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 Enhancing Long-term Stability and Reliability

for

East Bay Community Energy

Prepared by
Optony Inc.
2885 Kifer Road, Suite #201
Santa Clara, CA 95051

March 2018

TABLE OF CONTENTS

Introduction 2

Strategies for Enhancing Long-Term Stability and Reliability 3

- Recommendation: Implement Energy Storage contracting strategy to reduce operational risks, provide grid stability, and promote stable and competitive customer rates- beginning in year 1. 3
- Recommendation: Include control clauses in EBCE's PPAs and DER incentive offerings- beginning in year 1 4
- Recommendation: Deploy Rate Pilots to shape and shift load curves beginning in years 2-3 and continue to monitor vehicle to grid technological progress. 5
- Recommendation: Site new DERs based on LDBP Integrated Hosting Capacity Analysis (ICA) to provide locational benefits 7
- Recommendation: Define Standard Operating Practices to improve data management and communication between EBCE, EBCE's Portfolio Manager, local DER asset owners, and EBCE's distribution system operator PG&E. 9
- Recommendation: Build upon EBCE ERM policies to incorporate risk mitigation opportunities possible from DERs 10

Appendix 11

References 17

About Optony 18

INTRODUCTION

As California Community Choice Aggregation (CCA) programs take over an increasing share of the load currently serviced by investor-owned utilities, questions of system reliability, grid coordination, and interconnection are increasingly on the agendas of Community Choice programs. It is no longer sufficient to rely on relatively low current wholesale market prices for renewable electricity to guarantee the environmental and economic viability of a Community Choice program. In addition, as CCAs look to meet economic development goals, stability and reliability are becoming intrinsic to the mission and resource planning of CCA service. Transitioning to local renewable energy assets (generation, demand response, energy storage, and demand side management) is becoming a key strategy for planning for future CCA operational viability. As a result, the use of these distributed energy assets must be thoroughly planned from the perspective of stability and reliability.

This segment of the Local Development Business Plan (LDBP) reviews stability and reliability in terms of both long-term economic feasibility of the CCA itself, as well as the technical feasibility within current grid infrastructure. Although the term "reliability" in the utility electricity service industry typically refers to the development and verification of industry standards for voltage, frequency, and safety under organizations such as the National Electric Reliability Corporation (NERC), this report considers reliability as inclusive of EBCE's organizational management, the energy programs it offers, and the long term fiscal impact of those decisions. It is the perspective of the LDBP Consulting Team that long-term stability and reliability of East Bay Community Energy (EBCE) as a Load Serving Entity (LSE) able to provide consistent electric service to its customer base at stable and competitive rates is an outcome achieved through balancing several operational, business, and utility activities. As such, the management of energy procurement, customer care, and strong relationships with partners and suppliers are all material to the evaluation of EBCE's business practices.

One partnership that is paramount to the long-term stability and reliability is EBCE's cooperation with the distribution system owner and operator, Pacific Gas & Electric Company (PG&E). Predefined methods and protocols for communication flow between EBCE and PG&E are essential to coordinating infrastructure upgrades, regular maintenance, and reliable power service to EBCE customers. Without a working relationship with PG&E, the transmission and distribution of energy necessary to provide reliable service to EBCE's customers will be put at risk. As EBCE encourages the development of new distributed energy resources (DER) for generation and capacity, it should work to consider the needs of its distribution partner PG&E, and the impacts and benefits that local DER assets can provide to grid reliability and distribution systems. If DER deployment is managed appropriately, and these new resources are sited to provide the full measure of locational benefits, EBCE can deliver value to PG&E through grid services and deferral of the need for new transmission and distribution infrastructure.

Stability for EBCE is also be defined in terms of the organization's financial health as a balanced budget, robust reserve account, and credit worthiness all impact EBCE's ability to provide stable operations and subsequent reliable service. The LDBP recognizes that, in the near-term, administrative overhead and operational costs of the organization are likely to increase along with the volume of DER owners seeking to be placed on specialized EBCE rate and tariff structures and interconnect their energy assets with the grid. Similarly, the volume of project developers lobbying EBCE with energy services, and demand for local programs such as demand side management (DSM) programs, energy storage, or energy efficiency offerings is also expected to increase. As a result, EBCE must anticipate and plan how to coordinate price signals and purchasing practices that incentivize customer behavior and programing.

STRATEGIES FOR ENHANCING LONG-TERM STABILITY AND RELIABILITY

Recommendation: Implement LDBP Energy Storage Contracting Strategy to reduce operational risks, provide grid stability, and promote stable and competitive customer rates-beginning in year 1.

The recommended LDBP Energy Storage Contracting Strategy has identified a mix of residential and commercial energy storage programs in the form of standing offers or rate incentives designed to create regulatory compliance with the AB2514 Skinner mandate[1], which requires that 1% of EBCE's peak load—equal to approximately 14 MW of energy storage capacity—will need to be under contract by 2020. The LDBP Energy Storage Contracting Strategy recommends that the 14 MW requirement can be reached through a mix of Residential, Commercial and Industrial, and Utility-scale energy storage capacity using a variety of tariff-based incentives and credit enhancement mechanisms designed to overcome the lack of established credit that EBCE (and all new CCA's) will experience in early years of operations. If achieved, not only does this capacity facilitate regulatory compliance but can create a dispatchable network of assets able to supplement the long-term stability and reliability of EBCE's operations.

