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PENINSULA CLEAN ENERGY AUTHORITY
Board Correspondence

DATE:	September 20, 2019
BOARD MEETING DATE:	September 28, 2019
SPECIAL NOTICE/HEARING:	None
VOTE REQUIRED:	None

TO: Honorable Peninsula Clean Energy Authority (PCE) Board of Directors

FROM: Joseph Wiedman, Director of Regulatory and Legislative Affairs
Jeremy Waen, Manager of Regulatory Affairs
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SUBJECT: Additional Background on Regulatory Risks and Opportunities

Power Charge Indifference Adjustment (PCIA)

The Power Charge Indifference Adjustment is a non-bypassable charge authorized by state law to ensure the preservation of “ratepayer indifference” as customers move from investor-owned utilities’ (IOUs) bundled electricity service to take electricity generation services from other LSEs, via CCAs or DA. Because the IOUs have made numerous long-term procurement commitments to satisfy State policies, such as 10 to 20-yearlong commitments to renewable technologies to satisfy the Renewable Portfolio Standard (RPS), the State has deemed it appropriate for departing load customers to continue to pay their share of the above market costs associated with these commitments. As such, all customers participating in CCA programs and DA are assigned a PCIA charge that appears on their bills alongside the generation charges that come from the CCA or DA provider. The particular PCIA charge depends on both on the customer’s class (*e.g.* residential, commercial, industrial, *etc.*) and the timing of their departure from the IOU’s bundled electricity service (*i.e.* the customer’s “vintage”).

The PCIA presents a continued operational challenge for CCA programs for numerous reasons. First, it creates a great deal of customer confusion by being presented alongside a CCA’s generation charges on customers’ bills. Second, it limits the amount of costs that CCAs can recover from CCA customers because those customers are paying for both the IOU’s above market procurement costs and the CCA’s procurement costs. Third, how the CPUC defines what is the “market value” for IOU’s procurement costs remains an ever-contentious dispute among LSEs. Fourth, CCAs have little foresight into what future PCIA charges will be for their customers, because the PCIA charges are revised annually through an expedited and opaque 6-month forecast proceeding before the CPUC.

After much pressure from the CCA community, the CPUC convened a proceeding to consider revisions to its PCIA construct (R.17-06-026). Though this proceeding remains open and active, the CPUC arrived at an initial Decision (D.18-10-019) in October 2018 which introduced numerous changes to the policies and methodologies used to inform the calculations of the PCIA. Additionally, the effects of D.18-10-019 are beginning to ripple through other proceedings before the CPUC, such as the annual rate forecasting proceedings where each IOU's bundled electricity generation and PCIA rates are established. The partial implementation of this decision proved contentious in the last cycle of these forecast proceedings and resulted in Pacific Gas and Electric Company's (PG&E) 2019 bundled electricity generation and PCIA rates being implemented July 2019, rather than January 2019. PCE staff anticipates the next forecast proceeding will be equally contentious and possibly result in another delayed rate change. PCE staff has taken lead roles in the main PCIA docket and all of PG&E's rate forecasting proceedings to ensure the PCIA is reformed in a fair manner that minimizes costs and that the actual PCIA imposed on our customers is accurate and in compliance with CPUC decisions.

Resource Adequacy (RA)

The resource adequacy program is a legal framework created by the State in the aftermath of the 2000-2001 Energy Crisis. The RA program exists to ensure the state has enough electricity generation capacity resources under contract to meet demand in real-time at all times. The California Public Utilities Commission (CPUC) is charged with overseeing compliance with the RA program rules for CPUC-jurisdictional load-serving entities (LSEs), such as community choice aggregators (CCAs). All CPUC-jurisdictional LSEs presently have a combination of procurement obligations under RA that extend one month, one year, and three years ahead of the anticipated capacity needs. For capacity providing resources to count towards satisfying RA requirements, these resources' generation capabilities must be evaluated and quantified by both the CPUC and the California Independent System Operator (CAISO). RA resources must also agree to be subject to a Must Offer Obligation (MOO) with the CAISO so that the CAISO has the certainty it needs to optimize grid reliability by calling upon these resources to provide additional generating capacity in real-time.

Initially, the RA program specified a procurement need for only one type of capacity resource product, called System RA, which could be met by capacity providing resources located anywhere within the CAISO's operational grid. Later, the CPUC identified a need for a second type of capacity resource product, called Local RA, which more specifically required the capacity providing resource to be near to major pockets of electricity load such as urban areas. Most recently the need for a third type of capacity resource product was identified, called Flexible RA, which requires resources to be capable of ramping up or down their generating capacity within a specific time period. This last product helps the CAISO respond to rapid changes in either demand (such as increased demand in early evenings) or supply (such as the late afternoon decrease in solar generation as the sunsets).

As California transitions its electricity sector to a cleaner electricity supply and fossil fuel plants continue to retire, the market for RA resources in California is tightening. Moreover, the increasingly diverse number of California LSEs in the state stemming from the growth of CCA programs and direct access providers (DA), has resulted in a more diverse group of buyers for RA resources while the owners of RA resources has remained relatively small. These two developments are challenging the current RA program as its rules were designed with the only the large investor-owned utilities in mind. The CPUC has responded to these market developments by instituting a number of changes in RA program rules including a recent requirement that all LSEs purchase Local RA three years ahead instead of just year ahead. The

Commission has also been exploring expanding the new multi-year Local RA contracting requirement to all three RA products and whether establishing a central buying of RA products (one or several larger buyers acting on behalf multiple LSEs) would assist in stabilizing the RA market. Additionally, considerations are being made at both the CPUC and the CAISO to determine how the capabilities of new capacity-providing technologies (such as battery energy storage) should be evaluated and quantified. Lastly, the CPUC continues to adjust how it counts the capacity values assigned to intermittent renewable technologies such as solar and wind.

