BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	Rulemaking 20-11-003

COMMENT AND TESTIMONY OF RECURVE ANALYTICS, INC IN RESPONSE TO ALJ STEVENS EMAIL RULING OF AUGUST 16, 2021 REGARDING STAFF CONCEPT PROPOSALS FOR SUMMER 2022 AND 2023 RELIABILITY ENHANCEMENTS

I. Introduction

Recurve is an industry leader in meter-based demand flexibility. Recurve provides transparent, accessible analytics to track changes in consumption and demand due to program interventions for both individual buildings and in aggregate to support resource planning and facilitate performance-based transactions. We have consistently encouraged and supported market-based solutions for decarbonization that have the ability to scale and ensure demand-side resources can make a meaningful contribution to the grid.[1] We support the urgent action recognized by the Governor in the July 30, 2021 proclamation and offer several strategies to accelerate "new clean energy and storage projects to mitigate the risk of capacity shortages and increase the availability of carbon-free energy at all times of day."

Our comments and testimony are focused on enabling a market-access model, Demand Flex Market, as the core programmatic solution for expanding load modifying resources available in 2022, 2023 and beyond. We believe that such a market-access model will accelerate projects across the board while providing an embedded means of ensuring accountability. The

[1] M. Golden, A. Scheer, C. Best. Decarbonization of electricity requires market-based demand flexibility, The Electricity Journal Volume 32, Issue 7, August–September 2019, 106621 *Available at:* https://www.recurve.com/blog/the-secret-plan-for-decarbonization-how-demand-flexibility-can-save-our-grid

key characteristics of this model are:

- Direct payment to aggregators anchored in system benefits (and other identified value or prices recognized for urgency or equity).
- Performance based on consistent, transparent open-source standardized measurement and verification already accessible.
- Eligibility criteria (by customer and local versus system events) can be used to ensure resources are incremental to the system plan and avoid double payment but ensure demand flexibility is used and useful.

In order to facilitate this transition, the CPUC should adopt rule changes that:

- Enable fast-track procedure for Community Choice Aggregators to access ratepayer energy efficiency and demand response program funds to quickly deploy demand flexibility markets.

- Utilize existing revenue-grade, open-source methods and code base to target, track all monitor demand response initiatives approved for this emergency response, as an alternative to time-consuming Load Impact Protocols for assessing performance.

- Remedy data access barriers that inhibit targeting and comparison group analysis for non-LSE entities and create a pathway for qualified third parties to handle covered information on behalf of non-LSE entities.

Recurve also offers specific comments on the Staff proposals offered in the August 16th Email Ruling from ALJ Stevens. Specifically:

- Considering a tiered approach to the "opt out" residential demand response program model and the opportunities and potential challenges of measurement and verification.
- Considering broader needs for targeting and optimization beyond the Smart Thermostat program to ensure new and existing programs are aimed at maximum peak impacts.

Our primary proposal for the Demand Flex Market is detailed in Appendix A. Two additional proposals are provided to illustrate other examples of how performance based programs grounded in standardized measurement verification can bring a wide array of resources forward.

I. Utilize a Market-Access Model to Deliver Demand Flexibility as a Load Modifying Resource by July 2022 and Beyond

One of the biggest challenges of this call to action is the quick pace at which actual projects need to come online. The Commission needs to be sending a clear price signal, aligning incentives, and streamlining processes to accelerate projects that are not currently anticipated within the system plans and can deliver demonstrable impacts. In many ways, the Commission has all of the key elements at its disposal:

- The Avoided Cost Calculator provides a long-term base system value price signal that can be augmented with other price signals to motivate short term action.
- Performance for energy efficiency and demand response can be quantified at the utility meter using existing open source methods and code base which are transparent and accessible to all market actors.
- Market-access models (like Demand Flex Market) enable the direct purchase of system benefits grounded in performance-based accountability (only pay for the benefits delivered) and have an audit trail to back it up.

