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City of Anaheim

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CEC IEPR 2023

Form 4. Demand Forecast Methods and Models

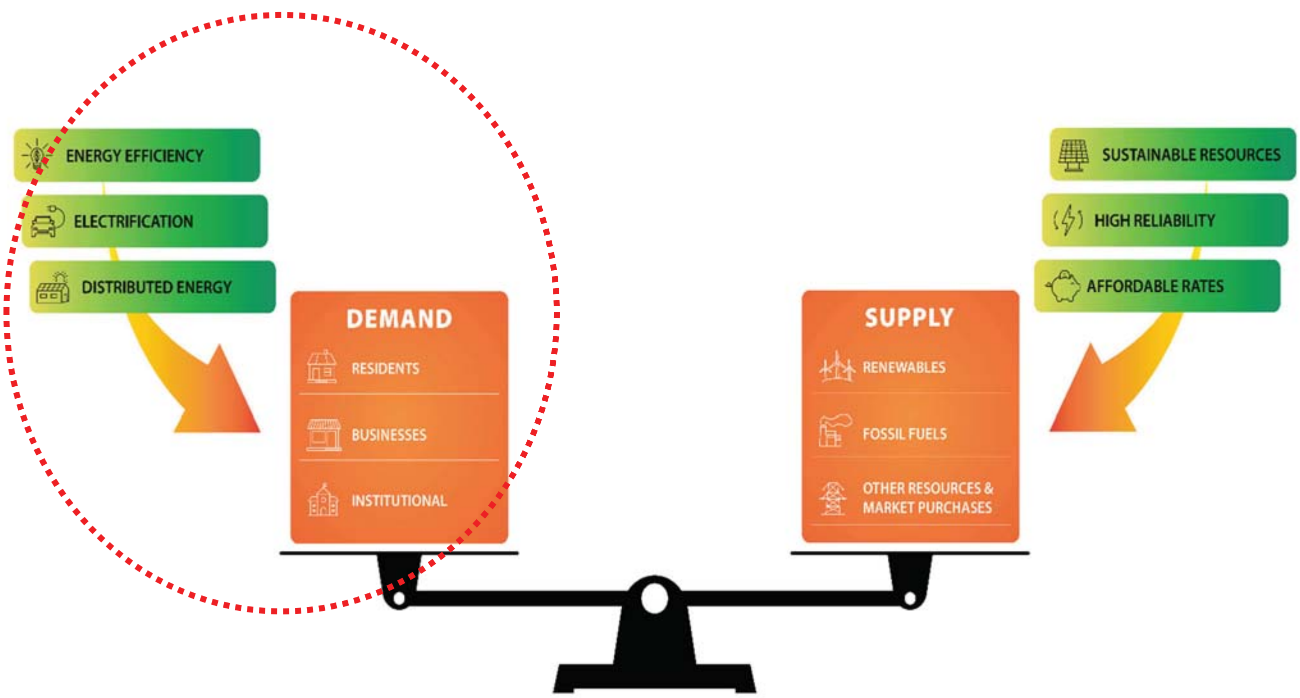
The attached document provides information on Anaheim's electricity demand forecast methods, models and data used to develop the submitted forecast forms per the CEC IEPR 2023 Report. Anaheim Public Utilities most recently developed the demand forecast through the Integrated Resources Planning (IRP) process. The attached document is the Demand and Peak Forecast section of the IRP.

VI. ENERGY DEMAND AND PEAK FORECASTS

Integrated resource planning is the process in which APU evaluates a multitude of supply-side and demand-side resources to meet customer energy needs in an efficient, cost effective, and reliable manner. Traditionally this integrated resource planning activity was primarily to ensure that all cost-effective demand side resources were deployed prior to commitment to new supply-side resources such as power plants. Supply-side resources usually involved long lead times to develop, and increased the use of fossil fuel causing the depletion of a limited resource and adverse effects on the environment. The passage of SB 350 requires integrated resource planning to consider and address the following elements in addition to traditional demand-side and supply-side resources:

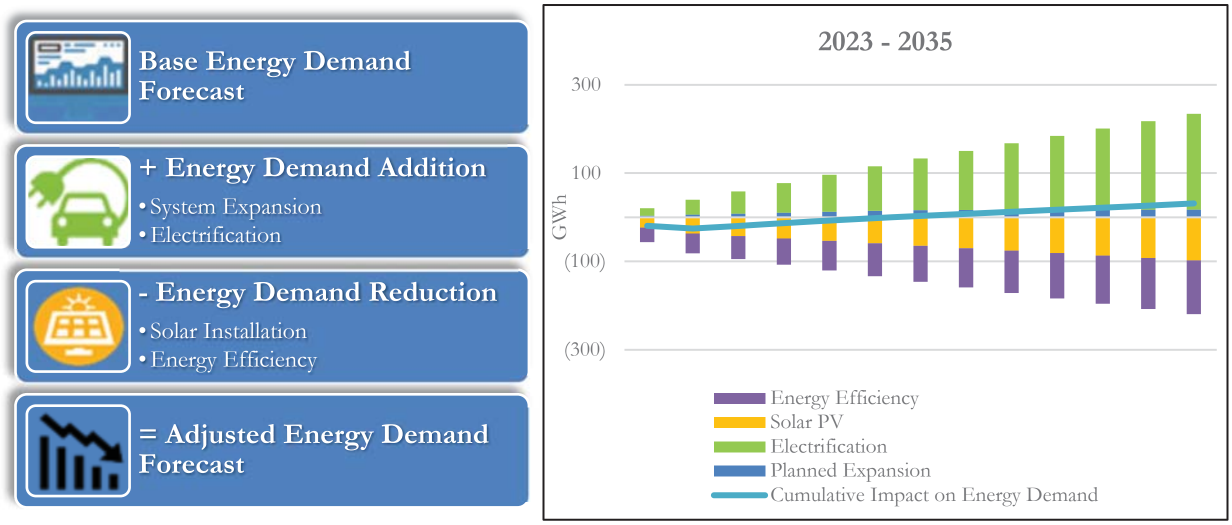
- Actively involve stakeholders. APU proactively solicited additional feedback from residential customers to build upon information obtained through the 2018 IRP Customer Survey process.
- Include energy efficiency and demand side management activities.
- Incorporate more robust analysis of more aspects of utility activities.
- Explicitly account for commodity price volatility and other risks to quantify the risk/reward tradeoff.
- Reflect a set of goals that are broader than just meeting energy demand, such as meeting RPS goals and GHG goals.
- Accommodate the load increases and decreases caused by transportation electrification and distributed energy resources such as rooftop solar.

The energy demand forecast, and peak forecast are both developed as a first step to evaluate APU's future energy needs. APU's forecasting methodology and different components of the forecasts are detailed below.



Pursuant to the 2023 IRP, APU performed a long-term statistical forecast of its expected load growth and then adjusted this base load forecast for the factors described above. This adjusted load forecast projects a total load growth of 1.41% between 2024 and 2035, effectively a low growth energy demand forecast, which indicates that the expected customer expansion and EV growth is being offset by customer solar installation and energy efficiency reductions. Load forecast beyond 2036 assumes a 0.25% annual load increase. The growth factor is consistent with average load growth between 2027 and 2036 and is applied due to the lack of information on all demand variables.

Graph 2: Cumulative Adjustments to Base Energy Demand Forecast



In determining APU's energy demand forecast, staff considered historical energy demand and customer growth trends as the basis for statistical modeling and econometric forecasting techniques to develop a "**base energy demand forecast.**" Once developed, the base forecast was further adjusted (referred to as the **adjusted energy demand forecast**) by planned system expansion, expected EV energy demand, estimated customer-side solar installations, and the effect of demand side management and energy efficiency. While system expansion and EV growth increase the energy demand, solar installation and energy efficiency programs reduce the energy demand.

The **adjusted energy demand forecast** was then used as the basis for the development of power supply expansion portfolio scenarios, which were analyzed to determine the recommended supply (resource) portfolio.

A. ENERGY DEMAND FORECAST - METHODOLOGY & ASSUMPTIONS

The energy demand forecast is determined in two steps:

The first step **establishes the base energy demand** forecast. It relies on traditional econometric forecasting techniques to develop relational equations that reflect historic consumption trends. The base forecast for energy demand is developed using a 5-year running average of historical temperature.

The second step **adjusts the base energy demand forecast** by taking into consideration residential and commercial projects within the City of Anaheim (City) that may affect energy demand. Information related to these projects is collected through collaboration with the City's Planning Department, APU Electric System Planning, and Community & Sustainability Programs. Examples of such projects include City-wide development and expansion plans, customer-specific capacity additions and/or energy reduction plans, and the installation of commercial-scale solar installations and other behind-the-meter distributed generation resources. Project timelines are evaluated and incorporated into adjustments that either increase or decrease the "base" forecast.

