MEMORANDUM

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TO: UTILITIES ADVISORY COMMISSION

FROM: UTILITIES DEPARTMENT

DATE: April 12, 2018

SUBJECT: Assessment of CPAU's Distribution System to Integrate Distributed Energy Resources

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RECOMMENDATION

This is an informational report to the Utilities Advisory Commission (UAC) to provide an update on CPAU's continuing study of distributed energy resources. No action is requested at this time.

EXECUTIVE SUMMARY

Staff undertook an assessment of the City of Palo Alto Utilities (CPAU's) electric distribution system to understand system capabilities to accommodate customer adoption of distributed energy resources (DERs)[1] and to identify constraints. In Palo Alto, Electric Vehicles (EVs) and local solar (PV) are two DER technologies projected to have significant penetration by 2030 and the potential to impact distribution system operations. At the system level, there is sufficient capacity to accommodate DER growth for the next five years. However, there are some sub-components of the system that require further assessment and monitoring (e.g. residential distribution transformers). Implementation of Advanced Metering Infrastructure (AMI) by 2022 will greatly enhance the visibility into distribution system operational characteristics and further enable the integration of DERs by offering new customer programs (such as, time varying rates).

Although no major immediate strategic shifts are needed to accommodate DERs, staff has identified a number of tasks that can be undertaken in the next three years to better position the City to manage longer-term potential impacts. These tasks are:

a) review and update the city's mapping of customer meters to the distribution transformer serving them to enable better assessment of distribution transformer loading,
b) identify distribution transformers that have potential to overload due to the high adoption of EVs, and upgrade them as needed,
c) better understand non-technical impacts of potential distribution system changes, such as the impact of larger distribution transformers on neighborhood aesthetics,

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[1] DERs are electrical energy resources connected to the CPAU distribution grid that can significantly change the location, timing, and magnitude of the CPAU's electric loads. DERs in Palo Alto include but are not limited to: distributed renewable generation resources such as solar photovoltaics (PV), energy efficiency (EE), energy storage (ES), electric vehicles (EV), and demand response (DR) technologies, as well as grid interactive and flexible resources such as EV smart chargers, smart thermostats, heat-pump water heaters (HPWH), and heat-pump space heaters (HPSH).

d) evaluate a standardized policy and fee for residential customers requesting electrical panels larger than 200 Ampere panels and implement if feasible, and
e) explore the potential to integrate smart inverter capabilities into distribution system operations.

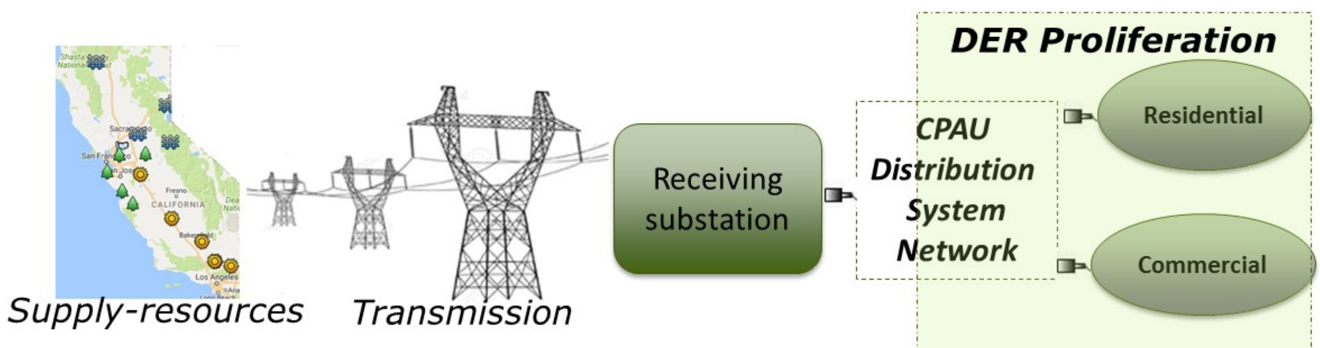
An interdisciplinary team of staff members from Utilities Engineering, Operations, Resource Management, and Customer Service will continue to work on these areas in FY 2019 and FY 2020. Staff is coordinating these actions with the development of the DER Plan and planning for AMI investment. Staff continues to seek collaborative opportunities with industry partners and ways to learn from industry best practices in these areas as well.

BACKGROUND

CPAU procures electricity from carbon-neutral resources located throughout California.[2] Electricity is physically received in Palo Alto at the Colorado Power (COP) substation, through high voltage transmission lines. CPAU's Distribution System Network is a combination of wires, substations, and distribution transformers, and is used to deliver electricity to customers. Figure 1. below provides an overview of the CPAU's electricity supply chain.

DERs in Palo Alto are mostly customer-sited resources and connected to the distribution system. Higher penetration of DERs may impact the reliability and operation of the distribution system. This report shares the findings of a distribution system assessment that was undertaken to evaluate whether the current system can accommodate and effectively integrate the growth of DERs.

Figure 1. Electricity supply chain from supply resources to end-customers



CPAU's distribution system consists of the following major components: transmission services, a sub-transmission network, substations, feeder lines, distribution transformers, Supervisory

[2] These resources are scheduled in the California energy markets (CAISO) by the Northern California Power Agency (NCPA) on behalf of CPAU. NCPA also schedules Palo Alto's city-gate load to the CAISO markets.

Control and Data Acquisition (SCADA) and other control and protection devices[3]. Attachment – B provides details of these components, their observed performance, and asset value. In summary, Palo Alto's electric distribution system consists of:

- Transmission line services
- 19 miles of sub-transmission network connecting substations
- 9 substations accommodating step-down transformers, protective equipment, and sending electricity to feeders
- 68 medium voltage feeders with 300 miles in length and connecting to 3,150 distribution transformers
- About 25,500 residential and 4,000 commercial electric meters

Overall, the distribution system is designed to serve the predicted peak load and maintain electrical safety of the system and public by ensuring:

- ✓ Normal capacity of any equipment is not exceeded under normal conditions
- ✓ Emergency capacity of any equipment is not exceeded under emergency conditions
- ✓ Voltage levels are kept within required limits
- ✓ System problems are isolated as quickly as possible

The draft DER Plan presented by Staff to the UAC in November 2017 included nine strategies to integrate DERs. These included strategies to lower barriers to adoption, offer customer programs, implement advanced AMI and rate structures, enhance distribution system planning, and incorporate DERs into electric supply planning. The DER plan goal is to enhance the value of DERs to all members of the Palo Alto community while avoiding or mitigating any potential negative impacts from DER growth.[4] The distribution system assessment results provided in this report are used to develop the distribution system planning strategy of the DER Plan. Table 1 below recaps the distribution system planning strategies and actions from the draft DER Plan.

The actions described in this report specifically address action item b) requirements "*Performing a Distribution System Assessment at regular intervals… ".*

[3] Attachment A provides a summary of the technical terms used in this report.

[4] Discussion of Proposed Distributed Energy Resources Plan, UAC November 2017 - https://www.cityofpaloalto.org/civicax/filebank/documents/61748

Table 1. Distribution System Planning Strategy and Actions to Accommodate the Growth of DERs at the Lowest Cost while Maintaining System Reliability to all Customers[5]

a. *Integrating the impact of DERs into long-term distribution system planning and considering the cost-effectiveness of DERs to strengthen distribution infrastructure;*

b. *Performing a Distribution System Assessment at regular intervals that assesses the available capacity for additional DERs throughout the distribution system within the context of planned upgrades and projected DER growth;*

c. *Evaluating the response of the distribution systems for various stresses in the system (e.g. concentrated locational DER growth, sudden loss of local PV generation due to cloud cover, operation of protective relays and fault currents, etc.);*

d. *Evaluating and implementing DER programs that can enhance distribution system reliability after the implementation of AMI;*

e. *Re-evaluate the interconnection fee structure and its impact on sizing electric services to accommodate EVs and all-electric homes;*

f. *Creating an implementation plan for a Conservation Voltage Reduction (CVR) program upon implementation of the AMI system when upgrading the substation transformer controllers;*

g. *Developing tools and processes to estimate interconnection fees of large DERs as part of the initial permitting process.*

DISCUSSION

This report discusses the following topic areas:

A) Benefits and challenges of DERs in distribution system operations
B) Industry trends in distribution system planning and DER integration
C) Findings on the Impact of DERs on Palo Alto’s distribution system

A) Benefits and Challenges of DERs in Distribution System Operations

DERs may have disparate impacts and benefits on the distribution system depending on size, type, technology, location, engineering practices, and penetration level. The list below is explained in more detail in Attachment C.

