SCE Report: DR20.02

Project Report

Wedgewood Demand Response and Flex Demonstration

2015 Manhattan Beach Blvd.
Redondo Beach, CA 90278

Prepared for:
Southern California Edison
Emerging Markets and Technologies
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Wedgewood Study

Disclaimer

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SECTION 1 EXECUTIVE SUMMARY

This document presents the results of advanced load control tests performed during 2020 as part of a demonstration project sponsored by the Southern California Edison (SCE) Emerging Products and Technologies group. The study evaluated the ability of software to reduce electricity demand during peak times through advanced demand management and load flexibility, while minimally impacting tenant comfort. The study also evaluated how the system would react to a simulated Demand Response (DR) one-hour ahead load reduction dispatch event.

The project evaluated the use of Extensible Energy's DemandEx™ load management software to manage electricity demand in an office building by controlling the HVAC systems in coordination with local solar power generation. DemandEx is designed to reduce a customer's electricity costs by reducing demand peaks and by shifting energy use from more costly demand periods to less costly periods. This is done through strategies such as shifting energy from periods of low solar generation and high demand to periods where solar is generating power. While the software is capable of controlling a variety of categories of equipment, the evaluation focused only on its ability to control HVAC, as HVAC constitutes a significant portion of the controllable load and is the main driver of demand peaks in office buildings.

Two hypotheses were tested: First, a load shift hypothesis tested whether the software could effectively reduce the customer's HVAC-related demand charges by between 10% and 25%, without negatively impacting building tenant comfort, by shifting operations and increasing loads during SCE's non-peak (Mid and Off-peak) TOU periods and reducing loads during peak periods. The second, a load shed hypothesis, tested whether the software could enable two to four hours of load shift of at least 20% of whole-building load in response to simulated day-ahead, hour ahead and 15 minutes ahead load curtailment signals from SCE.

The project demonstrated that significant demand reductions can be achieved during peak demand times through load shift. Demand was reduced 15.5% on warmer days when cooling was needed, with reductions of 28% in the morning and 13% in the evening (**Error! Reference source not found.**). In addition, the control software was able to reduce energy consumption in the evening hours by 19%, while compensating with increased energy consumption in the afternoon when there is substantial renewable solar generation. Additionally, the system was able to shed load of approximately 14% compared to the maximum observed peak demand for the one-hour DR test.

The project encountered some challenges due to COVID-related shutdowns and pre-existing issues with the building control system that limited the achievable results. Savings should increase when the building returns to full operation and when repairs to the control system are implemented.

If extrapolated to a full year under current building operating conditions, demand charge cost savings could be $3,600. Adjusted for COVID-related effects, the demand charge cost savings could be around $5,400 per year. With additional software-only repairs to the building management system, it was estimated that demand cost savings of up to $9,000 per year may be achieved.

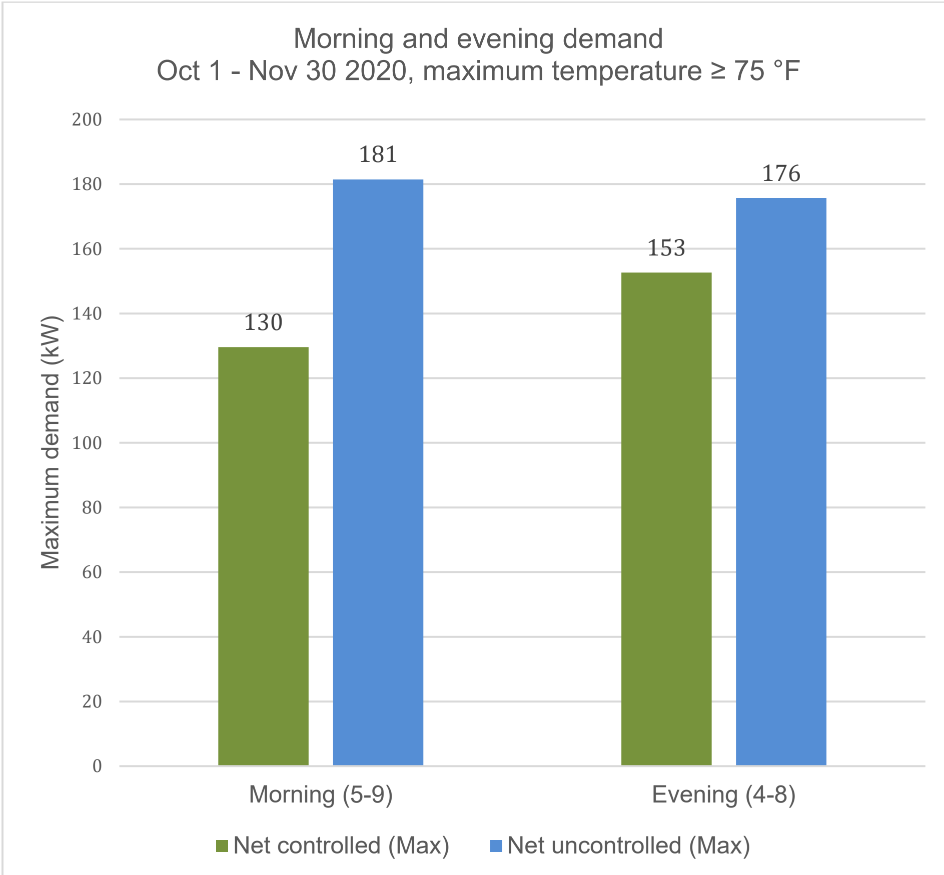


Figure 1: Morning and evening demand reduction due to DemandEx control on warmer days (maximum temperature ≥ 75 °F).

If deployed at multiple sites, this load-flexibility capability could provide a significant demand shifting benefit for utilities and the California grid, in addition to potentially significant direct utility cost savings to the site customers. In addition, the ability to shift demand from periods with less solar generation into periods with more solar generation would support the state's transition to renewable generation and result in reduced emissions.

The study effects were achieved in a region with mild climates and in a building with significant configuration issues. Greater effects could be expected in regions with hotter climates, and in buildings with properly configured control systems.

SECTION 2 INTRODUCTION AND OBJECTIVES

The ability to shift building loads without significantly impacting occupant comfort, convenience or productivity is a key commercial strategy supporting California's ability to address grid challenges. These challenges include power intermittency, demand peaks, and localized capacity resulting, in part, from rapid growth of customer self-generation, behind the meter (BTM) storage, and increasing intermittent loads such as from EV charging and electrification. Additional resources are needed throughout the state to compensate for differences between forecasted and actual load.

2.1 Background

The Wedgewood facility study site, located in Redondo Beach, California, is a class A, 86,400 square-foot, two-story office building built in 1985. The building houses multiple tenants, including offices and a data center, and has a centrally managed HVAC system with a total of 118 individually regulated zones. The HVAC system is controlled using a central Automated Logic building management system (BMS) that communicates with the equipment over a BACnet network. Cool air is provided by four 60-ton rooftop units (RTUs), while warm air is provided by a central boiler. The four RTUs were brand new, having been replaced in June 2020. Individual zones are regulated using variable air valves (VAVs) that control the amount of air flowing into each zone, and a reheat system to warm incoming air as needed. The site is also equipped with three solar photovoltaic arrays with a total generating capacity of 624 kWstc (standard test conditions).

The Wedgewood facility was selected for this study based primarily on a 2018 SCE energy audit of the site. The audit establishes that the Wedgewood campus has a combination of factors that are favorable for electric load optimization techniques and Demand Response (DR) capability:

- Solar PV production accounts for approximately 48% of the facility's total energy usage.
- The facility is on the time-of-use (TOU) rate structure TOU-GS-3 Option R.
- Energy usage is often greatest during current utility peak TOU periods.
- Fixed operating schedules provide an opportunity for time-based optimization.
- Building demand peaks in the morning and the evening supporting favorable opportunities for load shift (determined by evaluating the rate schedule and solar PV production to maximize customer economics).
- System DR capability is fast and flexible.

Recent work by Lawrence Berkeley National Lab (LBNL) in its DR potential study confirms that the load-resource balance is already increasingly difficult to maintain on sunny spring days (**Error! Reference source not found.**). While the issues of ramping, "duck curve," and curtailment of renewables have been discussed for years by planners and operators throughout California, progress has been slow in developing technologies and programs that directly address these issues – while solar deployments have continued at a rapid pace.