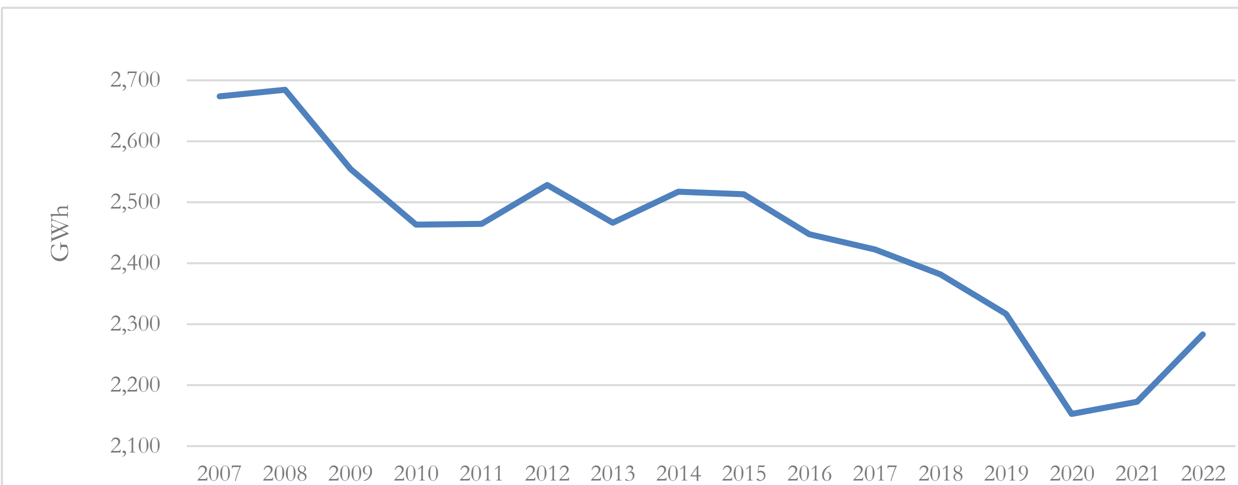
A.1. BASE ENERGY DEMAND FORECAST

Base Energy Demand Forecast

HISTORICAL ENERGY DEMAND

Prior to the economic recession in 2008, APU's average energy demand was between 2,500 and 2,700 GWh. From 2008 to 2011, a decline in energy demand growth was observed due to economic conditions impacting demand. The economy began to stabilize in 2011 and continued to improve through 2015. However, the corresponding demand growth was offset by behind-the-meter distributed generation, such as fuel cell and solar installations, as well as by energy efficiency in both the commercial and residential sectors. From 2017 to 2019, energy efficiency and solar penetration continued to reduce system demand. The COVID pandemic lowered system demand in 2020 through 2021. By 2022, a slight bounce back in energy demand occurred after statewide reopening.

Graph 3: Anaheim Actual Energy Demand 2007 - 2022



ECONOMETRIC MODELING

Econometric modeling is the application of mathematical and statistical methods to forecast future values and understand the relationship between variables. APU develops its forecast of total system energy consumption using econometric modeling. Hourly energy demand is estimated using least squares estimation and variables for expected temperature, calendar (weekday versus holiday), season and time effects (which capture specific hours as well as the cumulative impact of prolonged heat waves). Five years of historical hourly data are used to estimate the following econometric equation:

$$Total\ Energy_t = \alpha + \beta_1\ Temperature_t + D_1\ Holiday_t + V_t + M_t + \varepsilon_t$$

Where:

$Temperature_t$ = Temperature at hour t

$Holiday_t$ = Dummy variable to identify weekend and NERC holidays

V_t = Vector of dummy variables for the hours

M_t = Vector of dummy variables for the months

ε_t = Error term

VARIABLES INCLUDED: TEMPERATURE FORECAST

APU owns calibrated equipment at the Linda-Vista Reservoir that records hourly temperature in the Supervisory Control and Data Acquisition (SCADA) system. The IRP energy demand forecast assumes normal weather conditions and uses average hourly temperatures from the past five years (summer 2017 – summer 2022). The forecasted monthly temperatures in degrees Fahrenheit are summarized below in Table 1. Compared to data from the 2018 IRP, the total average and maximum temperature did not change; however, the minimum temperature increased by 13%. The monthly average temperature was higher in June – August and October – December, and lower in February, March, and September. The monthly minimum was higher in 10 out of 12 months of the year.

Table 1: Temperature Summary

Month	Average	Minimum	Maximum
January	60	38	92
February	59	36	93
March	61	42	94
April	65	48	104
May	67	51	96
June	72	56	100
July	76	61	105
August	77	60	105
September	75	55	105
October	71	52	105
November	65	41	99
December	59	40	86

VARIABLES EXCLUDED: ECONOMIC AND DEMOGRAPHIC FORECAST

Anaheim is a fully developed Orange County city with historically consistent growth and median income level and employment rate. A series of modeling tests determined that the inclusion of economic and demographic variables leads to increased variability, and results in overly optimistic demand growth. The hourly demand estimation excluding these variables proved to be more accurate.

Although economic and demographic variables are excluded from the base model, planned expansions and energy reductions are included as adjustments after the econometric regression modeling is complete.

MODEL VALIDATION

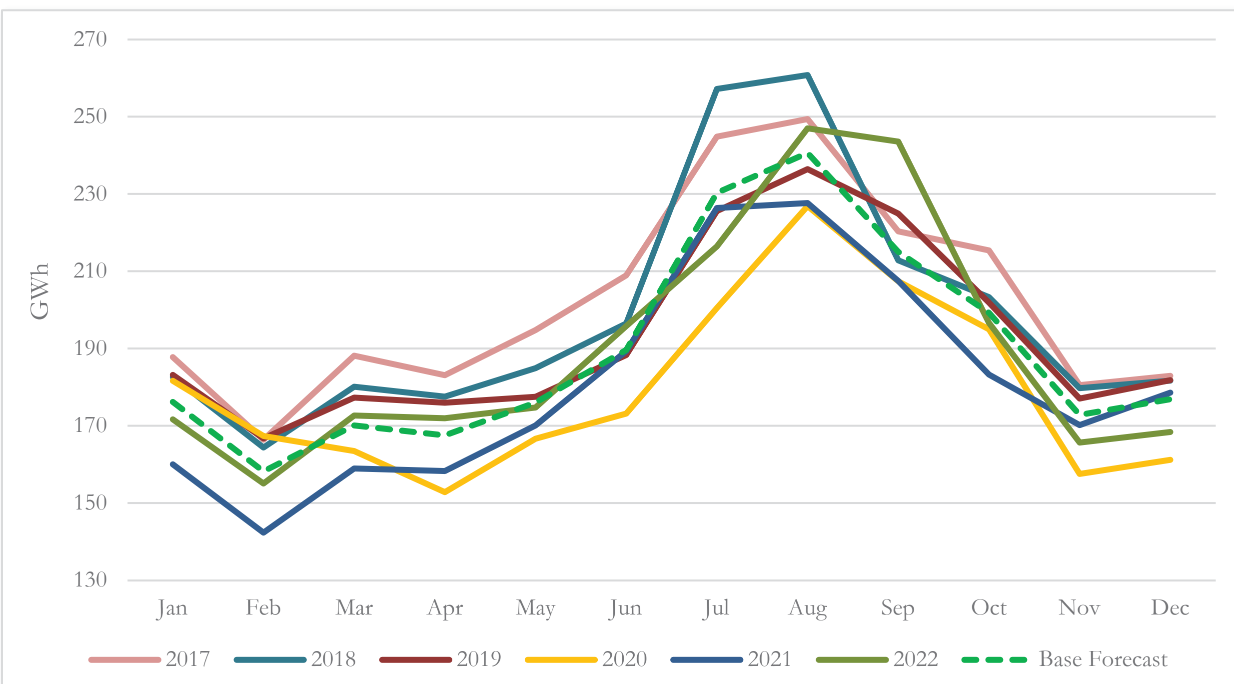
The base econometric model is validated by comparing modeling results to historical energy demand data. Essentially, the model is used to develop energy demand forecasts for 5 historical years (summer 2017 through summer 2022). The forecast results are compared to historical actual values and analyzed for reasonableness. The base model was proven to produce efficient estimation results averaging 0.28% variance from the testing period. Had the model been proven inefficient, alternative variables would have been introduced and a new model established to go through the validation process again.

Note that backcasts for selected historical months showed greater variance due to the pandemic impact. Therefore, two other models were introduced to remove the pandemic impact. However, upon review and comparison, the 5-year historical data regression model still yielded the most reasonable overall forecast. The regression model is accepted as the base forecast model. In addition, the energy demand forecast is subject to stress testing of a wide range of high and low demand forecasts to capture any deviations from the base forecast.

FORECAST RESULTS

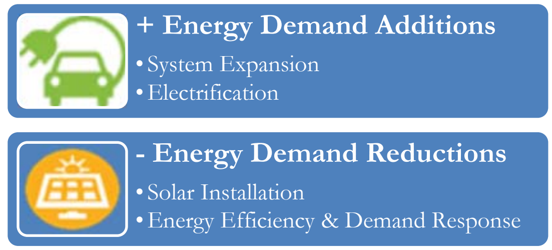
After validating the model, the base forecast for future years is generated and compared to historical energy demand. As seen in Graph 4, the energy demand forecast profile is comparable to historical energy demand. Overall, annual energy demand shape remains fairly constant, while peak demand appears to be lower than that of recent years. This is mostly due to the assumption of normal weather conditions rather than the incorporation of heat shocks in the base model.

Graph 4: Historical and Base Energy Demand Forecast by Month



A.2. ADJUSTMENTS

Planned energy growth and reductions are included as adjustments to the base economic model. Adjustments include planned new development, electric vehicle growth, behind-the-meter distributed generation, and energy efficiency targets.



This section focuses on the energy demand impact. The design, funding and details of these programs can be found in the following sections:

X. Transportation Electrification

XI. Solar and Other Distributed Generation

XII. Energy Efficiency and Demand Response Programs

XIII. Programs for the Low Income and Disadvantaged Communities

SYSTEM EXPANSION

Most of the buildable open land in Anaheim is fully developed. While new building developments may contribute to energy demand increase, a corresponding decrease also incurs from the demolition of existing buildings and infrastructure. As such, it is not appropriate to apply a growth rate based on historical trends. Rather, new development data is gathered from City permits and from APU's Electric System Planning, and these net impacts to energy demand are applied to the base model.

