EAST BAY COMMUNITY ENERGY

Notes regarding submitting comments on this Draft Work Product:

Comments are Due April 20, 2018.

Comments shall be no longer than 5 pages.

Comments should be submitted to LDBPcomments@ebce.org

Recommendations for Optimizing the Integration of DER Development with Procurement and Scheduling

for

East Bay Community Energy

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INTRODUCTION

East Bay Community Energy (EBCE) recently selected Northern California Power Authority (NCPA) as its portfolio manager to assume responsibility for the procurement of power resources from the CAISO wholesale energy market, as well as schedule coordination services. The energy purchase activities conducted by NCPA on behalf of EBCE will be directly influenced by federal, state and local policies that define Renewable Portfolio Standards (RPS), the percentage of greenhouse-gas (GHG) emissions-free power, power Resource Adequacy (RA) requirements, and economic constraints of the energy mix solicited from the market as defined by the continuing creation of EBCE's Integrated Resource Plan (IRP).

Given EBCE's mission to maintain competitive energy rates for its customers and provide an energy mix containing high renewable energy content, as well as setting and achieving Local Portfolio Standard (LPS) goals. LPS goals are similar to RPS requirements and define the total energy mix sourced from within the service area of a utility. Municipalities and utilities around the country are exploring the concept and the ability for their purchasing teams to source local resources that create environmental and economic benefits while retaining competitive and affordable rates[1].

As both RPS and LPS requirements are considered the actions of NCPA as a portfolio manager will require balancing environmental and social outcomes with economic performance and cost competitiveness. In that effort, a dispatchable network of local Distributed Energy Resources (DERs) will provide EBCE and its portfolio manager the ability to supplement its energy needs from within the service area. The ability to use local, dispatchable power is an emerging practice that has the potential to reduce EBCE's exposure to wholesale market risk while lowering its energy cost through load shaping or shifting programs that flatten the load profile of the service area and meet self-derived and state mandates.

For such programs to be successful, local DER generation must be considered for more than just its total capacity under contract, but also for its ability to provide renewable resources at the right time and place within the context of EBCE's daily load curves, while remaining cost competitive and adherent to a predetermined energy mix. As such, the following recommendations are informed by each LDBP section, and aim to convey, at a high level, a compiled list of program design features, internal policies, and priority actions able to be phased in over a five-year period to facilitate the cost-effective and locally-beneficial integration of DERs with EBCE's wholesale procurement and scheduling processes.

INTEGRATING DERS WITH PROCUREMENT AND SCHEDULING

Recommendation: Integrate control clauses into Power Purchase Agreements (PPAs) and incentive offerings, beginning in Year 1

Incentive offerings through EBCE's net energy metering (NEM) or feed-in tariff (FIT) programs, direct purchases, or collaborative procurements in partnerships with local schools, universities, commercial, or public-sector building owners are all expected to be supported by contract in the form of a Power Purchase Agreement or underlying energy contract. It is recommended that EBCE consider including specific language in such contracts that provides remote control features that grant EBCE the ability to use local resources to meet procurement and scheduling requirements, provide emergency backup, manage significant market risk exposures, or to render other crucial energy services in times of critical

[1] More information on LPS can be found from Boulder's Energy Future – LPS. Retrieved from: https://www-static.bouldercolorado.gov/docs/LPI_BoulderLPS_elecandgas_13July2011-1-201306171446.pdf

need that can save the CCA and its customers money. Control clauses can be designed to become implemented in years four to five when EBCE implements demand response (DR), and Virtual Power Plant technologies become a viable and mature option, as described later in this report.

EBCE's customer perspectives and perceptions about various local programs and strategies for clean energy development within Alameda County are an important factor in the long-term success and stability of the CCA. This is a critical consideration when it comes to implementation of dispatchability control clauses in the context of EBCE programs and incentives, because the idea of the agency controlling behind the meter assets can be intimidating to some customers. Therefore, clearly defining "Times of Need" is crucial, and it is therefore recommended that EBCE establish a clear definition of the term that conveys a sense of mutual benefit and builds trust with EBCE's customers and community stakeholders. It is also important to ensure that this definition, and the related control clauses contractually establishes the frequency, degree, and conditions under which EBCE can manage the underlying generation, storage, or dispatch of partnered or customer-owned DER projects.