A market access model creates a new channel for load-serving entities to bring more load modifying demand side resources forward to meet the critical reliability issues faced by California in the near term. More detail about how Demand Flex Market works is provided in Appendix A. The following summary provides background on why we believe it is a good fit to address the needs of the Governor's proclamation.

A. The Avoided Cost Calculator Provides a Base Price Signal

The Avoided Cost Calculator (ACC), currently provides the reference point for how the CPUC values demand-side resources in normal conditions. By providing a consistent and transparent way to value avoided energy use on an hourly basis, the ACC offers a streamlined way to consider and reconcile the multiple benefits realized by demand flexibility solutions that markets, businesses and projects can be built around.

In response to the Governor's proclamation, the Commission needs a rapid acceleration of projects to be able to deliver demand flexibility in the form of overall load shape reductions (energy efficiency), load flexibility shifts, as well as responsive reductions (demand response shed) in 2022 and 2023 and beyond. In this proceeding, the Commission can leverage the common understanding of value in the ACC and scale that value to reflect the urgency of meeting near-term resiliency needs. LSE's can augment the long-term ACC value with price signals to maximize responsiveness to critical events. *(Appendix A provides the detail on how the Demand Flex Market - PeakFLEX sends price signals to motivate action.)*

A. Meter-based Performance Empowers Demand Flexibility

California has the data resources to ensure that demand-side projects, programs and initiatives are tracked and monitored for their performance at the meter. Consistent, transparent visibility on this performance is possible when market actors collectively adopt open-source methods and code base that enable repeatability and replicability. CalTRACK methods and the OpenEEmeter code base are accessible to all market actors in California today and are appropriate for quantifying both energy efficiency and demand response impacts. Standardized implementation of comparison group analysis can also be streamlined with the use of GRIDmeter.

In response to the Governor's proclamation, the Commission needs a means of ensuring accountability for implementers to minimize the risk of rate-payer investment not delivering. A common view of performance with meter-based accountability helps achieve this end. By using these open-source methods, Demand Flex Market offers load-serving entities and rate-payers a common view of risk to reward that allows for a significant acceleration of demand response and energy efficiency projects.

The Governor's proclamation also demonstrates the urgency of deploying and quantifying energy efficiency and demand response impacts together. This integration is critical to enable demand flexibility markets of the future, and it is one of the key innovations of the Demand Flex Market (see detail in appendix A). Enabling single aggregators to deliver both efficiency and demand response impacts allows the LSE and the customer to leverage both value streams, something which, due to historic regulatory barriers, they have been unable to effectively do until now. In a recent ACEEE study, Integrated Demand Side Management (IDSM) efforts in California were cited as having a poor record – largely because of siloed regulatory objectives, budgets, and mis-aligned value propositions which in some cases are even pitted against one another.[2] These funding pools have not been tracked to resource acquisition at all and hence have provided no incentive to deliver on savings or load shed objectives. In addition there are very few programs, if any, that are optimizing load reductions from all available DERs at a customer site. While most of our comments are focused on harmonizing energy efficiency and demand response, this model has the potential to track any type or combination of behind the meter intervention to change consumption patterns at the utility meter.

Ensuring that programs perform as promised is also central to meeting the Governor's proclamation, as well as to the Commission's obligation to protect ratepayers against investments that don't deliver. By paying only for system benefits delivered, ratepayers are shielded from the risk that large budgets will be spent on ill-conceived or poorly executed program ideas, no matter how well-intentioned, because payment to the aggregator is grounded in delivered impacts. In addition, individual customers may have more options to access products and services that save them money and meet grid objectives with a wider range of products and services. Aggregators have the flexibility to innovate to deliver results based on the agreed upon performance expectations.

In addition to providing accountability for tracking outcomes of emergency spending, meter-based performance can build an actuarial feedback loop on an ongoing basis. By providing reliable and dependable analysis for forecasting purposes (qualifying capacity) as well as insight into the combined potential for efficiency and demand impacts in the future, meter-based performance gives all parties greater confidence in their ability to scale demand side resources.

