Development of Customized Measure Packages for Cost-Effective and Scalable Combined Demand Flexibility and Energy Efficiency Programs

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ABSTRACT

Rapid changes in electricity consumption and generation patterns are creating a significant need for additional sources of energy storage and load flexibility on electric distribution grids. For buildings to become more active participants in the electric grid, a new paradigm is required to enable utilities and buildings to shape load profiles at the system-level. To achieve this, existing buildings need to be retrofitted with enabling technologies to provide grid-interactive capabilities. The costs of enabling technologies such as communications, controls, and sensors can be significant, so utilities need a program design methodology that balances costs with benefits. This paper presents a data-driven methodology for creating utility programs that combine demand flexibility and energy efficiency from grid-interactive buildings. The proposed methodology uses utility AMI data in conjunction with simulations to determine cost-effective measures based on local building stock characteristics and load profiles. The steps include: (i) evaluating localized grid congestion issues, (ii) determining building stock characteristics and evaluating building load profiles, and (iii) identifying demand flexibility and energy efficiency measures to meet program objectives and budget. Additional criteria may be included in the evaluation, such as identifying opportunities for electrification and/or equity evaluation. The outcomes of the program evaluation support decarbonization of the electric grid by enabling the cost-effective deployment of behind-the-meter resources for providing demand flexibility. This work describes common grid issues and associated measures, presents a proposed program evaluation methodology, and provides an example reference implementation.

Introduction

There has been growing interest in grid-interactive efficient buildings (GEBs) among policy makers and researchers over the past decade (Satchwell et al. 2021; Perry, Bastian, and York 2019). GEBs address several technical and feasibility challenges in scaling variable renewable energy generation, applying deep energy retrofits to the building stock, and achieving energy and building sector decarbonization. An advantage of GEBs is that they take advantage of the increasing proliferation of smart building technologies and often rely on no- or low-cost retrofit measures. They also support structural changes on the electrical grid that are leading to new grid services, products and rate structures (Satchwell and Cappers 2018).

A key component of GEBs is the ability to provide demand flexibility (DF) and energy efficiency (EE) through active control and management of both building systems and on-site distributed energy resources (DERs). Demand flexibility can provide benefits to both building owners and the electric grid by reducing or shifting the consumption of electricity in response to utility signals. This can serve to reduce distribution system congestion issues, match time-based supply and demand profiles, and reduce demand or time-of-use charges for the building owner.

Many early implementations of demand flexibility were extensions of existing demand response programs and technology, such as smart thermostat or connected water heater programs. As programs expanded in the U.S., there was a need to increase the value of demand response by providing more frequent and targeted responses to grid issues. Additionally, scaling programs requires a need to decrease the implementation cost, while maximizing the financial benefits of the program. A method to address this is through the creation of standardized solution packages for common building types that are designed to be deployed without the need for significant customization. Additionally, data-driven targeted recruitment can be used to focus utility resources on the loads that provide the greatest potential for demand flexibility. Finally, by requesting and dispatching specific amounts of resources from buildings and DERs, utilities can ensure they are receiving a desired response to address constraints. A primary objective of these interactions is to enable behind-the-meter assets to respond to grid events in a manner that is similar to typical in-front-of-the-meter grid assets.

This paper provides methods that can be used to develop a utility demand flexibility program that targets specific loads that are key contributors to grid congestion driven by peak demand. The following items are discussed in this paper.

- Analysis of interval electricity consumption data from advanced metering infrastructure (AMI) to determine contributions to key grid constraint metrics.
- Simulation of flexibility potential for GEB enabling solution packages for common building types.
- Performance analysis for utility demand flexibility programs, including demand flexibility potential for solution packages.
- A comparison of demand flexibility recruitment portfolios for achieving utility-scale flexibility goals.

We demonstrate these ideas with a distribution grid congestion analysis developed for one substation and associated feeders from Spokane, WA that is the focus of an ongoing U.S. Department of Energy (DOE) Connected Communities grant. The target substation is nearing capacity and serves a range of customer segments. We also show a range of customer recruitment portfolios to illustrate the tradeoffs in developing utility pilots and programs that engage different customer segments.

Advances in Demand Side Management Programs

The history of demand-side management (DSM) programs dates back to the energy crisis of the 1970s when governments and utilities began exploring strategies to address increasing energy demand and volatility in energy markets (Gellings 2017). Initially focused on promoting energy conservation through efficiency, DSM programs gained traction in the 1980s as policymakers sought to mitigate the need for costly investments in new power generation infrastructure. Throughout the 1990s and early 2000s, DSM evolved with advancements in technology and a growing emphasis on sustainability, leading to the introduction of more sophisticated demand response initiatives and incentive programs. In recent years, DSM continues to evolve with the emergence of smart grid and building technologies, increased data processing power, and innovative demand-side solutions control schemes aimed at fostering a more resilient and efficient energy system.

The first DSM programs were energy efficiency programs, often mandated by utility regulators, funded through a charge or allocation on the customer utility bill, and required to meet minimum standards of regulatory scrutiny through cost effectiveness tests. For a long time, it was difficult to find an energy efficiency program that went beyond offering rebates for specific asset upgrades according to the deemed savings dictated in regulator-approved technical resource manuals. The value of energy efficiency is typically based on the avoided cost of energy for a particular utility and the expectation is static energy reduction across unspecified times.

