California Resource Adequacy Procedures, Community Choice Aggregators and Direct Access

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1. Introduction

Last year, in late August through late September, I posted a six-part series on The California Independent System Operator (CAISO). A link to the last paper in this (which contains links to the others) is below. This part-6 paper discussed how CAISO appeared to be evolving into a Western Regional Transmission Organization (RTO). Although I need to check into this evolution, and perhaps post a part-7, that is not what this paper is about. If you read the above title, it pretty well describes what this post is about, because a substantial change is in progress for all of these entities.

https://www.energycentral.com/c/pip/california-independent-system-operator-part-6-–-expansion

However, CAISO is heavily involved in this process, and when I started researching this subject, I quickly ran into a challenge that I dealt with continually when I was writing the CAISO series: a language problem. CAISO has their own language. Also, the other California regulatory bodies, utilities and other electric power entities tend to use this language. Thus, I quickly encountered a term I had never seen before. The term was TAC area. I scurried around the documents that used this looking for a translation of "TAC", and finally found it: "Transmission Access Charge", which didn't help a bit.

I needed to do other things, so I put my research aside until this morning (4/11), when I had time to track this down. I found it in a CAISO Glossary of Terms, which referred me to a specific location in the 2,700 page long CAISO Tariff, where I found the following beginning of a definition:

"TAC Areas (From CAISO Tariff, Appx F, Schedule 3, Section 3): TAC Areas are based on the Control Areas in California prior to the CAISO Operations Date. Three TAC Areas will be established based on the Original Participating TOs (transmission owners): (1) a Northern Area consisting of the PTO Service Territory of Pacific Gas and Electric Company and the PTO Service Territory of any entity listed in Section 3.3 or 3.5 of this Schedule; (2) an East Central Area consisting of the PTO Service Territory of Southern California Edison Company and the PTO Service Territory of any entity listed in Section 3.4, 3.5 or 3.6 (as indicated therein) of this Schedule 3; and (3) a Southern Area consisting of the PTO Service Territory of San Diego Gas & Electric Company. Participating TOs that are not in one of the above cited PTO Service Territories are addressed below…"

In other words "utility service areas". Now you know why I included a simplified glossary as the initial post (before 1 through 7) in my CAISO series. I also tried to avoid the use of specialized terms or acronyms, and/or defined them close to where I used these.

And I shall do the same in this post dear readers.

2. Current Regulations

The California electric utility infrastructure has been continually evolving since the first disastrous events around Y2K (a.k.a., "The Meltdown"). Although we continue to have problems, we continue to work on solutions. You will be pleased to know the problem we are trying to fix this time has nothing to do with wildfires or bankruptcy. Rather it is resource adequacy.

2.1. Resource Adequacy

Note that much of the text below is drawn from Part 2 of the CAISO Series. For you picky word-smiths (like me), note that I've carried forward the convention used in the CAISO Tariff of capitalizing words that have a specific meaning in this tariff. I've also put a link to the latest version of the CAISO Tariff in the reference at the end of this paragraph. Note that Appendix A of this document is a "Master Definition Supplement".[1]

Resource Adequacy is a long-term planning tool required by the California Public Utility Commission (CPUC) and the CAISO, implemented by Load Serving Entities (LSEs) and Metered Subsystems (MSSs).[2]

A Load Serving Entity (LSE) is an entity that either serves its own load or the load of others, planning capacity in advance of the demand. Those resources for this load service cannot be from another LSE.

There are two types of LSEs: California Public Utility Commission (CPUC) LSEs and Non-CPUC LSEs. CPUC Load Serving Entities include community choice aggregators, investor-owned electric utilities and electric service providers. These have a Resource Adequacy (RA) requirement from the CPUC: "*The Commission's RA policy framework – implemented as the RA program -- guides resource procurement and promotes infrastructure investment by requiring that LSEs procure capacity so that capacity is available to the CAISO when and where needed.*"

Non-CPUC LSEs are those entities that are outside of the CPUC's jurisdiction, and include federal power marketing authorities and Out-of- (the CAISO's) Balancing Authority Area Load Serving Entities (OBAALSE).