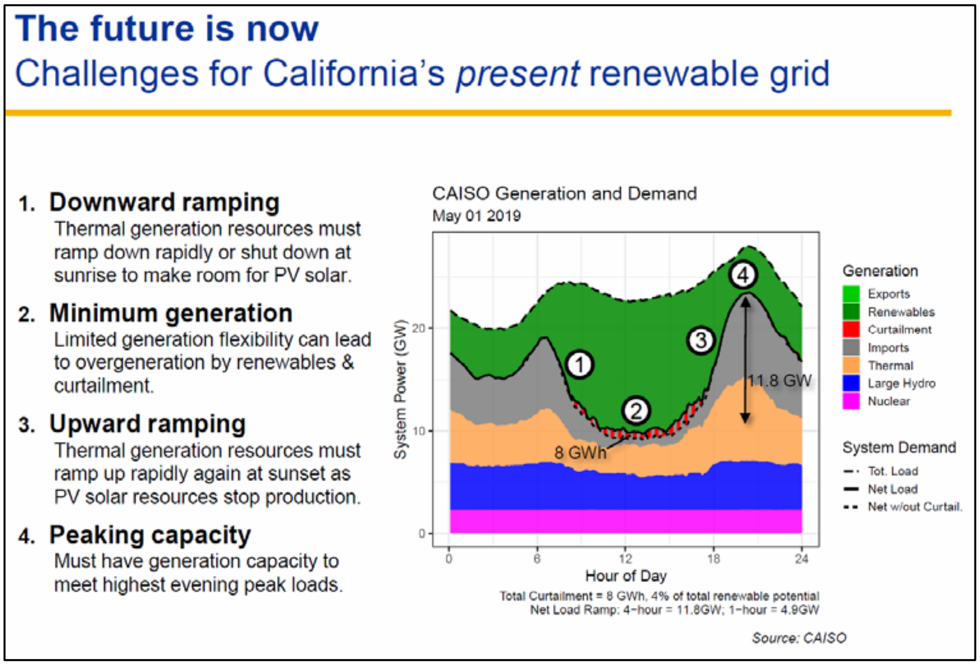


Figure 2: California Load Resource Balance

As a result, average daily curtailment has grown throughout the year, particularly in the spring (see **Error! Reference source not found.**). The data from the CAISO illustrates that the ability to shift load is rapidly becoming more valuable to the grid than the ability to curtail load.

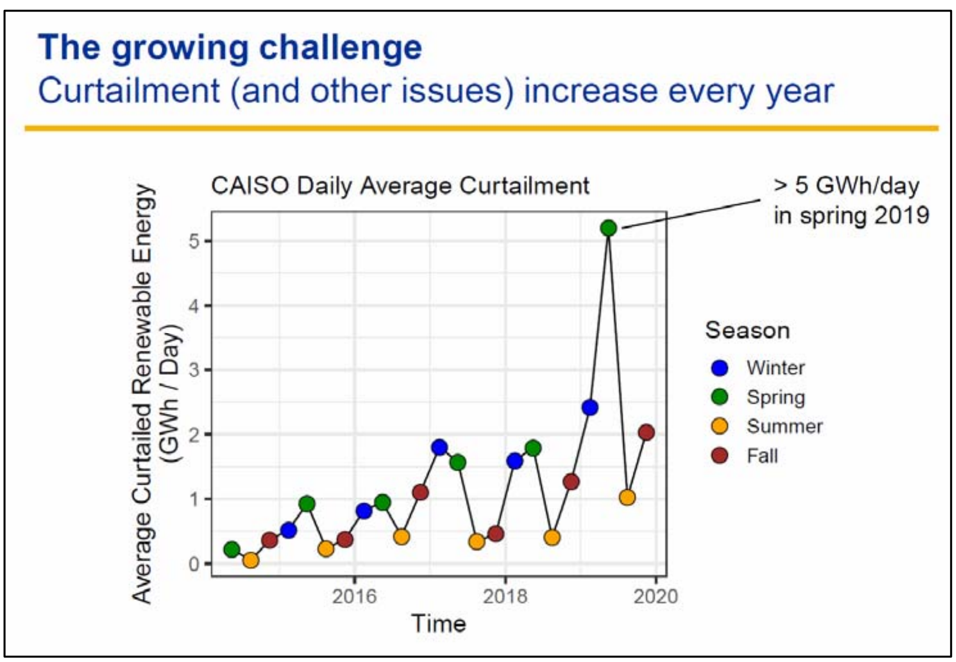


Figure 3: Curtailment Activity

At the same time, the combination of behind-the-meter (BTM) distributed energy resources and advanced system controls can be intelligently controlled to better manage customer loads to participate in traditional load shed programs, or to conform to emerging time of use rates and other emerging energy pricing signals. For example, Extensible Energy's DemandEx software is designed to use predictive algorithms to optimize loads based on forecasted and actual weather and solar generation while considering utility rate structures.

2.2 Study Hypotheses

In a phased approach, the Wedgewood Demand Flex study was designed to evaluate the ability of the software to modify the Wedgewood building's HVAC operations in two ways to support current and future California and SCE DR programs and load management initiatives.

- **Load Shift Hypothesis:** First, can the software effectively reduce the customer's HVAC related demand charges by between 10% and 25%, without negatively impacting building tenant comfort, by shifting operations and increasing loads during SCE's non-peak (Mid and Off-peak) TOU periods, and reducing loads during peak periods?
- **Load Shed Hypothesis:** Second, by driving a deeper level of HVAC setback than under normal operating conditions, can the software enable two to four hours of load shift of at least 20% of whole-building load in response to simulated day-ahead, hour ahead and 15 minutes ahead load curtailment signals from SCE?

SECTION 3 PROJECT APPROACH

The Wedgewood project evaluated the ability of Extensible Energy's DemandEx load management software to manage electricity demand in an office building by controlling the HVAC systems in coordination with local solar power generation. This would be achieved by shifting energy from periods of low solar generation and high demand to periods where solar is generating power. While the controller has the capability to manage other categories of equipment, HVAC generally constitutes a significant portion of the controllable load and is the main driver of demand peaks in office buildings like Wedgewood. Therefore, this project concentrated on control of the HVAC system using the building's thermal properties to manage load.

The initial project approach was to install the Demand Ex equipment after the site completed their RTU HVAC replacement project, followed by a distinct baseline "listen-only" period (May – June 2020), followed by a controlled period (July – November 2020). Because of project initiation delays, including late replacement of the site's HVAC equipment and schedule impacts of COVID-19, the team was required to develop an alternative staggered day operational strategy to conduct tests during the remaining limited test period. The measurement and verification (M&V) plan was updated to describe the alternate strategy, as per the Efficiency Valuation Organization (EVO) International Performance Measurement and Verification Protocol (IPMVP) "Adjacent Measurement Periods (On/Off Test)" guidance.

To evaluate load shed capabilities, the initial project approach was to designate several days during the control period and respond to a day-ahead, hour ahead, and 15 minute ahead simulated DR dispatch event notification. Based on limited control period, as a result of COVID-19 delays, the team elected to perform a single one-hour ahead test to demonstrate the system's overall DR capabilities.

3.1 Project Kickoff

In January 2020, AESC and Extensible Energy ("the team") initiated the study with a project kickoff meeting followed shortly after by an on-site assessment of building equipment, electric panels, building control systems, and overall facility layout. A project schedule was developed delivered to the SCE Project Manager after the kickoff (Figure 4).