Though they are also in a utility's DSM portfolio, demand response (DR) programs are typically separated from energy efficiency programs, use different funding mechanisms, and utilize custom success metrics. DR is treated as a demand-side, not supply-side resource, so it is typically subject to cost effectiveness testing similar to EE programs. The method of recruitment and dispatch for DR programs is treated similarly; programs are offered by market segment to a service territory with direct enroll or via aggregator options. In a commercial building setting, a call, email, or text message will alert the building operator that they should reduce load during a time period in exchange for financial compensation. In a residential setting, newer programs use smart thermostats to adjust setpoints or ask the homeowner to make adjustments manually. The long-term goal of these programs is to improve the load factor (a measure of how efficiently energy is being utilized) of the grid or avoid expensive overbuild of peak-serving capacity, but the MW participating is often too little in magnitude to make a material difference. Demand response programs also do not forecast the magnitude or location of availability. Utilities have typically viewed demand response as unpredictable and not able to provide sufficient load reduction rates (Carvallo 2023).

Several factors are spurring DR programs to rapidly expand and innovate; (1) Utilities are experiencing and will continue to experience larger and more frequent peak loads driven by data centers, manufacturing, EVs, and building electrification (Downing, J., et al. 2023); (2) The majority (79%) of customers are served by utilities undergoing massive overhauls to their supply mix as they moved toward increasingly renewable (variable) generation (SEPA Power 2024). (3) regulation is discouraging utilities from choosing new-build infrastructure investments over demand side management to support growth in peaks. Therefore, traditional DSM programming does not address the increasing need for additional grid services.

This has laid the groundwork for many utilities (and their regulators) to evolve DSM programs, supported by increased data suggesting the value of EE depends crucially on the timing of the energy savings, and that DR must be more frequent and reliable to enable increased VRE resource integration (Gerke, et al 2022). In recent years, the market has seen an influx of pilots in the non-wires alternative (NWA) or virtual power plant (VPP) category providing demand flexibility (Wood Mackenzie 2023). Demand flexibility initiatives use communication and control technologies paired with "smart", often AI-based algorithms to shift electricity usage to align with when supply is abundant and/or clean in a reliable and repeatable manner, with little to no impact on building occupants. The service provided by demand flexibility is meant to mirror a supply side resource in its availability and predictability but since the capacity does not come from peaker plants, it is a much cleaner alternative. Buildings that want to participate in demand flexibility markets or programs have increased technical requirements, including communication and control hardware, sensors, and accessibility of real-time energy data. Large commercial buildings present a significant opportunity as they have large controllable loads that are accessible through building automation systems. However, depending on the specifics of the needed grid services and the distribution of building types in a territory, a combination of single-family residential, multi-family residential, small commercial and large commercial buildings may be needed.

EE and DR programs of the past generally offered the same bundle or rebate across the service territory, which may cause utilities to pay for recruitment of low-value customers. With DF programs there is more value from flexible load located in capacity constrained areas with high relative periods of congestion or location-based costs. Additionally, flexibility-enabling equipment may differ based on building type, age, and use. Therefore, it is important that cost-effective DF programs include customer targeting and building technology package analysis services, as well as incentives that take into account the full suite of grid services benefits.

Methodology

This section describes a data-driven methodology for designing demand flexibility utility programs. The purpose of this section is to describe generalized methods that can be used to customize a program to achieve the specific objective of a utility. The general steps in the methodology include: defining program objectives, load analysis, measure and solution package design, and EE and DF potential assessment. This work supports the planning phase of a new utility DF pilot program.

Defining Program Objectives

The first step in the proposed methodology is to define program objectives that support the needs of the utility. Grid-interactive buildings provide demand flexibility and energy efficiency by modifying building system operations and utilizing behind-the-meter DERs. The operational outcomes may support constraints in generation, transmission, or distribution systems.

High level analysis of generation, transmission and distribution system capacity and loads is used to determine the primary system of interest. Once, this is determined, further analysis is used to identify system sub-constraints and potential root causes. A utility that has identified a substation-level distribution congestion issue may utilize analysis with telemetry or AMI data to determine root causes for the congestion. An example analysis for a substation demonstrates how building heating and cooling loads may lead to a temperature-dependent loading of the substation (Figure 1). This type of analysis can inform the development of program objectives.

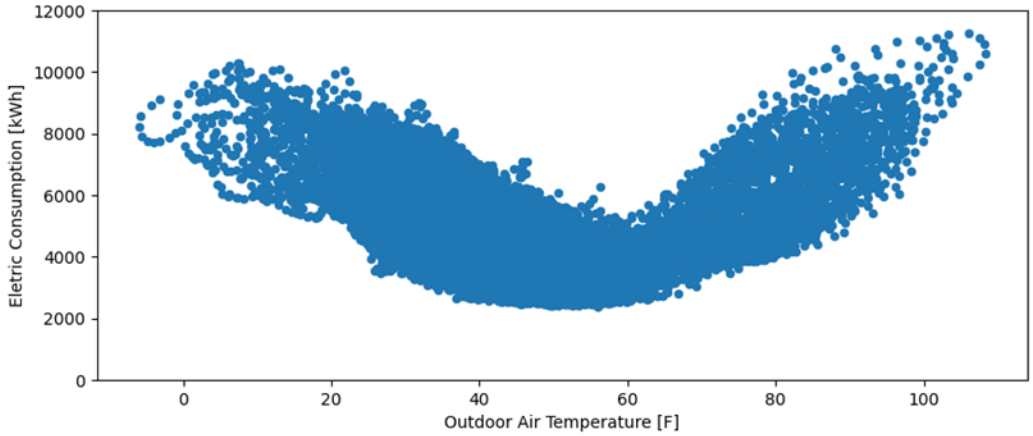

Figure 1. Hourly electric consumption versus outdoor air temperature on residential-dominant feeder.