Anaheim's most recent development projects are expected to cumulatively contribute an additional 34 MW capacity to Anaheim's distribution infrastructure through 2035. When estimating the impact to load, staff took into consideration both the distribution system expansion and the varying levels of capacity factors for each customer sector.

System expansions related to transportation electrification is accounted for separately under the section below.

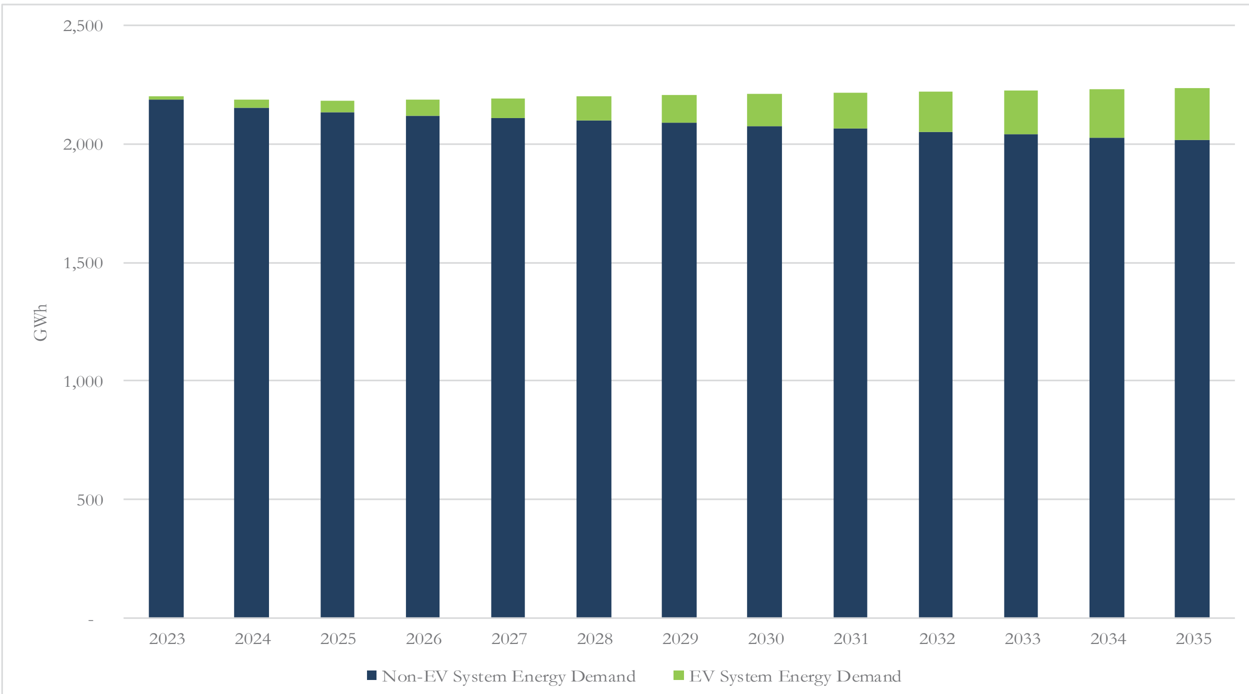
EV PENETRATION & TRANSPORTATION ELECTRIFICATION

APU's incremental EV load is expected to average 17 GWh annually, from 2023 to 2035. This results in a cumulative EV load of 134 GWh in 2030, which is more than double the 2018 IRP forecast of 63 GWh in 2030. By 2035, the estimated cumulative EV load reaches 217 GWh, or 9.7% of the total system load. The CEC no longer provides the "Transportation Electrification Common Assumptions" workbook[8] made available during the 2018 IRP process. The forecast is derived from the CPUC 2022 Unified RA and IRP Modeling

[8] APU relied on the "Transportation Electrification Common Assumptions 3.0" workbook for the 2018 IRP EV Energy Demand forecast. It included utility-specific forecast on EV growth, energy demand increase per EV, and GHG emission savings per EV.

Datasets[9] with data comparison again the CEC IEPR Demand Forecast[10]. Note that the statewide CPUC's 38 MMT Portfolio is used to approximate EV energy demand in APU territory. This is consistent with the California Air Resources Board (CARB) 2022 Scoping Plan[11] approach for the electricity sector.

Graph 5: Estimated Electric Vehicle Energy Demand Growth



FUEL SUBSTITUTION (BUILDING ELECTRIFICATION)

Additional achievable fuel substitution (AAFS) was introduced as a new load modifier in the CEC's 2021 IEPR. As explained in the 2021 IEPR, "Fuel substitution refers to substitution of one end use fuel type for another, such as changing out gas appliances in buildings for cleaner more efficient electric end uses."[12]

AAFS is also a component of the CPUC's IRP demand forecast. APU's AAFS may be derived from the CPUC's IRP demand forecast, as a percentage of the Southern California Edison region's overall AAFS energy demand. This method captured a minimal cumulative energy demand increase of 2% by 2035. However, Anaheim is a

9 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/unified-ra-and-irp-modeling-datasets-2022 "study_10_2023_Renewables_Output_Profiles", "study_10_2024_Renewables_Output_Profiles", "study_10_2026_Renewables_Output_Profiles", "study_10_2030_Renewables_Output_Profiles" and "study_10_2035_Renewables_Output_Profiles"

10 https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1 "TN241221_20220119T103905_CED 2021 Baseline Forecast - SCE Mid Demand Case"

11 Pg. 201 of the 2022 Scoping Plan Update: https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp.pdf

12 Page 3, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report and https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581

fully developed Orange County city, with half of the utilities service area within low income and disadvantaged communities. APU's AAFS impact may be at a rate that is different from the overall SCE region.

Due to the lack of internal data for AAFS analysis and the minimal impact derived from the CPUC dataset, AAFS is not introduced as a separate demand adjustor into the 2023 IRP demand forecast. However, APU's adjusted base energy demand forecast is compared with the CEC's demand forecast inclusive of the AAFS considerations, to ensure APU's forecast is comparable to the CEC's forecast.

As more information becomes available, APU may include AAFS as a separate demand adjustor.

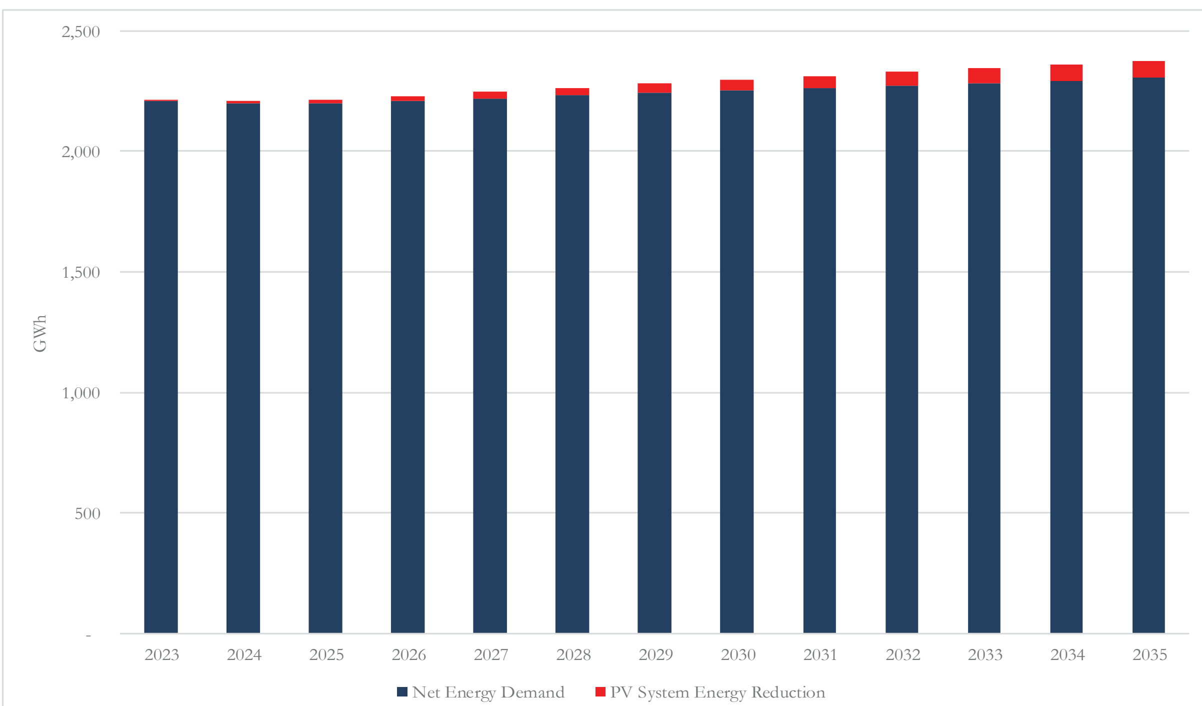
SOLAR INSTALLATION & OTHER DISTRIBUTED GENERATION

Behind-the-meter distributed generation information is obtained from SB 1 and City permit applications. This includes micro turbine, fuel cell, solar and battery storage installations.

The Inflation Reduction Act of 2022 extended the 30% tax credit for solar installations through 2032. Behind-the-meter solar installation is estimated with recent year annual installation totals, and with specific project plans from commercial customers. APU estimates to have 51.5 MW of new solar installations within the next decade, including solar plus battery storage projects. To estimate solar generation, a proxy capacity factor of 18% is applied to the solar capacity forecast. Detailed solar capacity calculation and peak impact analysis may be found in the "Peak Shift Analysis" section.

In 2022, behind-the-meter solar distributed generation is estimated to account for 3.4% of APU's total energy demand and is expected to grow by 0.25% or greater annually, depending on when larger planned commercial installations take place. Graph 6 shows the estimated annual impact of behind-the-meter solar installation growth.