Specific examples of times of need may include: extreme locational marginal price (LMP) spikes in the CAISO Day Ahead (DA) and/or Real Time (RT) markets, unexpected severe peak load events triggered by either extreme weather, blackouts, or emergency disruption from natural disasters such as floods, fires, or earthquakes. Energy Risk Management (ERM) policies should be defined that trigger either automated or manual dispatch of DER demand response protocols. In addition to placing clear contractual limits on EBCE's asset control activity, EBCE should also be prepared to offer fair and beneficial compensation to participating customers in the form of shared energy savings that result from reduced/avoided procurement costs and CAISO-imposed imbalance fees, or progressive rate designs that are able to protect savings or rates for customers enrolled in DER response programs.

Specific contracted control terms that allow EBCE to regulate that could be considered include:

- State of Charge (SOC) of energy storage (ES) systems (e.g., EBCE could signal the storage systems to discharge 20% of their stored energy to shave a severe system wide peak load)
- Charge and discharge timing for energy storage or electric vehicle (EV) chargers (e.g., EBCE could limit the chargers to 80% of capacity during specified times of need up to a specified number of times each year)
- Generation "on-off" modes for solar photovoltaic (PV) systems or other distributed generation sources
- Access to live performance data, dashboards, meter and interval data

In order to create equitable partnerships that leverage the value of dispatchability for mutual benefit, it is recommended that EBCE specify the following conditions in applicable contract language:

- The maximum number of events or control days that EBCE can manage customer asset generation, state of charge, or dispatch
- Notification sent to customer through digital app, text message, email or other channel informing of an upcoming EBCE control action
- Option for customer to temporarily opt-out of or override the specific control action, and decline to be compensated for participation for that particular event

- Pre-defined explanation of how compensation for participation will be structured and allocated, including pricing terms and conditions
- Definition and quantification of the specific events, parameters and total impact that controls can result in, such as 20% SOC control on ES or percent power outputs of EV chargers

Recommendation: Deploy an Integrated Data Platform to coordinate DER response to procurement and scheduling needs, beginning in Year 1

Building control clauses into contracts is just one part of the requirements needed for a network of DERs to be able to supplement or offset wholesale energy procurement needs. Utilizing DERs as a local resource able to meet variable energy demands is also dependent upon an underlying data and communication infrastructure engrained into the distributed assets that is able to receive and transmit data and signals from both ends of the generation and consumption spectrum in real time. The use of smart features, including meters, sensors and remote controls, is ultimately essential to communicating energy use and generation data over the internet to EBCE's staff and its portfolio manager to align procurement and scheduling practices able to meet energy needs and provide a reliable energy mix under high renewable penetration and Local Portfolio Standard (LPS) conditions.

While additional information about the buildout of an Integrated Data Platform can be found in the Capacity Building Section, minimum features of an integrated platform able to offer procurement and scheduling benefits include:

- A user-friendly, web-based platform with secure user login portals and role-based security that supports multiple levels of access and that is accessible to: Internal Staff and EBCE Board Members, External Consultants/Contractors/Vendors/Community Groups/ Labor Organizations, and EBCE Customers
- Detailed energy usage data available to staff/consultants/contractors/customers down to the meter level
- Capacity to integrate multiple structured and unstructured data streams (including AMI/Green Button, EDI and SQMD data, parcel data, weather data, SCADA and BEM, natural gas/fuel-switching smart appliances, CAISO DA/LMP market pricing, EBCE accounting/budgeting, customer interactions, etc.), and provides timely access to data and performance metrics.
- Platform provides analytical tools that support load research (hot-spot, load profiling/forecasting, rate-making, etc.)
- Embedded Rate Design and Value-at-risk functionalities to support internal modeling and decision-making processes
- Integrated Customer Relationship Management (CRM) tools with workflow capabilities that can support staff and consultant customer engagement and sales, as well as customer-level program participation and outcome tracking
- Advanced, automated data cleaning, validation, account-level billing adjustment, and settlement functions
- Program-level key performance indicator (KPI) tracking
- Robust capacity for Application Programming Interface (API) integration to support third-party applications

Recommendation: Deploy Time-of-Use (TOU) and NEM Rates to provide locational and temporal value from DERs in Years 1-2. Prepare for transition to innovative TOU and Value of Distributed Energy Resource (VDER) rate structures beginning in Year 3.

An integrated data platform, as recommended above, would allow EBCE to develop and maintain granular, accurate, and dynamic load profiles and demand forecasts that would help the organization optimize financial performance and target expensive loads for reduction through its DER programming. Once established, an integrated data platform can provide the energy and billing data needed for effective rate design structures able to value DERs on temporal and locational bases and nudge customers, through price signals, away from expensive peak market pricing periods. The deployment of rate pilots for DER assets based on locational and temporal benefits has the potential to flatten local load profiles in all customer sectors. If successfully scaled, rate pilots can improve the financial and procurement performance of Portfolio Managers by mitigating the need to approach the wholesale market for expensive short-term contracts required to meet unanticipated spikes in customer demand.