Well-integrated DERs could provide benefits to the distribution system such as:

+ Voltage support (especially toward the end of the feeders)
+ Peak shaving (potential for investment deferral)
+ Loss reduction
+ Potential for intentional islanding (microgrid) to enhance reliability

[5] Draft DER Plan, Strategy #6 for Distribution System Planning, UAC November 2017 https://www.cityofpaloalto.org/civicax/filebank/documents/61748

At the same time, challenges in integrating DERs in the distribution system include:

- Thermal rating violations (or overloading)
- Voltage increase or fluctuations
- Protection issues, load masking, wear and tear of circuit apparatus (tap changers and switches)
- Complaints on electric system conditions from adjacent customers

The objective of distribution system planning in the context of DERs is to maximize the value of DERs to the community while mitigating any adverse impacts and to provide the lowest cost electric distribution service, maintaining system reliability, and enabling customers to adopt these technologies.

B) Industry Trends in Distribution System Planning and DER Integration

Distribution system planning for DERs is getting increased attention in the electric industry due an increase in installations/use and the issues listed above.[6] Various state regulations or planning goals have driven utility planning efforts, as well as operational realities created by high penetration of DERs in certain utility jurisdictions. California's Integrated Demand-Side Resources (IDSR) proceeding, New York's Reforming the Energy Vision (REV) initiative, and Hawaii's Integrated Grid Planning are some of the prominent industry initiatives to integrate DERs.

These early industry efforts have primarily been focused in the following areas:

i. Conducting integration capacity analysis to determine the capability of the distribution system to integrate DERs; and
ii. Demonstration projects to defer distribution infrastructure upgrades.

Integration capacity analysis presents the ability of individual distribution circuits to accommodate additional DERs without requiring significant upgrades in order to ensure system safety and reliability.[7] Demonstration projects are being undertaken to affirm if targeted incentives to guide DER deployment could provide grid benefits and defer needs for upgrades.[8] The findings of this report are related to the integration capacity analysis for CPAU's distribution system. Future efforts by City staff will focus on demonstration projects, among other things.

[6] Smart Electric Power Alliance Research, Beyond the Meter: Planning the Distributed Energy Future: Emerging Electric Utility Distribution Planning Practices for Distributed Energy Resources

[7] For example, refer to SCE's Integration Capacity Analysis maps and user guide

[8] For example, refer to PG&E's 2017 Distributed Resources Plan Request For Offers (RFO)

C) Impact of DERs on the CPAU Distribution System

CPAU's current annual electrical energy sales (960,000 MWh) and annual peak demand (180 MW) are approximately 15% lower than in the year 2000. The exit of electricity-intensive commercial customers from Palo Alto, increases in energy-efficient appliances and building energy codes, changes in customer behavior, and the installation of solar PV on rooftops are some of the reasons for the decreased electricity loads served by the distribution system. As illustrated in Attachment E, CPAU expects relatively little load growth through 2030. DERs such as energy efficiency and solar PV are expected to decrease the load, whereas EVs and other electrification initiatives will increase the load. Moreover, DER load impact would be unevenly realized amongst sub-components of the distribution system and in different seasons and times of the day. These potential impacts and mitigations are discussed in this section.

- ***Electric Vehicles – Impact on Distribution System***

Palo Alto has one of the highest EV ownership rates. In 2016, 22% of new vehicles registered in Palo Alto were electric, the highest market share in any city in the United States.[9] The City's Sustainability Implementation Plan (SIP) calls for actively encouraging its residents and non-resident commuters to adopt EVs through policies, incentives, and provision of EV charging infrastructure.[10] The current EV forecast is to have about 6,000 residential EVs in Palo Alto by 2020 and about 19,000 by 2030. In addition, there are estimated to be approximately 5,900 and 20,000 commuter EVs in 2020 and 2030 respectively. While residential and commuter EVs are expected to account for approximately 5% of the total electrical load by 2030, the load increase will be unevenly distributed among customer types as well as by location. Residential sections of the distribution grid will have significantly more load growth, with demand increasing up to 30% by 2030.

After examining various components of the distribution system, distribution transformers located in residential neighborhoods were found to be most vulnerable to increased EV loads. Overall at the system level (sub-transmission network, substations, feeders), CPAU has sufficient capacity to integrate EV load.[11] Unmanaged EV charging could potentially overload distribution transformers serving the residential neighborhoods (last mile delivery point of the distribution system).

Staff performed a review of the City's distribution transformer inventory, the methodology for sizing transformers, and the potential impact of EV load growth. Attachments B and D provide

[9] ICCT Briefing, California's Electric Vehicle Market Update, May 2017 - https://www.theicct.org/sites/default/files/publications/CA-cities-EV-update_ICCT_Briefing_30052017_vF.pdf

[10] Palo Alto Sustainability Implementation Plan (2018 - 2020) Key Actions - https://www.cityofpaloalto.org/civicax/filebank/documents/63141

[11] Large EV charging projects, such as DC fast charger stations undergo case-by-case basis review. Any distribution system upgrade costs are paid by the project developer.

details of these reviews. This review was somewhat limited absent additional AMI data and some mapping accuracy updates at the individual parcel level. About one-third of total CPAU distribution transformers are rated at or lower than 25 kVA and serve about 7 to 8 residential customers. These lower-rated transformers are most vulnerable to the impacts of EV load growth. The upper limit of economic impact, if all of these transformers had to be replaced over the next ten to fifteen years, is approximately $5 million.[12] However, the utility may be able to avoid transformer replacements by incentivizing smart charging behavior with time-varying rate structures or other managed charging options.

To improve its assessment, staff plans to undertake a comprehensive analysis of EV impacts on distribution transformers. While complete AMI data will not be available for several years, staff can establish a range of potential EV loading profiles based on other sources available. These load profiles would take into account evolving EV charging patterns due to the availability of long-range electric cars and the increasing installation of higher power chargers (Level-2)[13] at homes. Detailed modeling of the operations and financial impact would guide the development of new strategic programs and incentives under the DER Plan. To support this analysis, staff also plans to closely review and update the electric system map to validate the mapping of distribution transformers to customer meters. CPAU's current mapping of distribution transformers to customer meters needs further review for accuracy. In the long term, AMI meters would be effective in predicting distribution transformer operating conditions with accurate customer meter mapping.

If the City finds that distribution transformers need to be upgraded to accommodate load growth, particularly in residential areas, there may be other impacts that need to be addressed. In a recent underground district rebuilding project, for example, staff has been evaluating the possibility of increasing the size of transformers in that area to accommodate future electric vehicles and other loads. However, the aesthetic issues created by the larger transformers present challenges that would have to be overcome in any long-term effort to increase transformer sizes proactively to accommodate load growth.

A parallel effort in the area for EV integration includes re-evaluating the utility's policies regarding home electric panel upgrades. For many homeowners, adding an EV or multiple EVs could require a panel upgrade. CPAU currently charges a fixed fee for panels of up to 200 amperes (A), but a variable fee for connection requests greater than 200 A. If a utility transformer requires an

[12] Assuming $5,000 to upgrade a 25 kVA pole-top distribution transformer. See Attachment D for Distribution Transformer Sizing and Installation Economics

[13] Level 1 charging is typically plugged into a standard 120V outlet and has load up to 1.9 kW (120 V @ 16 Amps). Level 2 chargers are sold separately from the car, plugged into a 240V outlet, and has load up to 19 kW (240V @ 80 Amps).

upgrade due to a greater than 200A panel being installed, that cost is currently assessed to the homeowner.[14] CPAU currently has a Utility Service Capacity Fee Rebate program to help residents install EV chargers and be eligible for a rebate up to $3000 for these system costs.[15] Staff needs to re-evaluate the interconnection fee structure and its impact on sizing electric services to accommodate EVs and all-electric homes.

- ***Solar PV – Impact on Distribution System***

Palo Alto has observed a steady growth of local solar PV systems for the past two decades. Currently, CPAU has over 1000 solar systems installed with 10 MW of capacity that meet 1.6% of the City's electrical energy needs. CPAU's forecast is to have about 2,500 solar systems by 2030, with 35 MW of cumulative capacity and meeting 5% of the City's energy needs.

At the system level, CPAU has sufficient capacity to accommodate solar PV growth. However, sub-components of the distribution system, particularly balancing at the feeder level, could be impacted by unmanaged PV system growth. Potential challenges could include the risk of reverse power flow[16] and short-term voltage fluctuations that could adversely impact adjacent customers, the protection devices, and cause wear and tear on circuit apparatus (tap changers and switches).