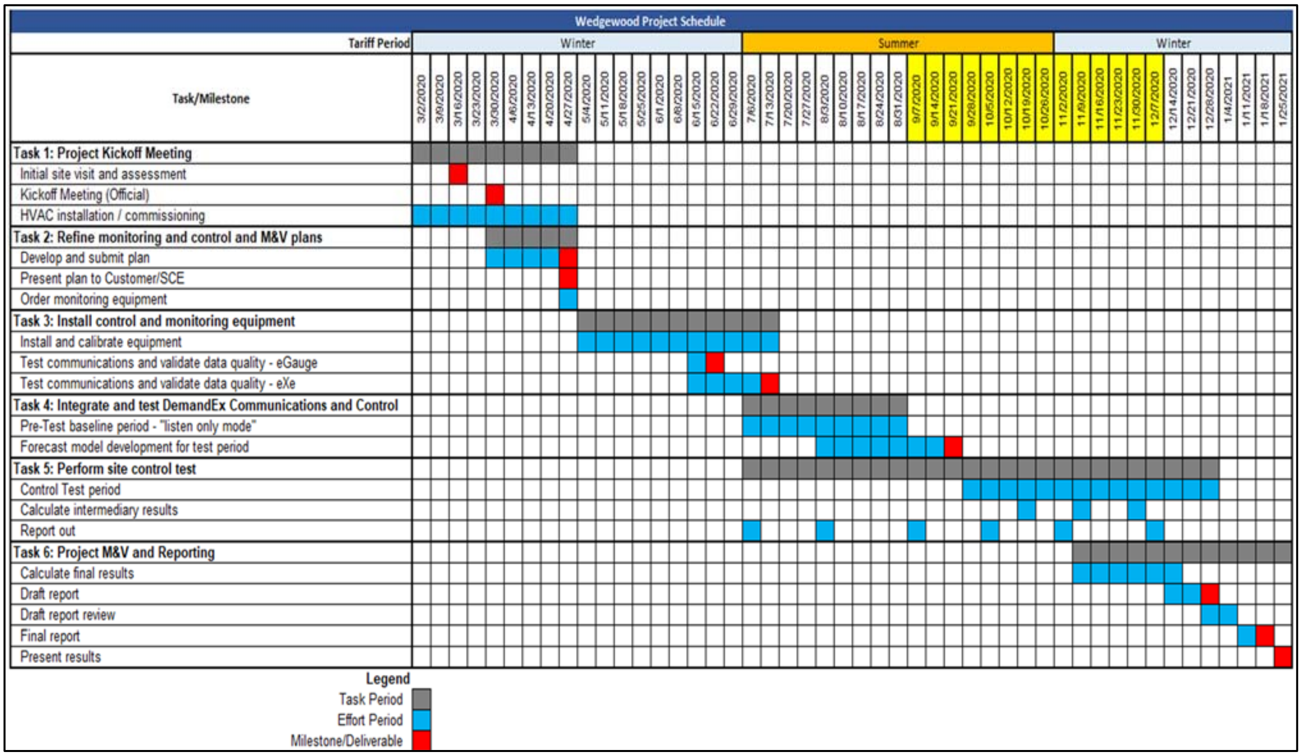


Figure 4: Project Schedule

3.2 Monitoring, Control and Analysis Strategy

The team collaborated to develop a Monitoring, Control and Analysis Strategy to meet the objectives of the proposed study. AESC worked with Extensible to determine the site monitoring needs and data collecting solutions. Extensible led the plan, the execution of load integration with the DemandEx software, and the execution of the control algorithms. The control portion of this plan replaced the suggestions for control found in the report from ASWB Engineering "Load Modifying Resource (LMR) Field Demonstration, Phase I: Energy Audit, Study Report, Draft" from February 2019 which was a generic shifting strategy (e.g., pre-cooling by arbitrarily modifying HVAC operating schedules by several hours each day).

Extensible discovered that the Building Automation System (BAS) controller was not mapped properly (e.g., was mismatched) to the individual equipment, resulting in numerous BAS discrepancies. For example, on the second floor, the north side HVAC equipment was reporting as the south, and vice versa. The result of this was that many of the zones on the second floor were not being controlled based on proper zone-level conditions and equipment feedback. Extensible worked closely with the controls company and Wedgewood but were unable to affect the necessary change in time for the control tests. As a result, they did not implement full zone-level control as planned, but rather employed a modified strategy that used whole building control.

3.2.1 Monitoring

AESC performed several site visits to establish a workable monitoring strategy which required monitoring both the total building load and the total solar generation. Both control panels were in the main motor control center, however the physical layout of the panels necessitated two separate data loggers. These loads were monitored with two eGauge data loggers using 3 phase voltage taps and current transformers to measure true power. These were installed, commissioned, and operational as of mid-June 2020.

3.2.2 Control and Analysis Strategy

After the equipment was installed and DemandEx communications were established, Extensible Energy analyzed trend data and ran tests to develop a control method. Initially, the intent was to use the full predictive control algorithms at the site. However, Extensible Energy discovered significant access limitations to the controllable devices and misconfiguration in the building control system. Therefore, Extensible Energy developed an alternate control approach compatible with the building equipment that used zone temperature shifting coordinated with solar generation and peak demand times. Concurrently, AESC developed a normalized metered energy consumption (NMEC) "Whole Building" M&V model. The model allows the team to assess the impacts of energy and demand intervention, normalized for weather and building schedule.

3.3 Control and Monitoring Equipment

AESC installed monitoring equipment on the main building feeder and the solar system. The actual installation of the data loggers required a few hours of an electrician's time. Physical installation of the gateway was accomplished by plugging it into the control network and into the building's local-area network. The data loggers captured net load and solar generation at 1-minute resolution. Installation was initially attempted in March 2020, but due to COVID-related shutdowns, the equipment was only fully installed in June 2020, followed by a period of calibration of the software and examination of the building control network.

3.4 DemandEx Communications and Control

AESC connected the DemandEx controller onsite while Extensible exercised the remote monitoring capabilities. Initially AESC was unable to use the building internet and temporarily utilized the cellular capabilities of the controller. Eventually, Wedgewood IT staff were able to configure internet access on the building's LAN and full connectivity to the device was established. Once the controller was commissioned, the team began the process of mapping the BACnet HVAC devices. Through this process it was discovered that there were multiple BAS discrepancies. The team brought these issues to the awareness of the facility engineering staff and BAS controls contractors. To date, the discrepancies have not yet been rectified.

3.5 Site Control Test

To achieve desired outcomes, DemandEx changes the operation of the building by sending control signals to the equipment in the building that, in turn, adjust energy use. At Wedgewood, this was accomplished by sending control signals via the gateway computer to the BACnet network which then changed the temperature setpoints in individual zones. DemandEx maintained temperatures within a comfort range based on the existing temperature ranges that were already configured in the building management system.

Control tests were run on alternating controlled and uncontrolled days. By alternating control days, multiple days with similar characteristics were captured, such as similar temperature ranges. On controlled days, setpoints were changed to shift demand out of the early morning peak period as well as out of the late afternoon / early evening peaks. On uncontrolled days, the system operated as it did before, without DemandEx control. Weekend days were reserved for tests or left uncontrolled and were not part of the analyses.

From a DR perspective, these alternating day tests can be considered day-ahead tests, simulating a situation where the utility called for a reduction in demand on the following day.

One single hour-ahead test was performed on November 16th, an unusually warm November day that reached 91°F. To simulate a DR dispatch event, control was stopped by noon, allowing the system to run in its standard operating mode, then control was reinstated at 3 PM to shift demand an hour later at 4 PM.

3.6 Measurement, Verification and Reporting

The team evaluated the energy and non-energy impacts of the control test per the revised M&V plan, as finalized.

3.6.1 Measurement and Verification Plan

The M&V plan was developed for this project to detail how energy and demand savings would be quantified. The plan adhered to specifications described in the IPMVP Core Concepts.

M&V involves the process of using measurements to reliably quantify energy savings within a facility, a process, a building, or a building subsystem. M&V for this project was used to verify the extent to which the DemandEx controller was able to achieve its demand reduction and load shifting objectives.

This project’s M&V plan described how savings are determined from the measurements of energy use before and after implementation of the project intervention, with appropriate adjustments made for changes in conditions. Such adjustments may be routine and expected, while others are non-routine and due to factors unrelated to the project. The plan also described how baseline energy use and demand are documented, how they vary, and what factors are its primary drivers. It detailed how adjustments to baseline use are made for unexpected events, such as added equipment or loads, or other unforeseen events that materially affect use and savings.

The M&V plan was required to document and describe the approach to quantifying savings, the key measurements required and computation methods, the timing of these activities, roles and responsibilities of involved parties, and the quality assurance requirements associated with the process.

3.6.1.1 Analysis Procedures

The baseline and post-installation modeling algorithms were regressions based on change-point models originally developed under ASHRAE Research Project 1050. Change-point models are a series of dependent piecewise linear relationships between energy use and ambient temperature. The change-point models are named by the number of parameters in the model and whether they apply to heating or cooling energy use. After each model was developed, the change-points and coefficients of the slopes of each line segment were determined, along with the goodness-of-fit-metrics. See ASHRAE RP1050 for change-point modeling details.

To facilitate development of energy models, the data were grouped into different bins based on the building operating periods, such as weekdays, weekends, or holidays. Thus, different models were developed in the baseline period according to these unique operation periods as they had different responses to ambient temperature. The resulting models were developed for each period and combined using an indicator variable. This approach applied to baseline period data.

The baseline model was required to meet the goodness-of-fit criteria described below:

1. The coefficient of variation of the root mean squared error (a measurement of the random error of the model) CV(RMSE) < 20%
2. The net determination bias error (a measurement of the model's bias error) NDBE < 0.005%
3. The coefficient of determination (a measure of how well the independent variables explain the dependent or energy use variable) $R^2 > 0.75$.

Definitions of these metrics may be found in ASHRAE Guideline 14-2014.

3.6.1.2 Demand Savings

The current building tariff is TOU-GS-3-R in which summer is defined as June through September. The alternating-day control tests meant that there was no actual reduction in customer demand costs during the test period, since a demand peak set on any day of a billing month determined the cost for the entire month. In addition, the delays due to COVID and building controls access and configuration issues meant that control tests were performed in the winter season, so actual energy TOU costs were at the lower winter-season rates. However, the tests were able to show demand savings on control days, and the study did demonstrate demand cost savings to the customer if control had been operating continuously.