In California, both the capacity of generation and transmission infrastructural redundancy has been built into the electrical system to provide Resource Adequacy (RA) and maintain service should an unexpected event occur which would otherwise interrupt normal grid operation. According to California Public Utilities Commission (CPUC) RA program, RA requirements for reliable operation will be determined based on the EBCE load forecast plus a 15% planning reserve margin (PRM)[2]. However, in recent comments before the CPUC, the California Independent System Operator (CASIO) indicates that future capacity planning processes will represent a paradigm shift in the industry. In reference to RA planning the CAISO made the statement that *"…grid evolution is already well underway"* and that RA requirements must reflect new system realities to remain viable, and that systems must be in place to provide the CAISO with new resources (presumably including data and market signal coordination with CCAs) to maintain reliability in the rapidly evolving environment[3].

Fossil fuel-based peaker plants, standby contracts (i.e., Reliability Must Run, or RMR contracts), and energy curtailment have all been traditionally used within the energy market to maintain balance within the energy market and ensure power is available when needed. However, large scale transmission-level resources used to balance energy supply and demand within the regional resource adequacy area may be less effective (more expensive, slower, or with higher line loss inefficiencies) to respond to unpredicted events than the distributed resources under consideration in the LDBP. Large natural gas peaker plants provide reliability for grid balancing both during peak load events and during daily ramps in demand.

[1] The Skinner mandate defines storage requirements for CA load serving agencies by 2020. Skinner & CPUC. 2017. AB2514-Skinner and CPUC R.10-12-007, Retrieved from: http://www.cpuc.ca.gov/General.aspx?id=3462

[2] CPUC. Resource Adequacy. Retrieved from: http://www.cpuc.ca.gov/RA/

[3] CAISO. Resource Adequacy Proposals: Retrieved From: http://www.caiso.com/Documents/Mar7_2018_Comments-ResourceAdequacyProposals_R17-09-020.pdf

During intermittent peaks caused by changes in energy consumption behavior (must commonly weather driven events, such as heat waves) and capacity requirements for daily evening ramps, CAISO must dispatch 11,000 MW in three hours to reach peak generation[4]. This report recommends that EBCE take into consideration the susceptibility to electricity service disruption from storm, earthquake, fire or other physical risks for large centralized assets.

At scale, a network of energy storage assets, demand response programs, and other DERs equipped with smart features and controls that provide EBCE with some level of dispatchability can provide some mitigation of the risks posed by EBCE from expected or unexpected peak demand periods, high Locational Marginal Pricing (LMP), and high imbalance fees in the CAISO market. DERs have been shown to improve grid reliability and stability by creating the ability to manage voltage and current within the distribution system[5], as well as financial stability for LSE's. In addition, solar and storage paired projects bring flexibility into the generation mix by providing a resource that can be throttled through price signals and/or direct control to create enhanced grid stability and beneficial energy procurement outcomes. This report recommends that EBCE participate in, and be aware of, additional programs underway for grid reliability benefits of distributed solar (see information under PG&E Rule 21 and the Smart Inverter Working Group[6]).

It is notable that for a virtual power plant (VPP) to provide financial stability and organizational reliability benefits to a CCA, an integrated data platform that is able to track indicators such as weather metrics, market price signals, and energy demand in real time is essential to provide the necessary business intelligence and inform decisions that can result in savings for EBCE and their customers. More information on the requirements of a VPP and integrated data platform can be found in the Recommendations for Integration of DERs with Procurement and Scheduling section of the LDBP.

Recommendation: Include control clauses in EBCE's PPAs and DER incentive offerings- beginning in year 1

The LDBP has consistently referenced the use of standing incentives including NEM, FIT, and other incentive structures (i.e., targeted cash rebates) to promote the local development of DERs. The resulting new generation or load shaping and shifting services provided by these DERS is expected to be supported by a Power Purchase Agreement (PPA) or another underlying energy contract.

The *Recommendations for Integration with Procurement and Scheduling* section of the LDBP recommends that, *"The specific language of these contracts should be written to include control features that grant EBCE the ability to use local resources to meet procurement and scheduling requirements, provide emergency backup, or to render energy services in times of critical need."*

Specific contract language built into PPAs or incentive offerings can enable EBCE to share savings achieved by using a dispatchable network of privately owned but partnered DERs to respond to gaps in energy

---

[4] California ISO. *What the Duck Curve Tells us About Managing a Green Grid.* Retrieved from: https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

[5] Rocky Mounty Institute (RMI). 2015. The Economics of Battery Energy Storage How Muti-use, Customer-Sited Batteries Deliver the Most services and Value to Customers and the Grid. *Retrieved from: https://rmi.org/insights/reports/economics-battery-energy-storage/*

[6] CPUC. *Rule 21.* Retrieved from: http://www.cpuc.ca.gov/Rule21/

supply and demand. As a result, *critical need* as identified in the *Recommendations for Optimizing the Integration of DER Development with Procurement and Scheduling* can apply to periods when EBCE encounters high wholesale imbalance as a result of unexpected spikes in energy demand. By including within incentive offerings contracts or PPAs the ability for EBCE to extend price signals to DER assets owner's local resources can be tapped to offset the need for real time wholesale settlement.

The practice of using local DERs as a dispatchable asset becomes more viable under a Virtual Power Plant Aggregation occurring in year 5-6 of EBCE operations once a credit rating has been established. Once in place, a VPP can be used to deploy aggregated DERs to respond to critical times of need and to regulate frequency, and voltage in the distribution system while providing opportunities for EBCE's portfolio manager to avoid high imbalance fees by tapping into local stored energy or generation capacity.

Additional information on control clauses and virtual power plant aggregations can be found in *Recommendations for Optimizing the Integration of DER Development with Procurement and Scheduling.*

Recommendation: Deploy TOU Rate Pilots to shape and shift load curves beginning in years 2-3 and continue to monitor vehicle to grid technological progress.