CPAU has a total of 68 feeder lines with most rated at 12 kV, and 8 feeders rated at 4 kV. Feeders with a 4 kV rating and with insufficient customer loads may not be able to connect a large solar system without risking undesired reverse flow into the substation. CPAU has an existing long-term capital improvement plan (CIP) to upgrade 4 kV feeder lines to 12 kV. With these planned upgrades, CPAU's system will even be more robust and able to integrate additional local solar capacity. Attachment B provides details of the CPAU feeders with observed maximum, minimum loading and already interconnected solar capacity by the feeder. In theory, maintaining the solar interconnected capacity below the minimum load of the feeder at all times of the year will prevent any risks of reverse power flow. Considering this constraint and past minimum loading of feeders, staff's rough estimate is that CPAU's distribution system could accommodate an additional 50 MW of new solar capacity.

One other problem utilities experience, besides reverse power flow, is drops in voltage. CPAU's feeders are relatively short in length and therefore do not experience a large voltage drop at the end of the feeder line. However, concentrated cumulative solar capacity on a feeder line can make it susceptible to voltage fluctuations due to cloud cover and other intermittent changes in the PV system generation. CPAU Rule 27 incorporates the latest smart inverter standards as

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[14] CPAU electric service connection fees, Rate Schedule E-15
https://www.cityofpaloalto.org/civicax/filebank/documents/8083

[15]CPAU Capacity Fee Rebate program; this program has been funded by revenues from the state's Low Carbon Fuel Standards program. CPAU receives these credits as result of supplying clean electricity fuel to electric cars.

[16] Reverse power flow in a distribution network can be problematic due to overvoltage and protection devices inability to operate under these conditions. See Attachment- C for more details.

required by IEEE 1547 to reduce voltage fluctuation.[17] Staff continues to monitor industry standards for smart inverter capabilities and will explore including additional standards as part of the utility's interconnection requirements if they will contribute to effectively operating the system.

NEXT STEPS

Based on the current assessment of the distribution system, Staff plans to work on the following tasks in FY 2019 and FY 2020:

a) review and update the city's mapping of customer meters to the distribution transformer serving them to enable better assessment of distribution transformer loading,
b) identify distribution transformers that have potential to overload due to the high adoption of EVs, and upgrade them as needed,
c) better understand non-technical impacts of potential distribution system changes, such as the impact of larger distribution transformers on neighborhood aesthetics,
d) evaluate a standardized fee to connect residential customers requesting services greater than 200 Ampere panels and implement if feasible, and
e) explore the potential to further integrate smart inverter capabilities into the distribution system operations.

Staff will also continue to seek collaborative opportunities with industry partners and learn from industry best practices in these areas.

RESOURCE IMPACT

Other than the AMI project, no major electric distribution system capital projects are needed to accommodate DER growth in the next 5 years. CPAU has assembled an interdisciplinary team using existing staff and resources to continue to analyze and implement distribution system level projects to facilitate the adoption of DERs. Any additional resources required for the DER plan implementation, including changes to distribution planning strategy, will be discussed in the context of the DER Plan adoption, and will be included in annual budgets as appropriate.

POLICY IMPLICATIONS

The distribution system assessment and follow-up tasks are consistent with the 2018 Utilities Strategic Plan (Strategic Plan). The Strategic Plan has identified implementation of sustainable and resilient electric system as a key priority: "Achieve a sustainable and resilient energy and water supply to meet community needs." Specifically, this initiative conforms to action #2 under this Strategic Plan priority. The action specified is to: "Establish and implement a Distributed Energy Resources plan to ensure local generation, storage, EVs, and controllable loads (like heat pump water heaters) are integrated into the distribution system in a way that benefits both the customer and the broader community."

[17] CPAU Rule 27, Smart Inverter Generating Facility Design and Operation Requirements - https://www.cityofpaloalto.org/civicax/filebank/documents/28893. These requirements include controls for voltage and frequency ride-through and ramp rate and re-connect ramp rate controls.

ENVIRONMENTAL REVIEW

The Utilities Advisory Commission's discussion of the Distributed Energy Resources integration does not meet the definition of a project under Public Resources Code 21065, and therefore California Environmental Quality Act (CEQA) review is not required.

ATTACHMENTS

A. Summary of Technical Terms Used in the Report
B. Outline of CPAU Distribution System & Components
C. Literature Review of Benefits and Challenges of DERs in Distribution System Operations
D. Approach to Distribution Transformer Sizing and Installation Economics
E. Technical Addendum for DER Projections

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ATTACHMENT –A
Summary of Technical Terms Used in the Report

Below is a list of definitions and explanations of basic electrical engineering terms and concepts used in this report.

- **Units of Measurement**: Many distribution system components are described according to their ability to handle electrical potential, measured in Volts (V) or kilovolts (kV), instantaneous flow of electrical charges or currents, measured in Amperes (Amps), and power, measured in MegaVolt-Amperes (MVA) or MegaWatts (MW). These equipment ratings are important as they represent the amount of electrical capacity the component can handle without negative consequences (like sparking) and how much power can instantaneously flow through the component before it is overloaded and potentially damaged.
    - Electrical Potential or Voltage (Volts): It represents electrical pressure applied to electrons which forces flow of charge through the circuit. Transmission level electrical potential is measured in the hundreds of kilovolts (115 kV in Palo Alto), sub-transmission components are in the 60 kV range in Palo Alto, and distribution level components handle electric potential in the tens of kilovolts. A building will typically have less than one kV of electric potential inside. Typical house voltage is 120 volts, or 0.120 kV. Electric potential can be considered analogous to water pressure in the water distribution system network.
    - Current (Amperes) – It represents instantaneous flow rate of charge or analogues of water flow rate in the water distribution system. Most electrical panels for residential customers are rated at 200 Amps or less.
    - Power: Power is measured in MVA or kVA. One MVA equals one thousand kVA. One MVA is similar to one megawatt (MW) and one kVA is similar to one kilowatt (kW), but MVA and kVA are used in scenarios like distribution planning where the engineer is trying to account for both the real productive power running through the system as well as the non-productive power flow (also known as "reactive power") that can result from inductive loads like motors. MW is used more frequently for peak load planning or demand response, when the important measurement is the amount of real productive power being demanded by customers at any moment of the day. In theory, power is equal to the product of the voltage and current, or P = IV.
    - Power vs. Energy: Power is measured in MVA or MW, and is the amount of energy flow at any instant. Total energy delivered over time is measured in Megawatt-hours (MWh) or kilowatt-hours (kWh) and is the total energy delivered over a defined amount of time. One MW of power running continuously for one hour results in one MWh of energy being delivered or 1000 kWh. 1 kWh can light a 100

watt incandescent light bulb for 10 hours, a 23 watt compact florescent bulb for 43 hours, or a 14 watt LED bulb for 71 hours. A 300 watt (50”) plasma television uses one kWh every three hours. Average monthly usage for a Palo Alto residential customer is about 500 kWh and peak load of 3 kW.

- **Components of the Electrical System:**
  - <u>Electricity Supply Chain:</u> The structure of electricity delivery can be categorized into three functions: generation, transmission, and distribution, all of which are linked through key assets known as substations.

Figure A.1: Conceptual Flow Chart of the Electricity Supply Chain

Source: [United States Electricity Industry Primer] by Office of Electricity Delivery and Energy Reliability U.S. DOE

  - <u>Distribution Substation:</u> A substation is a major node in the distribution system which connects the transmission or sub-transmission network to medium voltage distribution networks, houses equipment such as step-down transformers and other protective devices and where power can be switched from one line to another and lines can be shut off as needed. The figure A2. below illustrates the flow of electricity through a distribution substation.

Figure A.2: Flow of Electric Power Through a Distribution Substation

Source: [United States Electricity Industry Primer] by Office of Electricity Delivery and Energy Reliability U.S. DOE

  - <u>Feeders:</u> A feeder is a smaller distribution line running from a substation to residential or commercial customers. Each feeder will have a number of small distribution transformers on it, and each small distribution transformer will typically serve several homes or businesses.

- Transformers: They are used in the distribution system to change from one voltage to another voltage. When voltage is reduced in the direction of power flow, the transformer is a “step-down” transformer. When it is increased, it is a “step-up” transformer. Smaller size distribution transformers can be accommodated on the pole top. Larger size transformers are mostly mounted on a concrete pad.