Table 1: Tariff structure for TOU-GS-3 Option R

Option B, Option B-CPP, Option R (Legacy TOU Periods)

TOU Period	Weekdays		Weekends and Holidays	
	Summer	Winter	Summer	Winter
On-Peak	12 p.m. - 6 p.m.	N/A	N/A	N/A
Mid-Peak	8 a.m. to 12 p.m. 6 p.m. to 11 p.m.	8 a.m. to 9 p.m.	N/A	N/A
Off-Peak	All other hours	All other hours	All other hours	All other hours
CPP Event Period	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	N/A	N/A

CPP

CPP Event Energy Charge Periods: 4:00 p.m. to 9:00 p.m. summer and winter weekdays except holidays, only when a CPP Event is called.

CPP Non-Event Demand Credit Period: Summer Season weekdays, 4:00 p.m. to 9:00 p.m., when a CPP Event is not occurring.

Figure 5: Rate schedule

Demand savings were analyzed using two approaches. In one analysis, 15-minute demand was used to calculate demand values and peak demand, as well as to analyze the effect of control compared to baseline operation. The results of this 15-minute demand analysis are presented in Section 4 Results. Another analysis, developed for purposes of the verification, used hourly demand values based on NMEC statistical requirements. The results of this hourly demand analysis are presented in Section 5 Verification Results and the approach is described below. It is worth noting that hourly demand values will be less variable than the 15-minute demand values used for billing. Therefore, an analysis using hourly demand would be expected to show smaller baseline to impact differences than an analysis based on 15-minute demand.

First, the baseline model was developed through regressions using the whole building and solar production data collected during the baseline period. The utility demand was estimated using the following equation:

$$Utility\ demand\ (kW) = Modeled\ whole\ building\ demand\ (kW) - Actual\ solar\ production\ (kW) \quad (1)$$

Next, demand savings were calculated by subtracting the utility metered post-installation demand during the on-peak period from the maximum baseline demand calculated from above:

$$Demand\ savings\ [kW] = (Baseline\ demand\ (kW) \pm adjustments) - Post\ demand\ (kW) \quad (2)$$

The *adjustments* term was used to adjust the baseline in terms of the post-installation conditions. Routine adjustments are expected changes and will be made through regression modeling, most likely based on weather and solar availability in this case. Another type of adjustment, non-routine adjustment, will also be made as necessary using the criteria discussed in Section 4.

The utility charges the demand cost for the maximum demand that occurred during the on-peak period (coincidental) and during the entire billing period (non-coincidental). For this study, however, the demand savings were validated for every hour using the above equations. The maximum demand savings were calculated as the difference between adjusted baseline maximum demand of the day and actual monitored post-installation maximum demand of the same day. Additional savings were reported using the actual 15-minute demand recorded by the utility meter.

3.6.2 Reporting

AESC and Extensible Energy provided monthly status reports to SCE. These reports detailed:

- Planned Activities for each Month
- Accomplished Activities for each Month
- Project Status Compared to Plan
- Significant Problems or Changes
- Expected Activities for the Next Month
- Milestone and Delivery Status
- Current Schedule
- Overview of Fiscal Status
- Evidence of Progress

AESC and Extensible Energy developed this project report covering project objectives, approach, outcomes, and highlights of key challenges encountered and resolutions to those challenges, to inform future grid-interactive engagements.

Extensible Energy also developed “operating guidance” based on the control results at this site to inform relevant other SCE commercial customers with potential for solar plus load flexibility installations.

SECTION 4 RESULTS

The figure below shows daily maximum demand for controlled and uncontrolled days during the months of October 2020 and November 2020 (testing period). The data demonstrated that the technology was able to reduce the facility demand when daily maximum outdoor air temperature (OAT) exceeded 75˚F, as shown by the regression lines.

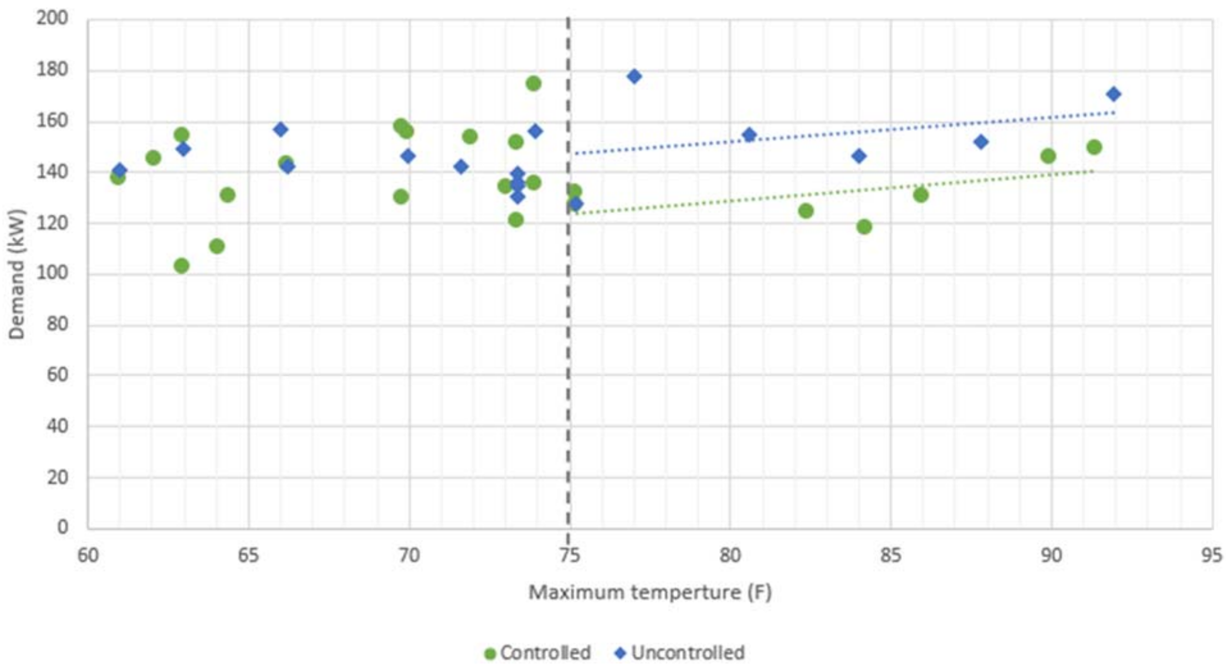


Figure 6: The maximum daily hourly demand on controlled and uncontrolled days during the testing period.

Figure 7 shows a similar plot of controlled versus uncontrolled demand, limited to days when the maximum temperature was at least 75 °F. This plot shows the demand as billed by the utility and reflects the higher variability of 15-minute demand compared to the hourly demand used in in Section 5 Verification results. Maximum daily temperatures were retrieved from the nearby Los Angeles International Airport weather station data, while 15-minute utility demand data were retrieved from Utility API.

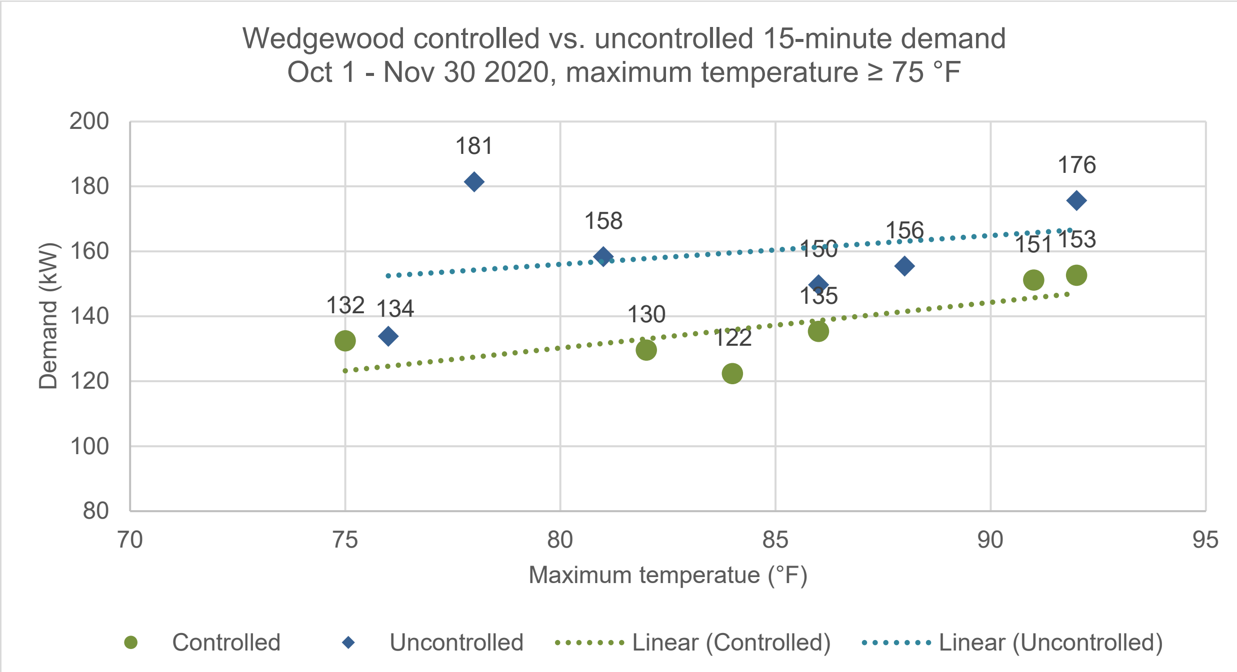


Figure 7: Daily maximum 15-minute demand on controlled and uncontrolled days on warmer days (maximum temperature ≥ 75 °F).

