in 2017, sum of year ahead forecasts in 2018, and IEPR forecasted requirement from 2019 to 2027

**FIGURE 6: SYSTEM RA CAPACITY AND OBLIGATIONS FOR CPUC JURISDICTIONAL LSES SOUTH OF PATH 26, 2017-2027**




* System RA requirement is final month ahead requirement (with RMR removed) in 2017, sum of year ahead forecasts in 2018, and IEPR forecasted requirement from 2019 to 2027

Aside from contracting activity, Figures 5 and 6 highlight the unequal distribution of various resource types between NP 26 and SP 26. First, the drop in available capacity between 2020 and 2021 is more drastic in Figure 6 than in Figure 5, which reflects the higher concentration of natural gas resources that employ once-through cooling in SP 26. Similarly, the loss of contracted capacity from switching to an ELCC methodology is greater in SP 26, which contains 73% of utility-scale solar capacity and 74% of wind capacity in the CAISO area as of 2018 (see Appendix 2 for a description of staff's assumptions regarding available capacity from 2019 to 2027). In SP 26, this loss represents about 6.0% of the regional system capacity requirement in each year and ranges from 8.1% of contracted capacity based on exceedance in 2018 to 11.2% of contracted capacity based on exceedance in 2027. In NP 26, the loss ranges from 3.6% of the capacity requirement (4.2% of contracted capacity based on exceedance) in 2018 to 4.4% of the capacity requirement (11.0% of contracted capacity based on exceedance) in 2027.

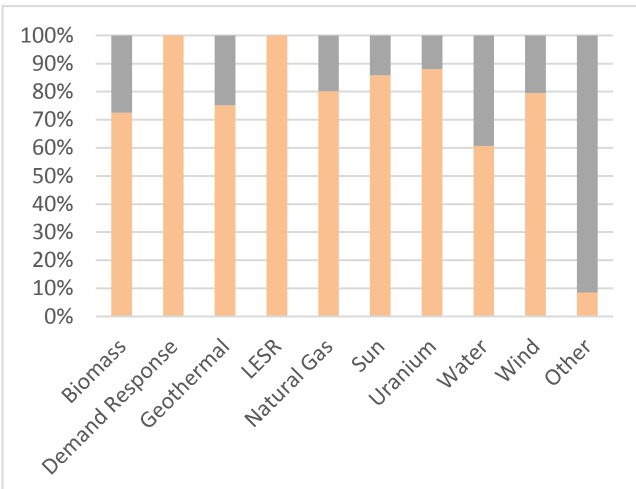
Although there is more utility-owned capacity in NP 26 across all years, overall contracted capacity is higher in SP 26 throughout the study timeframe. This reflects both the higher system capacity requirement in SP 26 and the availability of large generation resources outside of the CAISO area that are regularly scheduled into the CAISO markets (e.g. the Hoover Dam and the Palo Verde nuclear generating station). Figure 6 shows that available capacity in SP 26 is lower than the predicted system RA requirement in that region from 2021 to 2023. This is not a concern, however, given the availability of imports and the fact that LSEs can procure system resource adequacy on the other side of Path 26 (compare total system requirements with availability in Figure 3).

Figure 7, below, returns to the CAISO system level and presents the percentage of total available capacity by fuel type in selected years that had been contracted as of April 2017. Unlike in Figures 4 through 6, contracted capacity in Figure 7 excludes any resources that are not physically located within the CAISO area.

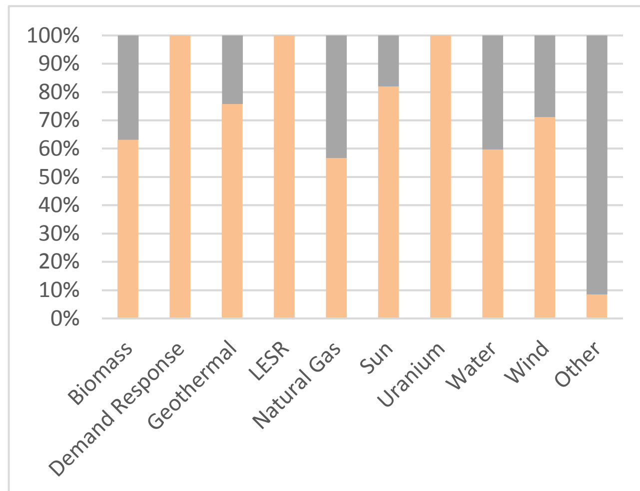
**FIGURE 7: SYSTEM RA CAPACITY UNDER CONTRACT IN SELECTED YEARS, BY FUEL TYPE**

Key: Available Under Contract

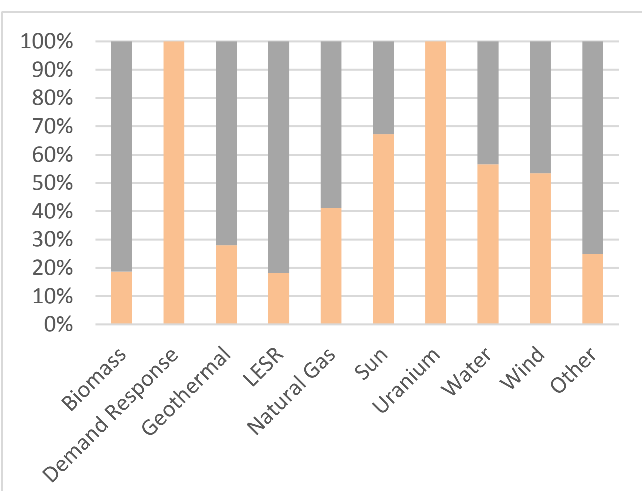
**7a: 2017**



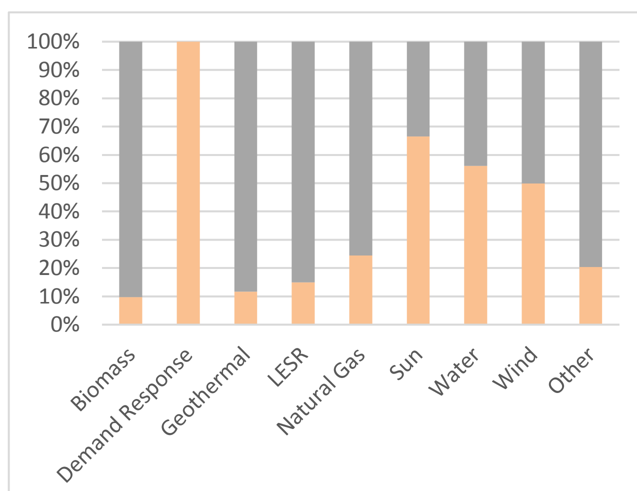

**7b: 2018**




**7c: 2022**




**7d: 2027**



Except for demand response and uranium (which only includes the Diablo Canyon nuclear generating station owned by PG&E), all resource types experience a decline in the percentage of capacity under contract as time goes on. This is consistent with the general findings presented in Figures 4 through 6. Nevertheless, significant differences are apparent in the percentage of each resource type that is contracted by 2027. The percentage of total capacity represented by natural gas fired generators declines from 59% in 2017 to 56% in 2027 (see Figure 3), though the percentage of that capacity under contract as of 2017 declines from 80% in 2017 to just 24% in 2027. Geothermal and biomass resources see similar declines in contracted capacity across the study period. Hydro, wind, and solar resources see much shallower declines in contracting activity, however. Hydropower resources represent roughly 14% of available capacity from 2017 to 2027, and the percentage of hydropower capacity under contract only declines from 61% in 2017 to 56% in 2027. This is likely due to the longevity of hydropower resources and the fact that most hydropower resources in California are utility owned (they would appear as "contracted" in all years). Solar and wind resources respectively represent 12% and 2% of available capacity in 2017, becoming 10% and 4% in 2027. Yet in the latter year, solar and wind resources are still 67% and 50% contracted, respectively.[98] Limited energy storage resources experience a steep decline in contracted capacity between 2017 and 2027 (from 100% to 15%). Procurement of LESR resources is traditionally associated with specific procurement authorizations, such as the requirement in D.13-10-040[99] to procure 1,325 MW of storage by 2021. Therefore, as with similarly mandated DR resources, staff expect the percentage of available LESR capacity under contract to approach 100% as the procurement authorizations are filled in future years.

Figure 8 depicts import contracts as a sum of August capacity and as a percentage of August CAISO area system requirements from 2017 to 2027. Imports include capacity from specific units that are located outside the CAISO area but are scheduled into CAISO markets, as well as contracts to withdraw from specific interties.

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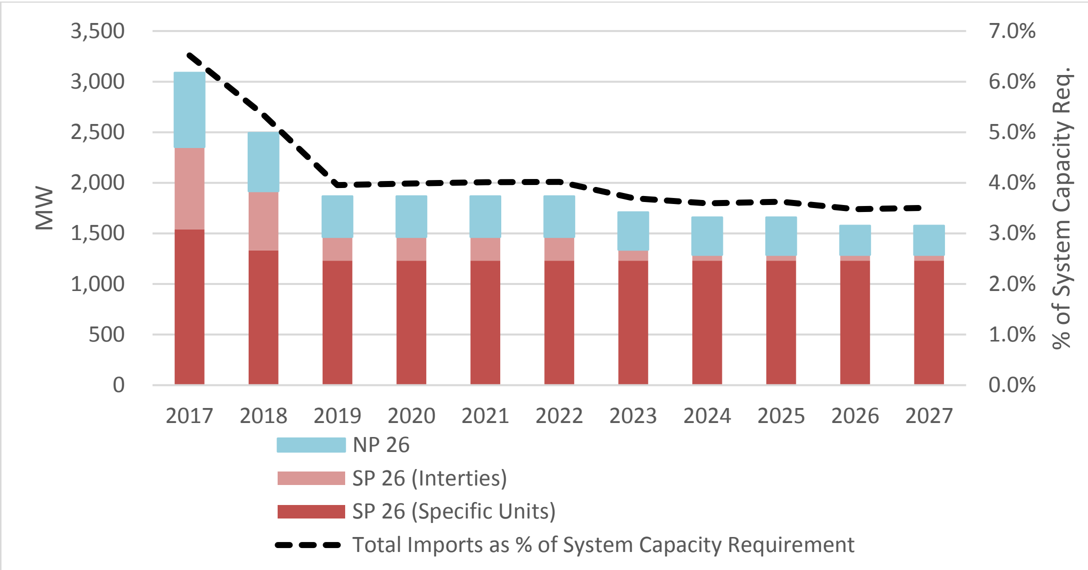
[98] Figure 7 also indicates that available solar and wind capacity is not fully under contract in 2017 and 2018, even though solar and wind resources procured through the Renewable Portfolio Standard should filter into the RA program. This is partly because some resources have begun operating as merchant units in the CAISO markets before their power purchase agreements with LSEs are set to begin. Thus, they are available, though they do not appear as "under contract" in 2017 and 2018. Furthermore, some capacity for solar and wind resources will be under contract to municipal utilities that are outside CPUC jurisdiction, and these contracts do not appear in the current analysis.

[99] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF

**FIGURE 8: CONTRACTED IMPORT CAPACITY FOR SYSTEM RA, 2017-2027**




Imports range from about 6.5% to about 3.5% of system requirements throughout the study period, and total contracted capacity declines over time in accordance with the findings of Figures 4 through 6. Imports are notably higher in SP 26 than in NP 26, and the majority of SP 26 imports are from specific units scheduled into the CAISO markets (LSEs in NP 26 only have contracts with interties).