Graph 6: Estimated Behind-the-Meter Solar Impact to Energy Demand



Planned distributed generation projects other than solar are forecasted only in the short term, with system size estimates obtained from Electric System Planning.

ENERGY EFFICIENCY

In accordance with AB 2021, APU is required to establish specific annual energy saving goals as a percentage of total annual retail electric consumption. SB 350 also mandated that the CEC develop utility-specific energy efficiency saving targets to help achieve doubling statewide energy efficiency savings in electricity and natural gas end uses by 2030.

APU, in conjunction with other members within CMUA, contracted with GDS Associates, Inc. to identify all potentially achievable cost-effective electricity efficiency savings and establish annual targets for energy efficiency savings for 2022-2031. The final report "Energy Efficiency in California's Public Power Sector"[13] was published and submitted to the CEC in 2021.

APU's energy saving goal, along with its impact to Energy Demand, are summarized in Table 2.

Table 2: APU Energy Efficiency Targets including Codes & Standards (GDS Associates, Inc.)

10 Year Energy Goals (Incremental Gross MWh)										
ALL Sectors (MWh)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Market Potential	17,825	17,277	15,621	11,732	7,636	7,346	7,363	7,435	7,222	7,264
Res Market Potential	3,710	3,340	2,603	2,506	2,582	2,721	2,792	2,991	3,226	3,411
Non-Res Market Potential	14,115	13,936	13,018	9,226	5,054	4,624	4,571	4,445	3,996	3,853
Total Potential as a % of Total Sales	0.82%	0.79%	0.72%	0.54%	0.36%	0.34%	0.34%	0.35%	0.33%	0.34%
Res Potential as a % of Res Sales	0.62%	0.56%	0.44%	0.43%	0.44%	0.47%	0.48%	0.51%	0.55%	0.58%
Non-Res Potential as a % of Non-Res Sales	0.90%	0.87%	0.82%	0.59%	0.32%	0.30%	0.29%	0.28%	0.25%	0.24%

[13] https://www.anaheim.net/DocumentCenter/View/11240

10 Year Energy Goals (Incremental Gross MWh)										
ALL Sectors (MWh)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Base Market Potential	17,825	17,277	15,621	11,732	7,636	7,346	7,363	7,435	7,222	7,264
Codes & Standards Advocacy	18,026	18,589	17,879	17,374	16,350	15,347	13,929	12,092	10,349	8,901

APU's voluntary demand response programs are only called upon under extreme conditions, and therefore is not included in the energy demand adjustments under normal weather conditions. In summer 2022, the residential demand response program generated 6 MWh savings, while the commercial voluntary load reduction program reduced 120 MWh. Currently, only voluntary demand response programs are in place. Estimated adjustments for demand response reductions will be considered for extreme weather conditions when dispatchable demand response programs are in place.

APU is planning to launch several dispatchable demand response programs in the upcoming years. By summer 2023, APU will implement an electric vehicle charging station and demand response program, titled "Drive Green Anaheim". The program aims to increase the proliferation of EVs in underserved locations by installing, operating, and maintaining charging stations and providing no-cost charging to local users. Through the program, commercial properties and multifamily dwellings in low income and disadvantaged communities will have the opportunity to become a public EV charger station host site and receive a turn-key EV charger program inclusive of design, procurement, installation, operation and maintenance. With growing EV demands on the local grid, EV charging stations will be equipped with demand response capabilities to be able to curtail EV charging during peak hours (between 4-9 PM) or during grid emergencies.

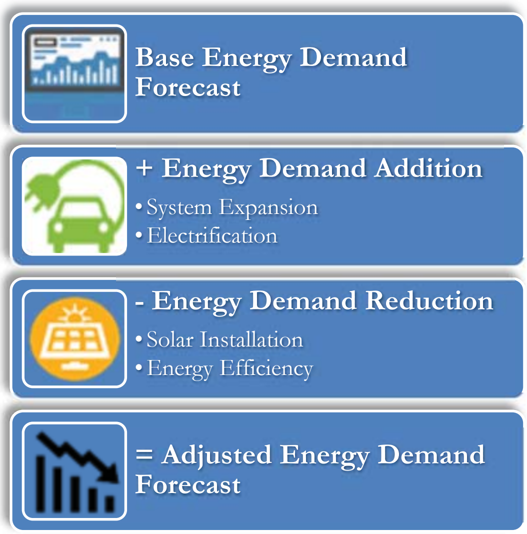
In 2024, APU will launch an expanded demand response program that provides customers with energy saving tools, incentives, and a user-friendly notification system that prompts participating customers to curtail usage during times of high demand, or when APU calls for a load curtailment event. As part of the expanded demand response program, new software management technology will be implemented that provides a one-stop-shop of services including customer enrollment tracking, customer participation in curtailing load, device registration, load impact, dispatch notifications, optimization with CAISO alerts, incentive processing, and behavioral analysis. A variety of energy saving tools and incentives will be available to customers, including smart thermostats, heat pumps, HVAC, pool pumps, small business equipment, commercial equipment, industrial equipment, energy management systems, electric vehicle supply equipment, electric school buses, and batteries for storing energy.

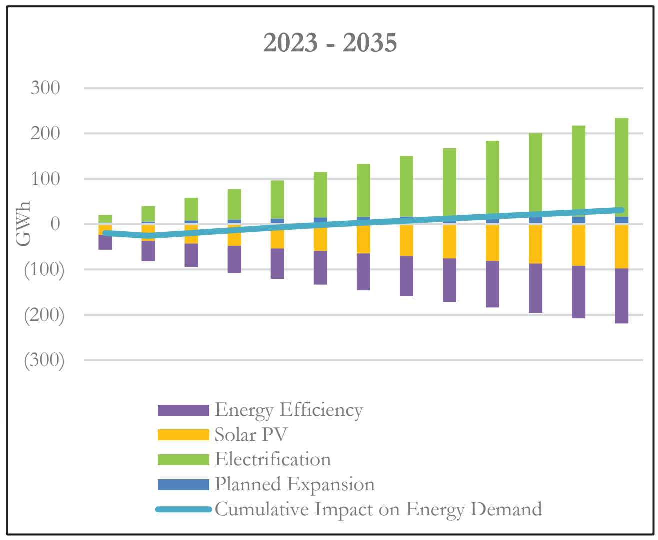
A.3. ADJUSTED BASE ENERGY DEMAND FORECAST

In total, APU expects a 1.41% net energy demand growth between 2023 and 2035, which is essentially a low growth forecast. Load forecast beyond 2036 assumes a 0.25% annual load increase. The growth factor is consistent with average load growth between 2026 and 2035 and is applied due to the lack of information on all demand variables. The net energy demand forecast is used in Section VII. Resource Portfolio Evaluation to determine the recommended resource portfolio to meet APU's future energy needs.

Graph 2 displays the estimated cumulative impacts to the Base Energy Demand Forecast. The energy demand additions are estimated to increase by 234 GWh cumulatively due to planned expansion projects and electric vehicle growth. During the same period, solar PV and energy efficiency are estimated to reduce the energy demand by approximately 208 GWh cumulatively. The overall cumulative net energy demand growth is estimated to be approximately 26 GWh as indicated by the blue line in the graph below.

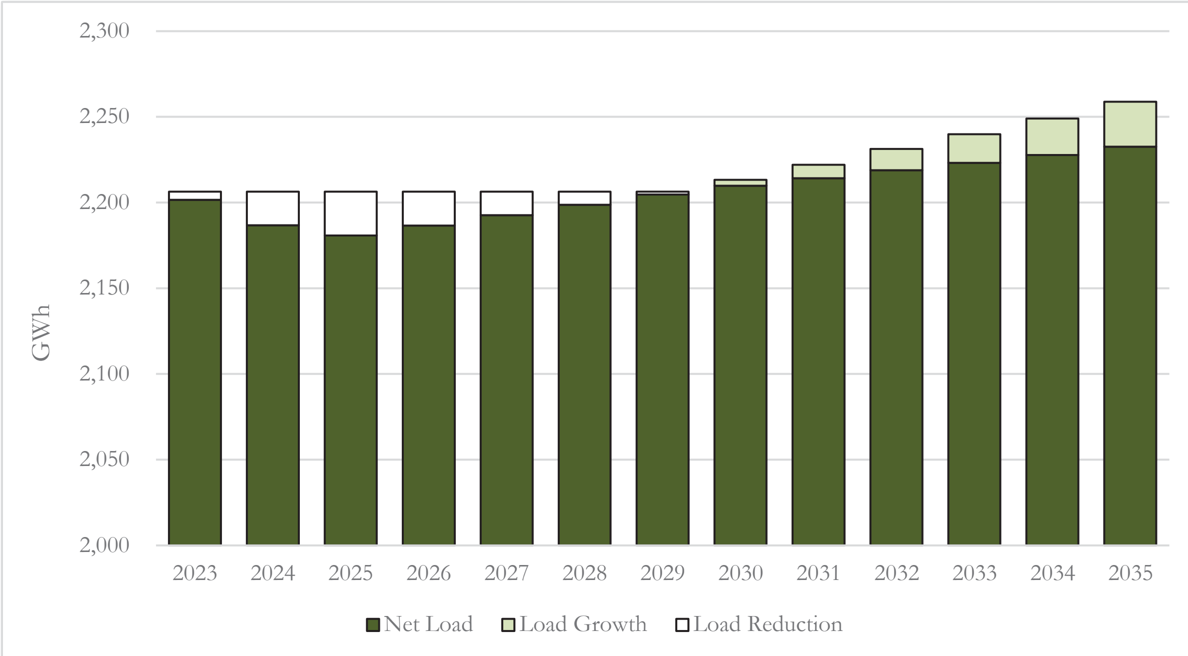
Cumulative Adjustments to Base Energy Demand Forecast





Graph 7 below depicts the Adjusted Energy Demand Forecast. The sum of all three bars is the anticipated Base Energy Demand Forecast, assuming no growth or reduction. Additions such as planned expansion projects and electric vehicles are displayed by the light green bar. The total reductions are displayed by the white bars. The Adjusted Energy Demand is the sum of the dark green and light green bars. The remaining white bar is the estimated net energy demand reduction per year. Load reduction in earlier years is mainly due to planned solar plus storage projects by commercial customers. Load increases in the later years are mainly due to EV penetration.