In summary, though the RA program has existed and has successfully preserved grid reliability for nearly two decades, the RA program is changing quickly. These changes create regulatory uncertainty and has made procurement of RA resources more challenging than in years past. Resolution of outstanding issues in the RA program will likely have to take place soon for the State to continue to reliability operate its electricity grid as it inches closer to achieving its green-house gas reduction goals. PCE's regulatory team is heavily involved in CalCCA's efforts at the CPUC and CAISO to design RA program structures which will support cost-effective and fair procurement of RA resources.

Integrated Resource Planning (IRP)

The Integrated Resources Planning process (R.16-02-007) is designed to help the CPUC ensure that energy procurement by California's LSEs will meet state's greenhouse gas goals over the next decade, while maintaining reliability and affordability. The IRP process is a biennial process, in which the CPUC first models what it views at the optimal resource plan to meet the state's GHG and reliability goals (termed the "Reference System Plan" or RSP). In parallel, the LSEs, including PCE, each prepare their own IRPs outlining their plans for procurement over that period for submission to the CPUC. These IRP submissions are aggregated by the CPUC into a statewide "Hybrid Conforming Portfolio," which provides an assessment of whether the state's LSEs collectively are on target to meet the state's GHG and reliability targets.

The first iteration of this two-year process (2017-18 cycle) concluded earlier this year. After internal analysis, the CPUC determined that the state's LSEs are on track to miss the minimum GHG reduction target. Unfortunately, this first effort at analyzing the LSE's collective showings suffered from some serious methodological issues and was very opaque. While PCE's IRP was praised by the Commission for its thoroughness and rigor, the collective failure of the state's LSEs still leaves PCE subject to CPUC's decision to develop procedures for ordering procurement to correct future shortcomings. PCE's staff has taken a lead role in CalCCA's IRP efforts to assist the Commission in developing a better and more transparent IRP process.

Additionally, based on modeling by CPUC staff in the IRP proceeding, the CPUC identified a potential System RA capacity shortfall of 2500 megawatts (MW) that is expected to emerge by 2021 as large once-through-cooling plants, other natural gas plants, and nuclear plants retire. This finding by staff led the Commission to open a procurement track within the IRP docket to explore how to fill the gap identified by staff. Based on comments filed in the docket, the CPUC has proposed ordering LSE's in Southern California Edison's (SCE) service territory to procure capacity to meet this statewide need. If the Commission adopts this proposal, it would create serious cost shifts among LSEs as LSEs located in SCE's service territory would be required to procure RA resources that are not needed to serve their customers. In the short term, this outcome could financially benefit LSEs operating in San Diego Gas & Electric's service territory and Pacific Gas & Electric's service territory, including PCE. However, in the longer term, the proposal would create a precedent for the Commission assigning RA obligations to PCE in a manner that is not consistent with our customers' need. PCE staff is taking a lead role in assisting CalCCA and other stakeholders in presenting alternatives to the Commission to avoid such a damaging outcome.

Direct Access (DA)

Direct Access is a program managed by the CPUC which currently allows a limited number of nonresidential energy consumers to choose an energy provider other than their investor-owned utility (IOU). The direct access program originally started in California via AB 1890 (1996) and was open to all residential and nonresidential customers and was an aspect of California's deregulatory efforts. However, flaws in market design, weak regulatory oversight and market monitoring, and gaming by industry stakeholders resulted in skyrocketing prices, the collapse of certain competitive providers, and shortages of energy supply leading to rolling blackouts during the 2000-2001. The market failures ultimately required PG&E to declare bankruptcy and was a factor in the recall of Governor Grey Davis. Coming out of the California Energy Crisis, the right to direct access was suspended in September 2001. Only customers who were still direct access customers at the time of the suspension were allowed to remain in the program which was about 10% of the three IOUs customer base. Periodically, the Legislature has authorized limited expansions of direct access for nonresidential customers via specific legislation (see, for example SB 695 (2009). Recently, SB 237 (2018) allowed for an expansion of direct access load by 4000 gigawatt-hours, which is approximately 2% of the load of the investor-owned utilities. The CPUC has been implementing the direct access expansion in Rulemaking 19-03-009. PCE's regulatory team and CalCCA have been actively involved in the docket to ensure fairness and adherence to the direct access program rules during the implementation of this latest expansion of direct access. On June 3, 3019, the CPUC issued Decision No. 19-05-043 which established the enrollment process for the additional direct access transactions allowed by SB 237. The decision established a phased approach to the expansion allowing 2000 GWh of additional nonresidential load to choose a provider other than their investor-owned utility or CCA. This first tranche of direct access will be allowed to depart their current service provider on January 1, 2021. The second tranche of 2000 GWh will be allowed to depart on January 1, 2022. The extended departure timeframes were chosen to minimize cost shifting due to the procurement of resource adequacy resources by load serving entities that are currently serving the departing load. PG&E has informed PCE that it anticipates approximately 46 GWh of PCE's current load to depart for direct access service from the first tranche. PCE will know the final amount of load departing for direct access in late-February 2020. It is unknown at this time how much load may depart PCE service in the second tranche because the direct access program uses a lottery process to establish which customers are allowed to depart. Moreover, requests for direct access service are confidential during the early stages of the enrollment and lottery process.

FISCAL IMPACT:

Not applicable.