The project demonstrated demand reductions of 28% in the morning and 13% in the evening, when comparing the maximum recorded demand between controlled and uncontrolled days having outdoor temperatures of at least 75 ˚F (Figure 8). In the morning (5-9 AM), demand was reduced from 181 kW to 130 kW, before solar generation fully ramped up. In the evening (4-8 PM), demand was reduced from 176 kW to 153 kW, as solar generation dropped off. Overall, this was a reduction of 28 kW, from the maximum uncontrolled demand of 181 kW to the maximum controlled demand of 153 kW, or a 15.5% reduction overall in demand. Had this reduction occurred for an entire billing period it would have saved the customer approximately $362 at $12.91/kW.

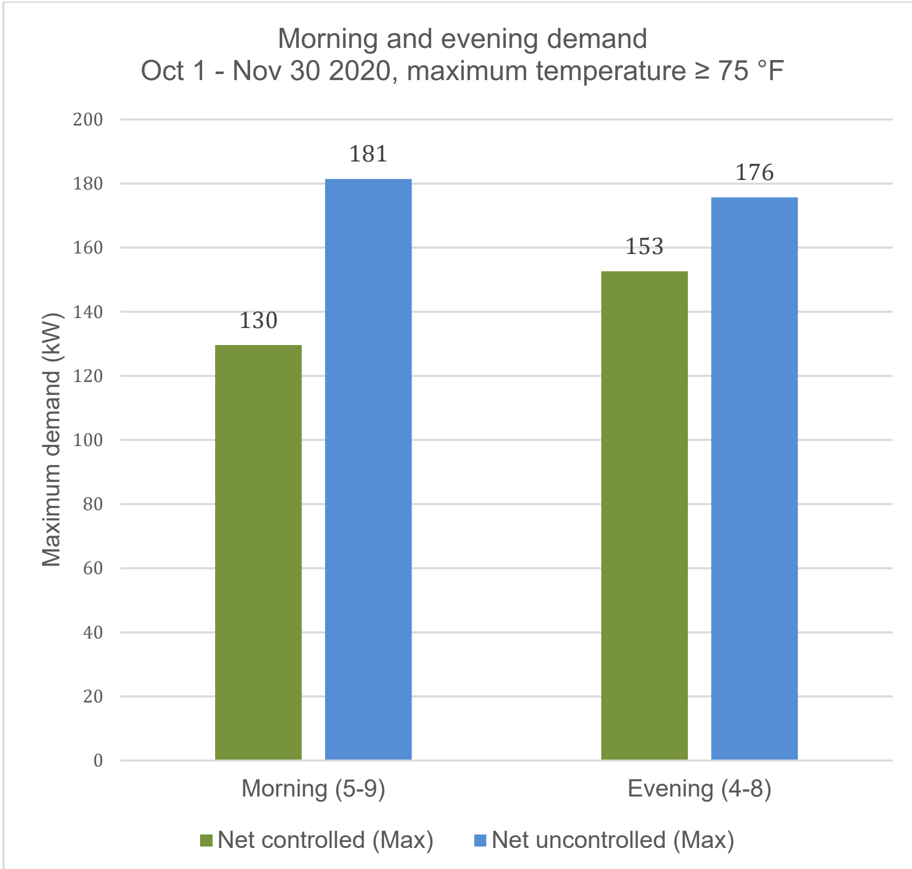


Figure 8: Morning and evening demand reduction due to DemandEx control on warmer days (maximum temperature ≥ 75 °F).

Figure 9 shows average 15-minute demand profiles for controlled and uncontrolled days. The controlled demand (green) can be seen to be reduced relative to the uncontrolled demand (blue). Controlled demand in the evening is also shifted by about 1/2 hour earlier in the day compared to uncontrolled demand. On average, the project reduced demand by 22 kW or 14%.

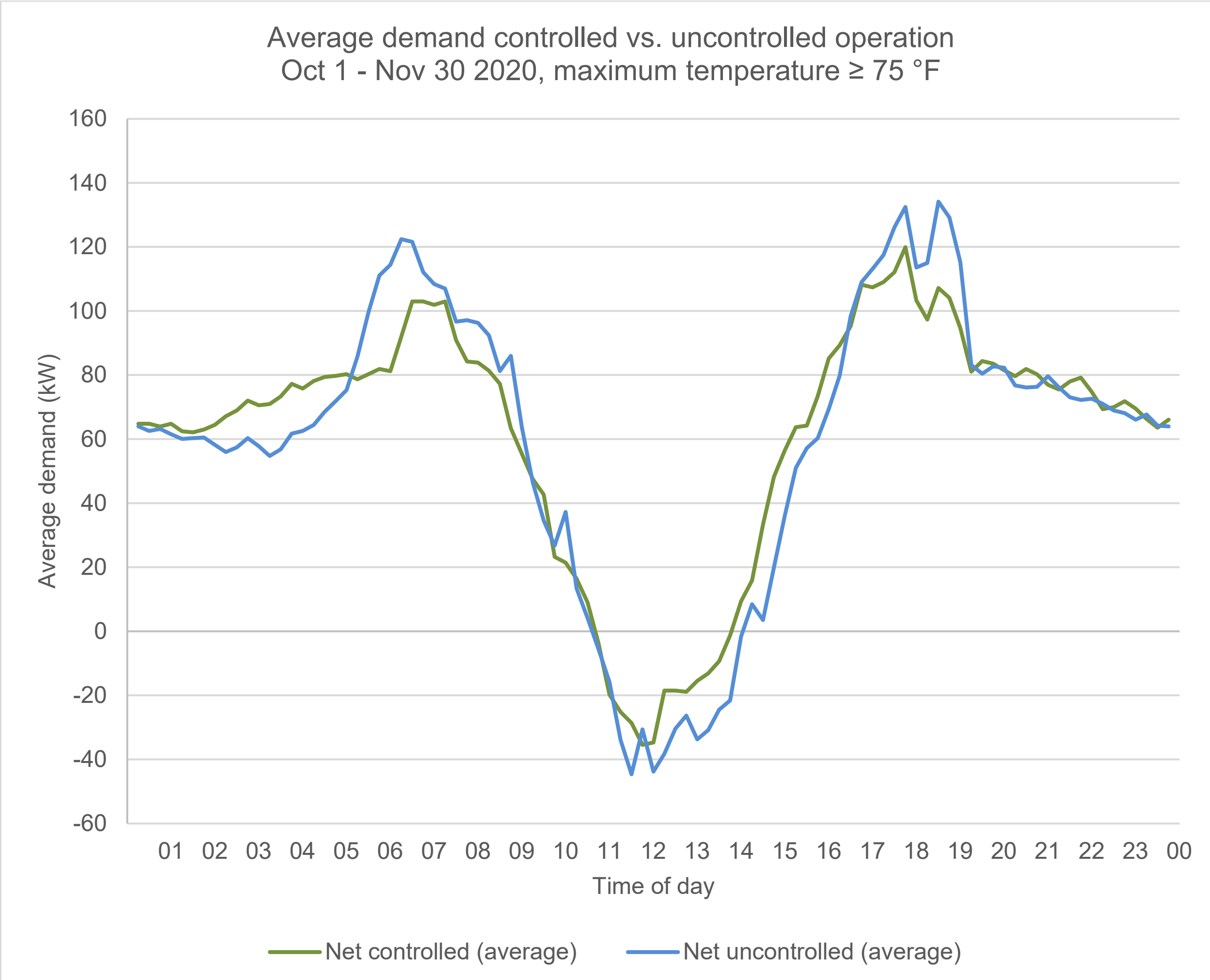


Figure 9: Average 15-minute demand on controlled and uncontrolled warmer days (maximum temperature ≥ 75 °F).

Figure 10 shows that control reduced energy consumption in evening hours (4-8 PM), while it increased consumption in the afternoon when there was greater solar generation (12-4 PM). On controlled days, net energy consumption was increased in the afternoon by 58 kWh, while in the evening net energy consumption was decreased by 79 kWh. This is a reduction of 19% of energy consumption in the evening hours.