  Figure A.3 shows typical pole-top vs pad mounted transformers. Figure A.4 shows example distribution transformers from CPAU inventory: a). Single phase overhead 37.5 kVA transformer, 2.3 kV primary to 240/120V secondary (can serve up to 9 residential customers), b). Single phase underground 75 kVA transformer, 12.4 kV primary to 240/120V secondary (can serve up to 25 residential customers)

Figure A.3: Pole-top Vs Pad-mounted Distribution Transformers

Source: United States Electricity Industry Primer by Office of Electricity Delivery and Energy Reliability U.S. DOE

Figure A.4: Example Distribution Transformers from CPAU inventory: a). single phase overhead 37.5 kVA, b). single phase underground 75 kVA

a). 37.5 kVA transformer

b). 75 kVA transformer

ATTACHMENT – B

CPAU Distribution System Overview, Observed Performance, and Asset Value

I. Distribution System Overview

CPAU's distribution system consists of the following major components:

- Transmission Service: CPAU receives electricity from 115 kV transmission lines (rated at 135 MVA). These lines provide a total system capacity of 405 MVA (and 270 MVA even if one line is taken out of service). These lines have sufficient capacity to meet current peak load of 185 MW. It is worth noting that CPAU system peaked at 210 MW in the summer of 2000, illustrating the excess capacity currently available in the transmission lines serving Palo Alto.

- Sub-transmission Network and Distribution Substations: Electricity from the transmission substation is distributed via a network of 60 kV sub-transmission lines to nine substations. The 60 kV network is about 19 miles in length with 12 miles of overhead and 7 miles of underground. The substations contain 60 kV to 12 kV and 60 kV to 4 kV step down transformers. CPAU's engineering practice is to design and operate the substation transformers at 50% of the rated capacity and these components have sufficient capacity to carry increased loads.

- Feeder Lines and Distribution Transformers: There are 68 medium-voltage feeder lines (4 kV and 12 kV) [1] originating from the nine substations. These lines are approximately 300 miles in length, of which about 60% of the line length is underground and about 40% is overhead. Electricity from these feeders is stepped down to 120/240/480 volts via 3,150 distribution transformers that serve 25,500 residential and 4,000 commercial electric meters. The capacity of these distribution transformers ranges from 5 kVA to 75 kVA in residential neighborhoods, with a typical 25 kVA transformer serving 7 to 8 homes on average. Larger transformers that serve commercial areas are rated up to 2500 kVA.

- Customer Loads: In 2017, CPAU observed a system peak load of 183 MW and annual energy purchases of 960,000 MWh (at COP substation). About 80% of the electricity was delivered to commercial customers and 20% to residential customers.

- Supervisory Control and Data Acquisition (SCADA): Sensors and communication equipment at COP, nine substations, and feeder lines provide visibility of the system via a SCADA system.[2] Upon the implementation of an Advanced Metering Infrastructure (AMI) system, loading of distribution transformers and voltage along the feeder lines will

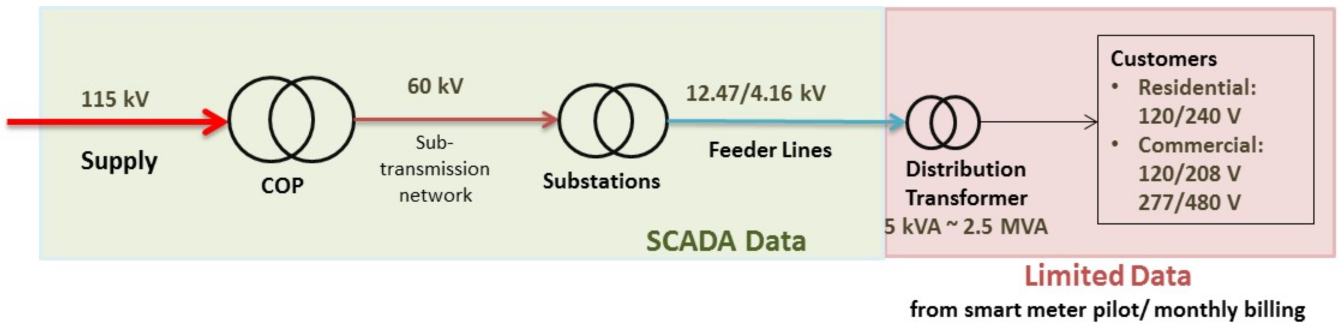
[1] Feeders are the electrical wires that carry power from sub-stations to customer load. Majority of feeder lines of CPAU distribution system are rated at 12 kV, with MVA ratings from 5.75 to 10.76.

[2] The SCADA system helps CPAU's planning and operations with the availability of real-time and 5 minute interval data acquisition.

also become visible to the distribution system operators and will help CPAU to better integrate DERs.

Figure B.1. below provides a schematic representation of CPAU distribution system.

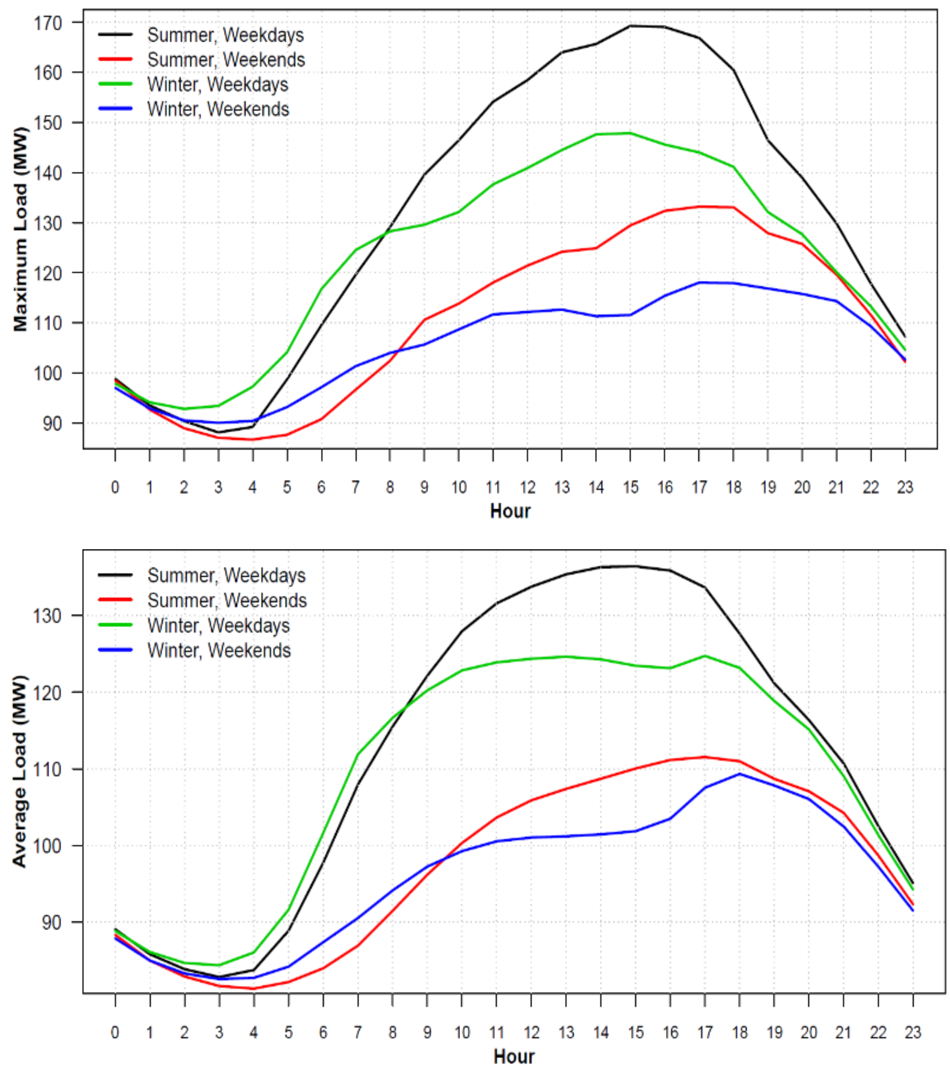
Figure B.1. Schematic of the CPAU Electric Distribution System



II. *Distribution System Observed Performance*

- System loading: Figure B.2. represents the maximum and average hourly load profile of the system observed at COP in calendar year (CY) 2016. CPAU distribution system peaked in late afternoon hours (2 to 5pm) on weekdays in summer time.

Figure B.2. Maximum and Average Hourly Load Profile at System Level (COP)



Data Source: SCADA data aggregated at COP across 115 kV to 60 kV stepdown transformers

- Substation transformers loading: CPAU substations have two or more stepdown transformers at each location with a back-up transformer available in most locations. Cumulative maximum rating across all substation transformers is 452 MVA and 50% of emergency ratings is about 250 MVA. In CY 2016, CPAU system peaked on September 26 around 4:05 pm with additional capacity of about 85 MVA available (compared to 50% emergency ratings).

- Feeder Lines Loading: Figure B.3. below represents the feeder lines capacity and maximum loading observed in CY 2016. Most feeders are currently operating at healthy margins and not reaching their peak rated capacities. Some feeder lines are reaching close to the rated capacities (e.g. feeders in substations 7) and these loads could be rebalanced by shifting loads to lesser loaded feeders.