### 3.4.3 Local Capacity

This section describes LSE contracting activity with resources sited in local reliability areas. Local resources are available to meet local RA requirements, and local capacity contracts are also counted towards system capacity requirements in the RA process. Appendix 2 provides additional information regarding the treatment of capacity contracts in this section.

Table 3, below, sums total August net qualifying capacity from the 2018 NQC list by local reliability area and compares it to the 2017 and 2018 local capacity requirements of CPUC jurisdictional LSEs in each local reliability area. The August 2018 NQC values reflect the new ELCC methodology and do not include available local capacity from the DRAM program or from utility-run demand response programs. Resources located in a local reliability area represent 71% of available August capacity on the 2018 NQC list.

**TABLE 3: AVAILABLE CAPACITY AND CPUC JURISDICTIONAL LOCAL RA REQUIREMENTS BY LOCAL RELIABILITY AREA**

| Local Area | 2018 August NQC (MW) | 2017 Local Req.* (MW) | 2018 Local Req.* (MW) |
|---|---|---|---|
| Greater Bay Area | 7,070 | 4,539 | 3,810 |
| Other PG&E Areas** | 7,529 | 4,766 | 4,942 |
| Fresno | 3,224 | | |
| Humboldt | 202 | | |
| Kern | 460 | | |
| North Coast / North Bay | 865 | | |
| Sierra | 2,147 | | |
| Stockton | 631 | | |
| **TOTAL NP 26** | **14,599** | **9,305** | **8,752** |
| Big Creek-Ventura | 5,521 | 1,534 | 1,778 |
| LA Basin | 10,283 | 6,595 | 6,693 |
| San Diego / Imperial Valley | 5,356*** | 3,569 | 3,833 |
| **TOTAL SP 26** | **21,160** | **11,698** | **12,304** |
| **TOTAL LOCAL** | **35,759** | **21,003** | **21,056** |

*Requirements for August 2017 are based on the month ahead RA process and reflect the 2017 local true-up. Requirements for August 2018 are based upon the year ahead RA process and do not reflect the local true-up, which will occur in April 2018.
**Local reliability areas outside the Bay Area but within the PG&E TAC area are grouped as "Other PG&E Areas" for local RA compliance.
***Includes 558 MW of capacity from the Carlsbad Energy Center, which NRG predicts will be online by Q4 2018.

Local requirements decreased in NP 26 and increased in SP 26 from 2017 to 2018, with a net increase of 53 MW statewide. However, Table 3 indicates that even without considering demand response, physical capacity in each of the local reliability areas generally exceeds local reliability needs.

Figures 9 and 10 below compare available local capacity in CAISO with CPUC jurisdictional LSE local RA requirements and the capacity that had been contracted by CPUC jurisdictional LSEs as of April 2017, grouped by NP 26 and SP 26. Unlike in Table 3, available capacity and contracted capacity in Figures 9 and 10 include DRAM and utility-run demand response. Aggregate local RA requirements for 2017 and 2018 reflect actual requirements (before the annual true-up in the case of 2018), whereas the requirements for 2019 through 2022 are based on CAISO projections in the *2019 Local Capacity Technical Analysis*[100] (completed in 2015), the *2020 Local Capacity Technical Analysis*,[101] and the *2022 Local Capacity Technical Analysis*.[102]

[100] Available at http://www.caiso.com/Documents/Final2019Long-TermLocalCapacityTechnicalAnalysisReportApril302014.pdf.
[101] Available at https://www.caiso.com/Documents/Final2020Long-TermLocalCapacityTechincalReportApr302015.pdf
[102] Available at http://www.caiso.com/Documents/Final2022Long-TermLocalCapacityTechnicalReport.pdf

**FIGURE 9: LOCAL RA CAPACITY AND OBLIGATIONS FOR CPUC JURISDICTIONAL LSEs NORTH OF PATH 26, 2017-2027**

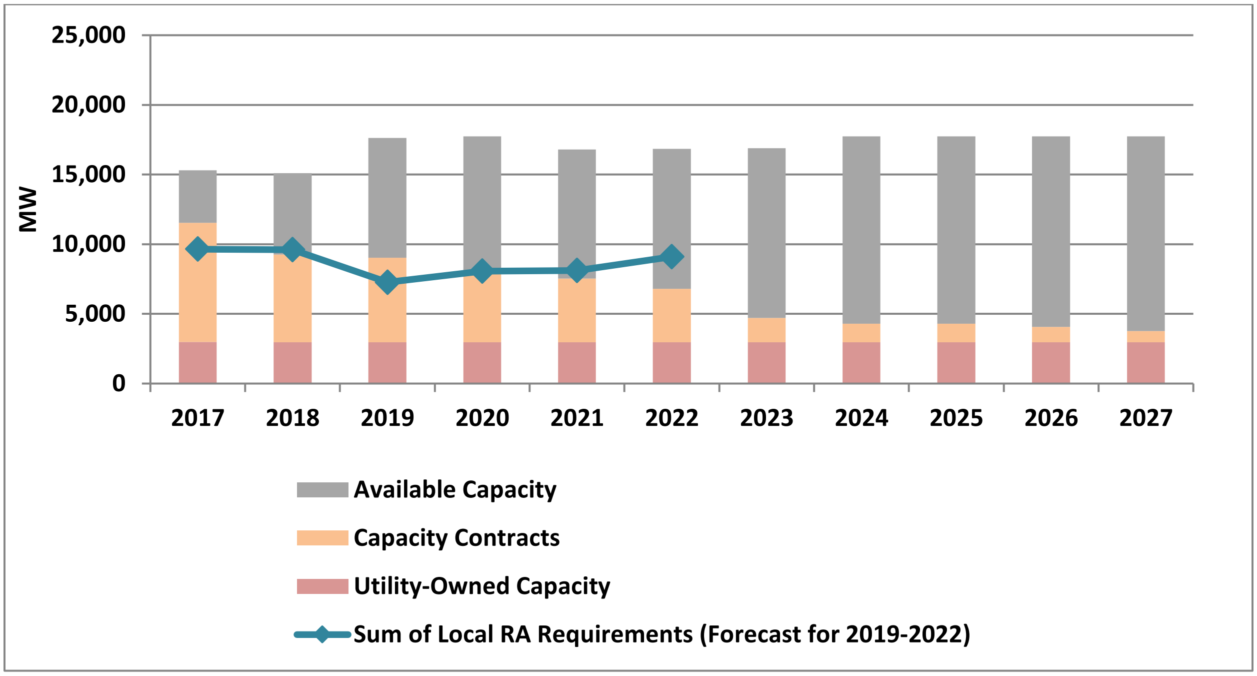
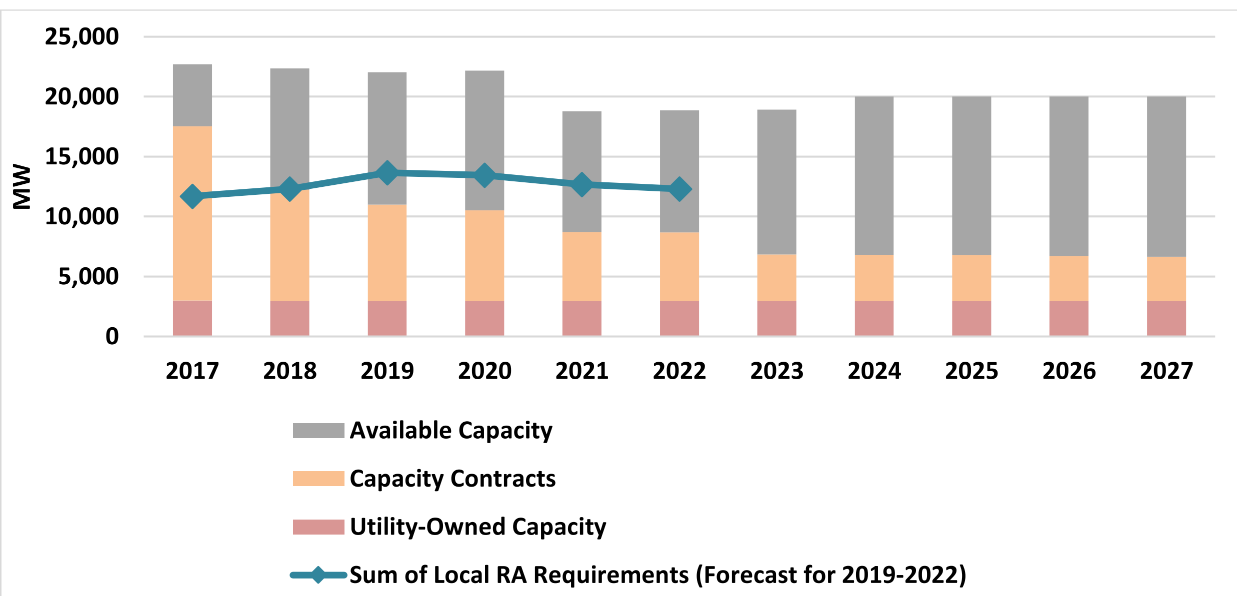



**FIGURE 10: LOCAL RA CAPACITY AND OBLIGATIONS FOR CPUC JURISDICTIONAL LSEs SOUTH OF PATH 26, 2017-2027**




Trends in available local capacity mirror those of available system capacity in Figures 5 and 6, namely that the retirement of OTC units by 2021 is more pronounced in SP 26. Local capacity requirements exhibit a less clear trend than system capacity requirements, however, as local requirements appear to move in opposite directions on either side of Path 26. This is likely the result of new and ongoing transmission constraints, as well as plans for new transmission infrastructure, which factor into the CAISO local reliability studies.

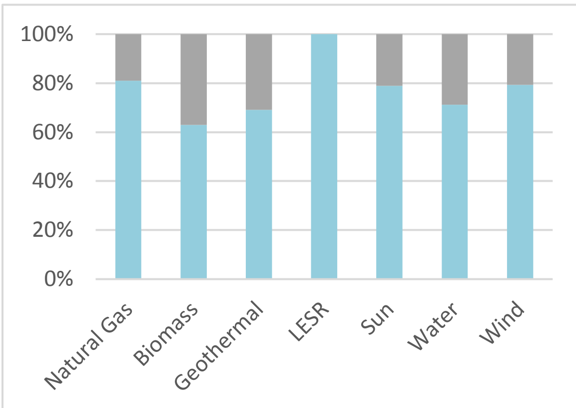
As of April 2017, LSEs had secured well over 100% of their 2017 local capacity requirements. This aligns with the RA program stipulation that LSEs must show procurement of 100% of their local capacity requirements for a given compliance year in their year ahead RA filings. In aggregate LSEs had nearly procured their entire 2018 local requirements by April 2017, as well. LSEs had also procured at least 85% of the aggregate requirement in each local reliability area by April 2017 (not shown in Figures 9 and 10). Yet this does not address local sub-area needs, which drive overall requirements and are the focus of CAISO backstop procurement. As discussed in the "Emerging Issues" section below, LSEs in aggregate were unable to procure adequate capacity to meet local sub-area needs during the 2018 year ahead RA process.

Figure 11 shows the percentage of total available capacity from local resources in selected years – by fuel type – that had been contracted as of April 2017. The figure excludes demand response, which staff considered to be 100% contracted in accordance with the fact that all available local demand response is counted towards local requirements in the RA program. Instead, staff focused on the other primary resource fuel types that contribute to local capacity in California.