EBCE Demand curves:

As the oft-reported California energy demand “duck curve” shows (see Figure 2 below), the growing proliferation of solar energy onto the electrical grid will lead to conditions under which customer demand drops significantly during the peak solar-producing hours in the late morning and early afternoon. This is typically followed by a dramatic upswing in demand in the late afternoon and early evening, as solar production ebbs and home-based energy use increases. This rapid upswing in energy demand (often referred to as the “evening ramp”) then requires an equivalent “fast-ramping” upswing in power supply—an increase that many traditional power generators are unable to provide, leading to reliance on inefficient fossil fuel-based peaker plants. With this duck-curve issue, adding more solar to the California grid threatens to further lower the “duck belly” during the middle of the day when solar operates most effectively, while doing nothing to reduce the “duck neck” during the evening ramp in the late afternoon and early evening. This is a real concern for grid operators, as well as for load-serving entities (LSEs) in California, like EBCE, because it leads to high locational marginal pricing (LMP) for power procurements during the evening ramp hours.

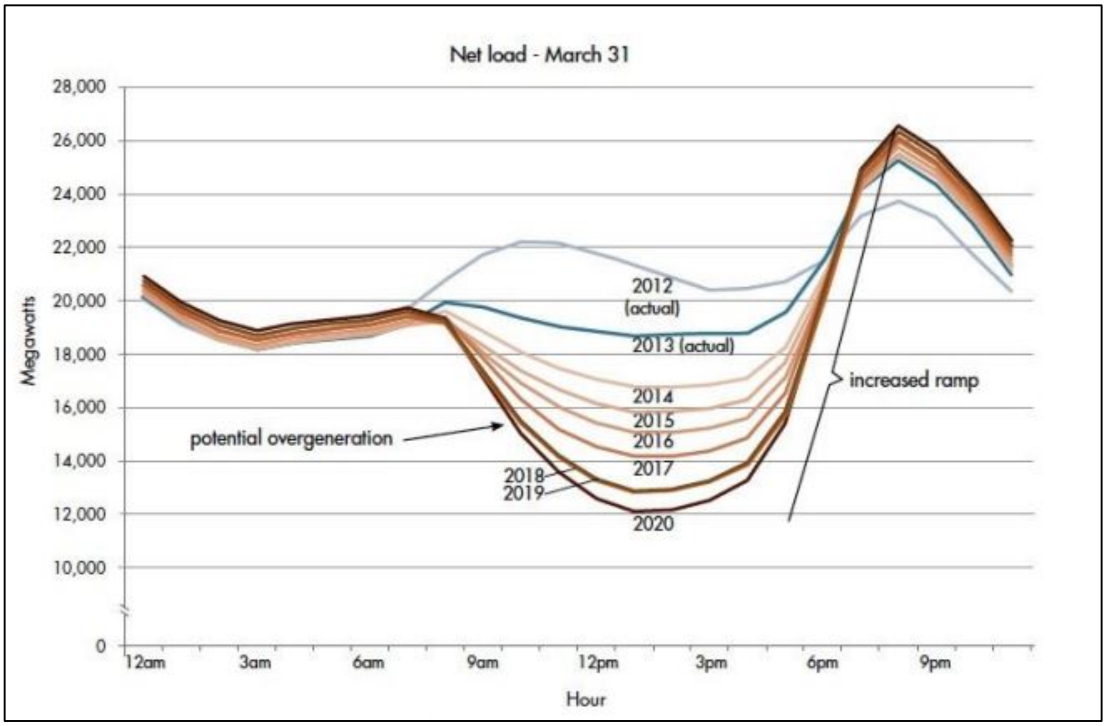

Figure 1: System-wide Hourly Net Load Profile on the CAISO grid, indicating the "Duck Curve" problem. [2]

However, in EBCE territory, a carefully-structured NEM program (with the LDBP recommended Supply-shift adder) and/or innovative TOU rate designs could help EBCE avoid contributing to the broad disparity between the duck belly and the duck neck, while still satisfying local demand for self-generated energy. Several arguments can be made to support this proposition: 1) EBCE's customer demand curve is different than the statewide curve; 2) the problem isn't just the duck belly (where there is still 12 GW of statewide demand shown for 2020), but also the duck neck and tail; and 3) storage and other solutions can help, and can be incented through a properly-designed NEM or TOU program to supplement procurement and scheduling activities.