Figure B.4. below maps minimum load observed on each feeder line in CY 2016 and existing solar PV capacity installed. Most 12 kV feeder lines have 0.5 MW to up to 3 MW of available capacity before connected solar capacity reaches a level equivalent to the minimum feeder load.

Figure B.3. Feeders capacity (MVA) and maximum observed loading (MW) in CY 2016

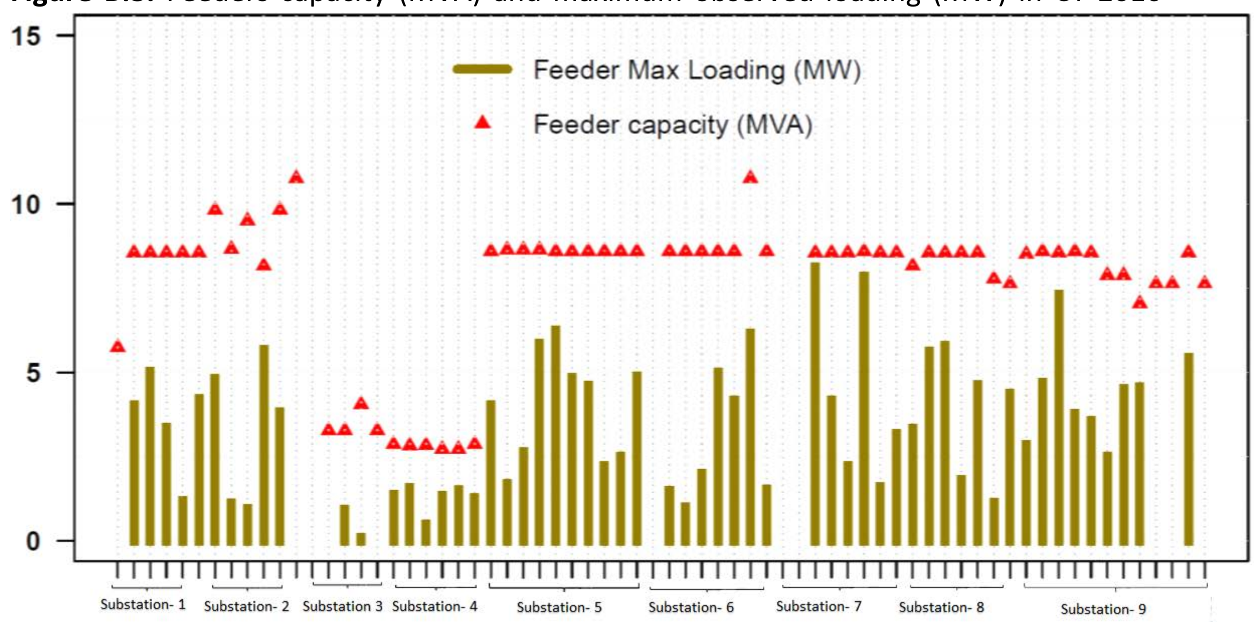
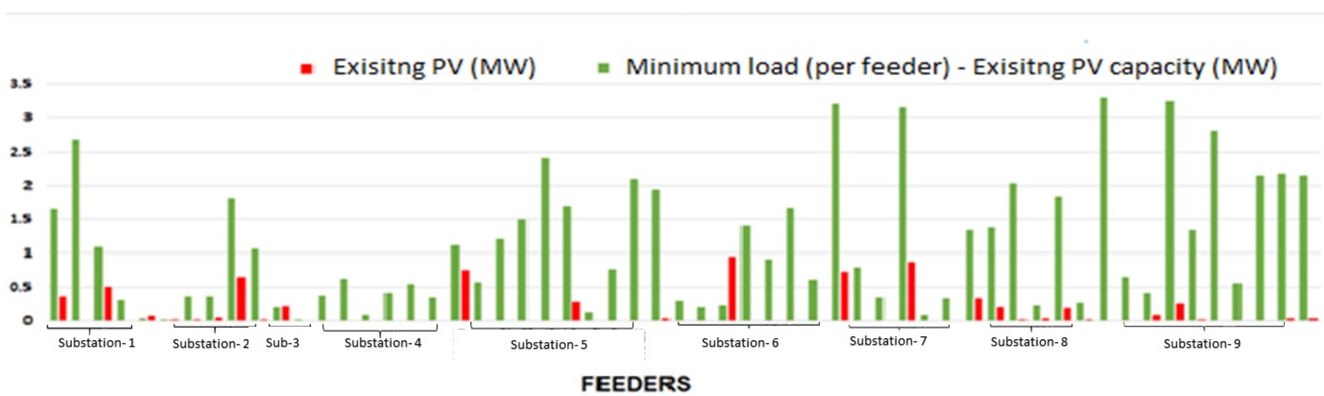


Figure B.4. Minimum feeder loading (in CY 2016) and existing solar PV capacity (MW)



- <u>Distribution Transformers:</u>

CPAU distribution system has 3,150 distribution transformers serving about 25,500 residential and 4,000 commercial electric meters. Currently, CPAU does not have visibility in the real-time loading of these transformers. Staff performs average summer and winter peak load estimation based on engineering formulae. Staff expects to have better visibility in the real-time loading of these components, with deployment of AMI and accurate mapping of distribution transformers to meters served.

Figure B.5. below shows a count of the distribution transformers according to their kVA ratings. One-third of these distribution transformers are rated at or less than 25 kVA. These are mostly residential transformers serving an average of 7 to 8 customers. High voltage rating transformers (> 75kV) serves medium and large commercial customers. The largest distribution transformer on CPAU system is rated at 2,500 kVA.

Table B.2. below provides count of distribution transformers by their physical location: pad mount, pole top or underground. Majority of the distribution transformers (1,782) are located on pole top and represent lower rating (<75 kVA) serving residential neighborhoods.

Figure B.5. Count of distribution transformers and their corresponding rated capacity (kVA)

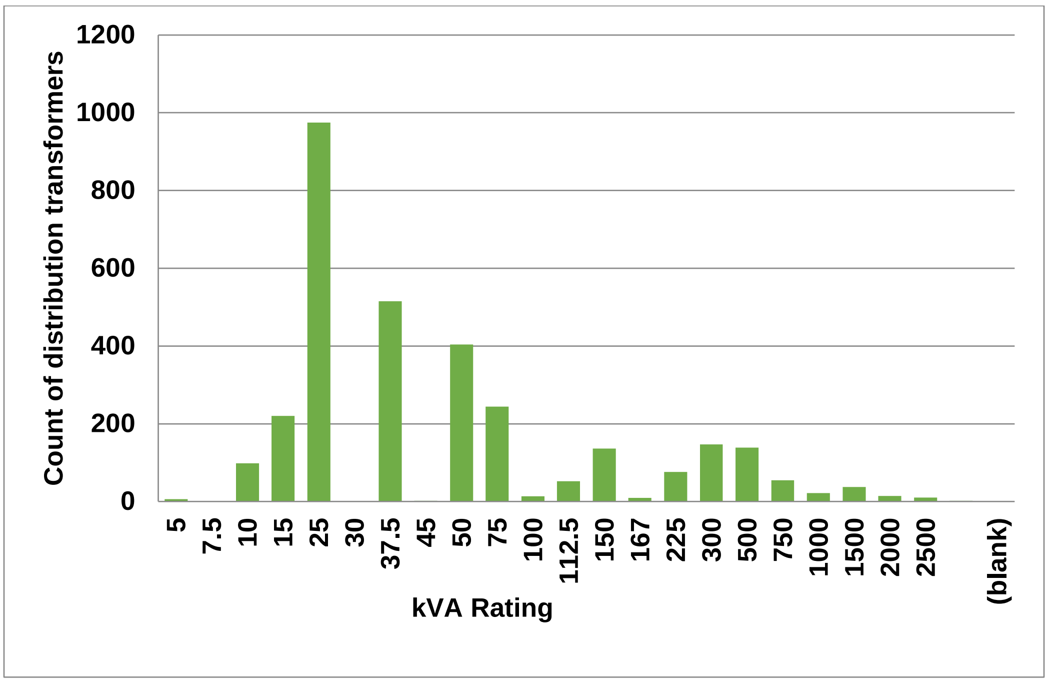


Table B.2. Distribution transformers count by their location: padmount, poletop, or underground

Distribution Transformer Type	Count
Padmount single phase	244
Padmount 3 phase	690
Pole top	1782
Underground Commercial	109
Underground Residential	325
Total	**3,150**

III. Distribution System Assets Value

Table B.3. represents acquisition cost and asset book value of various components of the CPAU electric distribution system. CPAU system has total net asset book value of 165.5 million (depreciated, net).[3] The table illustrates the relative magnitudes of investments in various distribution components, and provides a broader perspective to the DER integration discussion. For example, net book value of electric meters in the table is $2.3 million. With the implementation of AMI, these older meters would be retired and replaced with AMI meters. The acquisition cost of the AMI meters is estimated at $5 to $ 6 million and will be depreciated over a 15 to 20 year period.