A Metered Subsystem is a geographically contiguous system located within a single zone which has been operating as an electric utility for a number of years prior to the CAISO Operations Date as a municipal utility, water district, irrigation district, state agency or federal power marketing authority subsumed within the CAISO Balancing Authority Area.

In order to protect System Reliability, a resource adequacy program should include seven basic elements:

1. A procedure for forecasting system conditions relating to Demand, including the forecast peak Demand

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[1] California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff, April 1, 2019, http://www.caiso.com/Documents/ConformedTariff-asof-Apr1-2019.pdf
[2] California Public Utility Commission, Resource Adequacy Homepage, http://www.cpuc.ca.gov/RA/

2. A specified Reserve Margin – this is the amount of capacity over and above the predicted Demand that is necessary to provide adequate Operating Reserve and to account for Contingencies such as Generating Unit Outages and forecast error

3. Deliverability – this is a requirement based on Applicable Reliability Criteria that is designed to ensure that capacity needed to meet the Demand Forecast and the Reserve Margin is not constrained by transmission limitations when it is needed to serve Load. Local capacity requirements are also an important part of deliverability requirements.

4. Criteria for determining eligible resources and the amount of capacity able to satisfy the Reserve Margin

5. Plans developed by the LSEs that identify how they have met their resource adequacy requirements by assembling a portfolio of resources

6. Rules under which the resources identified in the plans are made available to the ISO Operator to balance Supply and Demand

7. A compliance program that ensures that LSEs comply with the resource adequacy program established by the Local Regulatory Authority and that precludes the LSE from inappropriately relying on the resource procurement practices of other Market Participants.

A primary method for LSEs and MSSs use to meet their resource-needs is via long-term power purchase agreements. I covered these in depth in Section 2 of a paper I posted several months ago. This is linked below.

https://www.energycentral.com/c/cp/future-grid-sun-wind-and-bess

2.2. Evolution of Load Serving Entities

A majority of California electric consumers are served by one or another type of Load Serving Entity (LSE). Furthermore the events that are encouraging legislators and regulators to change the rules regarding these entities mainly have to do with LSEs. Thus we cover these one type at a time in the subsections below, go through their evolution to date, and the likely direction they are moving in.

2.2.1. Electric Service Providers and Direct Access

Electric service providers (ESPs) and direct access were part of the original electric deregulation planned to occur around Y2K, but in the chaos that occurred thereafter these were allowed and disallowed several times for the following decade.[3]

Then in 2009, the state Legislature took the first step towards reopening retail competition in the California energy markets by enacting SB-695, which authorized the Commission to increase the allowable Direct Access kilowatt hour limit (allowance cap) for non-residential customers. Pursuant to SB 695, the CPUC, among other things, increased the allowance cap, established procedures for future adjustments of the allowance cap, developed a methodology to assign Resource Adequacy costs among

[3] CPUC, "Order Instituting Rulemaking to Implement Senate Bill 237 Regarding Direct Access and To Consider Changes to Existing Direct Access Procedures", 3/14/19, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M273/K116/273116603.PDF

Load Serving Entities, and implemented enrollment procedures to assign the increases to new Direct Access load during the phase-in period.

All LSEs must interact with CAISO through Scheduling Coordinators. Only Scheduling Coordinators that the CAISO has certified as having met its requirements may participate in the CAISO's Energy and Ancillary Services markets. There are detailed requirements for a Scheduling Coordinators (SC) as listed in the CAISO Tariff (mainly sections 4.5, 6.2, 10.3, Appendices B5 & B7) and the Business Practice Manual referenced below.[4]

One of the roles that electric service providers normally fulfill is to provide the SC function.

Recently the California Legislature has passed a bill, SB 237 that sets forth two main requirements. **First**, it adds Section 365.1(e) to the Public Utilities Code, which states:

On or before June 1, 2019, the commission (CPUC) shall issue an order regarding direct transactions that provides as follows: (1) Increase the maximum allowable total kilowatt-hours annual limit by 4,000 gigawatt hours and apportion that increase among the service territories of the electrical corporations. (2) All residential and nonresidential customer accounts that are on direct access as of January 1, 2019, remain authorized to participate in direct transactions.[3]

Second, SB 237 adds Section 365.1 (e) (1), which states:

On or before June 1, 2020, the Commission shall provide recommendations to the Legislature on implementing a further direct transactions reopening schedule, including, but not limited to, the phase-in period over which the further direct transactions shall occur for all remaining nonresidential customer accounts in each electrical corporation's service territory.