Rate design can provide powerful incentives able to influence customer behavior and spur the development of local DER capacity while shaping and shifting EBCE's load profiles in ways that create both grid and procurement benefits. When rate design incentivizes behind the meter (BTM) energy projects such as solar generation or energy storage, networks of dispatchable assets can then be created that are able to contribute to demand response and load shaping programs. Ultimately the behavior changes and load shaping services of DER networks backed by rates that contain dispatchability adders or Time of Use (TOU) price signals can create cost savings for EBCE by creating local flexibility that Portfolio Managers can use to optimize EBCE's coverage ratio and minimize the risk of costly imbalances. EBCE's Energy Risk Management (ERM) policies define the function of the coverage ratio, and this concept is explored in more detail in the *Risks and Mitigation* section of the LDBP.

While other sections of the LDBP reference rate design extensively, rates structures designed to spur the use of Electric Vehicle (EV) charging infrastructure is a new topic introduced in this section. If backed by TOU rate design features EVs can create long term reliability benefits for EBCE through electrification and fuel switching which will increase the total demand for electricity within the service area and support deep decarbonization of the energy ecosystem. Additional load from EV charging will result in additional revenue from power sales and has the potential offset self-cannibalization of load that occurs form energy efficiency and other demand-side management programing that EBCE offers. Ultimately, if EV usage is scaled within the service area in a way that aligns with renewable generation EBCE can yield simultaneous positive environmental and economic outcomes.

Two main use cases for EVs are appearing that can promote improved grid stability while also providing the potential to generate procurement savings for EBCE that can be passed on to rate payers, including 1) TOU rate structures for grid-enabled EV charging that has the potential to shape energy demand curves and reduce procurement risks, and 2) Vehicle to Grid interface to enable EVs to become mobile batteries able to provide two-way power services to the grid.

In the first use case, using TOU rates or real time price signals to influence customer behavior, EVs have the potential offer load shaping or shifting services able to flatten load curves and more closely align renewable generation with consumption. If priced with current and future energy needs in mind EBCE can in part use EV charging times to stay ahead of the duck belly as load growth occurs for EV charging.

EBCE's load curve shown in the figure below currently does not present as large a *duck-belly* problem as experienced within the rest of California's energy market. However, as the amount of PV generation doubles within the service area, EBCE's load curve is likely to progress towards the state load curve with characteristic load shape features that indicate low power imports and use of gas-fired generation in the middle of the day followed by a high evening ramp. For this reason, unless evening charging is supported by energy storage able to shift mid-day renewable load to evening use, this report recommends that EBCE look to deploy TOU rates that incentivize charging during periods during the middle of the day when PV generation is at its peak and power imports are less likely to result in congestion or cause reliability issues.

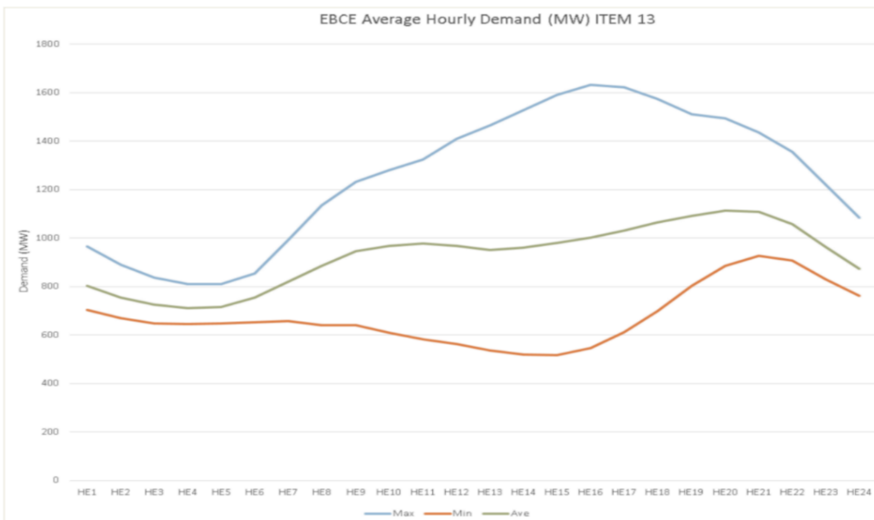


Figure 1: EBCE average Hourly Demand.[7]

This report places special emphasis on rate design and incentives that encourage mid-day and commercial workplace charging. The use of flat or evening-weighted residential charging rates is discouraged because, while overnight residential charging may be the most convenient for EV owners, evening charging does not align with the PV generation unless there is robust local deployment of energy storage at generation facilities. Aligning EV charging with PV production is anticipated to reduce reliability concerns, be less expensive than mid-day power, and will increase the direct renewable energy content of EV fueling.

EVs have been framed as mobile batteries which can be deployed as standalone energy storage while parked. For EBCE this framing is useful as the rate design, smart control features, and price signal features recommended for energy storage can be extended to Vehicle to Grid (V2G) program design. Additionally, V2G offers similar benefits as energy storage and has the potential to allow EBCE to access stored energy in EV batteries to provide frequency regulation or to offset expensive procurement needs in the real-time ISO market.

[7] Note- This hourly load curve was produced using 15 and 60 minute interval data for the EBCE service territory provided by PG&E under the CCA Info Tariff (Item 13).