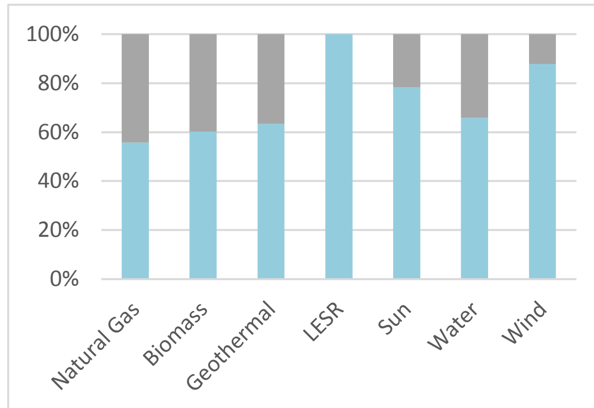
**FIGURE 11: LOCAL CAPACITY UNDER CONTRACT IN SELECTED YEARS, BY FUEL TYPE**

Key: Available Under Contract

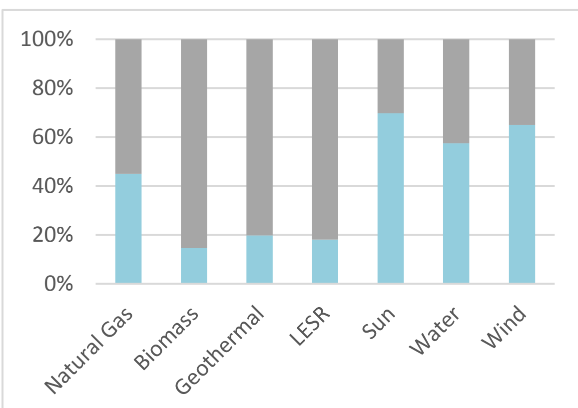
**11a: 2017**



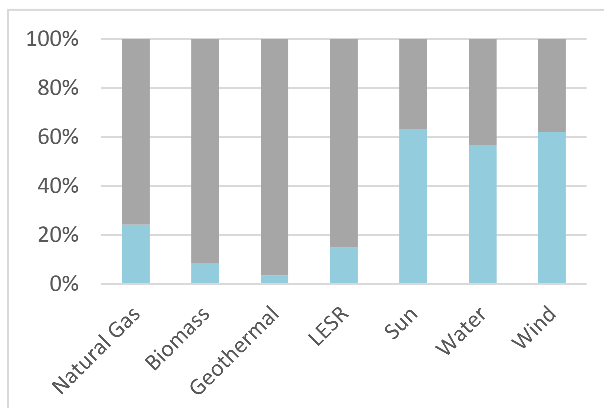

**11b: 2018**




**11c: 2022**




**11d: 2027**




In 2017, only natural gas and storage had more than 80% of their available local capacity under contract. As in the analysis of system capacity (see Figure 7), all local resources experience a decline in the percentage of capacity under contract over time. This decline is particularly pronounced for local natural gas resources, the percentage of whose capacity under contract drops from 80% in 2017 to 24% in 2027. Similar declines are apparent for local biomass and geothermal resources, whereas local wind, solar, and hydro resources are all over 55% contracted in 2027.[103] Again, the percentage of capacity from LESR that is under contract should approach 100% in all years as related procurement mandates are met.

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[103] As noted previously, there are two main reasons why available wind and solar capacity is not fully contracted in 2017 and 2018. Some units are currently in operation, but their power purchase agreements with LSEs have not

## 4. EMERGING ISSUES

Within the past year in particular, several new challenges have arisen within the RA program. These challenges are identifiable within the results of the contract data analysis above and involve several topics addressed in the history section. They include (1) an apparent decrease in forward procurement, (2) LSE requests for local requirement waivers, (3) growth in CAISO back-stop procurement, including three RMR contracts and two CPM designations, (4) acceleration in load migration from the IOUs to new and existing CCAs, and (5) divergent trends in local procurement activity, notwithstanding recent waiver requests. We discuss each emerging issue in the subsections below and offer potential solutions in the final section of this report.

### 4.1 Less Forward Procurement

In comments on the 2016 staff report *An Assessment of Capacity Under Contract*,[104] parties noted an apparent decrease in forward procurement in comparison with findings of the earlier 2014 *Joint Reliability Plan Track One Staff Report*.[105] Staff collected data for the 2014 report in May of 2014, fifteen months before LSEs would need to show 100% procurement of their August 2015 system capacity requirements. The 2014 report showed that as of May 2014, LSEs had already procured 95% of the August 2015 requirement and roughly 85% of the estimated August 2016 requirement. It is difficult to compare these results directly with those from the 2016 report, since data collection for the latter took place in October rather than in May. The 2016 report shows that as of October 2015, or ten months in advance of the requirement to show 100% procurement of the August 2016 system capacity requirement, LSEs had procured over 100% of their August 2016 requirement, as well as 78% of the estimated August 2017 requirement and 69% of the estimated August 2018 requirement.

As previously noted, staff collected data for the current report in March and April of 2017, which means the current data are more directly comparable with those from the 2014 report. The analysis above (see Figure 4) shows that as of April 2017, LSEs had procured only 75% of their August 2018 system capacity requirements and 69% of their expected August 2019 requirements. Staff determined that inclusion of known contracts held by LSEs that did not respond to the 2017 data request would not noticeably change these results (or other results in this report). In addition, the switch to an ELCC methodology for determining the net qualifying capacity of wind and solar resources only accounts for about a quarter of the change in procurement levels between the 2014 report and the current report. Staff therefore concludes that there has been a decrease in forward procurement activity since 2014, including a decline of roughly 15 percentage points in the proportion of system capacity requirements that are under contract one year before the compliance month (excluding the effects of ELCC). The reasons for this are as yet unclear but are likely tied to the uncertainty caused by recent growth in out-of-market

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begun, and they therefore are not contracted for RA in 2017 and 2018. In addition, some capacity from wind and solar resources will be under contract to municipal utilities that are not within CPUC jurisdiction and are not considered in this analysis.

[104] Available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451994

[105] Available at http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9107

procurement and the expansion of CCAs outside the year ahead RA framework, as described in the following sections.

## 4.2 Local Reliability Concerns

The local RA program includes certain measures to mitigate market power and to address resource availability. One such measure is the local waiver process. In the event that an LSE is unable to secure enough capacity to meet its local resource adequacy requirement (RAR), it may request a waiver for the deficiency, subject to the following conditions:

> *(1) A demonstration that the LSE reasonably and in good faith solicited bids for its RAR capacity needs along with accompanying information about the terms and conditions of the Request for Offer or other form of solicitation,*
> *and*
>
> *(2) a demonstration that despite having actively pursued all commercially reasonable efforts to acquire the resources needed to meet the LSE's local procurement obligations, it either*
>
> > *(a) received no bids,*
> >
> > *or*
> >
> > *(b) received no bids for an unbundled RA capacity contract of under $40 per kW-year or for bundled capacity and energy product of under $73 per kW-year,*
> >
> > *or*
> >
> > *(c) received bids below these thresholds but such bids included what the LSE believes are unreasonable terms and/or conditions, in which case the waiver request must demonstrate why such terms and/or conditions are unreasonable.*[106]

Prior to the 2018 year ahead RA process, LSEs had only ever filed two local waivers with CPUC. However, in September and October of 2017 several LSEs began contacting Energy Division staff regarding the inability to procure adquate local and system capacity. Of the twenty-seven LSEs that submitted year ahead 2018 RA filings on October 31, 2017, eleven filed waiver requests to cover local deficiencies totaling roughly 270 MW. In addition, the year ahead filings identified a collective deficiency of around 40 MW in system capacity. As LSEs must meet 100% of their local capacity requirements in the year ahead RA compliance process , the local deficiencies have subsequently carried over into the monthly RA process for 2018.

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[106] D.06-06-064 at 73. Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/57644.PDF.

## 4.3 Growth in Out-of-Market Procurement

### 4.3.1 Capacity Procurement Mechanism (CPM)

In response to the deficiencies identified in the 2018 year ahead RA process, CAISO issued CPM designations on December 22, 2017 for the three units identified in Table 4 below.

**TABLE 4: 2018 CPM DESIGNATIONS FOR LOCAL CAPACITY**

| Unit | MW | CPM Price[107] | Local Reliability Area | Sub Area[108] |
|---|---|---|---|---|
| Moss Landing Unit 2 | 510 | $6.19 / kW-month for 490 MW<br>$6.31 / kW-month for 20 MW | Greater Bay Area | South Bay / Moss Landing |
| Encina Unit 4 | 272 | $6.31 / kW-month | San Diego / Imperial Valley | - |
| Encina Unit 5 | 273 | $6.31 / kW-month | San Diego / Imperial Valley | - |

The designations are for twelve months beginning January 1, 2018 – though their duration may be shortened – and the exact amount of capacity under the designation in any given month will depend on the individual and collective deficiencies in that month. In particular, the designation for Encina may be reduced on a megawatt-by-megawatt basis as Carlsbad Energy Center comes online.[109] This nevertheless represents the first annual CPM designation by CAISO. In accordance with the stipulations of CAISO Tariff Section 43A, all three units will receive compensation at the augmented CPM price.[110] This procurement appears to be very expensive in comparison to the 85th percentile of prices for local RA documented in the *2016 Resource Adequacy Report*[111] (see Table 6 below).

### 4.3.2 Reliability Must Run (RMR) Designations

On November 28, 2016, Calpine Corporation (Calpine) requested that CAISO perform reliability assessments in support of an RMR designation for four natural gas fired generators: the Yuba City Energy Center, the Feather River Energy Center, the King City Energy Center, and the Wolfskill Energy Center (186 MW total). After performing the requested studies, the CAISO Board of Governors subsequently approved RMR status for Yuba City Energy Center and Feather River Energy Center (94

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[107] California Independent System Operator, *December 22, 2017 Year Ahead Local CPM Designation Report*, p. 1, http://www.caiso.com/Documents/December222017YearAheadLocalCPMDesignationReport.pdf.
[108] A sub area is a subset of a local reliability area whose unique configuration of generation, transmission, and load contributes to local reliability needs within the local reliability area as a whole.
[109] See the relevant CAISO market notice, available at http://www.caiso.com/Documents/CapacityProcurementMechanismDesignation-122217.html.
[110] Available at https://www.caiso.com/Documents/Section43A_CapacityProcurementMechanism_asof_Sep25_2016.pdf.
[111] Available at http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942

MW total) on October 15, 2017. Both generators are located in the Sierra local reliability area. On June 2, 2017, Calpine requested an additional reliability assessment in support of an RMR designation for the 570 MW Metcalf Energy Center, which is a combined cycle natural gas generator located in the Greater Bay Area local reliability area. The CAISO Board of Governors approved RMR status for Metcalf Energy Center on November 2, 2017.

On December 31, 2017, FERC approved both RMR agreements, subject to refund based on settlement procedures intended to determine whether the agreements are just and reasonable.[112] The agreements are tentatively in effect for one calendar year. As noted previously, this represents the first increase in RMR capacity designations within the CAISO area since the local RA program began in 2007. All three resources are located in sub-local areas within the PG&E TAC area, and CPUC allocated local and system RMR capacity to CPUC jurisdictional LSEs in the PG&E TAC area using the methodology for allocating CAM capacity.[113] The RMR designations represent procurement of 675 MW outside the RA program's typical competitive solicitation process and suggest a growing lack of coordination between "in market" and "out-of-market" procurement within the RA construct. Table 5 below documents the proposed cost of the 2018 RMR designations as documents in Calpine's FERC filings.