The above changes will result in a large number End Users (consumers) migrating from investor-owned electric utilities (IOUs) energy provision (a.k.a. bundled service) to provision of energy from electric service providers (a.k.a. direct access). IOUs would continue to provide transmission and distribution services.

2.2.2. Community Choice Aggregators (CCA)

In addition to the above, another main source of customers departing from California investor owned electric utilities are the community choice aggregators (CCAs).

Note that the decision referenced in the paragraph below, and referenced again later, is considered to be "Track 1" of the overall proceeding: " In general, *Track 1 issues are issues that needed to be resolved prior to 2019 (such as adopting Local Capacity Requirements (LCR) and Flexible Capacity Requirements (FCR) for 2019), or issues that are capable of being resolved early. In addition, Track 1 makes preliminary findings or policy determinations to provide guidance on issues to be addressed in more detail in Track 2 or Track 3.*

[4] CAISO Business Practice Manual, Scheduling Coordinator Certification and Termination, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Scheduling%20Coordinator%20Certification%20and%20Termination

In recent years, the number of CCAs in California has increased dramatically. In areas where CCAs are launching or expanding, customers are automatically defaulted into the CCA's service, resulting in a significant volume of electric load shifting from investor-owned utilities to CCAs. Further, CCAs have launched or expanded at times of the year that do not necessarily correspond with the year-ahead Resource Adequacy (RA) process. Without CCAs' participation in the year-ahead process, it was assumed that the departing load would continue to be served by utilities, and associated RA requirements were therefore assigned to those utilities, who then had to procure for that load. For example, by the end of 2017, the CPUC had approved 11 CCA implementation plans for launch or expansion in 2018, corresponding to over 3,100 MW, but none of this load migration was captured in the year-ahead RA process.[5]

The CPUC believes that participation in the year-ahead forecasting process by all LSEs who plan to serve load in the following year, including accurate forecasting of expanded territory or customer base, will ensure a more equitable allocation of the RA requirements, because the estimates of expected load will more closely match actual load in the following year. Therefore, the CPUC adopts this requirement. Requiring all LSEs to participate in all aspects of the year-ahead RA process for load they will serve in the following year will mitigate the cost-shifting issues that can result from misaligned timing of LSEs' formation or expansion and the year-ahead RA filing schedule.

In instances where the CAISO deems there is a "collective deficiency," the CAISO has an option under the Capacity Procurement Mechanism (CPM) to procure additional local RA capacity (backstop procurement). The costs of any additional capacity are allocated to the LSEs in the area where the deficiency occurs.

Under the current process, the CAISO allocates the cost of backstop procurement to only those LSEs that exist at the time when the allocation is made. Thus, if a CCA comes into existence after the allocation period, that LSE does not receive any allocation of the "collective deficiency" costs for the entire backstop capacity period. In turn, utilities that have since lost load (generally the investor owned utilities) receive a disproportionately larger share of the collective deficiency costs, which is ultimately shouldered by bundled customers.

In the future, all newly forming or expanding LSEs must provide more notice of their intention to serve new load, and therefore the Commission anticipates that they will receive appropriate backstop cost allocations based on that expected load.

3. Centralized Resource Procurement

Initially resource procurement was performed by a number large utilities, a somewhat larger number of small utilities, and a relatively small number of electric service providers. The first community choice aggregator (CCA) was Marin Clean Energy, which was certified in 2010. Currently the CPUC website for CCAs (link below) shows approximately 25 CCAs, and many of these are in the process of forming as noted above. Also many of these are likely to be very small.

http://www.cpuc.ca.gov/general.aspx?id=2567

[5] CPUC, "Decision Adopting Local Capacity Obligations for 2019 and Refining the Resource Adequacy Program", Decision 18-06-030, 6/25/2018, section 3.4.1, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M216/K634/216634123.PDF

After much discussion in Track 1 and Track 2, California is moving to centralized procurement of energy resources. Although this change is still in process, many of the attributes of this new system are defined. The following subsections suggest elements of this new system. The Track 1 decision is completed, but only provided an outline of this transition. Track 2 is in progress, and a decision is expected in the fourth quarter of this year.