Graph 7: Adjusted Base Energy Demand Forecast



APU's energy demand forecast was completed in 2022. The CEC released its energy demand forecast for the 2021 Integrated Energy Policy Report (IEPR) in February 2022[14]. Staff compared APU's adjusted (or expected) energy demand against the IEPR 2021-2035 demand forecast: Medium Baseline Demand with Medium Additional Achievable Energy Efficiency (AAEE) Scenario 3 and Additional Achievable Fuel Substitution (AAFS) Scenario 3[15]. Scenario 3 represents full compliance with all regulations, including CARB's Advanced Clean Fleets Regulation. APU's forecast is very close to the CEC's forecast in the beginning years, with a 4% variance observed in 2035.

It is noted that the CEC assumes a distribution loss factor of 6.37%. Or, it requires 106.37 MWh of total system energy in order to serve the retail customer consumption of 100 MWh. APU's historical distribution loss factor is typically around 3.5%. When the CEC's forecast is adjusted down with the lower distribution loss factor, it becomes lower than the APU forecast by roughly 6% in 2035. The difference is considered acceptable for long-term planning purposes. In addition, a range of high and low energy demand will be tested under Resource Portfolio Evaluation – Stress Testing.

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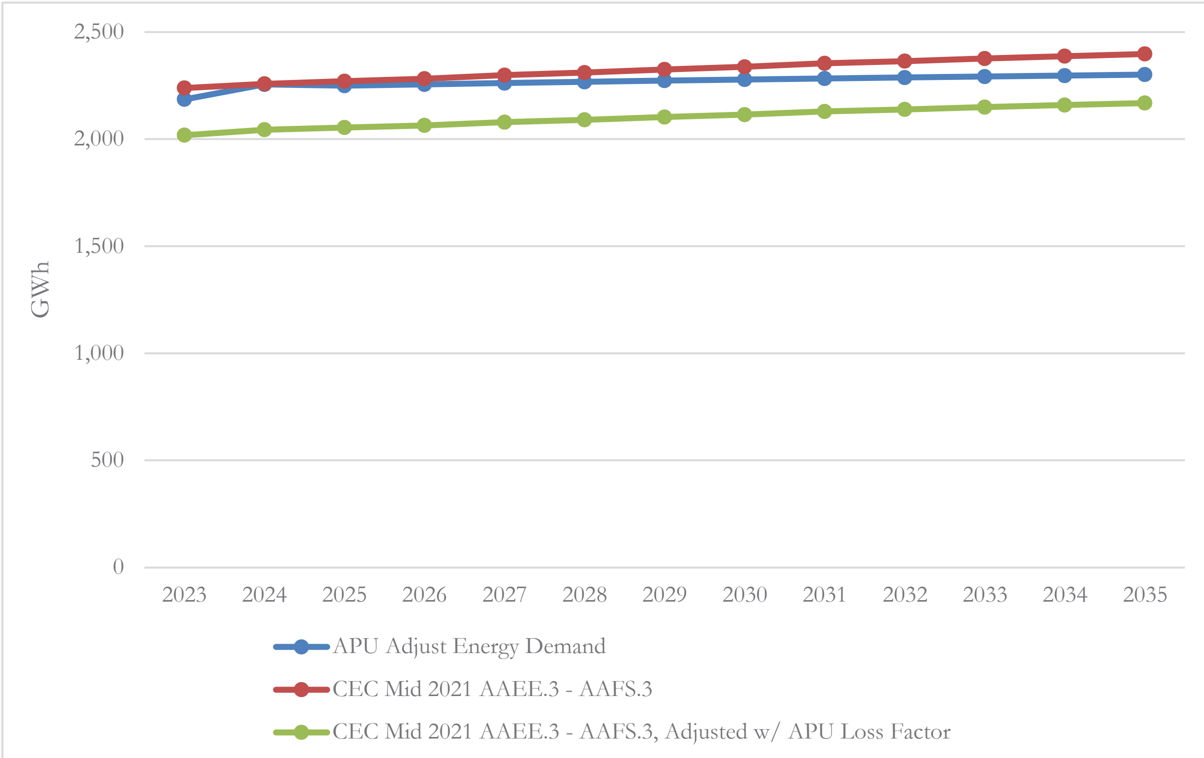
[14] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report and https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581

[15] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1 and https://efiling.energy.ca.gov/GetDocument.aspx?tn=241382

Graph 8: APU vs. IEPR Energy Demand Forecast



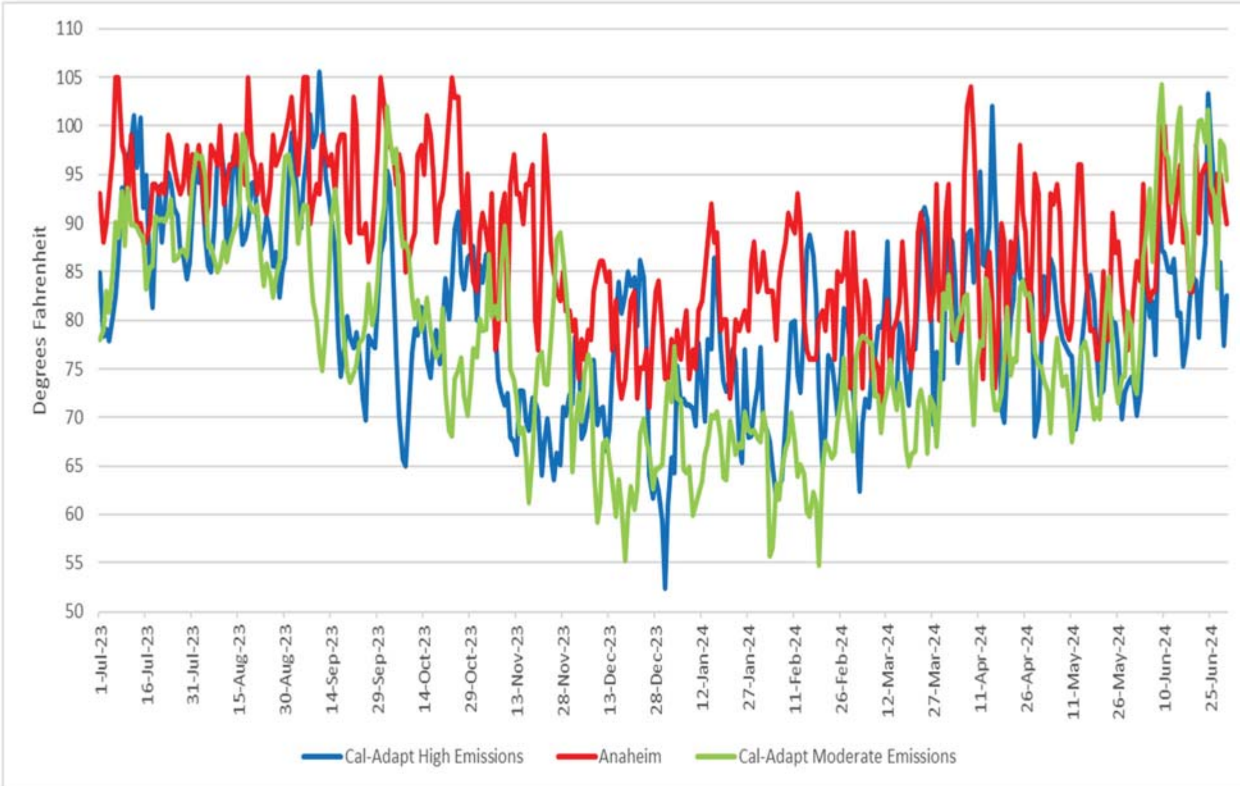
A.4. OTHER CONSIDERATIONS - EXTREME WEATHER

It is important to analyze the impact of weather extremes on energy demand due to its sensitivity related to temperature changes. Extreme temperature forecasts under high and low emission scenarios are available through Cal-Adapt, a climate change resource database developed by the Geospatial Innovation Facility at the University of California, Berkeley with funding and advisory oversight by the California Energy Commission.

The daily extreme temperature forecast data for the Anaheim area was obtained through Cal-Adapt[16] and then compared to APU's internal temperature forecast, which was developed using five-year minimum and maximum temperatures. APU's forecast consistently produces higher extremes compared to the Cal-Adapt forecast. The deviations between the forecasts are shown in Graph 9, which displays the high and low emissions Cal-Adapt high temperature forecast compared to APU high temperature forecast from July 2023 to June 2024. As the APU forecast produces higher extremes, it was selected to be the preferred temperature forecast to conduct the extreme weather analysis on energy demand.