Specifically, like ES assets EVs will require the following:

- The ability to interface with an integrated data platform able to share real time energy readouts on the state of charge and charging data through an encrypted transfer
- Control features built into IT infrastructure and chargers to allow EBCE to offer price signals in exchange for control over charge or discharge behavior
- The ability for EBCE to send notification of price signal opportunity to customers
- The ability for EV owner to opt-out of a price signal so they can avoid range anxiety and use the vehicle for transportation when needed.
- Smart programing dashboards allowing the customer to pre-define their charging needs and program charging times so that they have adequate range when they want to use the car for transportation.

Despite the promise of V2G technology and continuing funding interest from federal and state grant sources, the technology is still a developing and controversial given the risks of voiding warranties on vehicle batteries that can occur under V2G programs. As a result, the LDBP team views the technology as is unlikely to reach market readiness in the near-term (or next 2-3 years). In the near-term, smart charging incentives should be managed at the charger level, rather than at the vehicle level, leaving time for the battery technology and EV interface controls to mature. When V2G is ready for market pay for performance contracting strategies or utilization of grant funding is recommended to protect EBCE from the risks of adopting nascent technology.

Sonoma Clean Power's (SCP) GridSavvy program demonstrates an EV charging incentive program that can be administrated with little cost to EBCE. The program offers free, grid-enabled EV smart charging equipment to customers and in exchange for the ability for SCP to adjust, or briefly interrupt charging pays enrolled customers a $150 enrollment credit and a $5/month bill credit. While the SCP program can be expanded to offer real-time incentives tied to the cost of energy, adopting a flat rate incentive structure acts as an early iteration of EV load shaping that can be expanded in the future.[8]

Additional information on information flows that enable the use of ES to respond to grid and procurement needs can be found in *Recommendations for Optimizing the Integration of DER Development with Procurement and Scheduling*

Recommendation: Site new DERs based on LDBP Integrated Hosting Capacity Analysis (ICA) and Locational Net Benefit Analysis (LNBA) to provide locational benefits

New local energy projects, including renewable generation and energy storage, has the ability to create a network of dispatchable assets that can provide many significant benefits to EBCE. If sited with local benefits in mind a network of local assets can offset risk and enable EBCE to take advantage of peak load management (i.e., peak shaving, load shedding, load shifting service) to avoid costly CAISO imbalance charges for exceeding forecasted energy demands when unexpected spikes in energy load occur from heat waves or cool weather, for example. These strategies can help the CCA stabilize its Cost of Service, enhancing program stability and rate competitiveness.

[8] Sonoma Clean Power. *GridSavvy.* Retrieved from: https://sonomacleanpower.org/gridsavvy/

By identifying feeders and substations on the distribution network with remaining capacity for DER generation and storage EBCE and its DER partners can begin to site and prioritize new generation projects in ways that match existing grid constraint. This report recommends that EBCE work to prioritize and incentivize the construction of new projects on substation or feeders that have ample hosting capacity to minimize cost and lengthy delays that can slow project development in locations with insufficient hosting capacity. The development of local energy resources that help to defer the costs of transmission and distribution system upgrades are in the best interests of EBCE and PG&E customers alike, while simultaneously promoting new DER capacity within the service area. By establishing close working relationships in order to overcome challenges and foster collaboration and mutual benefits between EBCE and PG&E is a high priority initiative that supports the goal of enhancing long-term stability and organizational reliability.

A targeted siting process for new generation has already been conducted by the LDBP as part of the Solar Siting Survey and related Integrated Capacity Analysis (ICA). Using the LDBP ICA analysis in conjunction with PG&E's evolving ICA maps, as well as the Locational Net Benefit Analysis (LNBA) that is expected to be released in 2018, can allow for EBCE to prioritize projects that can provide valuable grid benefits as well as high generation potential. The LDBP Solar and Wind Siting Surveys can provide the foundation for EBCE's outreach to develop collaborative procurement models or pilot projects able attract outside capital during initial EBCE's early years of operations when a credit rating is still being established. Government or philanthropic grant sources should be of additional focus for EBCE in those early years, as sites identified through the lenses of stability and reliability can enhance local resilience and social justice outcomes.

An existing example infrastructure upgrade deferment in action can be found in EBCE's partnership with PG&E on a collaborative Request for Offers (RFO), which has been branded the Oakland Clean Energy Initiative (OCEI)[9]. The OCEI effort seeks to replace a 40-year-old, 165 MW, jet fuel-powered peaker plant in the Jack London Square area of West Oakland with a bundle of clean and distributed local resources, including energy efficiency, demand response, energy storage, and distributed generation. This was deemed a preferable alternative to a far more expensive, traditional transmission line project that had also been considered, potentially saving California ratepayers hundreds of millions of dollars.

It is expected that the OCEI project will trigger cost recovery proceedings with FERC, and be operational by 2022.[10] It is expected that the resulting cost recovery proceedings will be facilitated through FERC order 1000, which establishes the rules for cost recovery and binds PG&E to participate *"a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation."*[11]

As regional transmission and distribution planning continues in the EBCE service area ongoing communication between EBCE and PG&E around the impacts of new DER assets on existing infrastructure

---

[9] : EBCE. Brandt, M. February 21, 2018. *Oakland Clean Energy Initiative Request for Offers.* Retrieved from: https://ebce.org/wp-content/uploads/Item-7-EBCE-Oakland-Clean-Energy-Initiative-RFO_Complete_FINAL.pdf

[10] Business Wire. December 6, 2017. *PG&E Innovative Clean Energy Alternative to Aging Fossil Fuel Plant in Oakland.* Retrieved From: https://www.businesswire.com/news/home/20171206006022/en/PGE-Proposes-Innovative-Clean-Energy-Alternative-Aging

[11] FERC. *Order No. 1000 – Transmission Planning and Cost Allocation.* Retrieved From: https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

will be essential to finding benefits and value for both organizations. Regular grid impact studies design to track the voltage, frequency, and distribution benefits or impacts created by new generation, energy storage, and demand side management programs are recommended as a way to catalog and track ongoing local energy development. Funding sources for grid impact studies are still to be determined but potential revenues sources can include pollution charges or the special funds of either PG&E or EBCE or a joint agreement to split costs in the interests of identifying opportunities for mutual benefit.