3.1. Track 1

Note that the Track 1 Decision was issued in June of 2018. A reference with a link to this decision is at the end of the next paragraph. The remainder of this subsection are edited excerpts from this decision.

Weighing both the concerns and the potential benefits of moving to a central buyer, the CPUC believes that a central buyer system - for at least some portion of local RA - is the solution most likely to provide cost efficiency, market certainty, reliability, administrative efficiency, and customer protection. At the same time, to preserve procurement flexibility for all LSEs and limit program modifications to only the most critical areas, the CPUC does not adopt a framework for central procurement of system or flexible RA at this time. Central procurement of system for flexible RA may be considered in future years. [6]

Therefore, parties should propose central buyer structures for multi-year forward procurement of local RA in their Track 2 testimony. Proposals involving centralized procurement may have a single central buyer or a single central buyer per TAC area (see comments on TAC areas in the Introduction), and should address the ability to procure all available resource attributes (e.g. flexible RA), not just local RA requirements. It is possible that there could be more than one central buyer per TAC area, and we are willing to consider such proposals, but we are not yet persuaded of the feasibility of permitting two buyers per TAC area. Therefore, any such proposals must provide additional detail to allow the Commission to evaluate their feasibility. Specifically, proposals with two buyers in one TAC area must be concrete and implementable, and: 1) address equitable allocation of costs to all customers, and 2) ensure cost-effective, efficient and coordinated procurement for each local and sub-local area within the TAC.

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

3.2. Track 2

The information below is from a (Proposed) "Decision Refining the Resource Adequacy Program", which is referenced and linked at the end of this paragraph. The author has not identified any more current information as of this writing (4/15/2019).[7]

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[6] CPUC, "Decision Adopting Local Capacity Obligations for 2019 and Refining the Resource Adequacy Program", Decision 18-06-030, 6/25/2018, section 3.5.3, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M216/K634/216634123.PDF

[7] CPUC, "(Proposed) Decision Refining the Resource Adequacy Program", 2/21/2019. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M266/K785/266785992.PDF

The CPUC is persuaded by parties who recognize that the distribution utilities (the three large investor owned utilities) are the candidates with "the resources, knowledge and experience" to procure local reliability resources on behalf of all LSEs without excessive delay. We find that designating the distribution utilities as the central buyers for their respective TAC areas is the most practical, feasible solution in the near term.

That said, the CPUC recognizes that a broad range of parties oppose the distribution utilities serving as central buyers. Indeed, the distribution utilities themselves are either unwilling to take on this role or agree to do so on an interim-only basis.

The CPUC does not find a viable central buyer at this time and thus delays the designation of a central buyer in this decision. The CPUC continues to find that a central buyer structure, as outlined in the Track 1 decision, is the appropriate structure to implement multi-year local RA requirements. In the interim, the CPUC directs parties to undertake a series of workshops to develop workable central buyer proposals, as further discussed below. The CPUC intends to issue a decision in the fourth quarter of 2019 that addresses the central buyer designation.

One advantage of full procurement is that the central buyer can procure more efficiently by selecting effective and preferred resources at the lowest cost. By contrast, under a residual approach where LSEs secure their own resources, a procured resource may not be the most effective, potentially leading to inefficient procurement and collective deficiencies that result in backstop procurement.

Another advantage of full procurement is the ease of administration as it eliminates the need to track LSE self-provided portfolios and fairly allocates local requirements and costs to individual LSEs. Full procurement can also effectively account for load migration addressing stranded cost concerns. Under a residual framework, an LSE who experiences load migration may be potentially stranded with these resources and costs. The uncertainty around load migration discourages LSEs from procuring too far out given that they do not know if they will have a particular set of customers in the future.

The CPUC directs parties to develop workable implementation solutions for central procurement of multi-year local RA through workshops. The implementation details shall include, but are not limited to, the identity of a viable central buyer, the scope of procurement (e.g., full, residual), implementable cost allocation mechanism (e.g., how costs will be tracked and recovered), oversight mechanisms, other procurement details (e.g., resources to be included, selection criteria), market power mitigation tools, and necessary modifications to the RA timeline.