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[2] *Integrated Energy Efficiency and Demand Response Programs;* Dan York, Grace Relf, and Corri Waters September 2019; U1906, ACEEE https://www.aceee.org/sites/default/files/publications/researchreports/u1906.pdf

A. Market-Access Models are Available Today to Scale and Deliver Resource by 2022 and continue to deliver into the future

Load serving entities in California have already started adopting market access models to expand their demand-side portfolios. The Demand FLEXmarket is a great candidate for the Governor's call to action because load serving entities can directly buy the resource — they do not have to design a program. Because it is tied directly to the value the Commission has already identified for system benefits, the Demand FLEXmarket can be scaled in a timely fashion. It has built-in accountability to ensure payments are only made for delivered savings, while offering aggregators maximum flexibility to aggressively pursue projects across the state on behalf of load-serving entities. Appendix A provides the full details of the Demand Flex Market, and the Peak FLEXmarket in particular, that is currently being implemented by MCE.

In summary, a market access model, like the Peak FLEXMarket, gives any qualified aggregator the opportunity to sign up and deliver energy efficiency or demand response projects. These aggregators sign a standardized contract, known as a Flexibility Purchase Agreement (FPA), which details the terms for payment, including the measurement and verification for establishing performance. The base price per kW is formulated from the system benefits (avoided cost value) with a deduction for administration and the embedded measurement and verification of projects.

Streamlined contracting, eligibility criteria and prescribed performance expectations mean limited upfront effort to launch. Aggregators can sign into the market, with minimal contractual headaches, and start delivering projects. Because projects can, in theory, start flowing within days of market launch, the FLEXmarket may offer one of the most straightforward and timely ways for load serving entities and aggregators to "cut to the chase" and identify projects that can deliver by July 2022 and beyond July 2023.

Aggregator payment is tied directly to the system benefits delivered (i.e. avoided cost value) and augmented with a fixed peak payment and an additional incentive to identify and deliver resources based on day ahead need. Performance is tied directly back to the CPUC’s price signal, giving the Commission flexibility to amplify value (i.e. price signal) by putting a premium on the short term delivery of projects for 2022 and 2023. This price signal could come in the form of a scalar to the system benefit (i.e. 2x or 10x the current system benefit) or a targeted scalar (i.e. 2x or 10x of system benefit for impacts delivered from 4-9 PM).

The flexibility of value signals doesn't have to stop there. For example, in order to meet its objective of capturing value for customers that are in Energy Savings Assistance, Tribal Communities, or other disadvantaged communities, the Commission could establish an additional layer of value for delivered impacts to those defined populations (e.g. 2x to 10x more of the amplified overall or targeted 4-9 PM system benefits) in order to attract aggregators who can deliver value for those communities.

In the Demand FLEXmarket model, the agreed upon system benefit, along with any additional benefits the Commission wishes to recognize, would be the starting point for any given project identified by an aggregator. They would forecast the value of the project based on historic load shapes for core measures or historic performance (if available) using FLEXValue.[3] Final aggregator payment is for the delivered value calculated with the actual load shapes delivered and any discrete loads dropped during load shedding events. A record of each transaction is maintained for audit purposes, providing revenue-grade accountability within the system for aggregators, load serving entities and regulators.

See Appendix A for full details of how the Demand FlexMarket is designed. We believe that it will be foundational to addressing the Governor's call to action because load serving entities can directly buy the resource, not design a program. With available funding this model could be deployed by any LSE in California to start delivering resources by July 2022.