### TABLE 5: 2018 RMR UNIT REVENUE REQUIREMENTS AND COSTS

| RMR Unit | Requested Revenue Requirement as documented in FERC filings | August 2018 NQC value (MW) | Potential Cost of RMR contract $kW-month |
|---|---|---|---|
| Metcalf | $ 72,460,702 | 580 | $ 10.41 |
| Yuba City | $ 4,463,326 | 47.6 | $ 7.81 |
| Feather River | $ 4,430,295 | 47.6 | $ 7.76 |

In comparison with the 85th percentile costs provided in the *2016 Resource Adequacy Report* and documented in Table 6 below, the RMR procurement also appears to be very expensive.

### TABLE 6: AVERAGE LOCAL RA CONTRACT PRICES BY LOCAL RELIABILITY AREA

| Capacity Prices by Local Area, 2016-2020 | 85% of MW at or below ($/kW-month) |
|---|---|
| LA Basin | $3.65 |
| Big Creek/Ventura | $4.34 |
| Bay Area | $3.00 |
| Other PG&E Area | $2.50 |
| San Diego-IV | $4.33 |
| CAISO System | $3.00 |

[112] See FERC docket numbers ER18-230-000 (available at https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14739583 ) and ER18-240-000 (available at https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14741407). Both RMR agreements were approved in the same ruling, available at https://www.ferc.gov/CalendarFiles/20171229153421-ER18-230-000.pdf.

[113] See the *2018 Final RA Guide* at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454920

## 4.4 Growth in Community Choice Aggregators (CCAs)

When the RA program began in 2004, there were a total of fifteen LSEs (three IOUs and twelve ESPs) serving load in California. Direct access had been suspended during the energy crisis to ensure more certainty in procurement cost allocation, and the number of LSEs remained relatively constant through 2010, when the Commission established rules regarding the limited reopening of Direct Access pursuant to SB 695 (Kehoe, 2009).[114] The first CCA began serving load in 2010, and the number of CCAs has expanded rapidly since 2015. As of December 8, 2017, thirty-six LSEs had been approved to serve load, including ten CCAs that plan to begin service in 2018,[115] but were not serving load in August of 2017.[116] After December 8, three more CCAs filed implementation plans to serve load for the first time in 2018. CPUC has not approved these additional plans, but if they are approved and become registered CCAs, there will be thirty-nine LSEs serving load in California in August of 2018.

Table 7, below, shows the growth in LSEs from 2008 through 2018, including approved and pending implementation plans. Note that Table 7 only captures growth in the total number of CCAs (and other LSEs) and does not address growth in the load served by existing CCAs.

**TABLE 7: NUMBER OF LSES, 2008-2018**

| LSE Type | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 (Approved)* | 2018 (If Addl. Filings Approved)** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IOU | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| ESP | 12 | 10 | 9 | 13 | 12 | 14 | 14 | 16 | 15 | 15 | 15 | 15 |
| CCA | 0 | 0 | 1 | 1 | 1 | 1 | 2 | 2 | 4 | 8 | 18 | 21 |
| **Total** | **15** | **13** | **13** | **17** | **16** | **18** | **19** | **21** | **22** | **26** | **36** | **39** |

*Includes CCA plans approved as of December 8, 2017. Note that some CCAs may not yet have filed bonds with the CPUC, which means they are not officially registered as LSEs. We use the term "LSE" more generally here to highlight the potential number of entities serving load.

**Includes all CCA plans, including those filed after December 8, 2017 (which have not been approved).

Table 8 provides additional information regarding the timing of CCA onboarding and its effects on the RA program. This includes the number of CCAs participating in the year ahead (YA) resource adequacy process, as well as the total load eventually served (or, in the case of 2018, planned for service) by new CCAs and as a result of expansion by existing CCAs into new jurisdictions. As shown in Table 8, new or expanding CCAs generally have not participated in the YA process – which sets LSEs' annual obligations – for the year in which they start serving load. This is often because CCAs do not file implementation plans for first time service or for expanded service in additional jurisdictions until after April of a given year,

[114] Available at http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100SB695

[115] Note that an CCA does not become an LSE once its implementation plan is approved. A CCA must first register with the Commission by submitting a bond. After the CCA is registered, it is officially an LSE subject to the requirements of PUC Section 366.2.

[116] One of these CCAs began serving load in September 2017. The remaining nine filed implementation plans in 2017 to begin serving load in 2018.

which is the cutoff for submitting an initial annual load forecast and thus for participating in the next year's YA process. The direct result of this timeline mismatch is that new CCAs do not receive YA obligations, and IOUs are required to procure capacity for the remaining obligation in their TAC areas that is not covered by CCAs and ESPs that participated in the YA process. Once they begin serving load, CCAs are brought into the month ahead (MA) resource adequacy process and must procure capacity to meet their monthly obligations.

As Table 8 shows, the difference between CCA load anticipated in the YA RA process and the load actually served in real time can be substantial.[117] This leads to significant uncertainty in determining appropriate responsibility for capacity procurement in the YA process. Since IOUs receive responsibility for any capacity requirements not assigned to CCAs and ESPs – under the reasonable assumption that IOUs will serve the load not served by other LSEs – this uncertaintly results in IOUs covering the system, local, and flexible capacity requirements for the subset of customers that will depart when the CCA begins serving load. IOUs assume this responsibility until such a time as the CCA becomes certified and registered to serve the load and is assigned RA obligations by the CPUC and the CEC. This uncertainty may also contribute to the previously-noted decrease in the proportion of capacity requirements that LSEs procure one or more years ahead.

[117] The MA RA process includes adjustments to capacity requirements to account for load migration that occurs between YA forecasts and MA forecasts. The final row of Table 6 accounts for these adjustments in addition to any CCA load that did not appear in the YA forecasts but did appear in the MA forecasts. If all LSEs participate in the YA process and provide robust forecasts, then these adjustments should be relatively minor.

**TABLE 8: SYSTEM CAPACITY REQUIREMENTS AND PARTICIPATION BY NEW AND EXPANDING CCAS IN THE YA RA PROCESS**

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 (Approved)* | 2018 (If Addl. Filings Approved)** |
|---|---|---|---|---|---|---|---|---|---|---|
| Number of CCAs Participating in YA RA Process | 0 | 1 | 1 | 1 | 1 | 2 | 3 | 5 | 9 | N/A |
| Number of CCAs Serving Load in August | 1 | 1 | 1 | 1 | 2 | 3 | 3 | 8 | 18 | 21 |
| (A) CCA YA Load Forecast for August (MW) | 0 | 31 | 45 | 173 | 211 | 564 | 798 | 1,299 | 2,704 | N/A |
| (B) CCA Month Ahead Load Forecast for August (MW) *** | 34 | 46 | 177 | 216 | 321 | 733 | 835 | 2,565 | 4,683 | 5,752 |
| (B) – (A) CCA August Load not Included in YA Forecast (MW) | 34 | 15 | 132 | 43 | 110 | 169 | 37 | 1,266 | 1,979 | 3,048 |

*Includes CCA plans approved as of December 8, 2017

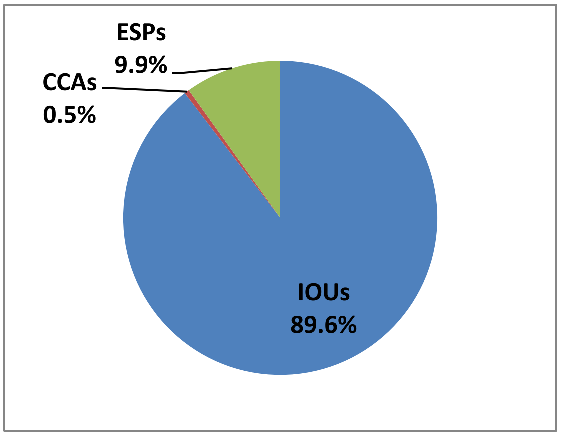
**Includes all CCA plans, including those filed after December 8, 2017 (which have not been approved)

***For 2018, this is the sum of YA forecasts and load forecasts in CCA implementation plans that were not included in YA filings

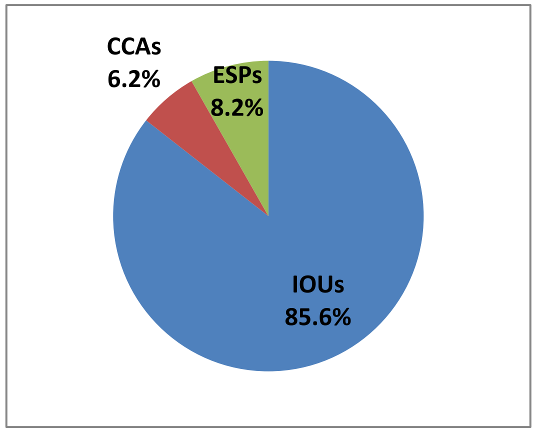
Figure 12 provides another visualization of this uncertainty. Figures 12a and 12b depict August load shares of the three LSE categories according to YA filings for 2014 and 2018, respectively. Figure 12c provides August 2018 load shares that also include the CCA implementation plans approved by CPUC as of December 8, 2017. Figure 12d provides August 2018 load shares that include approved and unapproved CCA implementation plans.

#### FIGURE 12: LOAD BY LSE TYPE, 2014 AND 2018

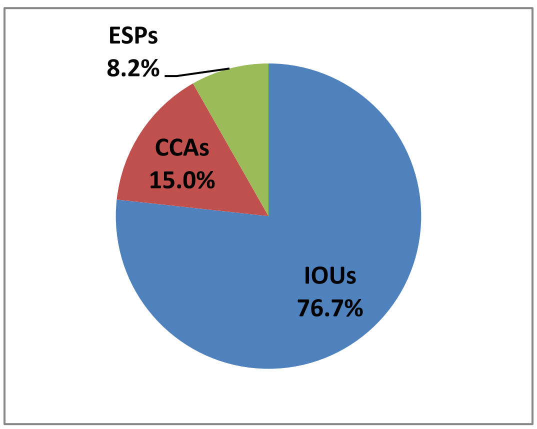
**12a: 2014 YA Load Forecasts for August**



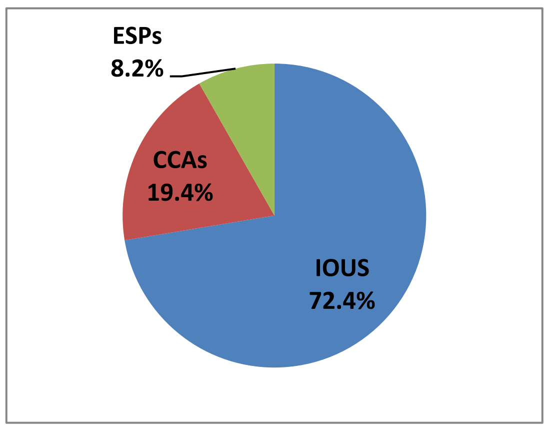

**12b: 2018 YA Load Forecasts for August**




**12c: 2018 YA Load Forecasts for August, Plus Approved CCA Implementation Plans**




**12d: 2018 YA Load Forecasts for August, Plus Approved and Unapproved CCA Implementation Plans**




## 4.5 Trends in Local Procurement by LSE Category

Notwithstanding recent local capacity shortfalls, trends in local procurement activity differ based on the category of LSE undertaking procurement. Table 8 below shows how much of the capacity under contract as of April 2017 was attributable to each of the three LSE categories. The proportion of contracted capacity held by CCAs and ESPs decreases one year out and remains lower than the 2017 level in each subsequent year, whereas IOUs continue to hold the vast majority of contracted capacity through 2022. This is partly because a large portion of the state's generation capacity – particularly in Southern California – is located in local areas, and IOUs procure some portion of local resources to meet their system capacity requirements.