After determining the primary system of interest, specific grid services that are desired from the program are defined. The most common grid services address issues with capacity constraints. Common grid services provided by buildings are:

- Generation – Energy
- Generation – Capacity
- Contingency Reserves
- Transmission & Distribution – Non-Wires Alternatives

Less common grid services that can be provided by buildings are:

- Frequency Regulation
- Voltage Support
- Ramping

Utilities may also identify non-energy program objectives. It is becoming more common for utility programs to ensure the equitable dispersal of program benefits within traditionally underserved communities, such as those defined by the White House Climate and Economic Justice disadvantaged communities census tract designation (Council on Environmental Quality 2024). This requirement can be achieved by identifying specific geographic bounds during the objective stage and defining positive benefits to these communities.

Load Analysis

This step analyzes available grid data to potential load sources that can address the grid issues identified by the program objectives. The analysis is conducted across multiple customer segments, spatial scales (e.g., feeder segment, feeder, substation, etc.) and temporal scales (e.g., hour, day, season).

Various spatial scales are studied to identify appropriate bounds for mitigation measures. Growth planning may be incorporated to evaluate the locational impact of population growth, increased electrification of vehicles and buildings, and growth in distributed energy resource

(DER) adoption like solar photovoltaics (PV). The outcome of this study identifies target customer and building stock characteristics.

Various temporal scales are studied to understand the seasonality, day-of-week and time-of-day profiles of loads in relationship to grid constraints. This also aids in determining the best solution packages for buildings and DERs that align with the time scales needed to address the grid issues. Future constraints can also be evaluated by studying growth trends, like the increase in vehicle electrification.

The key data sources needed for grid issue analysis depend on the scope of the study. For distribution load analysis the following data is needed: (i) interval meter data at hourly or sub-hourly time intervals, (ii) data for each meter ID that includes feeder ID, substation ID, and a link to customer address or parcel ID, (iii) data for each customer address or parcel ID that can include customer type, and building type, age, and size (sq ft), and (iv) interval data of feeder or substation load. Additional publicly available data can be used in the analysis like historical weather data and weather forecasts, and time information like weekday vs. weekend, time of day, day of year, and common holidays.

This data is used to build a detailed understanding of electric loads at different spatial and temporal scales. For example, the relationship between temperature, time-of-day, and day-of-week on feeder and substation load profiles. This information is used in conjunction with customer types, and their contribution to peak load in congested regions, to develop targeted solution packages to engage the right customers to mitigate grid issues.

Measure and Solution Package Design

Solution packages combine enabling smart building technology and more traditional building performance retrofits. This converts traditional buildings into connected grid-interactive assets providing both energy efficiency and demand flexibility. Potential solution packages are identified by evaluating available technology for the expected building types that exist within the service territory. The initial list of potential technologies and solution packages is first evaluated for technical and program implementation feasibility. Once a solution package is defined, the associated control measures that provide demand flexibility from the building are determined.

Solution packages are then bundled into a recruitment portfolio that considers the number of deployments within each customer market segment for each solution package. This model is demonstrated in Figure 2.

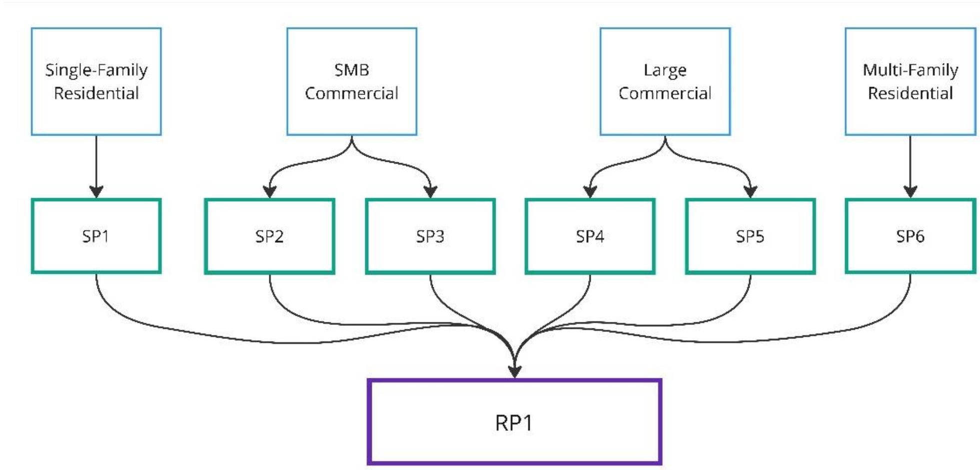

Figure 2. Diagram showing the flow from customer market segments to solution packages and recruitment portfolios.