[3] As of June 30, 2017. The City reports this net capital assets position in the annual Comprehensive Annual Financial Report as well, see p.g 38. https://www.cityofpaloalto.org/civicax/filebank/documents/62344

Table B.3. Capital Asset Value of the Distribution System Components

Electric Capital Assets	Acquisition Value (Million $)	Accumulated Depreciation (Million $)	Assets Book Value (Million $)
ELE - Equipment -Meters	4.8	(2.5)	2.3
ELE-Equip- Street Lighting	10.0	(7.5)	2.5
ELE-Equip- Traffic Signal	12.3	(9.4)	2.9
ELE-Equip- Communicatcation	1.0	(0.6)	0.3
ELE-Equip-Communication underground duct	0.9	(0.9)	0.0
ELE-Equip- Substation	41.3	(19.3)	22.1
ELE-Equip- Underground conduits, manholes and vaults	28.6	(11.0)	17.6
ELE-Equip- Distribution Transformers	20.4	(10.3)	10.1
ELE Equip-Pole, Tower , fixtures	30.8	(14.7)	16.1
ELE-Equip- Overhead Conductor	18.6	(5.4)	13.2
ELE-Equip- Underground Conductor	64.2	(24.4)	39.8
ELE-Equip-Tools, Estimating Software	2.6	(2.4)	0.2
ELE-Bldg.-Gen Plant	4.4	(1.9)	2.5
ELE-Services (all-in costs of performing system services, not including equipment cost)	51.6	(18.6)	33.0
ELE-Equip-Misc. Equipment (SCADA web portal, vehicles, GIS workstation, CAD , Utility billing system)	19.5	(16.6)	2.9
TOTAL	**311.0**	**(145.5)**	**165.5**

ATTACHMENT – C

Literature Review of Benefits and Challenges of DERs in Distribution System Operations

DERs may have disparate impacts and benefits on the distribution system depending on size, type, technology, location, engineering practices, and penetration level. Table C.1. below lists potential benefits of well-integrated DERs whereas Table C.2. illustrates challenges in integrating DERs growth. These benefits and challenges are listed based on the basis of industry literature review and may not specially be applicable to the CPAU distribution system.

Table C.1: Potential Benefits of Well integrated DERs to the Distribution System

+ Feeder Voltage Support (especially toward the end of the feeders)	There is a gradual drop in the feeder line voltage depending on the feeder length and load connected to the line. Commonly, automatically adjustable On Load Tap Changers (OLTC) or switched capacitors devices are used to provide voltage support.[1] Well-integrated features of advanced solar PV or ES inverters can also provide the voltage support.[2] However, this requires advance communications on the distribution operations side.
+ Peak Shaving (potential for investment deferral)	Coordinated operations of customer-sited DERs (solar PV, ES, and DR) can reduce the system or a substation peak demand and hence defer the need to upgrade major components of the system (such as substation transformers, feeder lines, and distribution transformers).
+ Loss Reduction	Distributed generation is co-located with customer load, and hence avoiding transmission and distribution system losses. [3]
+ Potential for Intentional Islanding (microgrid) to Enhance Reliability	Distributed generation along with ES and smart controls can be designed to operate in a microgrid fashion. It can be disconnected from the distribution grid in case of emergency and provide backup power to the host site.

[1] OLTC are located at distribution substations and they raise the starting voltage for a feeder under load, so that points along the feeder have desired voltage levels. Distribution system operators are required to maintain the feeder and secondary system voltage within certain limits (ANSI voltage limits standards of ±5%).

[2] Through reactive power set points or by dynamic volt/var related response. For example, see NREL technical report on Duke Energy case study: [Feeder Voltage Regulation with High-Penetration PV Using Advanced Inverters and a Distribution Management System]

[3] Transmission system in California has annual losses of around 2-3% CPAU's distribution system incurs ~2.5% losses.

Table C.2: Potential Challenges of Integrating DERs to the Distribution System

– Distribution Transformers Thermal Rating Violations or Overloading	Transformer overloads can occur when some contingency conditions occur or if they are already at operating 80%-90% of their full nameplate rating and extra capacity is needed (especially during hot summer months). Unmanaged EV charging or other DER loads in the late evening hours can trigger such overloading. In practice, transformers can be overloaded to a certain extent to keep the continuity of the load for economical or reliability reasons. However, this could lead to loss of useful life of the transformers.[4]
– Voltage Increase on a Feeder	Legacy distribution systems are designed for the radial flow of the power (i.e. power flow in unidirectional from the medium voltage system to the low voltage system). However, at a high penetration level of distributed generation, there are instants when the net production on a circuit is more than the net demand (especially at noon), and as a result, the direction of power flow is reversed. This reverse flow of power can result in over voltages along the distribution feeders.[5]
– Voltage Fluctuation, Protection Issues, Load Masking, Wear and Tear of Circuit Apparatus (tap changers and switches	Distributed solar PV generation gets impacted by shading due to passing clouds, temperature, and insolation variations. This results in in fluctuations in its output power of the PV system. Higher penetration of PV resources on a given line can cause voltage fluctuations and further nuisance switching of capacitor banks.[6]

[4] https://www.fleetcarma.com/impact-growing-electric-vehicle-adoption-electric-utility-grids/

[5] There are many industry articles documenting this trend. For example refer to, Technical Impacts of Grid-Connected Photovoltaic Systems on Electrical Networks, Journal of Renewable and Sustainable Energy

[6] NREL Technical report on High-Penetration PV Integration Handbook for Distribution Engineers

ATTACHMENT – D

Approach to Distribution Transformer Sizing and Installation Economics

I. Current Practices to Size Distribution Transformer

Engineering staff estimates the size of distribution transformers by taking into account factors related to the customer load and using the electrical engineering industry best practices for sizing that have evolved over time. The design factors considered for commercial and residential demand estimation are different. Traditionally, commercial loads require larger transformer capacity, hence approach for sizing these devices has been more detailed that the sizing approach used for residential transformers.

- Estimating Commercial and Industrial Demand

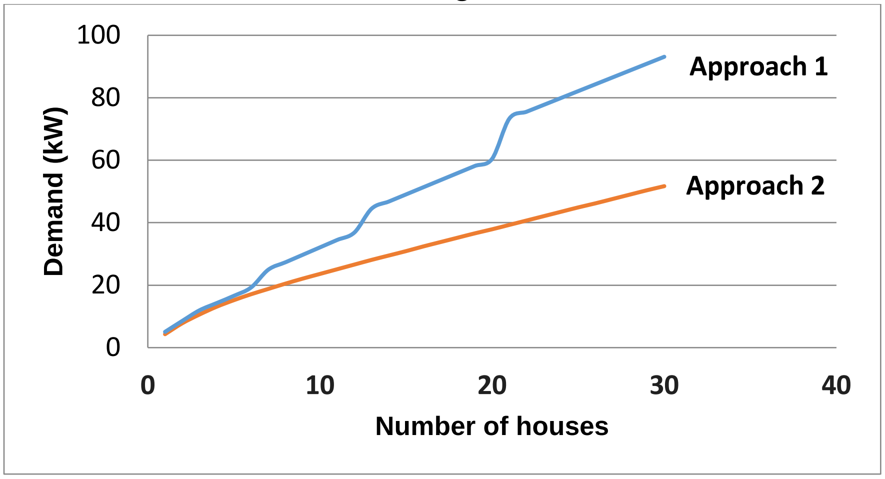
Staff utilizes various techniques to estimate the kVA demand of commercial or industrial loads. Most medium and large commercial customers have summer peaking load and equipment sizes of 75 kVA or greater. These larger size transformers are mostly pad mounted. Commercial customer load estimation techniques include:

  - *Load estimation based on comparable locations:* If there exists a similar business type with similar electrical design, then this approach is effective to estimate the demand and it provides quite accurate results.
  - *Load estimation based on connected load:* All new connection applications for electric service are required to complete an electric load sheet. This sheet summarizes the customer's connected loads by type. Total demand can be estimated by applying appropriate demand factor for each load type.
  - *Load estimation based on building area:* Engineering staff use reference tables listing typical load factors, power factors, and maximum demand by square footage for various business types.
  - *Load estimation based on customer electrical panel size:* Engineering staff use reference tables listing typical utilization factors for various business types.