**TABLE 8: PERCENTAGE OF CONTRACTED CAPACITY BY EACH LSE CATEGORY, 2017 TO 2022**

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|
| IOU | 91.86% | 99.42% | 98.75% | 98.62% | 98.13% | 98.04% |
| CCA | 2.51% | 0.46% | 1.13% | 1.20% | 1.67% | 1.75% |
| ESP | 5.64% | 0.11% | 0.12% | 0.17% | 0.20% | 0.21% |

Table 9 depicts the percentage of total actual (or expected) local requirements met by contracts held by the three LSE categories. The breakdown of procurement by CCAs and ESPs in 2017 roughly matches the aggregate 2017 load ratio shares of CCAs and ESPs , which is expected. Yet, there is significant over-procurement by IOUs in 2017 (again, partly due to the need for system capacity), and the proportional drop in procurement by CCAs and ESPs one year out is much greater than the drop in procurement by IOUs. This suggests that CCAs are engaging in a lower level of long term local procurement for their existing load.

**TABLE 9: PERCENTAGE OF TOTAL LOCAL REQUIREMENTS UNDER CONTRACT BY EACH LSE CATEGORY, 2017 TO 2022**

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|
| IOU | 124.27% | 95.00% | 94.79% | 86.31% | 78.22% | 72.22% |
| CCA | 3.39% | 0.44% | 1.08% | 1.05% | 1.33% | 1.29% |
| ESP | 7.62% | 0.11% | 0.12% | 0.15% | 0.16% | 0.15% |

# 5. Proposed Solutions

As discussed in the previous section, a number of issues have emerged since the 2014 report. First, retail choice, by way of CCA growth and expansion, has increased the number of procurement entities (from 19 LSEs to a projected 36-39) and complicated LSE procurement efforts, including local sub-area contracting. In addition, for the 2018 compliance year, there were 11 LSE local and system waiver requests, with three RMR designations and two annual CPM designations, highlighting the inefficiencies in the local RA procurement framework. Finally, the revised analysis of current multi-year contracting indicates that relative to estimated RA requirements, less capacity is under contract in the one- and two-year ahead time frame, perhaps in part due to load migration uncertainty.

In the remainder of this section, staff explores potential solutions to address the emerging issues that have arisen in the past year – most notably, considerable load migration and an increase in backstop procurement at prices higher than average RA prices – and recommends potential courses of action. At the same time, staff recognizes that existing policies and requirements must be considered, including the State's loading order (as implemented by the Commission's policies on preferred resources), Senate Bill 350 and its implementation through the IRP proceeding, and existing procedural rules for Commission review of LSE procurement efforts. Prior to laying out the two potential procurement frameworks, staff outlines below some broad multi-year considerations that would apply to either framework.

## 5.1 IRP Coordination

Staff recognizes that all RA procurement efforts will need to be coordinated with IRP planning efforts. The pending IRP Proposed Decision adopts a reference system plan that guides procurement planning efforts necessary to achieve SB 350 GHG reduction goals. This reference system plan would be refreshed every two years, and LSEs would be 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.*[118]

For all of the solutions proposed below, staff recommends close coordination with the IRP process. The integrated resource plans filed by LSEs will need to be coordinated with any multi-year local procurement, should such a framework be adopted.

## 5.2 IRP Studies Regarding Existing Gas Fleet

[118] IRP PD, R.16-02-007, pp. 74 – 75

The IRP Proposed Decision addresses the reference system plan's interaction with the existing gas fleet. It is worth noting that the RESOLVE model assumes that the existing natural gas plants will remain available through the modeling period (with the exception of the OTC retirements and other planned retirements). Staff has identified that there is a need to refine this assumption in future IRP cycles:

> *[B]ecause the RESOLVE model handles classes of resources and not individual plants, and because the expiration of the ITC and PTC would drive early procurement of solar and wind resources, lowering utilization of the natural gas capacity in the near term prior to retirement of the Diablo Canyon nuclear plant in the medium term, staff recommended that more analysis was needed to identify the types of gas plants, or plant attributes, that are most desirable and most needed for reliability. Further work was also identified as needed on how to design procurement or contractual mechanisms to support sustaining the desirable natural gas plants and characteristics in the near and medium term to support attainment of the 2030 GHG target sector wide at least cost while maintaining reliability.*
>
> *Commission staff proposed to work with the CAISO to study options for ensuring ongoing viability for renewable integration and resource adequacy/reliability purposes.*[119]

Given these results and the emerging RA capacity backstop issues that have arisen in 2018, it is likely that a joint agency analysis will be needed to assess the critical generation resources necessary for long-term grid reliability. Staff recommends that in the absence of such an analysis, the CAISO should coordinate with the CEC and the CPUC to develop a list of resources available to meet local reliability needs. Such a list would support both of the potential frameworks discussed below. It would be similar to the lists already developed by the CAISO as part of its local capacity requirements study, but possibly modified to include each resource's flexible operating characteristics (needed for renewable integration), among other attributes. A transparent list of resources that meet overlapping Commission goals will help to ensure local reliability while supporting the attainment of other SB 350 targets.

## 5.3 Potential RA Framework Changes to Address Emerging Issues

Below, staff presents two different RA frameworks to address some of the issues that have arisen in the RA program over the past year: (1) a multi-year local RA framework with the distribution utilities as the central buyer for residual local RA requirements, and (2) a multi-year local RA framework with all LSEs responsible for multi-year local RA resource procurement.

### 5.3.1 Solution 1: Multi-Year Local RA Framework with Distribution Utilities as Central Buyer for Residual Local RA Requirements

This proposal would include multi-year local RA requirements with the IOUs as central buyers for residual local RA resources, as follows:

[119] IRP PD, R.16-02-007, pp. 116-117.

- Multi-year local requirement, two to five years forward
  - 100% local requirement two years forward
  - 80% minimum local requirement three to five years forward
- Central buyer: The IOU for each TAC area would be assigned the responsibility for residual local RA procurement in their service area.

The distribution utility for each service area would be authorized to use a Cost Allocation Mechanism to allocate net capacity costs to all benefiting LSEs in their service area. The key components of this proposal are discussed below.

**Inputs to Multi-Year Local RA Requirements** – On or around May 1st of each year, the CAISO issues its one-year forward and five-year forward Local Capacity Technical Reports. The CPUC considers the one year forward study in setting the local RA requirements for the coming compliance year. Staff proposes that in addition to adopting a one-year forward study, the Commission also adopt the five-year forward study to be used in setting potential multi-year local requirements. However, it would be optimal for the local study period used for setting multi-year requirements to align with the year for which they are being set. In the event that CPUC adopts a multi-year local framework that looks less than five years ahead, staff recommends that CAISO modify its long-term Local Capacity Technical Report to align with the adopted framework.

Staff proposes that the inputs and assumptions of the five year ahead study be evaluated to ensure that they are coordinated with the goals specified in SB 350. For example, the inputs and methodology used in the study may need to be modified to accurately account for the SB 350 goal of doubling of energy efficiency. The current 2022 study is based on the final adopted California Energy Demand Updated Forecast 2017-2027 developed by the CEC, using the mid-demand baseline and low-mid additional achievable energy efficiency (AAEE). It may be more appropriate to use a higher AAEE assumption for the five-year forward study. In addition, staff proposes that any additional demand-side local reliability procurement[120] and any other behind-the-meter procurement in local areas be incorporated into the CEC's IEPR load forecasts to ensure that additionally authorized (but not yet operational) demand side resources will appropriately offset future RA requirements in the associated local areas.

**Multi-Year Local RA Requirements –** Staff proposes to utilize the CAISO's Local Capacity Technical Report process and to consider adopting a 100% two-year forward local requirement based on the one-year forward Local Capacity Technical Report and a minimum 80% three to five year forward local requirement based on the long-term Local Capacity Technical Report.  Staff is proposing a range of three to five years as a starting place for future discussions with parties.

[120] As was authorized by D.13-02-015 and D.14-03-004 and approved by D.15-11-041 for (local reliability in the Western LA Basin and Moorpark sub-local areas)

For the long-term Local Capacity Technical Report, staff proposes that the study assumptions be vetted through a CPUC stakeholder process to ensure close coordination with the IRP system reference plan. Staff proposes to adopt local requirements for only the CPUC-jurisdictional LSEs. As noted above, in the event that CPUC adopts a multi-year local framework that looks less than five years ahead, staff recommends that CAISO modify its long-term Local Capacity Technical Report to align with the adopted framework.

**Local Procurement Coordination Between LSEs –** Following the Commission's adoption of the short-term and longer-term local reliability requirements, staff proposes that LSEs meet and coordinate existing local procurement. In order to assess existing LSE procurement in each local area, it will be necessary for all LSEs to coordinate their local procurement with the distribution utility for each service area. Staff proposes that all ESPs and CCAs currently serving load or planning to serve load in the distribution service area report all local resources owned or under contract (and available to the CAISO for dispatch) to the CPUC and/or the distribution utility for the service area.

It will also be necessary for the utility that serves load to bundled customers in the distribution area to coordinate its local bundled procurement with distribution utility. Staff welcomes ideas from parties on how LSE procurement can be pooled together to develop one local portfolio for the entire service area. It should also be noted that bundled procurement rules required under AB 57 and PUC 454.5 do not apply to all LSEs; they only apply to IOUs.

**California Energy Commission Peak Demand Load Forecast –** Currently, the CEC provides the RA program with a short-term load forecast used to develop individual LSE adjusted peak load forecasts for the coming compliance year. In the proposed RA framework, two- to five-year forward load forecasts would likely be required in order to calculate each LSE's share of local RA requirements.

**Accounting for LSE Procurement –** In order to ensure equitable cost allocation, each LSE would be assigned its own balancing/tracking account (one per LSE per IOU) to track its prior, independent local resource procurement by local sub-area. This local capacity, having been identified by the LSE through the local procurement coordination process outlined above, would be deducted from its local sub-area responsibility. The LSE would be responsible for the costs of any capacity it had procured independently, as recorded in the LSE's balancing/tracking account, and the costs of future local procurement by IOUs would be allocated amongst LSEs according to the cost allocation methodology described below. At this time, it is not clear exactly how tracking accounts could be implemented. Staff welcomes parties' comments and ideas.

An alternative to the tracking process described above could be a buy-out process. This would require that any existing local RA contract be purchased by the distribution utility following the LSE procurement coordination process. These purchases (or transfers in the case of utilities' bundled local procurement) would be used to develop the distribution utilities' local portfolio position. Once this position is established, the distribution utility would issue its all source RFO to fill any residual local (including sub-local) needs.

**Annual Multi-Year Local Capacity Solicitation –** Staff proposes that two months after the local procurement coordination meeting between LSEs and the distribution utility, the distribution utility for each service area would hold an annual multi-year local capacity solicitation to meet multi-year RA requirements. An independent evaluator would be required for this solicitation. If the RA requirement were for less than five years, it is possible that this procurement could be pre-approved in a revised procurement framework or thorough an advice letter process.

**Development of a List of Generating Resources Needed to Maintain Reliability and Support Attainment of 2030 GHG Goals –** Staff proposes that CAISO would, in coordination with CEC and CPUC, develop a list of local resources with flexible operating characteristics and other needed attributes, to be used in guiding multi-year resource procurement. This list would be developed in the absence of a risk of retirement study described in the IRP coordination section above (Section 5.2).