EE and DF Potential Assessment

This step assesses the potential from demand flexibility at various utility scales (i.e., feeder, substation, transmission, generation levels). The potential utility-scale impact is dependent upon the underlying building stock characteristics, types of demand flexibility measures, enabling technology, and depth of control interventions (e.g. 2F vs. 4F zone temperature setpoint adjustments). In the early planning stage, it is critical to assess the potential impacts and opportunities associated with various strategies. The analysis needs to be tuned to represent the underlying building stock diversity, such as distribution of building types, fuel types, buildings that meet eligibility criteria for enabling technology, demand flexibility capacity and response.

It is currently difficult to calibrate individual models for each potential building in a targeted recruitment campaign, due to cost of generating models, limited information available required for model inputs, computational cost to tune individual models. Instead, prototype models that represent the load on utility feeders or substations can be utilized to understand the aggregate impact. These models can be used to generate a set of portfolios to determine the potential to meet key program objectives.

Prototype building models used in a demand flexibility program assessment need to cover a diverse range of expected building and system characteristics, operational schedules, behavior patterns, and load profiles. This requires selecting a set of base models, applying different system types, and adjusting schedules. This work uses the building energy models available from the NREL End-Use Load Profiles for the U.S. Building Stock (NREL 2021). The End-Use Load Profiles (EULP) data set consists of OpenStudio models of common building types (e.g., single-family residential, multi-family residential, medium office, stand-alone retail). The model inputs were calibrated based on available empirical data sources to provide hourly end use load profiles that represent expected values found in the building stock. Models were selected from the EULP database to match specific known characteristics about the building stock in the service area being analyzed. Solution package measures are then applied to the models and simulated with specific control interventions using actual weather data from grid peak events. By simulating many models, the sensitivity of DF metrics can be assessed in relationship to the variation of building characteristics anticipated in the pool of recruitment candidates.

The overall energy efficiency and demand flexibility potential is assessed by applying the solution packages to prototype building models and then simulating these models with various control measures. A base case model is first simulated without the addition of any solution packages. This model represents the expected performance of a building during a peak demand event given no change in equipment or operations. Next, the model is simulated with the addition of a solution package and with associated demand flexibility control measures applied. The demand flexibility measures modify the operation of the building during a demand event. Each combination of building model, solution package, and measure is considered a DF scenario. Each DF scenario is evaluated for a single building model by comparing the electric demand to the base case (Figure 3). This provides an estimate of an individual building's performance. The analysis provides insight into specific building characteristics that provide the greatest performance for a given DF scenario, possible screening criteria for targeted recruitment, and whether particular solution packages and/or demand flexibility control measures will provide sufficient performance when deployed into the building stock.

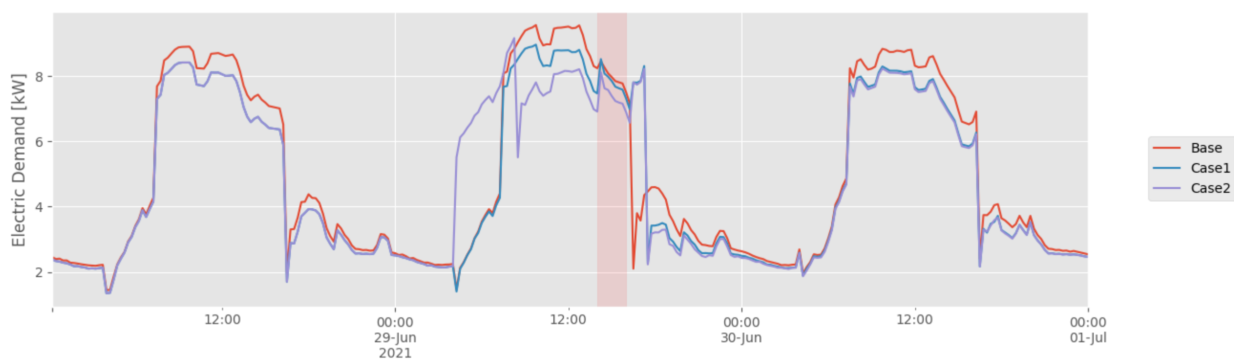

Figure 3. Comparison of electric demand from simulation of a building with Base - Smart thermostat, Case 1 – adds 2°F zone temperature setback, Case 2 - adds 4 hr of preconditioning.

A measured aggregate demand curve is calculated that represents the electric demand for a group of potential customers that is of interest in the demand flexibility program. The AMI data is selected for this particular group, which may be a feeder segment, feeder, substation, customer market segment, or building type. Once the group is selected, the electric demand interval data for that group is aggregated for each time interval. This provides the baseline utility demand curve that is used for the study. The electric demand results for the simulations of the DF scenarios are used to generate a weighted aggregate demand curve. This curve is generated by using a non-linear optimization routine to find a set of weights for each building model that minimizes the deviation between the simulated aggregate demand curve and the measured aggregate demand curve at each time interval. The weighting method uses the following calculation. After calculating both the measure and simulated aggregate demand curves, the difference between these curves is computed at each time interval. This provides an assessment of the demand reduction achieved at the aggregation level over time. Demand reduction may be a function of solution package performance and demand flexibility control measures, providing both energy efficiency and demand flexibility benefits. This comparison is shown below in Figure 4.