16 https://cal-adapt.org/

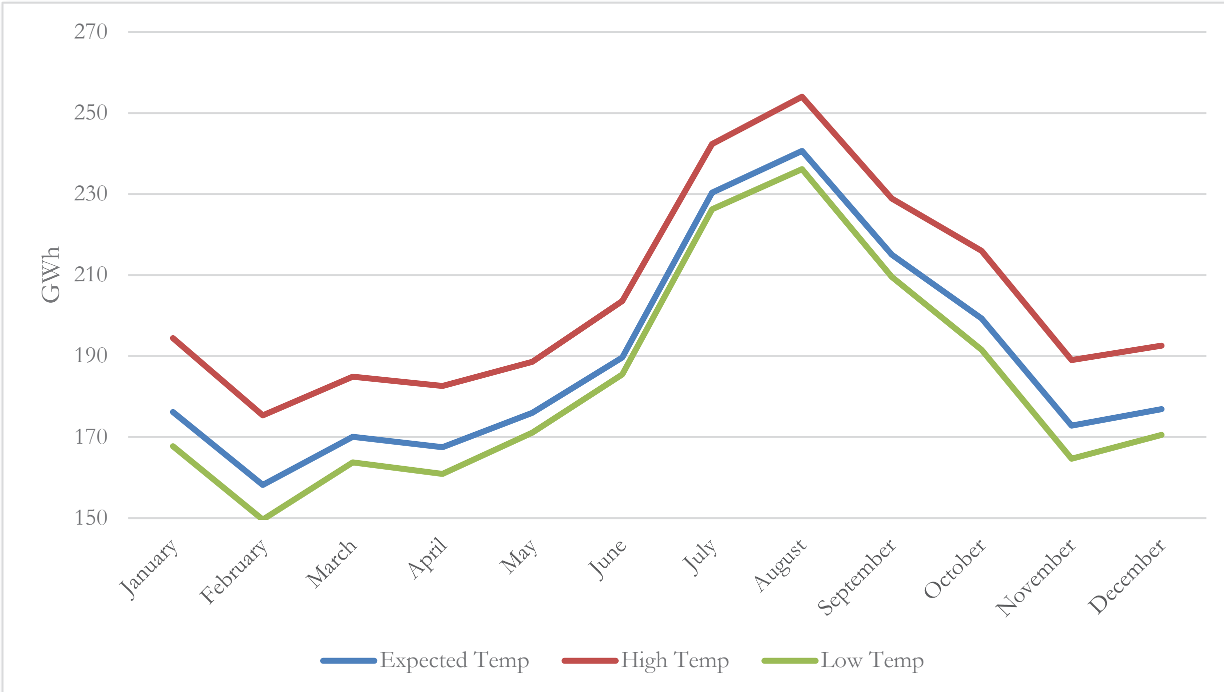
Graph 9: Cal-Adapt vs APU Maximum Temperature Forecast



The econometric model described in VI.A.1. estimates a coefficient of 2.19 MWh for the temperature variable. This is interpreted as an increase in energy demand of 2.19 MWh for every degree Fahrenheit increase. For example, an increase in temperature of 20 degrees Fahrenheit results in a corresponding increase in demand for that hour of 43.8 MWh. Applying the extreme temperature forecast to the economic model produces a bandwidth of expected energy demand under high and low temperature extremes.

Graph 10 below displays the estimated deviations from expected energy demand due to extreme weather impacts. The high weather extreme results in an increase from expected energy demand of 180 GWh annually, with the highest monthly impact in the month of January of 18 GWh. The low weather extreme results in a decrease from expected energy demand of 75 GWh annually, with the largest decrease being in the month of February of 9 GWh.

Graph 10: Forecasted Energy Demand with Extreme Temperatures



The energy demand variation due to extreme weather impacts will be used to stress test the resource portfolio in VII. F. Stress Testing.

B. PEAK FORECAST - METHODOLOGY & ASSUMPTIONS

The peak forecast is also developed along with the energy demand forecast for use in consideration of the reliability aspects of power supply Resource Adequacy and electric distribution system planning:

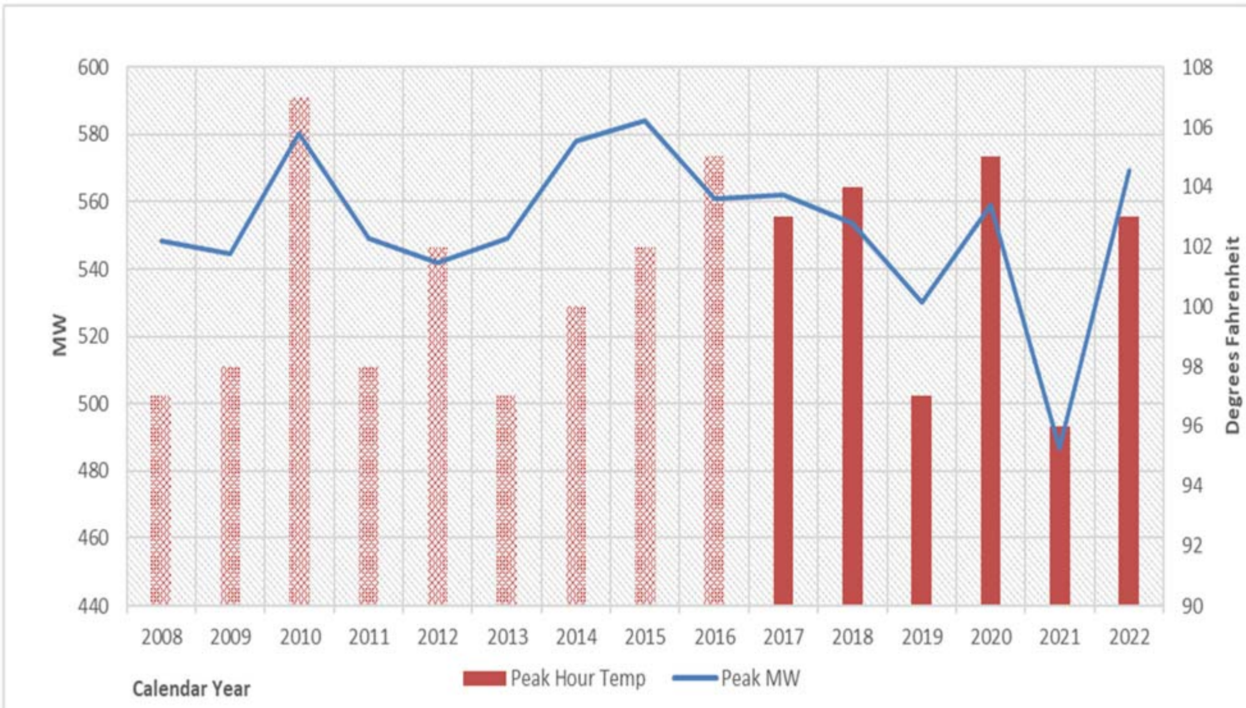
- Peak forecast is used to determine the Resource Adequacy capacity needed to meet reliability requirements.
- Hour-by-hour peak and energy profile analysis is used to determine which resource's generation portfolio provides the best match. It also assists APU's effort to explore possibilities in using clean energy to meet the peak demand.
- APU's Electric System Planning relies on the long-term peak forecast to plan for necessary distribution system expansion.

B.1. CONSIDERATION OF THE HISTORICAL SYSTEM PEAK

Although APU's total energy demand declined from 2017 to 2021, the total system peak has fluctuated over the past several years between 487 and 569 MW. Anaheim saw the lowest peak in 2021 as a result of lower-than-average temperatures of 96 degrees. In 2022, the peak increased sharply compared to 2021, which was due to temperatures increasing back to the normal average. APU's annual system peak is typically observed in the months of August or September when temperatures average 76 degrees and reach up to 105 degrees.

Graph 11 illustrates the temperature impact on the peak energy demand. Temperature data since 2017 are used for the 2023 IRP forecast and represented in solid red. Peak hour temperature data from earlier years are not used for this forecast and represented in shaded red. The peak energy demand patterns were different in the earlier years due to the differences in the availability of rooftop solar, energy efficiency programs, demand response tools and time-of-use rates.

Graph 11: APU Historical Peak Demand



B.2. DEVELOPING THE PEAK FORECAST

When developing the peak demand forecast, APU considers historical load factors.

APU's load factor is calculated by taking the total energy demand for each month and dividing it by the peak demand for the same month. Historical average load factors are calculated for each month for the most recent five years. The load factors are applied to the adjusted monthly energy demand forecast to develop the peak demand forecast.

Table 3: Historical Load Factors

Month	2017	2018	2019	2020	2021	2022	AVERAGE
January		73%	79%	81%	75%	79%	77%
February		74%	81%	79%	79%	69%	76%
March		79%	80%	73%	75%	71%	76%
April		66%	70%	57%	64%	53%	62%
May		71%	78%	60%	67%	66%	68%
June		67%	59%	58%	61%	60%	61%
July	68%	62%	60%	60%	66%		64%
August	60%	66%	68%	55%	65%		63%
September	54%	66%	59%	55%	59%		59%
October	53%	61%	60%	53%	66%		59%
November	67%	68%	68%	70%	60%		67%
December	76%	76%	80%	78%	78%		78%

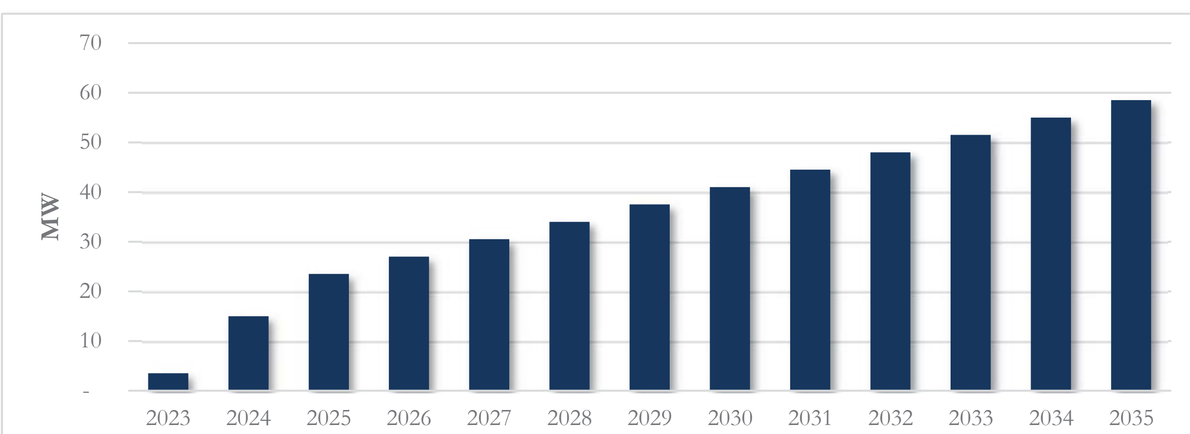
The peak demand forecast is validated by comparing the model's "backcast" output to the previous five year's actual data. The average peak forecast's accuracy to predict monthly peak is between -2.4% and 1.1%. The average annual peak forecast accuracy was in the range of -3.3% to 5.5% and within the acceptable confidence level.