Additional information on substations can be found in the Appendix.

Recommendation: Define Standard Operating Practices to improve data management and communication between EBCE, EBCE's Portfolio Manager, local DER asset owners, and EBCE's distribution system operator PG&E.

The LDBP recommends that EBCE work to encourage the deployment of a network of local DER's through various programs and incentives during years 1-4, and then aggregate them into a Virtual Power Plant (VPP) by year 5 of operations. A VPP will enable EBCE to meet its local Resource Adequacy requirements, respond to market conditions in real time to balance supply with demand and provide a range of locational grid benefits, and create a local procurement option for EBCE's scheduling coordinator that can reduce exposure to market risk and enhance stability of EBCE's competitive retail rate structures. VPP aggregation is possible either with EBCE leading the aggregation or in partnership with a private sector aggregator.

Regardless of which strategy is used, development and operation of a VPP will increase the work load for EBCE's staff and administration. The increased work load imposed by a large network of DERs can in part be managed by creating Standard Operating Practices (SOPs) and business rules that enhance communication quality and efficiency between PG&E, EBCE, and EBCE's vendors and customers. This can be supported efficiently and cost-effectively through the integrated data platform recommended throughout the LDBP, which can be programed with adopted SOPs and automated to retrieve and deliver important market indicators to the proper stakeholders, and dispatch various VPP services when defined thresholds have been exceeded (i.e., when EBCE's load exceeds forecasted levels, or when CAISO market pricing exceeds specified limits). SOPs should define the key staff, consultant, or partner responsible for relaying communication and filings between EBCE, its customers, and its regulatory or distribution partners.

For example, increasing customer data requests or guidance on interconnection, bills, and rates, or other program design features that affect the customer experience could be made available as a web portal on the EBCE site.

It is likely that, since PG&E has a long-standing presence in the customer service arena, some costumer confusion may occur about where to report downed lines, equipment outages, or other disruption to service. To preempt customer confusion SOPs should be created for call center staff defining how to direct customer inquiry. Educational outreach may be needed in addition to online marketing changes to ensure information flows to EBCE as well as to PG&E when relevant.

To support ongoing customer care, the LDBP recommends that customer communication records are cataloged in the integrated online data platform which will create opportunities for EBCE to identify operational efficiency improvements. Second, the LDBP team recommends that call-center staff be included in the program roll out process and that staff is provided with regular briefings and training describing how to manage inbound customer questions or concerns prior to any rebate or incentive offering, billing changes, or major alteration in EBCE's day to day operations.

Finally, call-center staff is likely to interact with customers through several IT platforms including phone calls, emails, customer relationship management (CRM) platforms, social media, and other forms of digital communication. Care should be taken throughout that process to protect customer data, provide secure and encrypted data storage, and verify customer identity before making changes to service.

Recommendation: Build upon EBCE ERM policies to incorporate risk mitigation opportunities possible from DERs

EBCE recently adopted Energy Risk Management (ERM) Policies and Regulations[12] which *"acts to identify the risks associated with the procurement of power supply, identify those responsible for administering the various elements of the risk management policy from procurement operations to oversight, and set policy parameters for managing risk associated with procuring and hedging the power supply portfolio."* The contents of the document highlight essential considerations and operating practices that will directly improve EBCE's long term stability and reliability as an organization by reducing exposure to volumetric, price, and counterparty credit risks.

While the ERM is comprehensive and highlights both internal and external risk it is the recommendation of the LDBP team that risk planning under the direction of the risk oversight committee includes consideration services that can be provided by DERs such as energy storage, demand response, and load shaping and shifting programs. Specifically, DERs with dispatchable capacity have the potential to provide energy traders and portfolio managers with local resource flexibility that can be used to optimize EBCE's coverage ratio and minimize the risks of costly imbalance fees on the real-time market.

Additional recommendations and procedures for the use of local resources to respond to market volatility can be found in the *Analysis of Risks and Mitigation* section.

[12] EBCE. February 7, 2018. *Staff report Item 10 Energy Risk Management Policies and Regulations.* Retrieved from: https://ebce.org/meetings/board-of-directors-meeting-2718/

APPENDIX

Transmission and Distribution Systems in the EBCE Service Area

EBCE has a number of in service area generating assets that provide local resource adequacy and respond to energy needs within the service area. A total of fifteen power plants have been identified from a survey of the California Energy Commission's Power Generation Maps[13]. These power resources provide a total of ~1534 MW of power to the grid. 353.5 MW of the capacity qualifies for RPS, creating a 23% renewable power mix.

The average age of operating power plants is 12.3 years, with the oldest power plant being the 40 year old Oakland C Gas Turbine which provides 223.5 MW of gas power. The newest power plant is the Santa Rita Jail fuel cell at 2 years, providing 1.4 MW of power.