**Coordination with the Current Year-Ahead RA Requirements –** The current RA construct requires that LSEs procure 100% of their annual local RA requirements before the beginning of the compliance year. Compliance filings demonstrating this procurement are submitted to the Commission and the CAISO on or around October 31st of each year. These year-ahead local requirements are allocated to LSEs net of CAM and RMR capacity credits (i.e., capacity already contracted for through existing centralized procurement mechanisms).

Under this proposal, the multi-year RA requirements would require the distribution utilities to procure a minimum 80% of local resource adequacy requirements from three to five years ahead and 100% of local requirements two years ahead. In short, the one-year ahead 100% local requirement would be expanded to two years, meaning LSEs would not be required to make annual local RA compliance showings. The distribution utility would be assigned the responsibility for making this showing to the CPUC and the CAISO.

Because system and flexible RA benefits are often bundled, it will be necessary to coordinate any additional RA benefits that result from multi-year local procurement, with the year-ahead and month-ahead procurement processes. As is currently done with CAM credits, LSEs would be allocated system and flexible capacity credits count towards meeting their year-ahead and month-ahead system and flexible obligations.

**Compliance with Multi-Year RA Requirements –** Staff proposes that the existing citation program be extended to the multi-year RA framework and hopes to further refine this element in the next iteration of this framework.

**Market Power Mitigation –** Staff recognizes the potential for considerable market power, given that resource procurement will be for transmission-constrained local sub-areas, where competition largely does not exist. To mitigate the risk of generators exercising this market power in the competitive solicitation process, staff recommends a price cap at or below the CAISO's CPM soft offer cap. If prices exceed this cap, then the procurement obligation would need to be waived and the procurement would take place either in a future year, which would allow time for additional LSE procurement, or under CAISO backstop authority, which would ideally limit cost recovery to the cost of service.

**Capacity Procurement Mechanism –** The CAISO currently has an annual CPM process, including a CPM risk-of-retirement process. Staff recommends that the annual CPM process remain annual and not be expanded to include the multi-year RA framework, which would avoid costly contracts that may not be necessary if new resources offer into the following year's solicitation. In addition, staff proposes that the cost allocation for the CAISO CPM be revised to exclude stranded capacity costs and to only include going-forward fixed costs, based on a cost-of-service framework, with LSEs assigned the cost responsibility in proportion to the benefit they receive. This will limit the incentive for generators to utilize backstop mechanisms, instead of bilateral procurement, as a way of getting a higher capacity payment. CAISO has recently opened a stakeholder process – "Review of Reliability Must-Run and Capacity Procurement Mechanism"[121] – to review the reliability must-run tariff, agreement, and process, and will seek to clarify the differences between RMR procurement and backstop procurement under the CPM. Staff proposes incorporating this proposal into this stakeholder process.

**Filing Timeline -** The filing due date for the two-year showing would be the same as the current timeline for year-ahead filing (around October 31st). The three to five years ahead minimum 80% showing could be set on or around January 1st which would provide a longer procurement period for the distribution utility.

**Cost Allocation –** Since multi-year local procurement would benefit all customers in the distribution utilities service area, the total net capacity costs would be allocated to all benefiting customers. Staff proposes using the Commission's Cost Allocation Mechanism (CAM), 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. Under PUC Section 365.1(c)(2), the Commission has the authority to:

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[121] http://www.caiso.com/informed/Pages/StakeholderProcesses/Review_ReliabilityMust-Run_CapacityProcurementMechanism.aspx

*(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…*

As described above, the CAM currently allocates the net capacity costs of the contract. However, staff proposes that if an LSE provides the distribution utility any local procurement contracts during the annual coordination process described above, then these contracts will be used in calculating each LSE's portion of the costs. At this time, it is not clear exactly how this could be implemented. Staff welcomes parties' comments and ideas.

Alternatively, under a buy-out process the need to track individual LSE procurement would not be necessary. The distribution utility would buy existing local contracts directly from LSEs prior to issuing a multi-year RFO. All net capacity costs associated with local procurement (either LSE procurement or RFO procurement) would be allocated consistent with PUC Section 365.1(c)(2).

**Advantages and Disadvantages of Centralized Distribution Utility Local Procurement**

Some of the advantages of centralized distribution utility local procurement include the following:

- Ensures that sufficient capacity is procured to meet local capacity needs for the next three to five years. In so doing, centralized procurement reduces the likelihood that strategically located local resources will be mothballed or retired.
- Allows the distribution utilities to utilize purchasing power in constrained local areas, thereby helping to ensure the least-cost solution for all customers, bundled and non-bundled.
- Allows the CPUC to ensure that local reliability procurement will be coordinated with California's SB 350 policy goals, least-cost best-fit principals, and preferred resource procurement mandates.
- Mitigates the need for potential expensive backstop procurement in the local sub-areas.
- Addresses the issue of load uncertainty associated with multi-year RA requirements and stranded costs.

Some of the disadvantages of centralized distribution utility local procurement include the following:

- Difficulty in tracking cost responsibility for LSEs that self-provide. An alternative buy-out process could eliminate this difficulty. However, it would present the challenge of determining an appropriate buy-out price for each existing local contract.
- Allocation of capacity credits could be administratively burdensome.
- Requires additional work by CEC staff to develop two to five year forward LSE peak load forecasts. In addition, the multi-year requirements may necessitate additional work by CAISO staff to modify its long-term Local Capacity Technical Report processes.
- The proposal does not address outage replacement costs or transmission and distribution alternatives to local capacity requirements.

### 5.3.2 Solution 2: Multi-Year Local RA Framework with LSEs Responsible for Multi-Year Local RA Resource Procurement

Like Solution 1, Solution 2 would also impose a minimum 80% local requirement three to five years out and a 100% requirement two years out, but individual LSEs would each be assigned the responsibility for meeting their own multi-year local RA requirements.

**Determination of Multi-Year Local RA Requirements -** Multi-year local requirements would be set in the same manner as described for Solution 1.

**Local Area Disaggregation -** The CAISO's backstop authority is determined based on the reliability needs in each local sub-area. Local procurement requirements were originally aggregated to mitigate market power in local sub-areas. Traditionally, the IOUs have procured to the sub-local level to avoid expensive CPM procurement costs. Smaller LSEs have not procured to each sub-local requirement, and there has thus been historical natural leaning. However, as IOUs lose load share to CCAs, it will make less sense for them to procure sub-local area resources. Therefore, to address potential leaning and out-of-market backstop procurement, disaggregation of local area requirements will likely be necessary.

**Development of a List of Generating Resources Needed to Maintain Reliability and Support Attainment of 2030 GHG Goals -** Same as Solution 1.

**Compliance with Multi-Year RA requirements -** Same as Solution 1.

**Filing timeline -** Same as Solution 1.

**Advantages and Disadvantages of Multi-Year Local Procurement Requirement for all LSEs**

Some of the advantages of multi-year local requirements for all LSEs include the following:

- Ensures that sufficient capacity is procured to meet local capacity needs for the next three to five years.
- No additional administrative burden from allocating capacity credits. Each LSE would have its own procurement responsibilities, so there would be no need to allocate capacity credits. Additionally, there would be no need for LSEs to meet and coordinate with the distribution utilities regarding local procurement.
- LSEs remain the sole buyer for their portion of local capacity requirements.
- Mitigates potential back stop procurement by the CAISO.
- No administrative burden on the distribution utility to track local procurement by LSE.
- The distribution utility would not be burdened with the financial responsibility to procure multi-year contracts for its entire service area.

Some of the disadvantages of multi-year local requirements for all LSEs include the following:

- Load uncertainty two to five years ahead (as well as load migration occurring after initial procurement) may lead to difficulty in allocating (and re-allocating) the local RA requirements to LSEs equitably. As discussed in the emerging issues section of the report, load uncertainty is difficult, even in the current year-ahead timeframe. Load uncertainty may lead to additional stranded cost issues.
- Load uncertainty will also make it challenging to allocate the current capacity credits (CAMs, RMR, and DR) because these credits are based on load ratio shares. If load ratio shares change drastically from year to year, there are is drastic changes to capacity credits, which leads to uncertainty regarding future RA obligations.
- A multi-year forward capacity responsibility will burden LSEs with costs before they know their load even further into the future, and thus threatens their financial viability.
- Market power may affect smaller LSEs with little purchasing power, which could lead to increased backstop procurement by the CAISO and potential market failure.
- As in Solution 1, the multi-year requirements will necessitate additional forecasting work by CEC and may necessitate additional forecasting work by CAISO.
- As in Solution 1, this solution does not address outage replacement costs or transmission and distribution alternatives to local capacity requirements.

## Appendix 1: Summary of Data Request

The data request cover letter appears below. Figures A1 and A2 on subsequent pages provide the data request instructions and Excel input template.

*Dear Load Serving Entity Representative,*

*The California Public Utilities Commission (CPUC) is requesting information about your generator contracting positions. In Commissions decision (*D.16-01-033*), regarding the Joint Reliability Plan (JRP), the Commission ordered Energy Division to "gather and disseminate information regarding expected electric resource availability and forward contracting of such resources, and make such information available to the public."*[122] *This data request seeks information consistent with D.16-01-033 and with the subpoenas served to LSEs in May 2014 (used to develop the* JRP Track 1 Staff Report*).*

*Please fill out the attached Microsoft Excel spreadsheet according to the instructions contained in the respective tab. Please include, by month, the system, local and flexible capacity amounts under contract for each resource. Please provide information for all resources including conventional generation, renewable, Demand Response and storage resources that are owned, in whole or in part, by the LSE or under contractual commitment to the LSE for all or a portion of its capacity.*

*Please do not include information related to the sale of capacity to other parties. Please provide information for system, local and flexible capacity amounts by month consistent with existing reporting obligations to the CPUC's Resource Adequacy program, assuming the current definitions are in place for the next 10 years. The CPUC is requesting this information for each month starting in January 2017 through December 2027.*

*For units that are under contract, but are not yet on-line, please provide all information in the worksheet "Contracted Resources" and select "Not COD" at the top of the drop down list in the Resource ID column. For IOU contracts please indicate if the contract is awaiting CPUC approval in "CPUC Approval" column. List "Y" if it is awaiting CPUC approval and leave blank if it is not. For all other LSEs, please leave this column blank. For resources that will increase their capacity over time, please specify the resources maximum nameplate capacity.*

*If you claim that any documents or information requested is confidential or market sensitive as set forth in D.06-06-066, including in the IOU or ESP Matrix attached as Appendix 1 and 2 to D.06-06-066, please produce the requested documents and information with appropriate confidentiality markings and explain the basis for the confidentiality claims. Electronic files shall be named to indicate their confidentiality in the file name (e.g., "LSEData_LSENAME_2015Nov20_CONFIDENTIAL.xlsx").*

*Please return the completed data request by Friday, April 3, 2017. Send completed data via secure FTP to the CPUC using the instructions attached to this email.*

[122] D.16-01-033 *OP 4*

- *Email to: jrg@cpuc.ca.gov*
- *Use Subject: LSE Data Request Reply*
- *Rename Template: LSEData_LSENAME_DATE.xlsx*

*If you have any concerns or objections regarding this request please email jrg@cpuc.ca.gov immediately. For additional questions, please contact jrg@cpuc.ca.gov.*