Recommendation: *Utilize a market access model for any LSE to accelerate demand response and energy efficiency projects to meet reliability needs called in the governor's proclamation. A market access model must:*

[3] FLEXValue is an open source calculation engine that is accessible to aggregators in the Demand Flex Market model to assess the likely value (based on the ACC) from a given project. The current tool is designed for just the base ACC value but would be adapted based on scalar value the Commission may recognize within this proceeding or others. For more information see: https://flexvalue.recurve.com/

- *Use consistently applied M&V (open-source preferred) for quantifying impacts 4-9 PM for all hours of the year.*
- *Anchor on 100% performance-based payments to aggregators based on delivered system benefit and other recognized value streams and price signals.*
- *Provide an audit trail of changes in energy consumption and payment.*
- *Allow all value streams in the current ACC and any additional value adopted by the Commission to reflect the urgency of meeting resilience needs in 2022 and 2023.*

II. Create a Fast Track pathway for CCAs to Fund a Market Access Model

Community Choice Aggregators are well-positioned to motivate customers to partake in this emergency call to action, but most have not developed demand-side programs to date. One explanation for this is the level of effort to design, implement and get approval for business plans and other procedural components to "elect to administer" or "apply to administer" demand side programs.[4] Temporarily suspending the requirements for full business plans or other longer-term planning requirements to meet this short term emergency, could enable CCAs to contribute more load modifying demand side resources by 2022.

CCAs, with a streamlined path to funding, could quickly procure demand-side projects and contribute to meeting this emergency obligation. These new projects would reduce load overall via efficiency investments tied to the system benefit value, and build extra capability within the state to respond to load shed events which will improve reliability. CCAs could use similar triggering criteria as used for ELRP to extend the reach to a greater swath of projects or or identify and call their own resiliency event to address discrete resource needs as MCE has done with Peak Flex Market in 2021.

Several pathways could mitigate the risk of double payment for resources delivered. First, eligibility criteria could be used as a screen to ensure that participants are not already enrolled in other programs or system-wide DR aggregations that CAISO is counting on in the system plan. Alternatively, aggregators could be obligated to demonstrate incrementally for customers contributing both to system needs and demonstrate additional load for local events, as

[4] These rules were outlined in D.14-01-033 and have not been modified to date.

required for ELRP. Where comparison groups are used as the foundation of settlement, it may be possible to "net out" local impacts from system wide impacts. At the end of the day, however there is no way to tag specific electrons by territory. Complementary action, like local investments in load modifying resources coupled with system-wide dispatch could potentially be achieved with prioritization (i.e. system obligation takes first priority) or other rules allowing payment on coincident event days. Given the urgency of the action, the Commission has to balance the cost and risk of not bringing enough resources forward against the cost and risk of facing serious system reliability issues. At this moment we encourage the Commission to structure rules that will maximize the resources that come forward in 2022 and 2023 and ensure impacts are tracked and monitored to inform future rule changes and build a deeper understanding of qualifying capacity needs in the CEC forecast for the future.

Recommendation: *Suspend requirements for fully developed business plans for CCAs who wish to access funding for DSM programs. Proposals for launching a market access model for combined energy efficiency and demand response resources can be approved via Tier 2 Advice Letter (staff approval) for any CCA.*

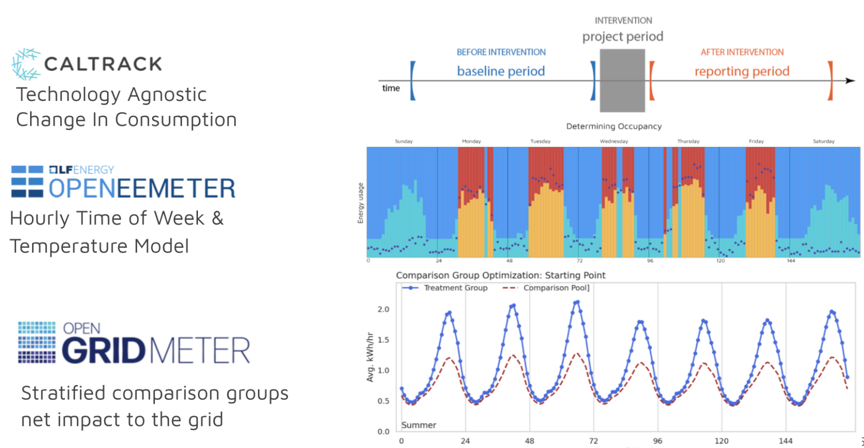
III. Leverage Existing Open-Source Revenue-Grade Measurement and Verification for Transparency and Consistency

The value of the open-source methods and code base (CalTRACK and OpenEEmeter) is not limited to the market access model described above. As the CPUC considers the options to address short and long term reliability and system needs, the collective understanding of performance is essential.