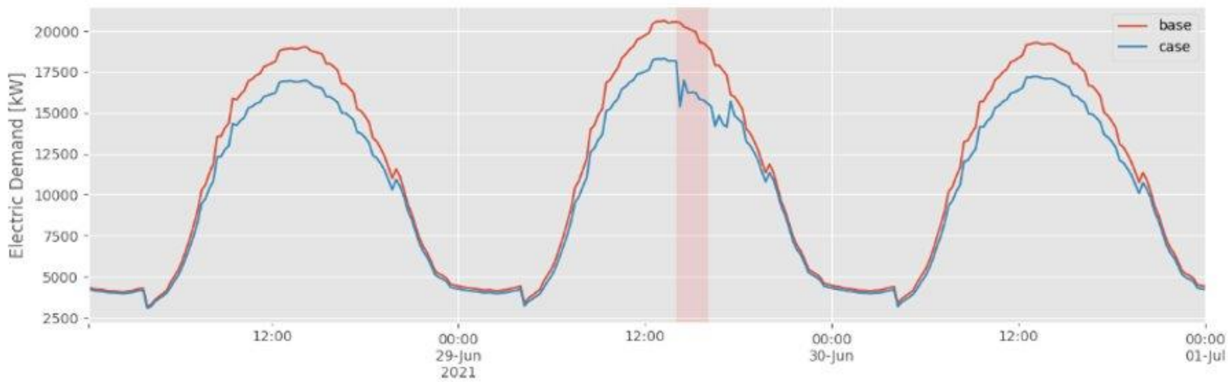

Figure 4. Comparison of aggregate electric demand between a base case (original building stock) and a case representing solution packages and demand flexibility control measures.

The demand reduction for the weighted aggregate curve is used to estimate the potential impact for recruitment portfolios. By calculating the metric of interest (e.g., average demand reduction during a 4 hour event) for the aggregate response and normalizing the value, a value can be estimated for each customer that is recruited into the program and assigned to a solution package. These values are then used to evaluate individual recruitment portfolios.

Results

This section demonstrates the proposed methodology applied to a reference example. For this example, data is used for utility customers served by one substation in Spokane, WA. The demonstration includes analysis of electric loads on the substation, development of tailored solution packages and targeted recruitment strategies, and a comparison of performance for differing recruitment portfolios. The program objectives are to achieve 1 MW of demand flexibility and 900 MWh/yr of energy reduction from approximately 100 customers located on the substation.

Load Analysis

This section describes the analysis conducted to evaluate congestion issues on a substation. Substation- and feeder-level demand were calculated by summing electric interval electric data for all customers. Figures 5 and 6 show the seasonal and diurnal timing of substation congestion peaks. Figure 5 shows hourly load profiles for one substation over 20 months. Load at this substation peaks during extreme heat events, which primarily is attributed to cooling-driven HVAC loads. In addition, utility transformer capacity is de-rated in high ambient temperature conditions. Winter substation peaks are not responsible for current congestion issues due increased substation capacity at lower ambient temperatures but may be assessed in future growth plans that include building electrification.

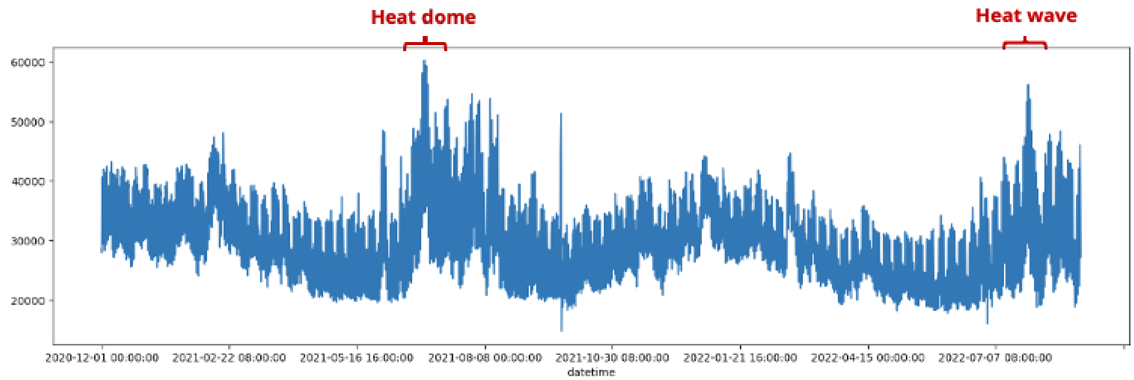

Figure 5. Hourly electricity consumption for all loads on an electric substation with highlighted extreme weather events.