B.3. OTHER CONSIDERATIONS

Peak Shift

APU estimates to have 51.5 MW of new solar within the next decade. Graph 12 details the estimated cumulative installed solar capacity for APU's service territory. The initial increase in 2024 and in 2025 is due to planned large commercial solar projects. Solar installation is estimated to remain stable through 2035. Under stress testing, a high demand scenario and a low demand scenario assumes extra low solar installation and extra high solar installation, respectively. More information can be found under Chapter VII. Resource Portfolio Evaluation, TEST 2: EXTREME HIGH DEMAND VS. EXTREME LOW DEMAND.

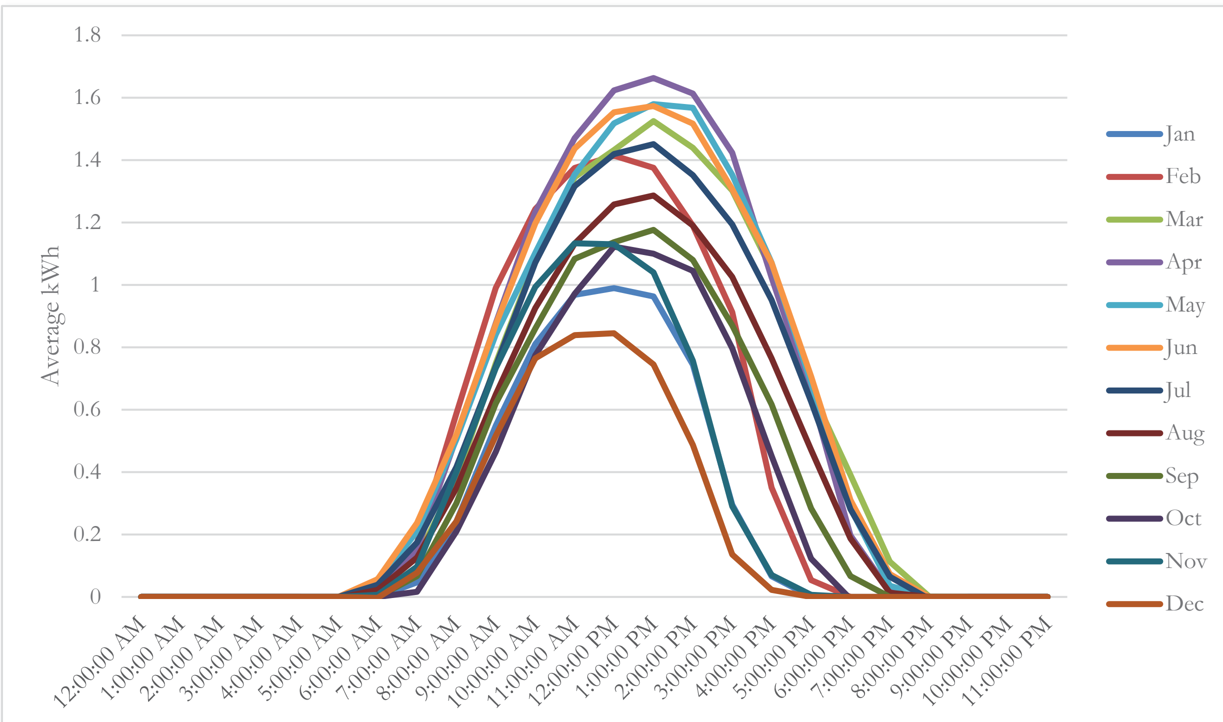
Graph 12: Estimated Cumulative Distributed (Behind-the-Meter) Solar PV Capacity



To develop an estimation methodology for customer-owned, behind-the-meter solar generation, APU studied the solar generation from the city-owned Anaheim Convention Center solar system. The system generates approximately 3,400 MWh of solar energy per year (as recorded in 2022) and has a capacity factor of 18%.

In 2022, April produced the highest generation, with 12.5 MWh per day. The month of December produces the least amount of generation per year, on average with 4.7 MWh per day. Graph 13 details each month's average hourly solar profile, as derived from the generation of the Anaheim Convention Center solar system. Peak solar generation is at noon October through February and at Hour 13 (1 PM) for the remainder of the year.

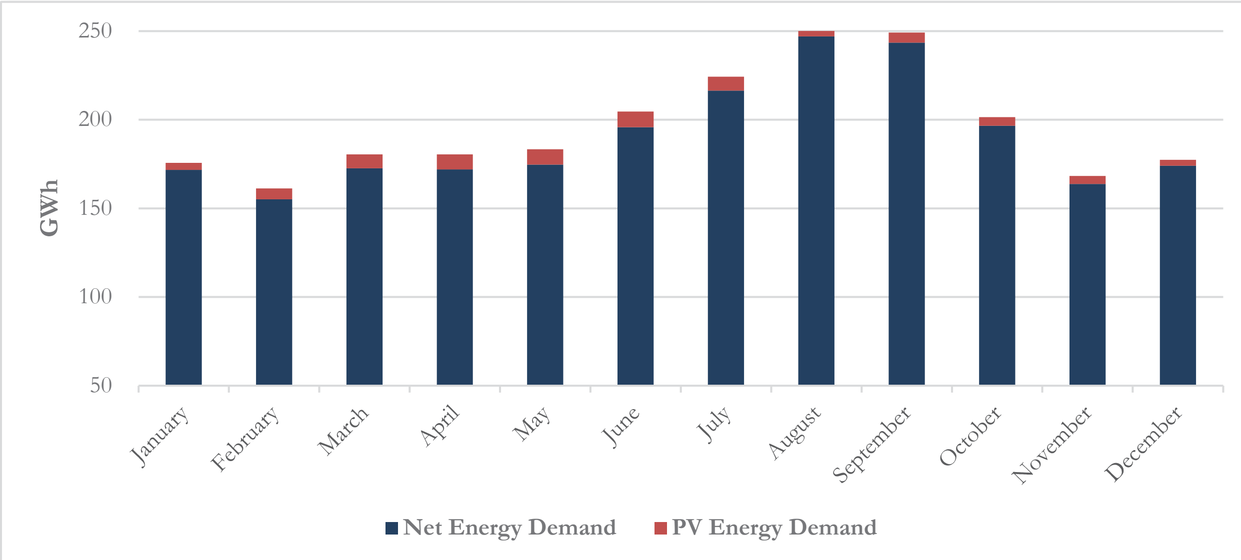
Graph 13: Average Hourly Solar Profile by Month: Anaheim Convention Center



Although production varies from system to system, the calculated capacity factor from the Anaheim Convention Center serves as a strong proxy to estimate production from installed private solar capacity within the City. This is especially true because the Convention Center is located in the center of Anaheim and is capable of capturing City specific weather effects.

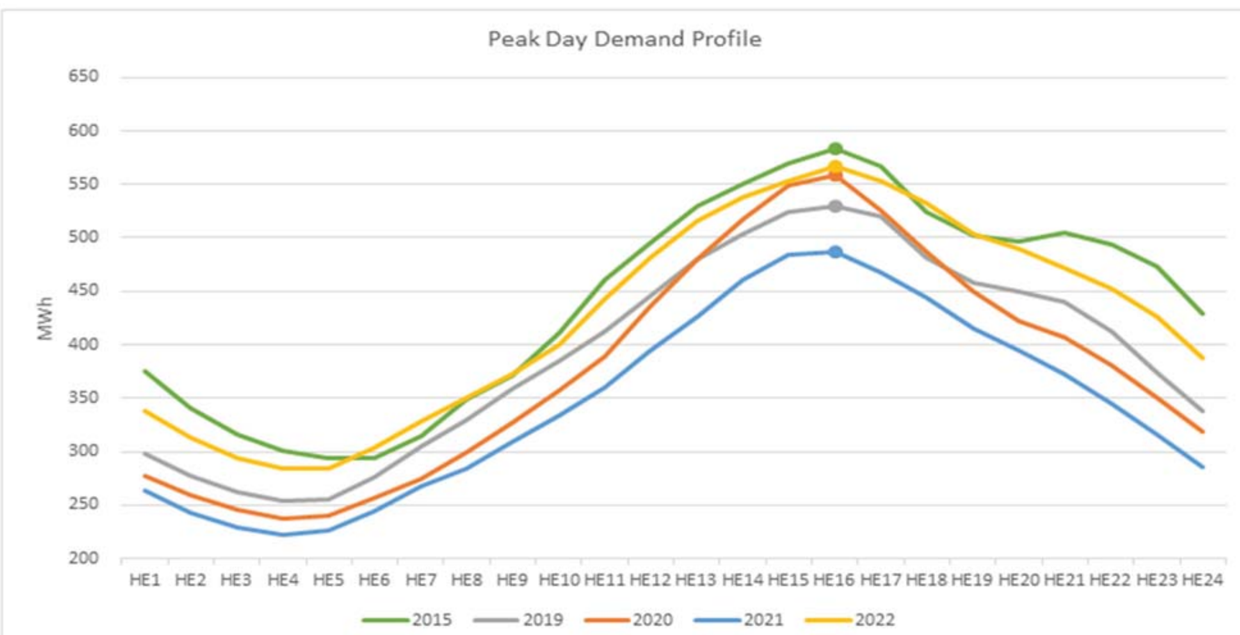
To calculate total distributed solar generation, the 18% capacity factor is applied to solar capacity data collected from SB 1 applications and City permits. Graph 14 details the estimated monthly distributed solar generation in 2022, and its effect on APU energy demand. The total estimated effect on energy demand using the proposed methodology for 2022 was 76,849 MWh, or a 3% reduction of Anaheim's total energy demand.