Power plant summaries	
Number of Operational Power plants	15
Average Age of power plant (Years)	12.30769
Max Age of power plants	40
Min Age of power plants	2
Total MW	1533.64
Total RPS MW	353.46
Percent RPS	23%

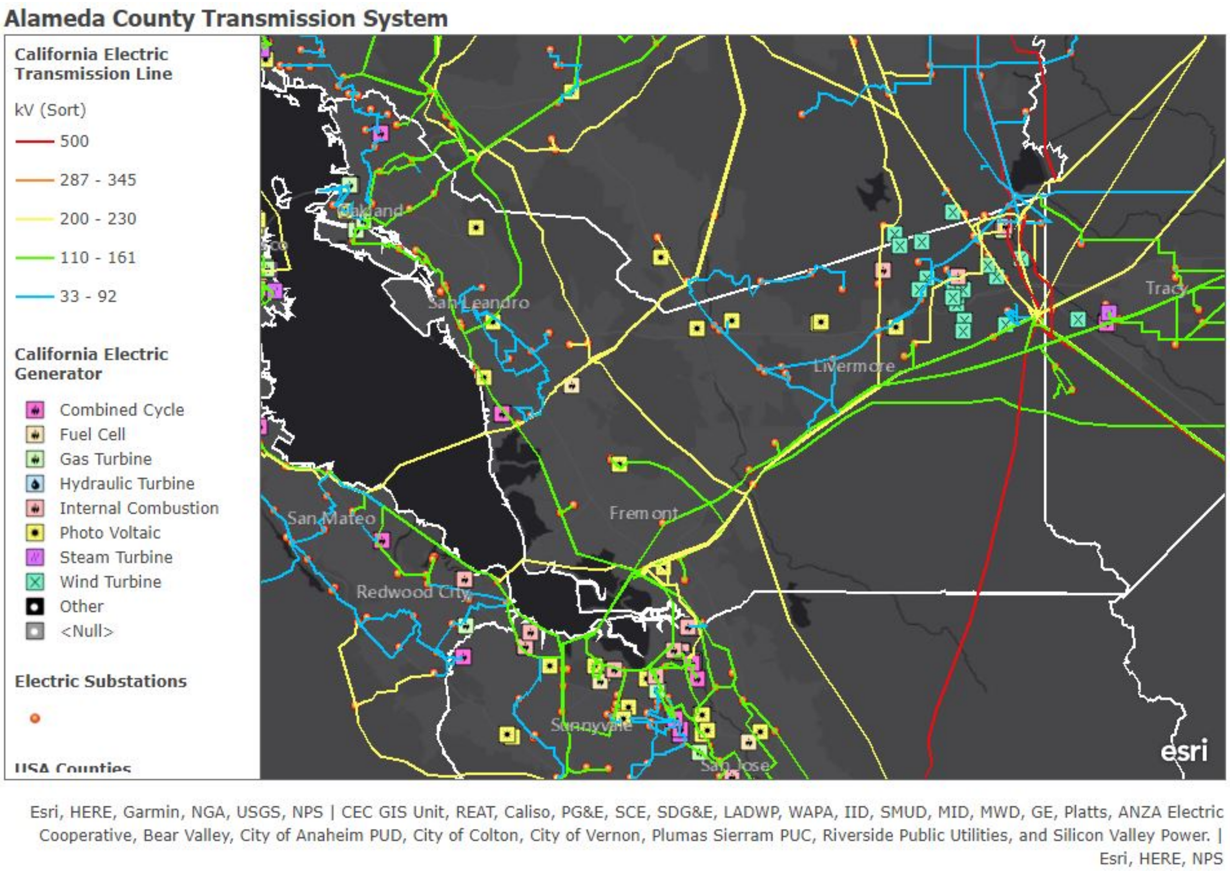
Transmission System in Alameda County

Electricity from these power plants are then connected to the transmission system consisting of 177 transmission lines that form a network consisting of 992 Miles of transmission lines. The transmission system operates in a range of 60kV to 500 kV. The transmission system then steps voltage at 89 substations distributed through the county.

Transmission System Summaries	
Total Miles of transmission Cable	992
Min kV	60
Max kV	500
Longest Line (mi)	58
Shortest Line (ft.)	33.53
Average line length (mi)	5.64

[13] CEC. *Energy Maps in California.* Retrieved from: http://www.energy.ca.gov/maps/

The map below shows the generators, transmission, and substations.



By using PG&E's ICA database maps[14] for the segments of the distribution grid creating the Integration Capacity Assessment (ICA). The ICA evaluates the constrained capacity at the feeder and substation level within the distribution system. Data from the survey identifies the following highest potential solar generation by zip code.

Highest Potential by Zip Code and City	
By Zip Code	
Livermore, CA 94551	96,507 kW
Fremont, CA 94538	83,755 kW
Hayward, CA 94545	72,478 kW
San Leandro, CA 94577	55,645 kW
Union City, CA 94587	54,437 kW

[14] https://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PV RFO/PVRAMMap/

These top five highest potentials represent the zip codes in which EBCE should focus evaluation of grid stability and reliability as it incents, procures, or directly develops new local generation capacity. There are 89 substations are recorded in PG&E's ICA database within Alameda County, 32 of which, shown in the table below, are within the zip codes listed above.