To date, most demand-side solutions were built on data-poor frameworks that provided limited means to assess program or technology performance. We now live in a data-rich environment that allows us to assess performance at every meter—but we need to have a common, transparent, accessible way of describing that performance. The historic protocols for energy efficiency and demand response were products of that data-poor system, and set a foundation for methods. Open-source methods and code base are an evolution of the application of those methods (not really the methods themselves) and offer a solution to harmonize embedded monitoring and tracking in a data-rich environment with multiple DERs offering performance.

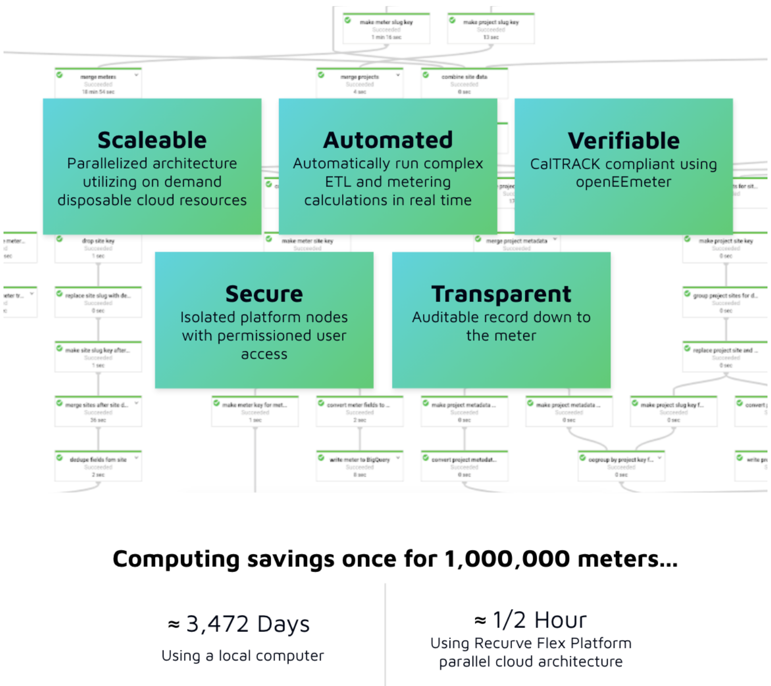
Performance must be grounded in a common value, tracked at the meter for individual sites, aggregate populations, and in relation to the "normal" grid activity. This allows for a holistic view of the impact of interventions on the demand side across silos. Impacts can be communicated up and down the market chain from regulators to load-serving entities to aggregators. This approach also enables communication across the multiple intertwined state agencies (CPUC, CEC and CAISO) that need to forecast, monitor and settle performance.

As noted earlier, and in multiple public workshops and proceeding comments to date, CalTRACK and the OpenEEmeter offer a consistent standard open-source approach to quantify avoided energy use at the meter. It is a weather-dependent model which allows for disaggregation of loads sensitive to heating and cooling needs. The hourly methods are based on the Lawrence Berkeley National Lab Time of Week and Temperature model originally designed for demand response impact assessment. GRIDmeter is a standardized approach to selecting comparison groups to look at impacts of intentional interventions relative to the overall grid.



Comparison group methods are widely accepted as a best practice to understand incrementality in a more meaningful way than site specific baselining alone.

California is a sweet spot with respect to capabilities to track and monitor the entire state for demand side impacts. With open source temperature-dependent modeling methods and code base, wide spread AMI, and computing capability, it is now conceivable for the Commission to expect project level tracking and non-participant comparison groups as part of the counterfactual analysis and settlement standards. Processing millions of meters multiple times a year is now possible.