Key NEM and TOU rate features to support DER deployment may include:

- Billing at different rates based on predefined intervals throughout EBCE's load profile
- Supply-shift adder for systems with integrated energy storage
- Monthly true-ups within billing systems
- Phase-in for residential and commercial clients, beginning with high energy users in the commercial sector and disadvantaged or low-income customers in the residential sector
- Separate billing codes for customers with solar plus storage assets able to provide energy dispatch benefits
- Adherence with state and regional NEM 2.0 requirements
- TOU peak hours that are aligned with EBCE's peak demand, which is earlier than the PG&E or CAISO system averages

[2] California ISO. Fast Facts. Retrieved from: https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

With the benefits of NEM and export adders, EBCE is recommended to include a NEM program in its operational plans from Day 1. However, EBCE should not overlook the impending changes to NEM on the state-level as the CPUC prepares to consider successor rates in the coming years. At that time, the investor-owned utilities (IOUs) will be able to propose an alternate valuation mechanism for distributed energy production. With recent proposed and enacted NEM successor programs among California municipal utilities in Roseville and Alameda, as well as suggested guidelines from various CPUC stakeholders[3], the emerging strategy with the highest likelihood of acceptance is the hybrid instantaneous-netting/export-credit model. Known by various names and structures around the country, the likely NEM successor tariff will be referenced here as the Value of Distributed Energy Resources (VDER), after the program enacted in New York state in 2017.[4]

The Local Development Business Plan (LDBP) team recommends a phased roll-out of both commercial and residential TOU rate pilots that require customer participation in beneficial EBCE DER and/or DSM programs, and TOU-structured NEM programs supported by community benefit adders, including those that capture the time and locational value of DERs. These strategies will provide additional incentives for customers to adopt dispatchable DER technologies.

Under VDER rate design, the following changes are likely:

- Offers of renewable credits only for generation or dispatch that aligns with Locational Marginal Pricing (LMP), or temporal benefit to EBCE
- Real-time or day-ahead billing that changes alongside EBCEs energy needs, as opposed to stacked or flat rate tariff structures
- Policies on Peer-to-Peer energy exchange supported by distributed ledgers or blockchain structures, such as pilots seen through the LO3 energy project and NY REV pilots.

By setting the valuation methodology for VDER prior to it being developed and proposed for authorization by the IOUs, EBCE has an opportunity to create an important precedent statewide, as Community Choice Aggregation (CCA) programs grapple with the investor-owned utilities (IOUs) and the California Public Utilities Commission (CPUC) to determine the "right" formula for valuing distributed energy exports. The formula should certainly include the offset of generation procurement that would no longer be necessary, but it should also include ancillary benefits such as those discussed briefly here, including reductions in resource adequacy (RA) procurements, reduced procurement costs and risks, reduced likelihood of imbalance penalties, reduced grid congestion and related increased congestion revenue rights (CRR) revenue potential, improved regional economic impacts, deferred cost of transmission and distribution upgrades, etc. The authors recommend that the EBCE VDER also consider Locational Marginal Pricing (LMP) to fully account for the ability of DERs to address locational issues around congestion relief and deferral of distribution infrastructure upgrades, and allow EBCE an effective means of incentivizing DER development in the most beneficial regions of its service territory (i.e., using the emerging Locational Net Benefit Analysis, or LNBA methodology being developed by the State). Again, similar to the New York VDER, EBCE is recommended to include an accounting of the societal value of DERs, including greenhouse-

[3] See recent White Paper from Gridworks, entitled "Sustaining Solar Beyond Net Metering" here: https://gridworks.org/wp-content/uploads/2018/01/Gridworks_SustainingSolar_Online.pdf
[4] https://cleantechnica.com/2017/03/06/new-yorks-compromise-future-net-metering/

gas emissions reductions (the social cost of carbon), health improvements, job creation, community resilience, and other benefits that are real measurable outcomes of locally-built DERs.

Additional rate design features for NEM and VDER can be found in the Net Metering Section of the LDBP

Recommendation: Aggregate smart feature-enabled DERs into a Virtual Power Plant as an energy procurement supplement able to provide load shaping and shifting services and advanced risk mitigation capabilities in Years 4-5

Once an integrated data platform is in place that allows EBCE and its portfolio manager to track energy needs in real time, and control contracts mature, a Virtual Power Plant (VPP) aggregation of deployed DERs can take place that grants EBCE and its portfolio manager the ability to shape local energy generation, storage, and consumption to balance environmental, economic, and policy goals by managing charge and discharge activities of dispatchable energy assets.