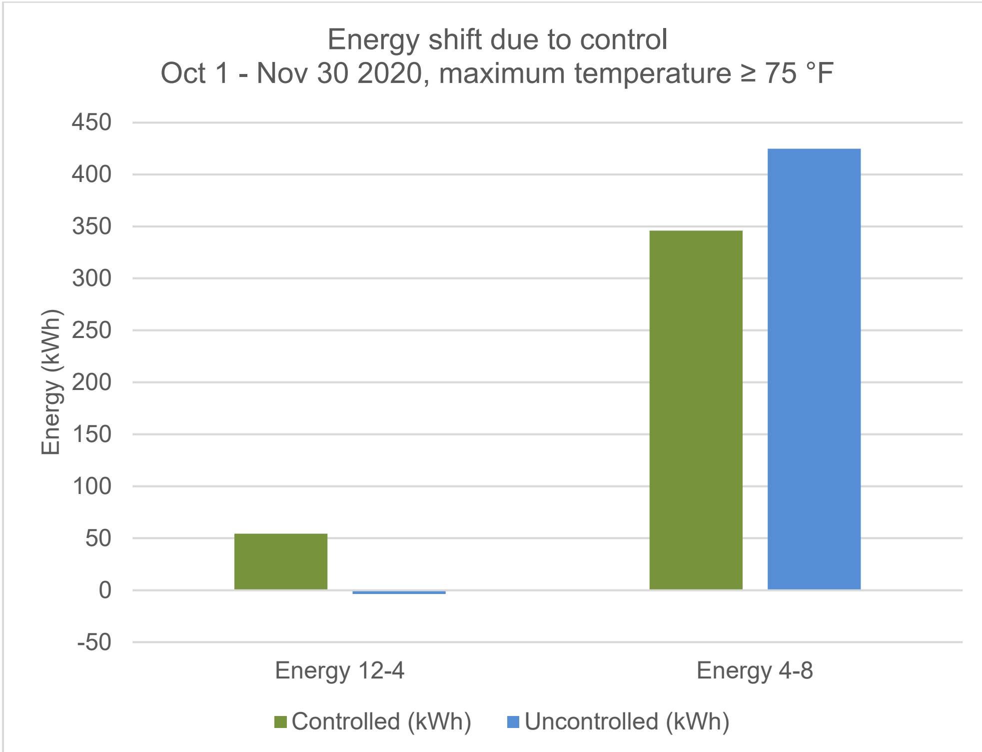


Figure 10: Energy shift due to control on warmer days (maximum temperature ≥ 75 °F).

4.1 Hour Ahead Test Results

Peak demand for an hour-ahead test on November 16th was 151 kW at 5 PM (note that only demand after 4 PM is considered for this test). This represents a 14% reduction compared to the maximum observed evening peak of 176 kW during the uncontrolled period. Because there was only an opportunity to perform a single hour ahead test, however, it is difficult to draw statistical conclusions from the data. Maximum temperature reached 91 °F on this day. The most comparable uncontrolled days in our test period were October 2nd, with demand of 176 kW and maximum temperature of 92 °F; and November 5th, with demand of 156 kW and maximum temperature of 88 °F (three degrees less than on November 16th). The hour-ahead control test achieved a reduction of just 3.2% relative to November 5th.

4.2 Annual Extrapolation

The control tests covered just two months in the fall, while the demand savings were observed only when daily maximum temperature exceeded 75 °F. However, ambient temperatures exceeded 75 °F every month of the year in Redondo Beach in 2019 (Figure 11). Thus, the results can be extrapolated to a full year of operation based on the correlation between temperature and demand. Based on a regression analysis, savings on demand charges for a full year, with similar operating conditions, would be about $3,600.

Operating conditions during the test months were affected by COVID-related shutdowns and reduction in occupancy. Prior years' demand was about 61% higher, on average, than during the COVID epidemic (Figure 12Figure 12). Thus, adjusting the facility demand to non-COVID operating conditions is expected to significantly increase the expected savings. However, new rooftop units were also installed in June 2020, just a few months prior to the test. These units are expected to use less power than the older units. Although the annual savings are still expected to increase, if adjusted for the above conditions, it is difficult to draw conclusions given the inherent uncertainty of the occupancy changes related to COVID shutdowns and additional adjustment required to account for the change in RTU efficiency.

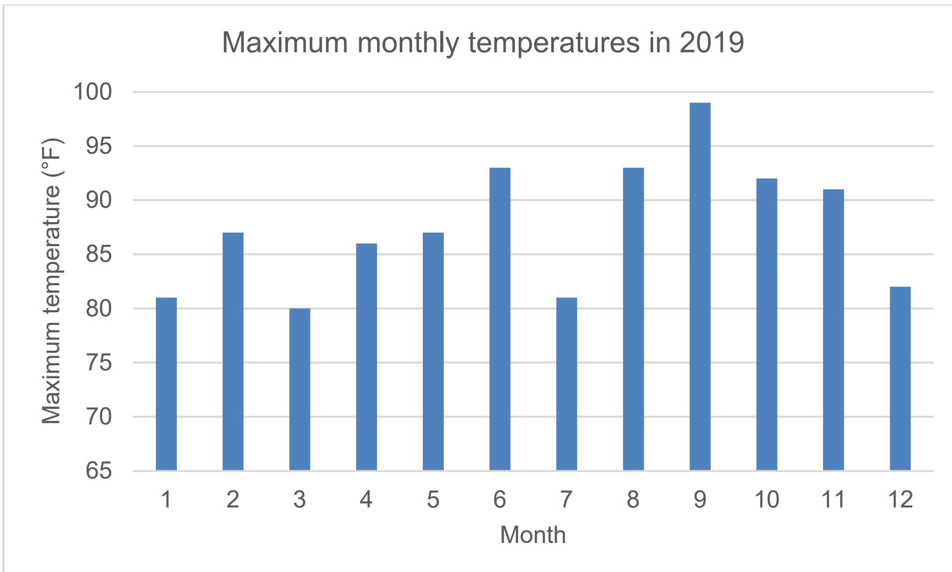


Figure 11: Maximum monthly temperatures at LAX Airport (near Redondo Beach) in 2019.

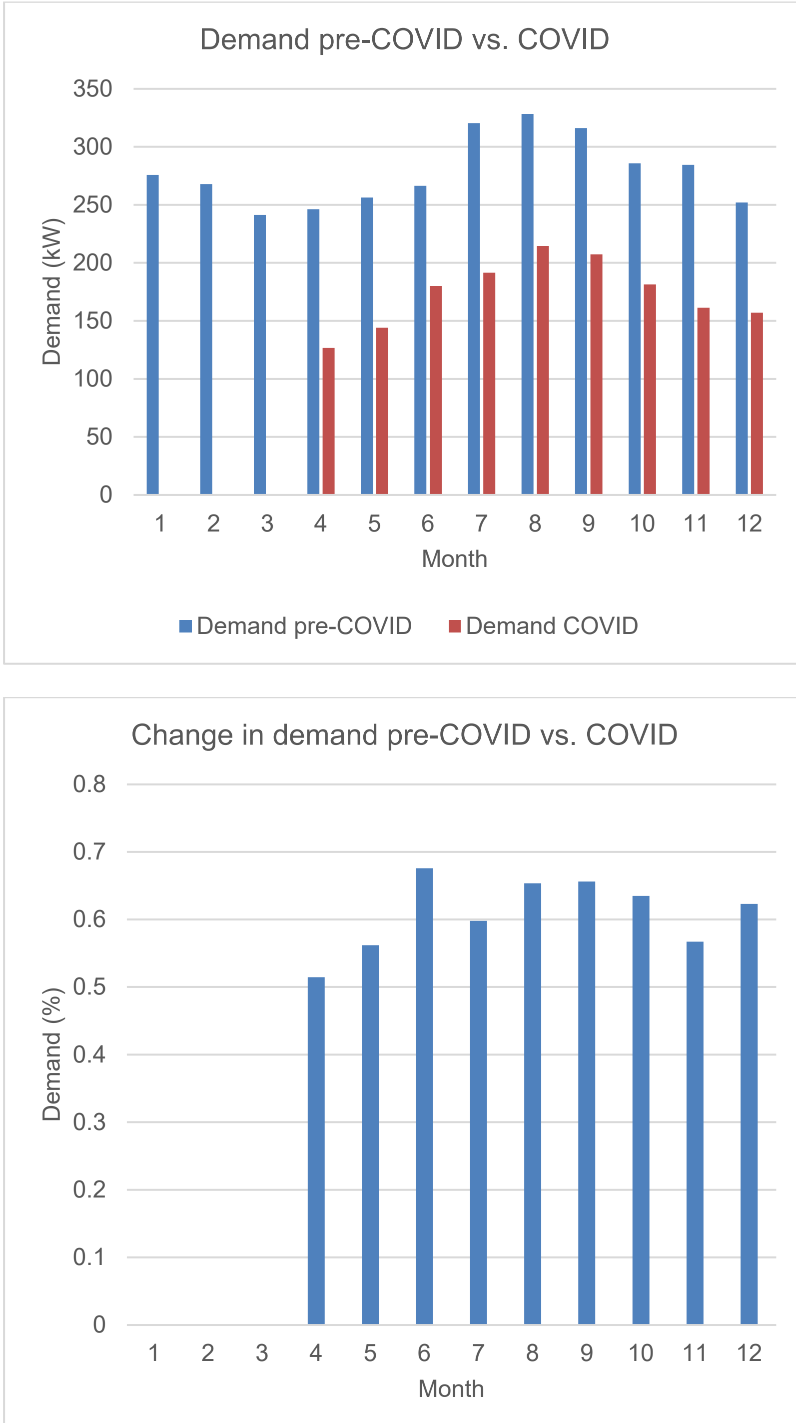


Figure 12: Demand pre-COVID vs. COVID.