Utilizing standardized baseline and comparison group approaches, Recurve analyzes full-service territory data sets before and after interventions, providing program managers and load serving entities resource planning insights, monitoring and tracking of interventions, and generating an audit trail for every project's impact and resulting payment. Recurve is currently applying these methods in a test for enabling settlement with CAISO.

Transparency across the market requires the secure and rapid operationalization of these data flows. Compliance with open-source methods builds the trust across market actors to operate demand flexibility markets at scale. This approach could serve as the foundation for assessing solutions adopted in this proceeding to target, track and monitor, as well as serve as the record of impacts. It could serve as an effective replacement to, in whole or in part, protracted processes currently used in the Load Impact Protocols (DR) or full scale evaluation (EE).

Recommendation: *Utilize existing open-source methods and code (CalTRACK, OpenEEmeter and GRIDmeter) for targeting, monitoring & tracking solutions adopted in this proceeding to address summer reliability needs. Consider streamlined review and approval of resources utilizing these open-source methods to assess impacts.*

IV. Resolve Outstanding Data Access Barriers for Non-LSE Providers to Conduct Targeting and Comparison Group Analysis

Utilities and CCAs securely utilize data to optimize their demand side activities. However, non-LSE classes of users (third party demand response providers, state-wide implementers, and other state or local agencies) have struggled to get access to non-participant data. In some cases, gaining access even to participant customer data has been challenging.

These barriers of data access significantly impede the ability to assess impacts in a robust manner and ensure that programs are targeted where they will deliver the biggest impacts (see Smart Thermostat section). For example, while utility demand side providers often use comparison groups to demonstrate demand response program impacts, data access barriers usually prevent third party demand side programs from doing the same, despite the method being recognized as a best practice.

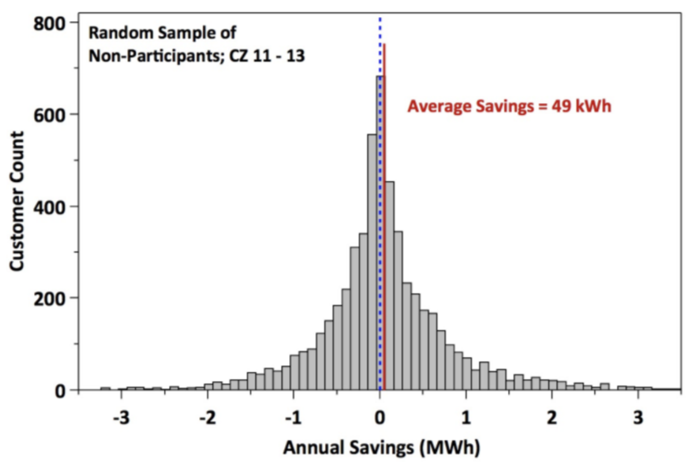
Even in cases where agencies have anticipated that a statewide implementer needs access to data, contracting barriers can create extra hurdles. For example, in the case of the Technology and Equipment for Clean Heating (TECH) program the web of contracting and non-disclosure agreements has significantly delayed the targeting components of the program. This in-turn hinders the accelerated deployment of heat pumps to replace inefficient air conditioners next summer. This is one of many examples where access barriers to non-participant data has inhibited interventions designed to optimize grid operations.

Any proposal approved in this proceeding will be directed toward optimizing grid operations. We recommend the Commission ensure that non-LSEs are granted secure access to covered information (non-participant data) under a non-disclosure agreement to facilitate targeting and comparison group analysis to support reliability. This would enable third parties, who may not be in direct contract with the CPUC or an LSE, to be authorized to handle covered information on behalf of a non-LSE (such as a statewide implementer or other state agency). Third party non-disclosure agreement requirements must be no less but also no more protective than those required of the load-serving entities. The Commission may also consider qualifying criteria for entities to handle covered information. The emerging issues and solutions around finding the appropriate balance of data access and individual privacy may warrant re-opening of the "smart grid" proceeding.