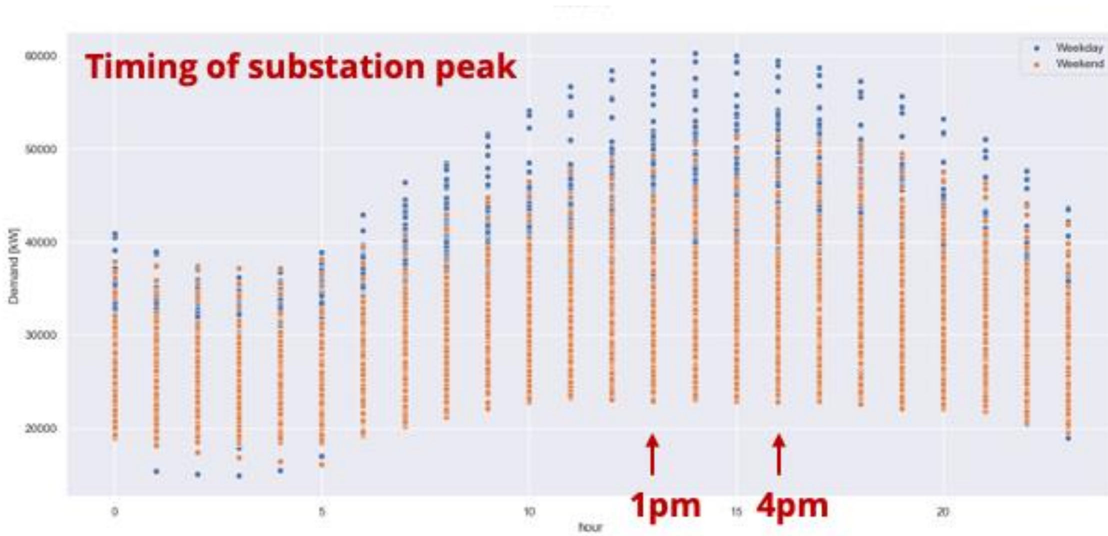

Figure 6. Hourly electric consumption for all loads on an electric substation during summer season separated into weekday and weekend periods.

Figure 6 shows substation load binned by time-of-day and weekday vs. weekend. Substation load peaks during weekdays in the early afternoon from 1-4pm. This suggests that substation congestion issues could be mitigated by shifting or shedding cooling-related loads in the early afternoon on exceptionally hot weekdays during the summer. It is likely that the increase in loads on weekdays is related to increased load from occupied commercial buildings.

Figure 7 shows load profiles for two distribution feeders served by the target substation during peak summer 2021 loads, and the contributions to peak load from several customer segments. Feeder 7 load is dominated by commercial customer segments, both large commercial (commercial_ci) and small commercial (commercial_smb) customers. Feeder 4 load is dominated by single-family residential customers (residential_sf), with a smaller contribution from small commercial customers (commercial_smb).

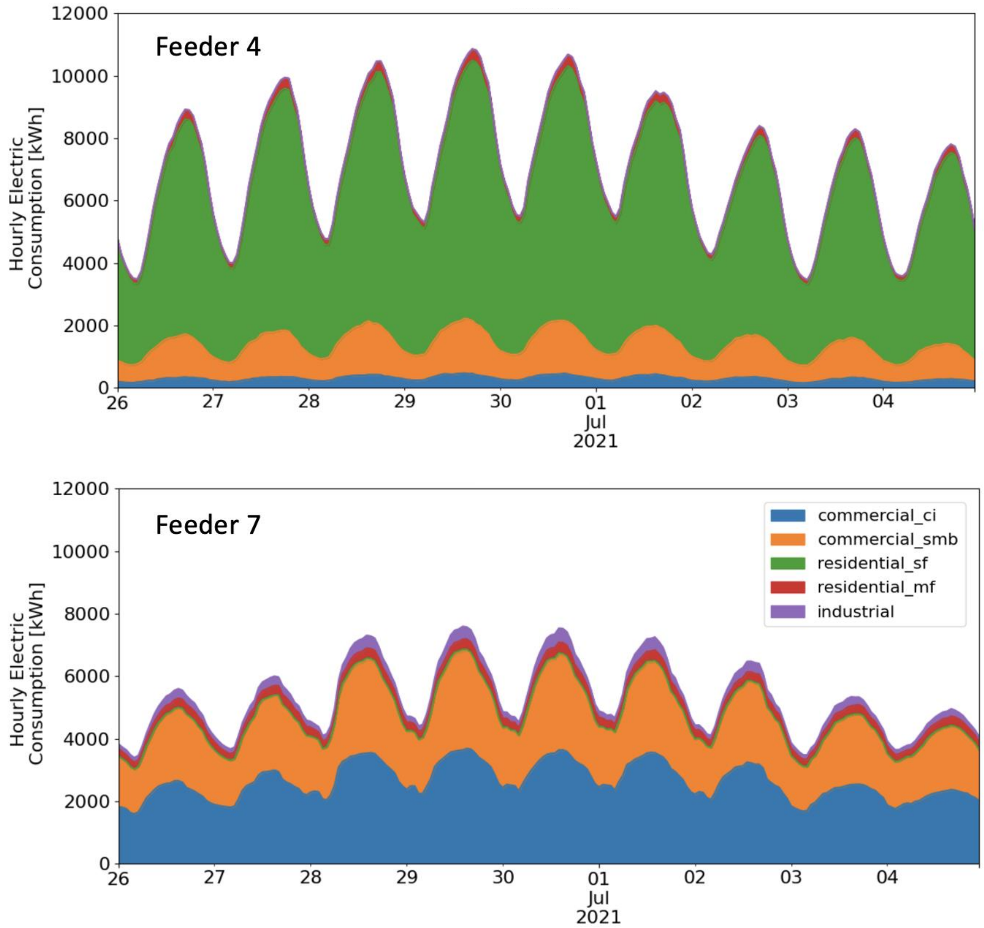

Figure 7. Hourly electricity consumption for feeder loads during a heat dome event with loads segmented by customer market segment.