Substations in Zip Codes with Highest Potential Solar Generation

Substation ID	Substation Name	Owner	Highest kV	Postal City	Zip Code
SS2391	Cayetano	PG&E	220kV to 287kV	Livermore	94551
SS2375	Fayette	PG&E	220kV to 287kV	Livermore	94550
SS2501	Frick Green Ridge Power	PG&E	33kV to 92kV	Livermore	94551
SS2500	Green Ridge Services (Dyer Site)	PG&E	33kV to 92kV	Livermore	94551
SS0022	Las Positas	PG&E	220kV to 287kV	Livermore	94551
SS2504	Lawrence Livermore	WAPA	220kV to 287kV	Livermore	94550
SS2506	Lawrence Livermore Lab.	PG&E	110kV to 161kV	Livermore	94550
SS0023	Livermore	PG&E	33kV to 92kV	Livermore	94551
SS2507	Midway Green Ridge Services	PG&E	33kV to 92kV	Livermore	94550
SS2989	N.N.	PG&E	220kV to 287kV	Livermore	94551
SS3235	N.N.	PG&E	33kV to 92kV	Livermore	94551
SS2508	Patterson Pass	Other	33kV to 92kV	Livermore	94550
SS0037	Tesla	PG&E	345kV to 500kV	Livermore	94550
SS0040	Vasco	PG&E	33kV to 92kV	Livermore	94551
SS2505	Zond Wind	PG&E	33kV to 92kV	Livermore	94550
SS0012	Dumbarton	PG&E	110kV to 161kV	Fremont	94555
SS0015	Fremont	PG&E	110kV to 161kV	Fremont	94538
SS0025	Newark	PG&E	220kV to 287kV	Fremont	94538
SS3237	Newark Distribution	PG&E	220kV to 287kV	Fremont	94538
SS0016	Nummi	Other	110kV to 161kV	Fremont	94538
SS0013	Eastshore	PG&E	220kV to 287kV	Hayward	94545
SS3229	Hayward O	PG&E	33kV to 92kV	Hayward	94541
SS0024	Mt. Eden	PG&E	220kV to 287kV	Hayward	94545
SS3230	Soto	PG&E	33kV to 92kV	Hayward	94541
SS3227	Cherry	PG&E	33kV to 92kV	San Leandro	94578
SS3225	Domtar 2	Other	110kV to 161kV	San Leandro	94577
SS3228	Oriole	PG&E	33kV to 92kV	San Leandro	94578
SS0030	San Leandro U	PG&E	110kV to 161kV	San Leandro	94578
SS3223	Ward	PG&E	33kV to 92kV	San Leandro	94577
SS3416	Air Liquide	Other	110kV to 161kV	Union City	94587
SS0010	Cryogenics	Other	110kV to 161kV	Union City	94587
SS0020	Jarvis	PG&E	110kV to 161kV	Union City	94587

Power Plants in EBCE Service Area by Age

Plant Name	MW	General Fuel	Status	Street	City	State	Zip Code	Age	Peaker	Renewable Energy	RPS Standard Eligible	Wind Resource
Oakland Power Plant	223.5	Gas	Operating	50 Martin Luther King Drive	Oakland	CA	94607	40	No	No	No	
EBMUD Wastewater Treatment Plant Power Generation Station	6.45	Digester Gas	Operating	2020 Wake Avenue	Oakland	CA	94607	33	No	Yes	Yes	
Santa Clara 85C	16.02	Wind	Operating		Livermore	CA	94550	33	No	Yes	Yes	Altamont
Alameda	54.8	Gas	Operating	2900 Main Street	Alameda	CA	95401	32	Yes	No	No	
PE Berkeley Inc.	26.35	Gas	Operating	Frank Schlessinger Way at Oxford Street	Berkeley	CA	94720	31	No	No	No	
Altamont Gas Recovery	9	Landfill Gas	Operating	10840 Altamont Pass Road	Livermore	CA	94550	29	No	Yes	Yes	Altamont
Diablo Wind LLC	17.98	Wind	Operating	6185 Industrial Way	Birds Landing	CA	94512	14	No	Yes	Yes	Altamont
RE Mohican	1	Solar	Operating	300 Pullman Street	Livermore	CA	94551	8	No	Yes	Yes	
CSU East Bay Fuel Cell	1.4	Gas	Operating	25800 Carlos Bee Blvd	Hayward	CA	94542	7	No	No	No	

Plant Name	MW	General Fuel	Status	Street	City	State	Zip Code	Age	Peaker	Renewable Energy	RPS Standard Eligible	Wind Resource
EBMUD Wastewater Treatment Plant Digester Gas Turbine	4.6	Digester Gas	Operating	2020 Wake Avenue	Oakland	CA	94607	7	No	Yes	Yes	
Mariposa Energy LLC	200	Gas	Operating	4887 Bruns Road	Unincorporated	CA	94514	6	Yes	No	No	
Oro Loma Sanitary District	1.5	Solar	Operating	2655 Grant Ave	San Lorenzo	CA	94580	6	No	Yes	Yes	
Chabot - Las Positas Community College	1.3	Solar	Operating	5020 Franklin Dr	Pleasanton	CA	94588	6	No	Yes	Yes	
Alameda Water District	1.3	Solar	Operating	43885 South Grimmer Blvd	Fremont	CA	94538	6	No	Yes	Yes	
Ghiradelli Chocolate	1	Solar	Operating	1111 139th Ave.	San Leandro	CA	94578	6	No	Yes	Yes	
Chabot Las Positas Community College District	2.3	Solar	Operating	3000 Campus Hill Dr	Livermore	CA	94551	6	No	Yes	Yes	
JATCO	1.1	Solar	Operating	725 Zwissig Way	Union City	CA	94587	6	No	Yes	Yes	
Carl Zeiss Meditec Inc.	1	Solar	Operating	5160 Hacienda Dr.	Dublin	CA	94568	6	No	Yes	Yes	