SECTION 5 VERIFICATION RESULTS

5.1 Regression Analysis

Because of COVID-19 delays, the team was required to use alternate day method (i.e., IPMVP - "Adjacent Measurement Periods" [On/Off Test]) rather than using two distinct baseline and post-installation periods. Therefore, daily peak hourly demand analysis was conducted to compare the net grid demand of the building, with and without controls.

An hourly baseline model was developed through regressions using the hourly average whole building demand and outside air temperature (OAT) data collected during the baseline period and the DemandEx control period. The following formula was used to predict the hourly average demand of the facillity:

$$Hourly\ average\ demand\ (kW) = a + b \cdot Hr + c \cdot Hr^2 + d \cdot OAT\ (3)$$

Where

Hr = hour number, representing occupancy profile

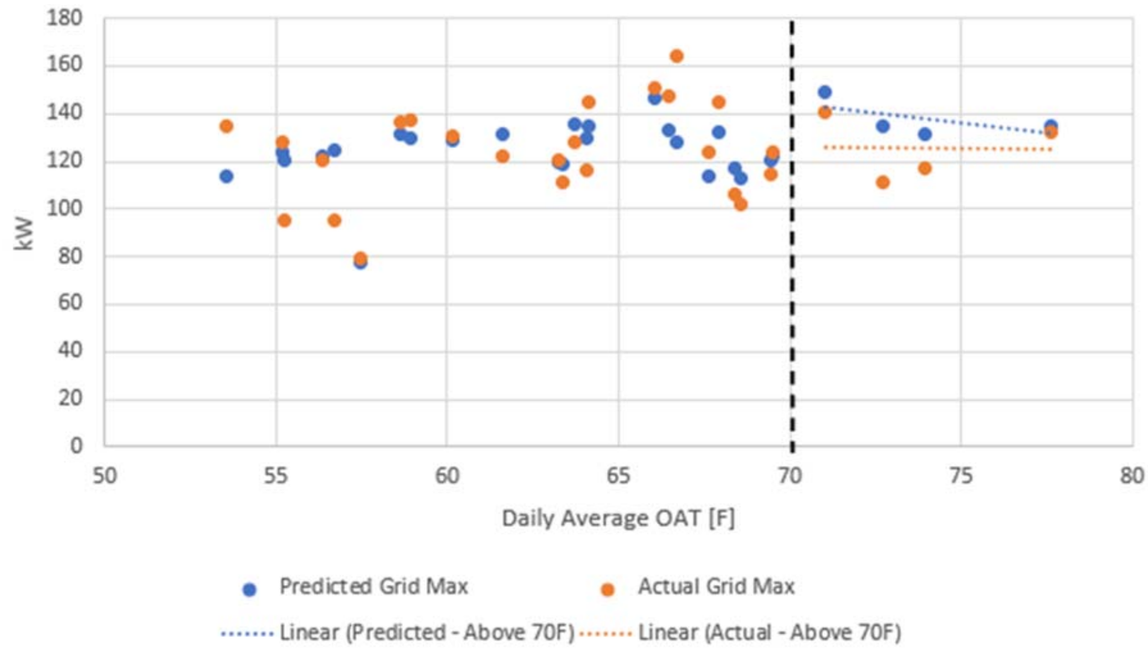
OAT = hourly average outdoor air temperature

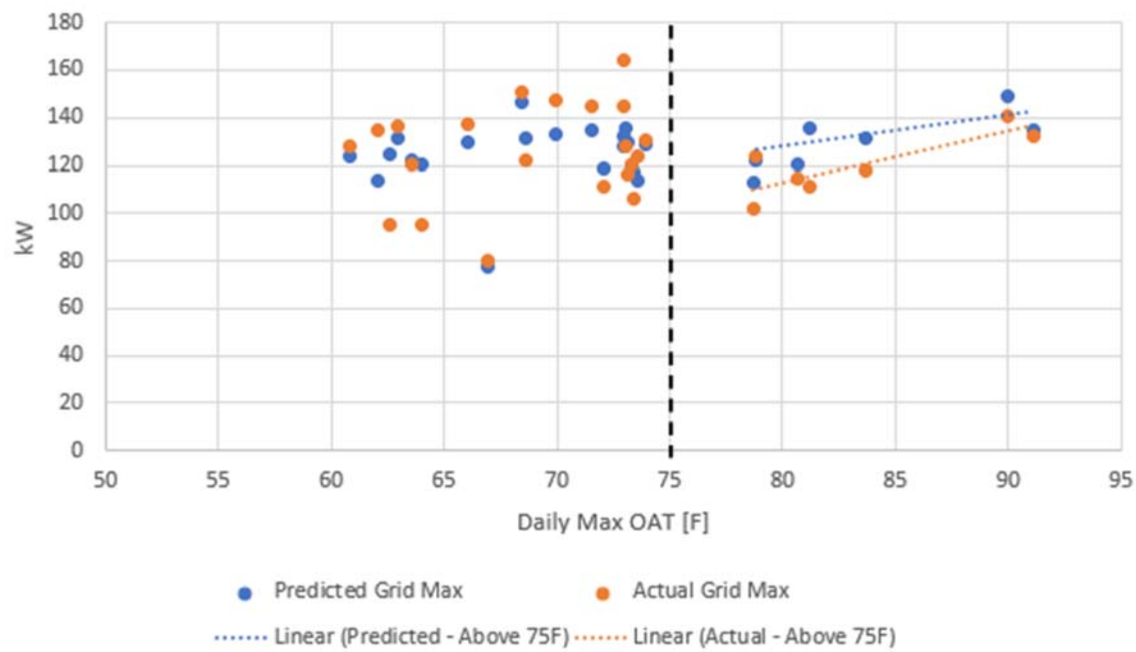
	Coefficients
a	-204.89
b	38.57
c	-1.59
d	2.17

The resulting model met the M&V criteria below:

	Calculated	Criteria
CV (RMSE)	8%	< 20%
NDBE	0.000%	< 0.005%
R^2	0.82	> 0.75
$\Delta E_{save}/E_{save}$	5%	< 50%

The hourly average net grid demand was calculated by subtracting the solar production from the modeled whole building demand, using equation (3) above. The resulting net grid demand model for baseline was compared to the actual hourly average demand measured during the post-installation period in the figure below. The comparison demonstrates that the DemandEx controller was able to reduce the hourly average net grid demand when daily average OAT was greater than 70˚F and the daily maximum OAT was greater than 75˚F, resulting in potential customer energy and costs savings.





The model developed showed the following houlry average demand savings:

Table 2: Savings based on modeled baseline.

	Max Daily Grid kW when Avg OAT > 70F	Max Daily Grid kW when Max OAT > 75F
Predicted (Modeled Baseline)	138	129

Actual	126	120
Savings	12	9
% Savings	9% ± 5%	7% ± 5%

It should be noted that the M&V was performed on hourly average data while the billing is based on 15 minute data. While the M&V generally supported the testing results, the actual billing savings is expected to include greater uncertainty as 15 minute data would include more variability than the hourly average data.

SECTION 6 KEY CHALLENGES

The project encountered several key challenges, including COVID-19 shutdowns, networking issues, and BAS configuration issues. These are discussed further below.

6.1 COVID-19

COVID presented unique challenges to the installation of the equipment and implementation of the project. COVID also reduced occupancy, reducing the magnitude of the tests' effects on demand.

Statewide shutdowns due to COVID in early March coincided with the planned installation date for the equipment, which significantly delayed installation. AESC staff were able to visit the site over the next few months to complete a site survey and install the equipment. However, this delay meant that the equipment was not installed until June 2020, essentially eliminating much of the pre-summer testing and calibration period, and shifting it into the summer, which was originally intended to be the main control test period. This was a major factor in the delayed start of control testing until after the summer. Despite this, the tests did show savings, particularly since the mild climate in the region provided enough warmer days to detect an effect on cooling load.