Figures 6 and 7 illustrate different considerations for mitigating congestion issues. If congestion occurs at the substation level, multiple different customer segments across feeders can be engaged to provide demand flexibility. However, if congestion is at the feeder level, the specific customer segments served by the feeder will need to be engaged with DF-enabling solutions. For example, DF-enabling solution packages for single-family residential customers could help mitigate congestion on Feeder 4, solution packages for large commercial customers could help mitigate congestion on Feeder 7, and solution packages for SMB customers could help mitigate congestion on both feeders. The solution packages designed to engage different customer segments are described in the next section.

Solution Package and Recruitment Portfolio Design

After completion of the substation load analysis, solution packages were developed for the customer market segments to address specific grid issues related to peak cooling load associated with buildings. The solution packages were evaluated for technical feasibility, likelihood of adoption, and demand flexibility potential. The solution packages under consideration in this example are shown in Table 1.

Some technologies were initially investigated, but not included in the final analysis, such as multi-family residential connected smart thermostats due to the complexity of integrating with typical HVAC systems. It is common to have distributed control of individual electric resistance heat, window AC, or mini-split heat pumps in these building types. The integration of multiple thermostats for control of one unit made this solution package (SP6) challenging to implement.

Table 1. Considered solution packages by customer market segment.

Number	Market Segment	Description	Included	Reason
SP1	Single Family Residential	Network connected smart thermostats	Yes	Readily available smart thermostat vendors exist
SP2	Small Commercial	Network connected commercial thermostats (BACnet)	Yes	Solutions available that integrate available thermostats into control platform
SP3	Small Commercial Plus	SP3 + Whole building energy meter	Yes	
SP4	Large Commercial	BACnet gateway controller	Yes	
SP5	Large Commercial	SP5 + additional BAS control programming	Yes	
SP6	Multi-family Residential	Network connected smart thermostats	No	Cost to implement with baseboard heat and split system HVAC control

The potential for demand flexibility for each solution package was assessed for the control measures shown in Table 2. The measures were all related to zone temperature setpoint adjustment, since the primary concern was reducing the cooling-driven peak load. The control measures include increasing zone temperatures by 1°F or 2°F, for scenarios with and without space pre-conditioning.

Table 3 shows the estimated ranges of demand flexibility potential (kW) from simulation for each market segment, based on the control measures shown in Table 2. The differences in DF potential within each market segment are driven by differences in building size, age, construction material, insulation and envelope tightness, DF control measures, and the duration of DF events. The differences in DF potential across market segments are driven by these same factors, and additional factors like HVAC system types, and different building use and load characteristics. The large range of DF potential within each market segment suggest an opportunity for targeted recruitment of specific customers with the largest DF potential, which can be inferred from customer-level AMI data.

Table 2. Demand flexibility control measures and applicable solution packages.

Number	Name	Description	Applicable SP
DF1	Increase zone temperature setpoint by 1 F	Lowers demand during peak events caused by HVAC cooling.	SP1, SP2, SP3, SP4, SP5
DF2	Increase zone temperature setpoint by 2 F	Greater demand reduction over DF1, but with more thermal comfort impact.	SP1, SP2, SP3, SP4, SP5
DF3	Precondition 2 hours ahead of event + DF1	Increases demand reduction over DF1, but also leads to additional energy consumption.	SP1, SP2, SP3, SP4, SP5
DF4	Precondition 2 hours ahead of event + DF2	Increases demand reduction over DF2, but also leads to additional energy consumption.	SP1, SP2, SP3, SP4, SP5

Table 3. Demand Flexibility Potential estimates by solution package.

Solution Package	Market Segment	Demand Flexibility Potential (kW)
SP1	Single-Family Residential	0.5 – 2.0
SP2	Small Commercial	10 – 25
SP3		10 – 25
SP4	Large Commercial	25 – 100
SP5		25 - 100
SP6	Multi-Family Residential	10 – 25

Comparison of Portfolio Performance

In this section, we evaluate several customer recruitment portfolios with different levels of enrollment for each market segment. These differences are meant to represent the number of available customers in the program area, value-based targeting of specific market segments, and/or challenges in recruiting a particular market segment.

Table 4. Description of recruitment portfolios and recruitment numbers for solution package.