The CPUC deems workable implementation solutions as those that specifically address the following known challenges to the local RA program:

(1) Costly out-of-market RA procurement due to local procurement deficiencies,

(2) Load migration and equitable allocation of costs to all customers,

(3) Cost effective and efficient coordinated procurement,

(4) Treatment of existing local RA contracts,

(5) Opportunity for and investment in procurement of local preferred resources, and

(6) Retention of California's jurisdiction over procurement of preferred resources.

We also encourage parties to consider how central buyer solutions may include options for procuring dispatch rights, or requiring capacity owners to economically bid into energy markets, if doing so is in the financial interest of ratepayers.

At the conclusion of the workshops, the part(ies) identified to develop a report shall file an informal workshop report outlining the recommendations reached and how each recommendation addresses the challenges noted above, into the RA proceeding. Following the submission of the workshop report, parties shall have an opportunity to comment.

The CPUC intends to issue a decision in the fourth quarter of 2019 that addresses and adopts implementation details for a central procurement structure.

The CPUC considers the duration of a multi-year forward local RA program. In the Track 1 decision, the CPUC directed parties to propose a multi-year local RA requirement with a three- to five-year duration in Track 2 of the proceeding, to be implemented beginning with the 2020 RA program year.

The CPUC observes a consensus for a three-year duration among a broad group of parties and is persuaded by the arguments made in support thereof. We agree that local requirements can significantly change from year to year as transmission projects come online and modeling assumptions change. Adopting a shorter duration will likely reduce the financial risks and costs of over-procurement of local RA, as identified by parties. A three-year requirement still provides preferred alternatives an opportunity to develop and reduce local capacity need in later years.

Accordingly, the CPUC adopts a minimum three-year forward multi-year RA requirement. We adopt this three-year multi-year requirement without a central buyer structure and LSEs shall procure to meet their individual three-year allocations beginning in the 2020 RA compliance year.

The CPUC finds the use of the CAISO's existing one- and five-year studies, with the requirement to incorporate engineer-managed adjustments for CAISO-approved transmission projects, to be a reasonable input to inform multi-year local requirements.

In the Track 1 decision, the CPUC concluded that, in the interest of market certainty in the near term, the percentage for the first year of multi-year local RA procurement should be a 100% requirement. For the second year, to address concerns of potential over-procurement of local RA, the local requirement was set to at least 95%. (D.18-06-030 at 29-30.) The CPUC directed parties in Track 2 to propose a *"reasonable amount of local RA procurement for Year 3 (and beyond, if a longer program is proposed) basing their proposals on data such as that presented by Energy Division in its [Track 1] proposal."* The CPUC also stated that generally, the procurement requirements should be greater than current voluntary local RA forward procurement levels.

As discussed in the Track 1 decision, we intend to adopt a high percentage of procurement for Years 1 and 2 in an effort to increase certainty and stability for necessary resources, as well as provide market signals for resources that are not contracted. The CPUC acknowledges the over-procurement concerns. In weighing the Track 2 comments and comments to the proposed decision, the Commission finds an appropriate balance with a 100% requirement for Years 1 and 2 and a 50% requirement for Year 3.

As discussed, the CPUC moves forward with a three-year multi-year local RA requirement without a central buyer. LSEs shall procure local resources based on individual local allocations, as is currently done in the RA program, for a three-year forward duration.

4. Electricity Procurement by CAEATFA

From the previous section it appears that large state investor owned utilities will end up being the central electric energy procurement body, but only in the short term (I would guess three to four years). Then these may be replaced by a new function that may be assumed by the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA). This new function may evolve from a bill currently making its way through the Assembly. The bill is AB-56 and there is a link to its site immediately below, followed by a link to CAEATFA.

https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB56

https://www.treasurer.ca.gov/CAEATFA/

It is early in the evolution of AB-56. In its current form this bill just proposes backstop procurement of renewables, but this would require that CAEATFA put all of the elements in place to provide the full centralized procurement function. Furthermore, California already consumes over 50% of its electric energy via "very-low-carbon" sources, if you include large hydro and nuclear (which are not officially "renewables"). Community choice aggregators will push this higher quickly, since a large majority of those prefer renewable power. California has already committed to have 60% of its electricity from renewables by 2030, and 100% from renewables (which one assumes will include large hydro by then) by 2045.