- Estimating Residential Demand

CPAU currently considers two approaches to estimate residential load demand. These sizing approaches are derived using historic regression for residential customer load and considering Bay Area weather conditions. Figure D.1. shows the demand estimation by two methods for a typical household with an average monthly usage of 500 kWh per month per customer. These approaches imply on an average 2 to 3 kW of demand per residential household. Engineering staff uses the best judgment to evaluate the results of these approaches and includes considerations for equipment and labor costs to recommend appropriate equipment size as needed at the time of upgrades or new connections.

Figure D.1. Demand estimation for sizing residential distribution transformers



Staff is currently reviewing if and how these sizing standards should be updated to consider increasing Electric Vehicle (EV) load in the residential areas. The current sizing approach is susceptible to growing electrification load and installations of Level-2 EV chargers at home.[1] Staff plans to undertake a comprehensive review of the existing residential transformers inventory along with considerations for changing EV loads. With the implementation of AMI capabilities, CPAU will have additional visibility regarding the real time loading of this equipment.[2]

II. Distribution Transformers Installation Economics

Distribution transformers installation economics are mainly dependent on two factors: equipment costs and labor costs. It also depends on how many customers the equipment could serve. Table D.1. below provides a range of cost estimates for example distribution transformers sizes located at pole-top, vault-mounted (or underground) and pad-mounted. Please note that these estimates are provided to guide the discussion of the distribution system assessment and does not necessarily represent CPAU actual costs for each upgrade. Each upgrade or new connection request may have different installation costs depending on the case –specific needs.

[1] A Level-2 charger can put a peak demand of 7 to 19 kVA.

[2] Most California utilities have incorporated monitoring and upgrade alerts for the distribution transformers based on the real-time AMI data.

Table D.1 Cost Estimates of Distribution Transformers

Transformer Ratings and Location	Equipment Costs ($)	Labor Costs ($)	Total Costs ($)
5 kVA to 25 kVA Pole top	$1,000 - $3,000	$3,000 - $7,000	$4,000 - $10,000
25 kVA Pad-Mounted	$3,000 - $7,000	$5,000-$9,000	$8,000 - $16,000
75 kVA Pad-Mounted	$7,000 - $12,000	$7,000 - $12,000	$14,000 - $24,000
100 kVA - 750 kVA Vault Mounted (underground)	$7,000 - $20,000	$11,000 - $16,000	$18,000 - $36,000
1000 kVA or 25,000 kVA Pad-Mounted	$20,000 - $50,000	$13,000-$20,000	$33,000 - $70,000

III. Illustration of Transformer Sizing and Decision Making Process to Upgrade Distribution transformers

For example, if a 25kVA transformer is currently serving 7 homes, the estimated loading of the transformer (assuming 3kVA loading on each home) is 21kVA, below the 25 kVA rating. If three of these homes purchase EVs that have the potential of charging at between 3 kVA (Level-1 charging) and 7 to 19 kVA (Level-2 charging), then most likely the 25 kVA transformer would not suffice.

In such a case, CPAU has two options. If another pole is available to mount another 25 kVA transformer, mount a second transformer and serve 3-4 homes from each transformer. Or the alternate would be to bring down the 25 kVA transformer and mount a 37.5 or 75 kVA transformer. If the transformer rating exceeds 75kVA, the weight is too heavy to mount on poles, hence has to be mounted on the ground on a pad – this tends to be more expensive.

City's current practice, is to charge the customer who triggered the upgrade to pay for the upgrade cost. CPAU currently has a Utility Service Capacity Fee Rebate program to help residents install EV chargers and be eligible for a rebate up to $3000 for these system costs.[3]

[3] CPAU Capacity Fee Rebate program - https://cityofpaloalto.org/gov/depts/utl/residents/sustainablehome/electric_vehicles/ev_chargers_for_homes/2017_utility_service_capacity_fee_rebate.asp

Technical Addendum for Distributed Energy Resource (DER) Projections

Initial projections for DER technologies were developed to inform both the proposed DER Plan as well as ongoing work regarding DERs. These projections will be updated as more detailed market assessments are performed.

The distributed energy resources considered for the purposes of these analyses were:
- Energy Efficiency (EE)
- Solar Photovolatics (PV)
- Electric Vehicles (EV)
- Demand Response (DR)
- Energy Storage (ES)
- Heat-pump Water Heaters (HPWH)
- Heat-pump Space Heaters (HPSH)

1. DER Adoption Projections

Preliminary forecasts of the number of DER systems through year 2030 are shown below in Table 1. The 2030 estimates are highly variable, as they depend on market conditions, technological innovations, and changing regulations, and therefore these estimates could increase or decrease by up to 50%.

Table 1: Estimated number of DER systems through 2030[1]

Estimated Number of Systems			
DER Technology	**2017 (current)**	**2020**	**2030**
PV	1,000	1,300	2,500
EV[2]	2,500	5,900	18,700
EE	40,880	45,000	60,000
DR	8	25	75
ES	11	85	580
HPWH	10	200	2,700
HPSH	0	25	800

<u>Assumptions & Limitations:</u>

These projections were developed for long-term load forecasting and budgeting purposes. They reflect current realistic estimates of technology adoption rates. The current forecasts do not achieve S/CAP goals by 2030, but staff will be coordinating with the sustainability team to

[1] These estimates represent current base case scenarios. Staff will explore appropriate high and low scenarios in further modeling.

[2] This is the total residential EVs currently registered in Palo Alto. There are also EVs which commute into Palo Alto, some of which charge while in Palo Alto and add to CPAU electricity sales. In addition to the residential EVs shown here, there are estimated to be approximately 3,100, 5,900 and 20,000 commuter EVs in 2017, 2020 and 2030 respectively.

accelerate adoption wherever cost-effective. These forecasts will be updated regularly and staff will continue to collaborate with other departments to support City sustainability goals.

- ***EE:*** Adoption rates for EE are based on the 10-year Energy Efficiency Goals for 2018-2027 which were updated in 2017.[3] For the years 2028 through 2030 the assumed savings are the average of the savings in 2026 and 2027 which is the methodology suggested by the CEC for estimating savings beyond the 10-year goals.[4] More details on the EE methodology for market potential can be found in Staff Report 7718 from March 6, 2017.
- ***PV:*** These projections are based on a technical and economic potential, with adoption growing steadily, with the growth rate itself plateauing as is typically seen in a maturing market. These projections include behind the meter installations in residential and commercial sectors, but do not include a Community Solar installation. These projections also do not include the feed-in tariff installations from the CLEAN program as these are counted as supply resources and count towards the electric utility's Renewable Portfolio Standard.
- ***EV:*** To-date Palo Alto has observed residential EV adoption rates approximately three times greater than the California statewide average, and this rate for residential adoption relative to statewide average projections is assumed to continue to 2030. To estimate the EV adoption rates of commuters into Palo Alto the observed adoption rate from 2017 census data for the entire Bay Area was extended to 2030.
- ***DR:*** This forecast is based on modest growth of the current voluntary large commercial demand response program. Somewhat more robust growth is expected after AMI implementation in 2023.
- ***ES:*** This forecast is based on statewide projections for batteries and CPAU electricity rate structures.
- ***HPWH:*** This forecast is based on historical of PV penetration, market readiness, and CPAU customer program management experience. Based on this forecast, staff projects a natural gas load reduction of up to approximately 1% from HPWH by 2030.
- ***HPSH:*** This forecast is based on historical of PV penetration, market barriers, and CPAU customer program management experience. Based on this forecast, staff projects a natural gas load reduction of up to approximately 1% from HPSH by 2030.

2. DER Load Impact Projections

Table 2 shows the impact of DERs on CPAU's energy sales based on the number of systems projected in Table 1. These estimates are also highly variable, as each underlying component could change by as much as 50% by 2030. Moving forward, the combined impact of all these DERs is expected to lower energy sales by 2.2% by 2020 and 6.6% by 2030.[5] The net effect of projected DERs coming online after 2017 is to offset other anticipated electricity load growth throughout CPAU territory,[6] leading to essentially flat total CPAU system loads from 2017

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[3] Although CPAU established our EE goals based on net savings, the energy efficiency savings shown here are on a gross basis (which includes EE savings due to free-ridership).

[4] The extension of savings through 2030 is based on the methodology put forth in the CEC presentation September 7, 2017 which can be found here: CEC presentation on Energy Efficiency Savings from Utility Programs.

[5] All percentages are relative to Fiscal Year 2017 electricity retail sales.