	Description	Recruitment (# of customers)					
		Single Family Residential	Small Commercial		Large Commercial		Total Enrollment
		SP1	SP2	SP3	SP4	SP5	
RP1	Standard	80	14	4	15	4	117
RP2	Low Large Commercial Recruitment	320	17	5	3	1	345
RP3	No Residential Recruitment	0	20	6	16	4	46
RP4	Low Small Commercial Recruitment	173	4	1	15	4	197

Table 4 shows four example recruitment portfolios that were developed to represent a similar total program budget. Solution package and enrollment costs were estimated assuming a 5-year program life, and included estimates for upfront solution package costs, annual costs, and the cost of recruiting customers and installing equipment. The portfolios include a standard portfolio baseline (RP1) with a mix of all customer segments, and additional portfolios that included lower enrollment from large commercial customers (RP2), no enrollment from residential customers (RP3), and lower enrollment from small commercial customers (RP4). Portfolios with larger DF contributions from smaller customers, including residential and small commercial, require significantly higher total enrollment numbers to meet the similar program cost targets.

Table 5 shows the estimated DF potential ranges for each of the recruitment portfolios, and the DF contribution by each market segment. Since total program implementation costs were held roughly fixed, each portfolio represented a different range in estimated DF potential, based on differences in solution package costs and DF potential from each market segment.

Table 5. Performance for varying recruitment portfolios.

Number	Description	Demand Flexibility Potential (kW)	DF Fraction (%)		
			Residential	Small Commercial	Large Commercial
RP1	Standard	1,330 – 2,220	5	15	80
RP2	Low Large Commercial Recruitment	685 – 1,140	35	35	30
RP3	Low Residential Recruitment	1,455 – 2,425	0	20	80
RP4	Low Small Commercial Recruitment	1,240 – 2,065	10	5	85

Figure 8 shows the demand flexibility potential for each recruitment portfolio (RP). These were calculated by multiplying the average DF potential by solution package (Table 3) and the recruitment targets for each recruitment portfolio (Table 4). All RPs were designed to have similar total program costs, and the different levels of DF potential between RPs is driven by different solution package costs, per kW of DF potential.

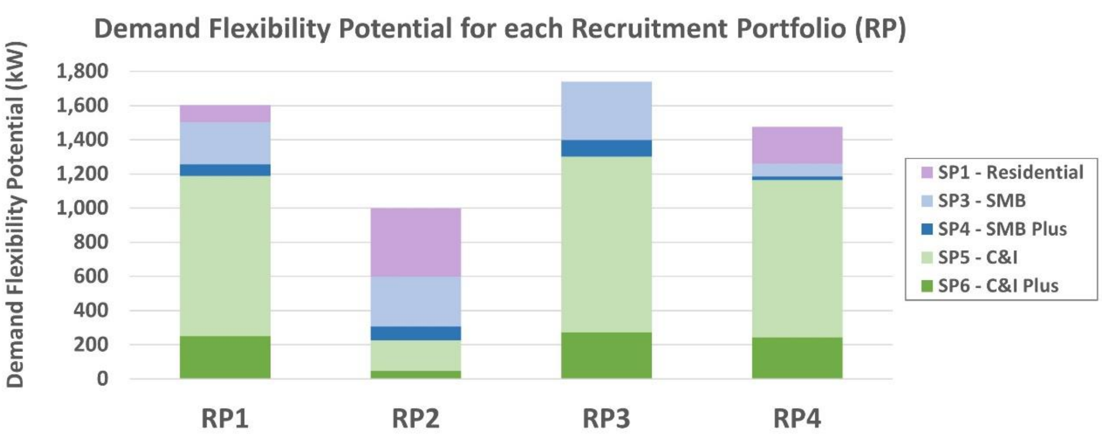

Figure 8. Demand Flexibility potential for each recruitment portfolio (RP), with contributions from each solution package (SP).

In general, we find higher DF potential, for a given program budget, for portfolios with a higher DF contribution from larger customers. For example, the low large commercial portfolio (RP2) led to a 49% decrease in estimated DF potential relative to the standard portfolio, while the no residential portfolio (RP3) led to a 9% increase in estimated DF potential relative to the standard portfolio. This trend is driven by an increased relative cost, per kW of DF, for recruiting more customers, and a higher cost per kW for DF-enabling solution packages for smaller customers.

Tables 4 and 5 show that there are many strategies for unlocking DF across multiple market segment. Recruitment strategies can be developed based on the required amount of DF needed to mitigate congestion, which customer segments are served in congested regions, and program budgets for mitigating congestion.

Conclusions

This paper presented a methodology for developing and evaluating solution packages and targeted recruitment portfolios for designing combined energy efficiency and demand flexibility utility programs. The need for a targeted recruitment strategy and scalable solution packages is necessary as more utilities transition from traditional demand response programs to more comprehensive demand flexibility programs. These programs require that a utility can interact with a more diverse set of loads across strategically defined spatial and temporal scales. To achieve this, data-based planning is required in the early programmatic design stage to ensure that there are multiple recruitment pathways available to achieving overall program objectives without over-customization of enabling technology. Furthermore, cost and performance can be evaluated early to enable cost-effective means of incorporating demand flexibility across multiple customer market segments. Finally, a reference example of the methodology is provided that includes analysis of electric loads on a substation, design and selection of solution packages by customer market segment, evaluation of recruitment portfolios. In the reference example, AMI data from a target substation is used to build market-specific solution packages and scenarios to achieve program objectives with adjustable levels of recruitment from the three target market segments. Overall, the outcome of this work provides utilities with a defined workflow for consistently designing programs that provide both energy efficiency and demand flexibility in a targeted manner that reduces overall program costs while maximizing benefits that address specific grid issues.

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