For example, under a VPP, EBCE staff would work through the data platform to create automated business rules able to manage real-time energy needs through a smart-enabled network of DERs. Evaluation of energy needs would occur in close collaboration with EBCE's portfolio manger and take into consideration local generation capacity based on day-ahead weather forecasts, market variability, and any ongoing open hedges held by the trading team. Daily evaluations would then trigger price signals to be sent to the VPP customer network indicating an opportunity to generate extra savings from the deployment of renewable generation, behavior changes, or storage discharge. Customers would then have the opportunity to opt out of the activity, as per their energy contract. The total capacity of participation is then returned digitally to the data platform for use by the procurement manager and the cycle concludes with the procurement manager settling any remaining imbalances. This approach can even yield new revenue streams for EBCE through existing market structures such as the Demand Response Auction Mechanism (DRAM), which allow registered entities to bid the resulting resource capacity into the CAISO market.

A process overview of this procedure, showing key inputs, decisions or calculations, and data outputs at each stage, is shown in tables below.

Tables 1-3 Virtual Power Plant Data Transfer and Notification Flow Process

Step 1: Integrated Data Platform monitors market conditions and runs calculations to determine profitable DER activities at a day-ahead and/or hourly/sub-hourly intervals

Data Inputs Used	Internal Calculation or Decision	Data Output	Action Triggered
• Weather forecast • Telemetry (i.e., AMI, HAN, etc.) • Historic generation from the asset • SOC of storage asset, or settings of EV chargers or other energy asset • Historic and current CAISO market prices • Total rolling hedge, and risk tolerance from ETRM and ERM policies	• Total profitable resources available on a day-ahead time frame (will change based on daily usage and generation) • Risk vs Reward assessment	• Participating customer list and preferences • Total possible shift or load-shape potential of each individual asset • Price at which DER response is valued per MWh	• Digital and encrypted notification for identified profitable DER response is sent to each customer

Step 2: VPP customer or DER power provider receives digital price signal

Data Inputs Used	Internal Calculation or Decision	Data Output	Action Triggered
• Digital encrypted notification from Integrated Data Platform	• Customer automatically opts in or can manually opt out (Yes/No)	• Total response capacity (total Y/N & MWh) from participants	• Total response capacity is sent digitally back to Integrated Data Platform through encrypted transfer

Step 3: Portfolio manager accesses Integrated Data Platform and settles load balance in the real-time or day-ahead market

Data Inputs Used	Internal Calculation or Decision	Data Output	Action Triggered
• Total response capacity is received by the Integrated Data Platform through encrypted transfer	• Total remaining balance for procurement is calculated	• Daily settlement report • Bill credit adjustments to participating customers (i.e., EDI 820)	• Remaining day ahead balance is settled through wholesale procurements

The above processes are dependent upon specific operating assumptions. First, that any data transfers between customers are secure and encrypted and that energy dispatch, DER generation, or demand shaving, shifting, or shaping activities are real and verifiable. Distributed ledger systems (i.e., Blockchain) designed to both track and protect data while ensuring accuracy, may become the technological backbone for quickly and securely conveying information between the data platform and each touch point along the process. Second, the process above assumes that DERs can actually provide cost savings over wholesale prices. This second assumption is largely a question of scale and uptake of VPP program and incentive offerings, as well as CAISO market design and development that monetizes grid services. Successful marketing, rate design, and contracting terms are all critical to promoting the long-term creation of a VPP able to compete with the wholesale price of energy.

It is likely that, during early implementation, opportunities will be limited by current CAISO market design, and only the most expensive loads experienced throughout a year of EBCE operations and procurement activities will present margins wide enough to illicit market participation in a VPP program. For this reason, continued work to define the price points and cost-savings distributions between EBCE and VPP participants is an expected requirement, and EBCE advocacy and engagement at CAISO for market development and evolution is recommended.

CONCLUSION

By integrating equitable and mutually beneficial control clauses, building an integrated data platform, and deploying advanced rate structures that plan for VDER pricing, EBCE can establish the scaffolding from which to aggregate a smart-featured DER network able to provide local resources that supplement or offset wholesale procurement needs. These features will establish the basis for a Virtual Power Plant able to respond in real time to variable procurement and scheduling needs. If data transfer protocols and standard operating procedures are embedded in a VPP and the integrated data platform on which it depends, EBCE's portfolio manager and associated energy traders and scheduling coordinators can gain access to the day-ahead or real-time markets of local DER capacity that can be used to offset procurement needs, create regulatory compliance, reduce EBCE's exposure to market risk, and ultimately create rate savings that can be extended to EBCE's customers.

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