Graph 14: Estimated Distributed (Behind-the-Meter) Solar PV Impact to Energy Demand



While the Anaheim Convention Center's solar production meter data is still an effective tool for estimating the total behind-the-meter solar generation, there is not a direct relationship between solar production and peak shift or peak reduction. Although distributed solar has grown as expected from 2015-2022; the peak has not shifted from HE16 to later in the day, as previously expected in the 2018 IRP. Some of the reasons for the unchanged peak hour may include the introduction of time-of-use (TOU) rates, successful voluntary demand response programs, and the proliferation of EVs and battery storage.

Graph 15: Peak Day Demand Profile



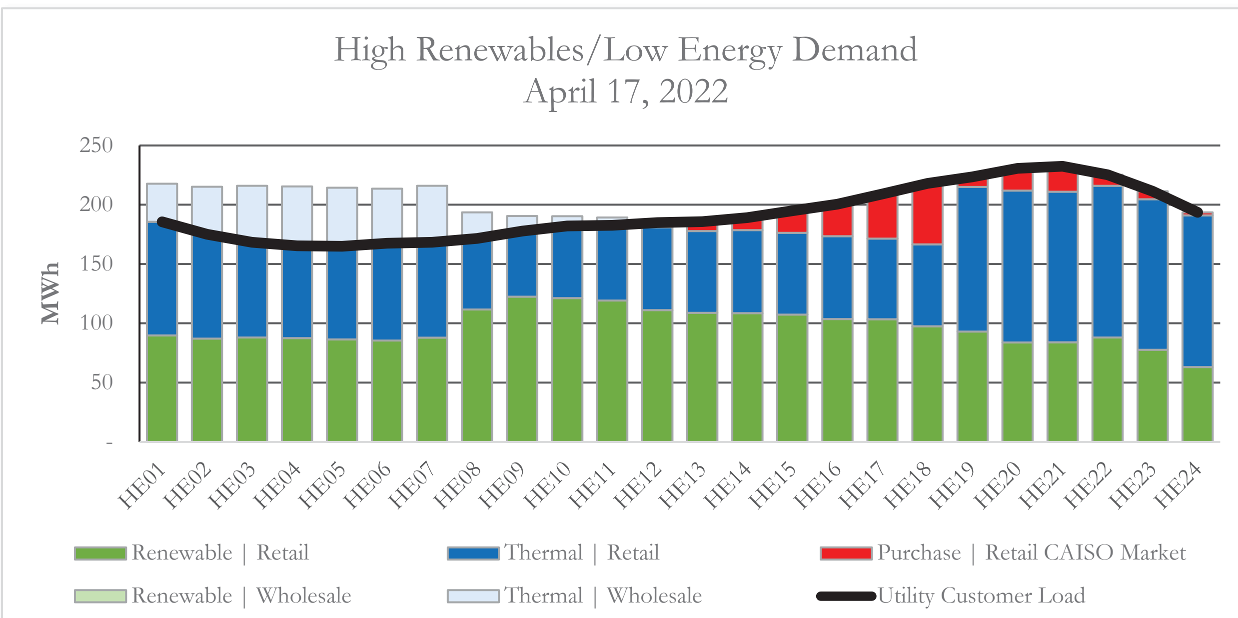
Clean Peak Analysis

Aligning renewable generation with peak demand is a current industry challenge.

In an effort to meet peak demand with renewable or other clean energy resources, APU takes into consideration its existing renewable generation portfolio, efficiency of Grid operations, energy storage options and forecasts, distributed energy resources, and energy reduction measures such as energy efficiency and demand response programs. This comprehensive consideration ensures APU meets energy and reliability needs during its peak, while reducing the need for new/additional electric generation, distribution, and transmission resources.

During certain times of the year, system peak can be served with a higher percentage of renewable energy. As an example, in April 2022, the Intermountain Power Plant (IPP)[17] underwent a scheduled maintenance outage for most of the month, which caused a significant reduction in generation capacity. On April 17, 2022, APU's 232 MW peak was served by 36% or 84 MW of large hydro and renewables.

Graph 16: Renewables Serving Peak Demand – Day with High Renewables & Low Energy Demand



During other times of the year, serving the peak with renewable energy faces its challenges. This is generally due to a higher peak demand, renewable resource availability, and CAISO dispatch signals. APU deployed eight voluntary residential demand response events in summer 2022 to reduce energy demand; however, additional energy was still needed during the hot and humid summer days.

On September 8, 2022, APU reached a system peak of 566 MW; more than double the system peak in the previous example. During the peak hour, only 17% or 96 MW of large hydro and renewable energy was available

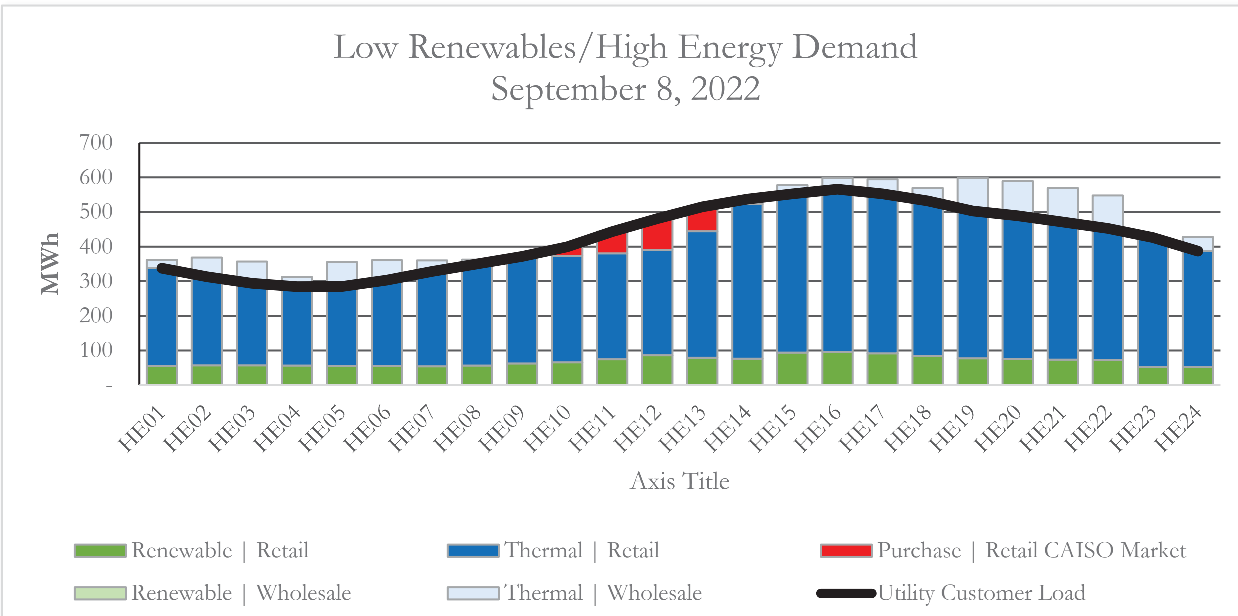
[17] Details of the power plant may be found in Section VIII.B. Generation and Transmission Resources

to meet the demand, even though APU has greater renewable contract capacity. This is due to various reasons, which include:

- De-rated landfill and geothermal generating units due to extreme heat,
- Minimal small hydro energy output due to drought conditions; and
- Wind energy output at 60% of April level.

Also, during the peak day, the CAISO dispatched APU's fossil fuel units to meet not only the APU peak, but also the system demand of other California load serving entities. The light blue bars in Graph 17 indicate the thermal (non-renewable) energy APU sold into CAISO market, per market dispatch signals.

Graph 17: Renewables Serving Peak Demand – Day with Low Renewables & High Energy Demand



Other than reducing peak demand through efficiency measures and demand response programs, APU takes into consideration how renewables or other zero emission resources may provide more clean energy during the peak hour. APU recently contracted for a solar plus storage project and is actively working on the evaluation and negotiations of three energy storage projects. In addition, the location and generation profile of new renewable projects are also considered. The goal is to acquire renewable projects with generation profiles most aligned with APU's energy demand profile.

Extreme Weather Impacts

Peak demand estimates are obtained for the extreme weather analysis using the load factor methodology, as described in VI.B.2. DEVELOPING THE PEAK FORECAST. Graph 18 displays the impact of extreme temperatures on peak demand. On average, peak demand is estimated to be 34 MW higher with extremely high temperatures, with the highest impact of 42 MW in October. Similarly, peak demand is estimated to be 10 MW lower with extremely low temperatures, with the highest impact of 14 MW in October.

Graph 18: Forecasted Peak demand with Extreme Temperatures