*Thank you for your support.*

## FIGURE A1: EXCEL TEMPLATE INSTRUCTIONS FOR DATA REQUEST

| | |
|---|---|
| **Instructions** | Please include, by month, the system, local and flexible capacity amounts under contract for each existing resource on the "Contracted Resources" tab and the "Owned Resources" tab. Please provide information for all resources including conventional generation, wind, solar, DR or storage resources that are owned, in whole or in part, by the LSE or under contractual commitment to the LSE for all or a portion of its capacity. Please do not include information related to the sale of capacity to other parties. Please provide information for system, local and flexible capacity amounts by month consistent with existing reporting obligations to the CPUC's Resource Adequacy program. The CPUC is requesting this information for each month starting in January, 2017 through December 2027. For units that are under contract, but are not yet on-line, please provide all information in the worksheet "Contracted Resources" and select "Not COD" at the top of the drop down list in the Resource ID column. For IOU contracts please indicate if the contract is awaiting CPUC approval in "CPUC Approval" column. List "Y" if it is awaiting CPUC approval and leave blank if it is not. For all other LSEs, please leave this column blank. For resources that will increase their capacity over time, please specify the resources maximum nameplate capacity. |
| **LSE Name** | Please enter or select the name of the LSE (Load Serving Entity) that the resource is under obligation to. |
| **Resource ID** | Enter/select from the drop-down menu. If a resource has not yet been assigned an ID select "No COD". Although a single contract can include multiple resources enter1 Resource ID per cell. E.g., 4 rows will be entered for a contract including 4 resources. |
| **Contract ID** | The Contract ID is the LSE's unique contract identifier. Although a resource can be under obligation to more than 1 contract at a time, enter 1 Contract ID per cell. E.g., if a single resource holds 3 different contracts, 3 rows will need to be entered. |
| **Resource Name** | Name of resource. Indicate specific units under contract if applicable. |
| **CPUC Approval** | For IOU contracts please indicate if the contract is awaiting CPUC approval. List "Y" if the the contract is awaiting CPUC approval or leave blank if it is not. For all other LSEs, please leave this column blank. |
| **Unit Type** | Please enter or select the resource's unit type from the drop-down menu. Unit type refers to the resource's technology. |
| **Fuel Type** | Please enter or select the resource's fuel type from the drop-down menu. |
| **Balancing Area** | Enter or select from the drop down menu whether the resource is in the CAISO's balancing authority (in CAISO) or outside of it (other). |
| **Other Balanceing Area** | If the resource is outside of the CAISO's balancing area enter what balancing area it is in. |
| **Nameplate Capacity** | Enter the resource's nameplate capacity value (MW). The nameplate capacity is the maximum rated output of the unit. |
| **Year** | Pleasd select a year from the drop-down menu. |
| **Month** | Please select a month from the drop-down menu. |
| **System Capacity (MW)** | Enter the amount of system capacity (MW) under contract by month, where applicable. A resource contracted for flexible capacity that is in a local area counts not only for flexible but also local and system capacity. |
| **Local Capacity (MW)** | Enter the amount of local capacity (MW) under contract by month, where applicable. A resource contracted for local capacity also counts towards system capacity. E.g. 6 MW of local capacity will also contribute 6 MW to system capacity. |
| **Flexible Capacity (MW)** | Enter the amount of flexible capacity (MW) under contract by month, where applicable. A resource contracted for flexible capacity also counts towards system capacity. E.g. 3 MW of flexible capacity will also contribute 3 MW to system capacity. |

## FIGURE A2: EXCEL DATA ENTRY TEMPLATE

| LSE Name | Resource ID | Contract ID | Resource Name | CPUC Approval | Unit Type | Fuel Type | Location | Balancing Area | Other Balancing Area | Nameplate Capacity | Year | Month | System Capacity (MW) | Local Capacity (MW) | Flexible Capacity (MW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
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# Appendix 2: Quality Assurance and Data Handling Procedures

This appendix expands upon the "Methodology" section of the report. It describes various quality assurance and data handling procedures performed on the contract information received from LSEs and, in some cases, on internal CPUC data that augmented the LSE responses. The appendix discusses these procedures by topic, beginning with changes to raw data submitted by LSEs and concluding with nuances in each of the main analytical areas: system capacity and local capacity. Throughout the report, staff attempted to treat data consistently with how capacity is counted in the various RA compliance areas – approximation of RA compliance processes was the impetus behind many of the quality assurance and data handling procedures described below.

## A2.1 Quality Assurance on Contract Data

In a handful of instances, staff removed duplicate contract information that LSEs had erroneously reported (that is, where a given contract for a given resource in a given month was reported more than once). In some cases, it was apparent that a given resource was "over procured" in a given month, even when no duplicate contracts appeared in the data. This is a result of the gap between data collection in April and subsequent year-ahead and month-ahead contracting activity, which might change the terms of certain contracts as LSEs sell capacity to one another. For August 2017 and August 2018, it was possible to amend these instances of over procurement by comparing LSEs' responses to actual RA filings.[123] Staff did not check to for over procurement of each resource in each month, though staff did identify individual instances to correct in the process of ensuring that contracted system capacity by fuel type in August of each year did not exceed available system capacity by fuel type in August of each year.

As discussed in the Methodology section of the report, LSEs reported system and local capacity contracted from wind and solar resources using the exceedance methodology[124] for determination of Net Qualifying Capacity (NQC), which was retired in 2017. System and local capacity values in 2017 contracts for these resources were left alone, as these were the values used to ensure compliance with 2017 requirements. Capacity values for 2018 and future years, however, were adjusted by applying the newly-adopted effective load carrying capability (ELCC) factors for wind and solar resources to the nameplate capacity of those resources using the following logic:

1. If the LSE had contracted with the resource in the same month during 2017, the contracted capacity in the given month and year was calculated as [resource's nameplate capacity] * [monthly ELCC factor] * ([contracted capacity for the same month in 2017] / [resource NQC for the same month in 2017]). This adjustment was made because LSEs do not always contract for a resource's full capacity, and neglecting to account for this would result in apparent over procurement of the given resource in a given month and year.

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[123] Staff focused on August specifically because CAISO annual system peak usually occurs in this month and because annual flexible capacity requirements are based upon August load forecasts.

[124] For an explanation of the exceedance methodology for calculating the NQC of wind and solar resources prior to 2018, see the *Qualifying Capacity Manual Adopted 2015* at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9187.

2. If the LSE had not contracted with the resource in the same month during 2017, or if the resource did not have an NQC value for the same month in 2017, staff assumed that the LSE had contracted for the resource's entire available capacity, and contracted capacity in the given month and year was calculated as [resource's nameplate capacity] * [monthly ELCC factor]. This was a reasonable assumption because in all cases, a single LSE had reported contracts with the resource in question.

3. LSEs reported contracts with a handful of wind and solar resources that were not yet online and which therefore did not have available NQC values in 2017 or 2018. In all cases, only one LSE had contracted with a given resource in a given month and year. Thus, staff assumed that relevant LSE had contracted for 100% of the resource's available capacity, and the contracted capacity in the given month and year was calculated as [resource 's nameplate capacity] * [monthly ELCC factor].

The nameplate capacity of most resources was available either in LSE responses or from the 2017 and 2018 Master CAISO Control Area Generating Capability Lists.[125] In the few instances where LSEs reported wind and solar resources that were not yet constructed and for which nameplate capacity values were not immediately available, staff used the highest contracted capacity for the resource in any month throughout the study timeframe as a proxy for nameplate capacity. This method understates available capacity from the affected resources, particularly after application of ELCC factors for 2018 and future years. Although the affected resources do not represent a significant amount of capacity, results for wind and solar resources in this report should be treated as conservative estimates more so than should results for other physical resources.

As discussed in the Methodology section, staff included some additional information from recent RA filings and from capacity allocation procedures to fill in data gaps and thus to make more accurate comparisons of available and contracted capacity. Some LSEs did not include 2017 contracts for the Demand Response Auction Mechanism (DRAM) or for utility-run demand response programs, and staff subsequently incorporated this information using August 2017 RA filings. Staff incorporated capacity for DRAM and utility-run demand response in 2018 using year-ahead allocations that were completed after the data collection. Staff also incorporated contracts for behind-the-meter (BTM) demand response and solar resources in the Western LA Basin pursuant to D.15-11-041,[126] which did not appear in the LSEs' data responses. Staff did not incorporate information for any of the four LSEs that did not respond to the initial data request.

Finally, staff compared generator fuel types in the respondent data to fuel types in the 2017 and 2018 Master CAISO Control Area Generating Capability Lists and made changes to respondent data where appropriate. LSEs may purchase RA capacity at interties with service areas outside the CAISO control area, for which the exact source of generation is not known in advance. In these cases, staff recorded

[125] The most recent Master CAISO Control Area Generating Capability List is available at http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx.
[126] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K064/156064924.PDF

the fuel type as "Import." Due to transmission system dynamics and the activities of scheduling coordinators outside of the CAISO system, it is impossible to determine the extent to which imports contain energy converted from solar and wind resources. Thus, where they are included in the analysis, these capacity values have not been adjusted by ELCC factors, which aligns with how imports are treated for RA compliance. In order to focus the analysis on units physically located within the CAISO area, staff also denoted the fuel type of any physical resource located outside the CAISO area as "Import," even if the unit is partially owned by a CPUC jurisdictional LSE or is otherwise scheduled into the CAISO markets on a regular basis. Solar and wind capacity from these units was not adjusted by ELCC factors, as the units do not have individual NQC values and are treated as imports for RA compliance. Where necessary, these units are specifically identified in the report.

## A2.2 Treatment of System Capacity

Staff estimated available system capacity in each year using several sources. From 2019 on, available system capacity in each year was derived from baseline estimates in the RESOLVE model used in the ongoing CPUC IRP (R.16-02-007). These baseline estimates include existing conventional generation, renewables (biomass, geothermal, small hydro, solar, and wind), demand response, and limited energy storage resources (LESR), and they account for both the established – or predicted – online dates of known resources and the established retirement dates of conventional generators. Staff used 2018 NQC values for baseline conventional generation capacity (or the 2017 NQC value if the unit was scheduled to retire in 2017); these values should not change significantly in subsequent years. Staff also converted the nameplate capacity of wind and solar resources to August ELCC values using the appropriate ELCC factors. Demand response capacity was increased by 15% in the analysis to align with treatment of demand response in system RA compliance procedures.[127]

Available capacity in 2017 is the sum of capacity values from the following resources: (1) the 2017 NQC list, (2) 115% of capacity for DRAM and utility-run demand response programs, both of which were derived from year ahead RA allocations to the LSEs,[128] and (3) contracts for BTM demand response and solar resources in the Western LA Basin that were active in 2017, including an additional 15% for demand response resources. Notably, because the ELCC methodology for wind and solar resource had not been adopted by the RA program in 2017, capacity values for wind and solar resources in 2017 are based upon the former exceedance methodology. The methodology for estimating available capacity in 2018 is analogous to that of 2017 and represents the sum of capacity values from the following resources: (1) the 2018 NQC list, (2) 115% of capacity for DRAM and utility-run demand response programs, both of which were derived from year-ahead RA allocations to the LSEs, and (3) contracts for

[127] See below for a more detailed explanation of the 15% adder for demand response. For more information on ELCC and treatment of demand response resources in RA compliance generally, see the *2018 Final RA Guide* at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454920.