[6] For budgeting purposes the Northern California Power Agency has developed an econometric regression to forecast electric sales from 2018 to 2030 with the current level of DERs (in other words assuming no additional

through 2030. However, a scenario with higher load growth, lower adoption of EE or PV, or higher adoption of EVs could result in an overall growth of electricity sales.

Table 2: Estimate of the impact of DERs on CPAU retail energy sales

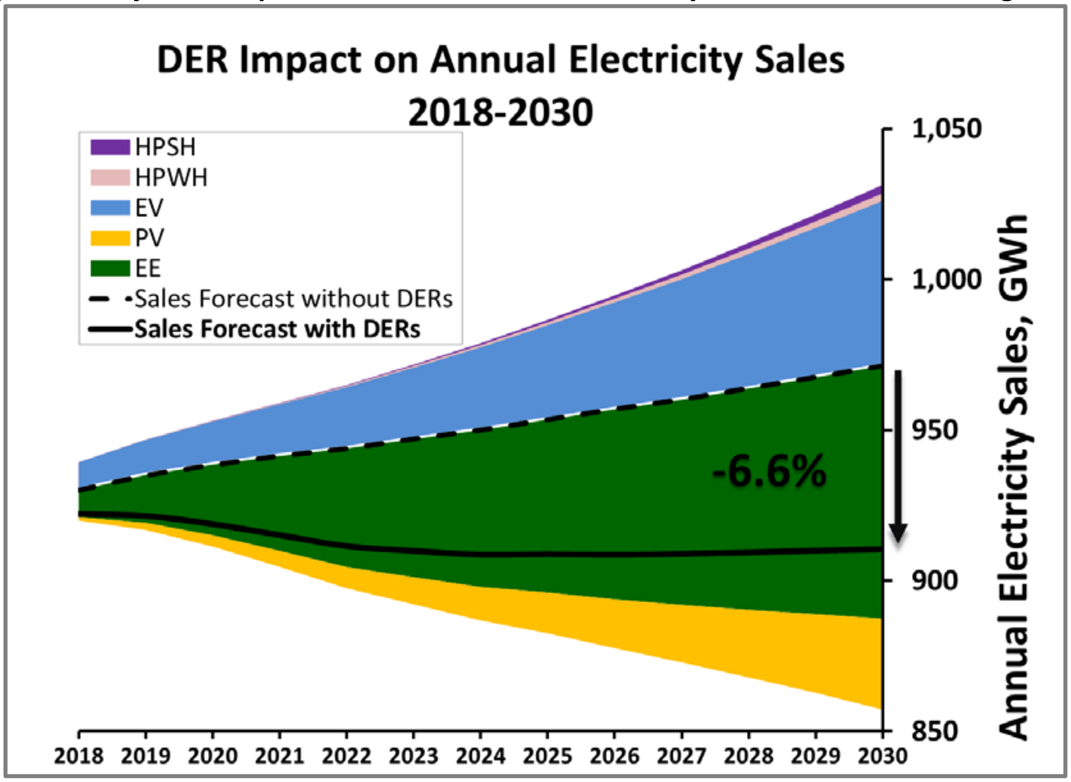
DER Technology	***2017 (current)***		***2020***		***2030***	
Contribution to Energy Sales	***MWh***	***%***	***MWh***	***%***	***MWh***	***%***
PV	-15,000	-1.6%	-18,800	-2.0%	-45,200	-4.9%
EV	7,100	0.8%	14,300	1.6%	54,800	6.0%
EE	-55,300	-6.0%	-78,800	-8.6%	-139,200	-15.2%
DR	7	-	23	-	200	0.02%
ES[7]	-	-	-	-	-	-
HPWH	9	-	190	0.02%	2,500	0.3%
HPSH	-	-	90	0.01%	2,800	0.3%
Combined DER Impact: from 2007	**-63,200**	**-6.9%**	**-83,000**	**-9.1%**	**-124,000**	**-13.6%**
Combined DER Impact: from 2017	**-**	**-**	**-19,700**	**-2.2%**	**-60,900**	**-6.6%**
CPAU Overall System Load Growth from 2017[8]	**-**	**-**	**-3,200**	**-0.3%**	**-6,900**	**-0.8%**

DERs). The CPAU overall system load growth from 2017 is the combination of this econometric forecast and the individual DER forecasts.

[7] Batteries and other ES devices may result in either net increased energy retail sales (due to battery losses where commercial customers use batteries to avoid CPAU demand charges) or net decreased energy retail sales (due to increased onsite consumption of behind the meter solar). For the purpose of these analyses these two effects are assumed to be roughly the same magnitude and therefore ES systems are not considered to have any net effect on energy sales.

[8] Going forward from 2017 the total CPAU load is forecasted to grow at roughly 0.4% per year if no more DERs were added to the system. With the addition of new DERs, the total CPAU load is projected to decrease by roughly 0.8% from 2017 electricity sales by the year 2030.

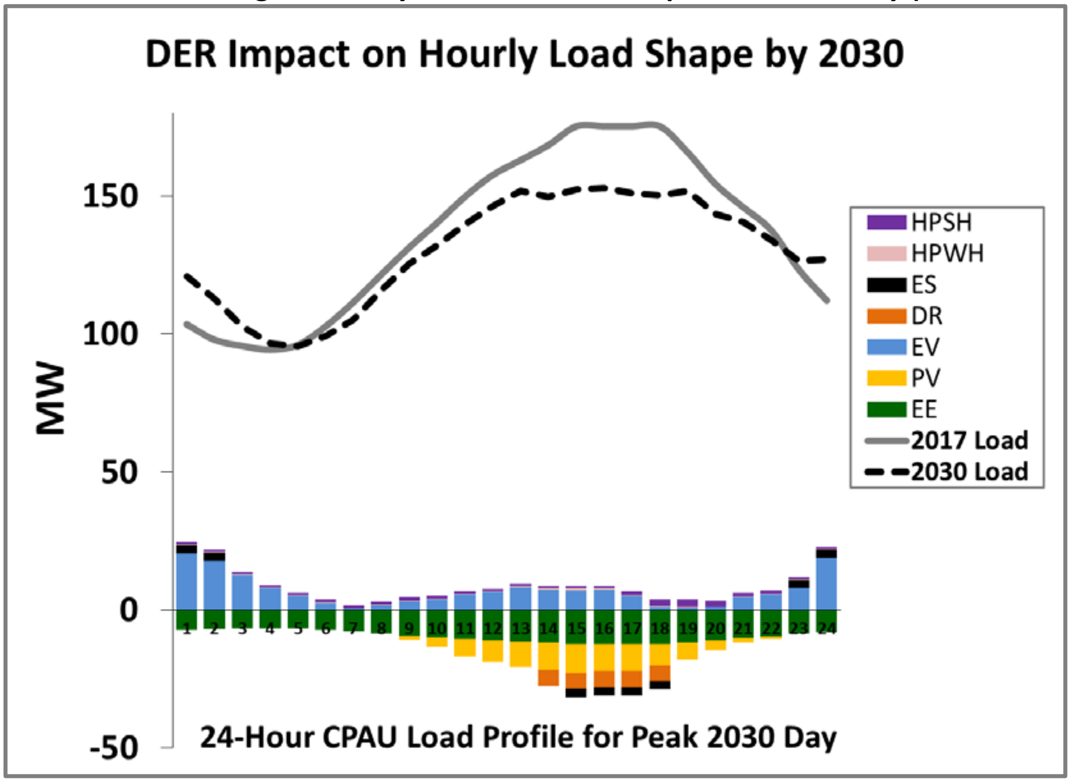
Figure 1: Projected impact of DERs on annual electricity sales from 2018 through 2030



Another important aspect of DERs is their ability to potentially flatten overall peak demand, especially due to PV and DR. The impact of the projected DERs on a peak summer day in 2030 is illustrated in Figure 3, showing that the combined effect is to flatten the overall load shape and lower the peak demand. This overall flattening of peak demand is anticipated to increase the overall system annual load factor from 62% in 2016 to 70% in 2030.[9] A higher load factor and flatter loads tend to lower overall CPAU costs.

[9] Annual Load Factor is a measure of transmission and distribution system utilization and is defined as the ratio of average annual energy load to the peak annual energy load. A high load factor means that system capacity is highly utilized, with average annual usage that is not much lower than the annual peak. A low load factor indicates that electric use has a high annual peak relative to annual average usage, meaning that substantial additional system capacity is needed to serve that high annual peak, generally resulting in higher costs due to low utilization.

Figure 2: Potential change in hourly electric loads on a peak summer day (2017 vs. 2030)[10]



[10] HPSH are included on a peak summer day since there is an expectation that heat-pump space heaters will be used as air conditioners on the hottest days.