Changes due to COVID also affected the energy needs of the site. Occupancy dropped significantly, resulting in demand that was 1/3 to 1/2 of pre-COVID levels. This reduced the observed impact from the control tests. In the annual extrapolation, we applied a correction to the observations made during COVID to adjust the results for an expected non-COVID year.

6.2 Communications and Connectivity Issues

The DemandEx system required Internet connectivity as well as connectivity to the BAS. Initially, we encountered challenges in providing Internet access to the gateway. This was due to some initial confusion on who maintained and controlled access to the Internet over the assigned ethernet port, as well as the need to assign an IP address to the DemandEx gateway that would not disable remote access to the BAS. Wedgewood IT staff were able to configure and install equipment to facilitate this. This network and IT support generally overlapped with the overall COVID-delayed installation timeline described above.

6.3 BAS Discrepancies and Control Issues

The building's control systems had several issues that limited the effectiveness of control. First, many zones were misconfigured. Second, the team had limited access to control points for each zone, due to the programming of the individual devices in the building. Both issues could be addressed through reconfiguration of the Automated Logic control software in the building. If the misconfiguration is addressed in the future, then the building would operate more efficiently and comfortably, and the software could provide better savings and load shifting capabilities. In addition, exposing the extra control points would further enhance the ability of our software to provide increased savings.

The most significant issue Extensible encountered was that about 60 zones (more than half of the 118 zones in the building) were misconfigured, effectively connected to the wrong RTUs. The RTUs to which these misconfigured zones sent control signals did not provide conditioned air back to the zones. Instead, these RTUs sent conditioned air to different zones. This caused the building’s mechanical systems to operate at cross purposes, wasting energy, failing to properly condition the zones, and leaving tenants less comfortable. Extensible conveyed this information to the building management and to their control’s contractor, who will work on fixing the issues by reconfiguring the software – unfortunately, however, not in time to benefit the control tests for this study.

An example misconfigured zone is zone number 10 on the first floor (1-10). The VAV for zone 1-10 receives air from RTU 4 but sends signals to RTU 3. If, say, the temperatures in zone 1-10 were to rise, then the equipment in the zone would send a cooling request to RTU 3, which in turn would cause RTU 3 to increase the amount of cool air it provides. This air, however, will never reach zone 1-10. Instead, some other set of inputs to RTU 4 will cause either more or less cool air to flow zone 1-10, leading to a failure to properly condition the zone, while simultaneously improperly conditioning another zone that receives air from RTU 3.

Another set of issues were caused by the limited control points that were accessible to our software. The individual controllers can, in principle, accept temperature setpoint values as well as airflow settings. Either of these control values would provide our software with finer-grained control over the energy use in the building. However, these control points were not exposed on the BACnet control network, and so were not accessible to our software. Instead, Extensible had to use a less effective workaround to adjust setpoints indirectly.

SECTION 7 PROJECT OUTCOMES

This project demonstrated that significant demand reductions can be achieved during peak demand hours through a simple control software installation with no changes to building operations. These results also showed that the control software successfully achieved the Load Shift and Load Shed hypotheses targets (repeated below for reference).

- **Load Shift Hypothesis:** First, can the software effectively reduce the customer’s HVAC related demand charges by between 10% and 25%, without negatively impacting building tenant comfort, by shifting operations and increasing loads during SCE’s non-peak (Mid and Off-peak) TOU periods, and reducing loads during peak periods?
- **Load Shed Hypothesis:** Second, by driving a deeper level of HVAC setback than under normal operating conditions, can the software enable two to four hours of load shift of at

least 20% of whole-building load in response to simulated day-ahead, hour ahead and 15 minutes ahead load curtailment signals from SCE?

First, the results showed that the control software reduced demand by 16% overall without negatively impacting tenant comfort. The software also reduced energy consumption in the evening while increasing energy consumption in the afternoon by shifting loads to the morning hours. This capability could provide a significant demand shifting capability for utilities, if deployed at multiple sites. It also demonstrates the potential for significant direct savings to the customer, creating a win-win for the utility and customer. Further, the ability to shift demand from periods with less solar generation into periods with more solar generation should support the state's transition to renewable generation and result in reduced emissions. These effects were achieved in a region with mild climates and in a building with significant configuration issues. The team expects even greater effects in regions in California and elsewhere with hotter climates.

For load shed, alternating control schedule effectively simulated multiple day-ahead signals. In addition, evening energy consumption was reduced by 19% on average on warmer controlled days. The single hour-ahead test reduced demand by 14%. (Due to practical challenges and schedule constraints the project was not able to simulate a 15-minute ahead load curtailment signal.) These savings were achieved even though the building had a significantly misconfigured control system.

During the calibration phase, it was discovered that the building's control systems had significant configuration issues that pre-dated the installation of DemandEx. Additional demand reductions should be possible if these configuration issues are corrected by Wedgewood's controls contractor. If corrected, a rough estimate of demand reductions of as much as 20-25% might be achievable.

SECTION 8 LESSONS LEARNED

Some of the main lessons learned involved installation, network connectivity, and interactions with the building's equipment.

For installation of the eGauge data logger devices, the team involved the electrician who regularly provides services to the site -- this helped provide a smooth interaction with the building personnel and ensured that the electrician was familiar with the building. AESC staff were on site for the initial site survey to identify equipment requirements and to assist in the installation. This contributed to successful installation of the data loggers.

Early involvement of IT staff is important. Each site has different network configurations. IT staff are needed to address security concerns and network configuration to ensure that the gateway and data loggers have the necessary network connectivity. The earlier the IT staff become involved, the more the installation is likely to proceed quickly.

Extensible Energy's staff studied the building carefully once connectivity was established. During this time, they communicated with the building's controls contractor, which helped to ensure access to the BAS and to understand how to interface with it. Eventually, they discovered significant, though previously unknown, misconfigurations in the building's controls. They also discovered that some control points -- which had appeared to be exposed -- were in fact inaccessible. A list of issues to check at a new site should incorporate validation of the equipment's operation and access to necessary control points. The earlier these issues are identified, the more time there will be to address them or work around them.

The rate schedule can have a significant impact on the potential savings and grid impacts from load flexibility. Wedgewood is on rate GS-3-TOU Option R. This rate schedule has high energy costs in the middle of the day, precisely when solar generation is at a maximum. The cost of energy drops in the evening on option R, when solar generation is reduced and generation sources with higher marginal costs and emissions account for a larger portion of the energy mix on the grid. Option R has been replaced with Option E, which has lower energy costs in the middle of the day and has significantly higher energy costs in the evening. Option R is less favorable to shifting energy use into periods of high solar generation, because of the increased energy costs under the rate schedule. In contrast, Option E favors shifting energy use into periods of high solar generation and out of the later afternoon and early evening, when high demand on the grid is more problematic. Thus, customers on Option E would tend to benefit more from an approach that shifts energy use into the middle of the day. Whatever rate schedule is in use, the application of advanced control algorithms that account for both TOU energy costs and demand, as are available in DemandEx, should still provide improved economical control and customer savings.

SECTION 9 RECOMMENDATIONS

This project demonstrated successful demand reduction of about 16% in an office building in the Los Angeles region. This demand reduction was achieved even though the BMS and HVAC controls were misconfigured and exposed limited control points. The team was also able to successfully overcome challenges due to COVID-19. Operating guidance resulting from this control test includes the following recommendations.

1. The tests indicated that DemandEx software can achieve demand reductions even in buildings that are not well configured. Therefore, it is possible to install DemandEx in such buildings without retrofits or repairs being made.

2. Additional demand reductions can be achieved in correctly operating buildings. Therefore, we recommend that an evaluation be made of the control system and HVAC equipment and appropriate corrective actions taken. This can be done even while DemandEx is operating to reduce demand.

3. Exposing control points needed for optimal DemandEx operation will also enable additional savings. The building should be checked and adjusted, along with recommendation 2, to expose control points that would enable improved operation of DemandEx.

4. Networking issues can delay installation and should be addressed early in the process. DemandEx's in-building gateway has minimal networking requirements, but it does require access to the Internet on several ports and access to the building's control network. Early coordination with IT personnel will facilitate the installation process.

5. Installation and calibration work are more effective when supported by the building's controls contractor. The controls contractor will be familiar with the control systems, can facilitate connection to the BMS, and can enable full access to the BMS by Extensible Energy personnel.

6. Electrical work is simple, though it requires a licensed electrician and access to the building's electrical panel. Working with the electrical contractor who normally services the building can help facilitate this work.

7. Coordination with building staff is important. They need to understand how the building will be operating differently and how they can work with Extensible Energy to adjust its operation using the DemandEx software.

8. The rate schedule should be considered when selecting a control method to ensure that the desired savings and objectives are achieved.

APPENDIX A. MEASUREMENT AND VERIFICATION PLAN

Wedgewood
MandV Plan Version