[128] Although the NQC list provides the qualifying capacity of DRAM resources, it does not currently provide local designations for those resources. CPUC allows DRAM resources to count towards local RA requirements via CAM credits, which are allocated by local area. (CAISO intends to begin crediting these resources toward local capacity requirements beginning in 2018.) Thus, staff incorporated available DRAM capacity into the analysis using the year ahead CAM allocations and ignored DRAM resources in the NQC lists.

BTM demand response and solar resources in the Western LA Basin, including an August ELCC adjustment for solar resources and an additional 15% for demand response resources.

Staff also augmented contracted capacity from demand response resources by 15% in the system analysis. Since demand response resources reduce load behind the meter, they eliminate the 15% planning reserve margin associated with their capacity, in addition to contributing directly towards RA requirements. Therefore, available and contracted demand response capacity values must receive a 15% upward adjustment to ensure a level comparison of total available capacity, total contracted capacity, and system RA requirements in California.

The RESOLVE baseline data that staff used to estimate available capacity do not specify whether incremental renewable and storage resources will be located north of Path 26 or south of Path 26. Therefore, staff used the 2018 NQC list to calculate separately the proportion of existing geothermal, biomass, hydro, wind, and solar capacity located north and south of Path 26 to distribute relevant baseline capacity for these resource types in the RESOLVE model between the two regions in each year. This calculation assumes that the distribution of each resource type north and south of Path 26 will not change significantly between 2018 and 2027. Staff used the total procurement targets presented in D.13-10-040, Appendix A at 2 to distribute baseline storage capacity between the two regions.

## A2.3 Treatment of Local Capacity

Staff intended for the available and contracted capacity totals in the local capacity section of the report to include only those resources physically located in a local reliability area (and thus available to meet local RA requirements). This was relatively straightforward for contracted capacity, as the location of physical resources is established, and CPUC allocates the capacity of utility-run demand response programs by local area. As in the system capacity section of the report, staff calculated available local capacity in 2017 and 2018 as the sum of (1) NQC values from the given year's NQC list, (2) capacity of DRAM utility-run demand response programs, based on year-ahead allocations, and (3) contracts for BTM demand response and solar resources in the Western LA Basin (if applicable), including an August ELCC adjustment for solar resources in 2018. Demand response capacity values did not receive an additional 15% in the local analysis, as the planning reserve margin does not apply to local resource adequacy.

Staff derived available local capacity from 2019 onward using the RESOLVE baseline data. For geothermal, biomass, small hydro, wind, and solar resources, available local capacity in a given year and a given local area was calculated as follows:

1. [total capacity in the RESOLVE baseline for the resource type in that year, including an August ELCC adjustment for wind and solar] * ([total 2018 NQC for units of the resource type in the local area] / [sum of 2018 NQC for all units of the resource type])

Available local demand response capacity in a given year and a given local area was calculated as follows:

2. [total demand response capacity in the RESOLVE baseline] * ([total 2018 demand response capacity in the local area, including utility-run programs and DRAM] / [total demand response capacity in that year, including utility-run programs and DRAM])

These calculations assume that the relative distribution of renewable capacity and demand response capacity inside and outside local areas will not change significantly between 2018 and 2027.

As described in the report, the purpose of analyzing local capacity here is to determine how much total capacity has been contracted from resources located in local reliability areas, not how much capacity has been contracted to meet local RA requirements specifically. The former gives a sense of whether these resources – which provide local transmission system benefits when they are running – are able to sell most of their available capacity within the RA framework, regardless of the nature of their capacity contracts (i.e. system or local). Although LSEs may contract different amounts of system and local capacity from the same resources in the same month, responses to the data request show that in such cases, system capacity almost always exceeds local capacity. In the few cases where contracted local capacity was substantially (greater than 5 MW) higher than contracted system capacity, staff determined that the local capacity values were incorrect based on unit ownership and on a comparison with 2018 year-ahead filings. For this reason, staff exclusively used contracted system capacity values in the local analysis.

## Appendix 3: Historical Local Area Requirements

Table A1 shows historical local area requirements from 2010 to 2018. The requirements for most local areas have remained relatively stable.

**TABLE A1: HISTORICAL TOTAL CAISO LOCAL AREA REQUIREMENTS (MW), 2010-2018**

| Area | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|
| **Humboldt** | 176 | 205 | 212 | 212 | 195 | 166 | 167 | 157 | 169 |
| **North Coast / North Bay** | 790 | 734 | 613 | 629 | 623 | 550 | 611 | 721 | 634 |
| **Sierra** | 2,102 | 2,082 | 1,974 | 1,930 | 2,088 | 2,200 | 2,018 | 1,731 | 1,826 |
| **Stockton** | 681 | 682 | 567 | 567 | 701 | 707 | 808 | 402 | 398 |
| **Greater Bay** | 4651 | 4,878 | 4,278 | 4,502 | 4,638 | 4,367 | 4,349 | 5,385 | 5,160 |
| **Greater Fresno** | 2,640 | 2,448 | 1,907 | 1,786 | 1,857 | 2,439 | 2,519 | 1,760 | 2,081 |
| **Kern** | 404 | 447 | 325 | 525 | 462 | 437 | 400 | 492 | 453 |
| **LA Basin** | 9,735 | 10,589 | 10,865 | 10,295 | 10,430 | 9,097 | 8,887 | 7,368 | 7,525 |
| **Big Creek/Ventura** | 3,334 | 2,786 | 3,093 | 2,241 | 2,250 | 2,270 | 2,398 | 2,057 | 2,321 |
| **San Diego** | 3,214 | 3,207 | 2,944 | 3,082 | 4,063 | 4,112 | 3,184 | 3,570 | 3,833 |

# Appendix 4: 2018 and 2022 Sub-Local Area Requirements

**TABLE A2: 2018 AND 2022 SUB-LOCAL AREA REQUIREMENTS**

| | | 2018 LCR Need Based on Category C | | | | 2022 LCR Need Based on Category C | | | |
|---|---|---|---|---|---|---|---|---|---|
| Local Areas | Sub-Areas | Resources Total (MW) | LCR Need Total (MW) | LCR Need/ Resource Total | Load Total (MW) | Resources Total (MW) | LCR Need Total (MW) | LCR Need/ Resource Total | Load Total (MW) |
| **Humboldt** | | 210 | 169 | 80% | 187 | 210 | 169 | 80% | 190 |
| | | | | | | | | | |
| **North Coast/North Bay** | | 869 | 634 | 73% | 1,333 | 869 | 440 | 51% | 1,249 |
| | Eagle Rock | 259 | 209 | 81% | | 259 | 233 | 90% | |
| | Fulton | 559 | 430 | 77% | | 559 | 411 | 74% | |
| | Lakeville | 869 | 634 | 73% | | 869 | 440 | 51% | |
| | | | | | | | | | |
| **Sierra** | | 2,125 | 2,113 | 99% | 1,818 | 2,125 | 1,967 | 93% | 1,814 |
| | Placerville | 30 | 78 | 257% | | 30 | 0 | 0% | |
| | Placer | 108 | 85 | 79% | | 108 | 77 | 71% | |
| | Pease | 105 | 101 | 96% | | 105 | 86 | 82% | |
| | Bogue | 92 | 0 | 0% | | 92 | 0 | 0% | |
| | South of Rio Oso | 740 | 787 | 106% | | 740 | 770 | 104% | |
| | Drum-Rio Oso | 674 | 575 | 85% | | 674 | 0 | 0% | |
| | South of Palermo | 1,429 | 1,625 | 114% | | 1,429 | 0 | 0% | |
| | South of Table Mountain | 2,125 | 1,826 | 86% | | 2,125 | 1,905 | 90% | |
| | | | | | | | | | |
| **Stockton** | | 605 | 719 | 119% | 1,169 | 605 | 702 | 116% | 1,035 |
| | Stanislaus | 204 | 158 | 77% | | 204 | 144 | 70% | |
| | Tesla-Bellota | 537 | 620 | 115% | | 537 | 643 | 120% | |
| | Lockeford | 23 | 68 | 300% | | 23 | 31 | 137% | |
| | Weber | 46 | 31 | 68% | | 46 | 28 | 61% | |
| | | | | | | | | | |
| **Greater Bay** | | 7,103 | 5,160 | 73% | 10,247 | 6,879 | 5,315 | 77% | 10,180 |
| | Oakland | 215 | 56 | 26% | | 215 | 50 | 23% | |
| | Llagas | 246.6 | 105 | 43% | | 247 | 24 | 10% | |
| | San Jose | 568 | 488 | 86% | | 568 | 111 | 20% | |
| | South Bay-Moss Landing | 2,408 | 2,221 | 92% | | 2,184 | 2,346 | 107% | |
| | Contra Costa | 2,186 | 1,063 | 49% | | 2,186 | 1,043 | 48% | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Ames and Pittsburg | 2,253 | 1,778 | 79% | | 2,253 | 1,758 | 78% | |
| | | | | | | | | |
| **Greater Fresno** | 3,579 | 2,081 | 58% | ***3,290*** | 3,579 | 1,860 | 52% | ***3,352*** |
| Hanford | 150 | 150 | 100% | | 150 | 148 | 99% | |
| Coalinga | 66 | 28 | 43% | | 66 | 32 | 49% | |
| Borden | 88 | 18 | 20% | | 88 | 19 | 22% | |
| Reedley | 8 | 19 | 250% | | 8 | 0 | 0% | |
| Herndon | 1,206 | 880 | 73% | | 1,206 | 852 | 71% | |
| Wilson | 3,579 | 2,081 | 58% | | 3,579 | 1,860 | 52% | |
| | | | | | | | | |
| **Kern** | 566 | 453 | 80% | 867 | 566 | 123 | 22% | 886 |
| Kern Oil | 122 | 133 | 109% | | 122 | 123 | 101% | |
| South Kern | 566 | 453 | 80% | | 566 | 0 | 0% | |
| | | | | | | | | |
| **LA Basin** | 10,735 | 7,525 | 70% | ***18,466*** | 8,138 | 6,022 | 74% | ***19,020*** |
| El Nido | 538 | 227 | 42% | | 538 | 0 | 0% | |
| Western | 6,354 | 3,621 | 57% | | 3,820 | 3,803 | 100% | |
| Eastern LA Basin | 4,166 | 2,361 | 57% | | 3,526 | 2,107 | 60% | |
| | | | | | | | | |
| **Big Creek/Ventura** | 5,657 | 2,321 | 41% | 4,804 | 3,860 | 2,597 | 67% | 5,020 |
| Big Creek | 3,323 | | | | 2,198 | | | |
| Rector | 1,006 | 515 | 51% | | 1,006 | 507 | 50% | |
| Vestal | 1,129 | 848 | 75% | | 1,129 | 848 | 75% | |
| Santa Clara | 811 | 250 | 31% | | 512 | 289 | 56% | |
| Moorpark | 2,334 | 504 | 22% | | 519 | 554 | 107% | |
| | | | | | | | | |
| **San Diego/Imperial Valley** | 4,915 | 4,032 | 82% | ***4,924*** | 4,572 | 4,643 | 102% | ***5,119*** |
| El Cajon | 101 | 75 | 74% | | 101 | 40 | 40% | |
| Mission | 4 | 28 | 757% | | 4 | 0 | 0% | |
| Esco | 163 | 8 | 5% | | 163 | 30 | 18% | |
| Pala | 105 | 23 | 22% | | 105 | 28 | 27% | |
| Border | 180 | 50 | 28% | | 180 | 62 | 35% | |
| Miramar | 96 | 0 | 0% | | 96 | 0 | 0% | |
| San Diego | 3,198 | 2,157 | 67% | | 2,840 | 2,502 | 88% | |