Plant Name	MW	General Fuel	Status	Street	City	State	Zip Code	Age	Peaker	Renewable Energy	RPS Standard Eligible	Wind Resource
Health Plan Inc. Kaiser Foundation	1	Solar	Operating	300 Pullman St.	Livermore	CA	94551	6	No	Yes	Yes	
Peralta Community College Dist	1	Solar	Operating	S Bacon Rd.	Oakland	CA	94619	6	No	Yes	Yes	
Community College District Chabot Las Positas	1	Solar	Operating	3031 Collier Canyon Rd.	Livermore	CA	94551	6	No	Yes	Yes	
Port of Oakland	1	Solar	Operating	530 Water St.	Oakland	CA	94607	6	No	Yes	Yes	
Russell City Energy Company LLC	625	Gas	Operating	3862 Depot Road	Hayward	CA	94545	5	No	No	No	
Ameresco Vasco Road LLC	4.34	Landfill Gas	Operating	4001 N. Vasco Road	Livermore	CA	94550	4	No	Yes	Yes	
Golden Hills	85.92	Wind	Operating		Unincorporated	CA		3	No	Yes	Yes	Altamont
Santa Rita Jail Fuel Cell	1.4	Battery	Operating	5325 Broder Blvd	Doublin	CA	94568	2	No	Yes	Yes	
ALTAMONT - 06W146C	30	Wind	Unknown		Livermore	CA	94550		No	Yes	Yes	Altamont
ALTAMONT - 06W146A	20	Wind	Unknown		Livermore	CA	94550		No	Yes	Yes	Altamont
ALTAMONT - 06W146B	18.5	Wind	Unknown		Livermore	CA	94550		No	Yes	Yes	Altamont
Patterson	21.8	Wind	Unknown		Livermore	CA	94550		No	Yes	Yes	Altamont
ALTAMONT - 01W146B	30	Wind	Unknown		Livermore	CA	94550		No	Yes	Yes	Altamont
ALTAMONT - 01W146C	11.9	Wind	Unknown		Livermore	CA	94550		No	Yes	Yes	Altamont

REFERENCES

1. Business Wire. December 6, 2017. *PG&E Innovative Clean Energy Alternative to Aging Fossil Fuel Plant in Oakland.* Retrieved From: https://www.businesswire.com/news/home/20171206006022/en/PGE-Proposes-Innovative-Clean-Energy-Alternative-Aging
2. CPUC. *Rule 21 Interconnection*. Retrieved from: http://www.cpuc.ca.gov/Rule21/
3. California Energy Commission. Energy Maps of California. Retrieved from: http://www.energy.ca.gov/maps/
4. EBCE. Brandt, M. February 21, 2018. *Oakland Clean Energy Initiative Request for Offers.* Retrieved from: https://ebce.org/wp-content/uploads/Item-7-EBCE-Oakland-Clean-Energy-Initiative-RFO_Complete_FINAL.pdf
5. EBCE. February 7, 2018. *Staff report Item 10 Energy Risk Management Policies and Regulations.* Retrieved from: https://ebce.org/meetings/board-of-directors-meeting-2718/
6. Edison International. *Vehicle-to-Grid (V2G) technology: EVs as Energy Storage?.* Retrieved from: https://www.edison.com/home/innovation/electric-transportation/vehicle-to-grid-technology.html
7. FERC. July 21, 2011. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*. Retrieved from: https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf
8. FERC. *Order No. 1000 – Transmission Planning and Cost Allocation.* Retrieved From: https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp
9. PG&E. October 21, 2016. *Pacific Gas and Electric Company Guide to Energy Storage Charging Issues For Rule 21*. Retrieved from: https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/GuidetoEnergyStorageChargingIssues.pdf
10. PG&E. *Interconnection and Renewables*. Retrieved from: https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/interconnections-renewables.page?ctx=business
11. PG&E. June 8, 2017. *Electric Rule No. 21: Generating Facility Interconnections*. Retrieved from: https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf
12. PG&E. *Wholesale Distribution Fast Track Interconnection Process*. Retrieved from: https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/energy-transmission-and-storage/wholesale-generator-interconnection/wholesale-distribution-fast-track-interconnection-process.page
13. PG&E. *Solar PV and Renewable Auction Mechanism Program Map*. Retrieved from: https://www.pge.com/en_US/for-our-business-partners/energy-supply/solar-photovoltaic-and-renewable-auction-mechanism-program-map/solar-photovoltaic-and-renewable-auction-mechanism-program-map.page
14. Sonoma Clean Power. *GridSavvy.* Retrieved from: https://sonomacleanpower.org/gridsavvy/
15. Skinner & CPUC. 2017. *AB2514-Skinner and CPUC R.10-12-007*, Retrieved from: http://www.cpuc.ca.gov/General.aspx?id=3462
16. Staff from, CAISO, PG&E, SCE, SDG&E. June, 2017. *Coordination of Transmission and Distribution Operations in A High Distributed Energy Resource Electric Grid*. More Than Smart. Retrieved from: https://www.caiso.com/Documents/MoreThanSmartReport-CoordinatingTransmission_DistributionGridOperations.pdf

ABOUT OPTONY

Optony Inc. is a global research and consulting services firm focused on enabling government and commercial organizations to bridge the gap between clean energy goals and real-world results. Optony's core services offer a systematic approach to planning, implementing, and managing commercial and utility-grade renewable power systems, while simultaneously navigating the dramatic and rapid changes in the solar industry; from emerging technologies and system designs to government incentives and private/public financing options. Leveraging our independence, domain expertise and unique market position, our clients are empowered to make informed decisions that reduce risk, optimize operations, and deliver the greatest long-term return on their solar investments. Based in Silicon Valley, Optony has offices in Santa Clara, and representatives in San Francisco, and Chicago.

For more information, visit www.optonyusa.com