V. Comment on Staff Proposal for Residential Opt Out Demand Response

Recurve supports the intention of the staff proposal to expand access of the Emergency Load Reduction program to residential customers. An opt out design may create significant additional market complexity (of opting in and out) and given the historic challenges of data flows presents some concerns. An opt out demand response model may be an effective way of familiarizing customers with demand response. If positioned alongside other, more proactive demand response interventions it could accelerate enrollments into higher tiers of action. An opt out model may also be well suited for CCAs implementation and wouldn't have to be limited to IOU administration.

By using CalTRACK and the OpenEEmeter, a pre- and post-weather dependent baseline could be established for the full population of residential customers. Historic baselining for all customers does not present a significant problem (as noted in the prior section) if data is available in a timely fashion. Given that it's an opt out design, there would be no comparison group remaining to assess incremental impacts. If the State is paying all customers for savings whether or not they save at the designated times, it is possible that those oblivious to their enrollment could put a significant drag on the value of the payments to those who did actively reduce load (everyone on the left side of the distribution illustrated above). It's likely that at some level customers need to make an active commitment, so the carrot can be more effective or the Commission may need to consider how to put some minimal sticks in the mix.



To support solutions that drive deeper savings, both by incentivizing intentional customer behavior and encouraging more solutions from aggregators, we encourage the Commission to consider a tiered approach to consider where the opt out model may fit into the market. In this prototype statewide integrated demand flexibility program model (prices and rules are illustrative only) would have the following three tiers:

Tier 1: FLEX Rewards Emergency Event Program - Opt-Out ($1.00 per emergency event kWh)

- $1 per emergency event kWh saved
  - Calculate the net demand reduction (net of savers and increasers)
  - Sum total reduced MW
  - Divide net by reduced MW to get a unit value
  - Pay "saving" customers that reduced that unit value * reduced MW (potentially those who exceed 5% reductions)
- Based on a 60-day pre-event baseline (excluding emergency event hours)
- ESA, CARE, or other identified group would get bonus of 50%

Tier 2: Active DR - Opt-in DR program ($1.50 total per emergency event kWh)

- Additional $.50 per emergency event kWh saved (credited to provider)
  - The provider can submit additional funds for credit on-bill every month
- Automatically enroll in a third party program (constitutes an opt-out from FLEX Event only)
- Active DR providers must be enrolled in a DR or LMR / FLEXmarket program and providers must demonstrate at least 4x non-emergency dispatches (or other negotiated value) during the baseline period for each event to qualify.

Tier 3: Virtual Power Plant - Opt-in to high dispatch used and useful VPP ($2.00 per emergency event kWh)

- Additional $1.00 per emergency event kWH saved (credited to provider)
  - The provider can submit additional funds for credit on-bill every month
- Auto enroll in third party program (constitutes an opt-out from FLEX Event only)
- VPP providers must be enrolled in a a program that serves as a load-modifying resource (such as a utility demand response program or FLEXmarket) DR or LMR / FLEXmarket program and providers must demonstrate at least 10x non-emergency dispatches during the baseline period for each event to qualify, and either maintain a fleet dispatch level of X events per month or be enrolled in the 8760 EE market).
- The process for calculating the impacts and transfer to the bill could be as follows:

- Settlement platform provider receives AMI data on a +3-5 days after meter read by utilities
- Settlement platform provider generates a revenue-grade baseline and measured event delta +2 days
- Settlement platform provider provides API / file transfer for each meter's baseline, delta, and value in $, to each utility
- The utility or CCA integrates event payment onto the bill
- Payment credit is for:
  - Opt-out State-Wide FLEX Event Program
  - Opt-in DR PROVIDER NAME

We anticipate there will be many comments and proposals on the staff concept for an opt out program design and we look forward to collaboration to find an appropriate solution.

VI. Comments on Staff Proposal for Smart Thermostats and Targeting

The staff proposal for Smart Thermostats provides an interesting example to contrast the value of a market access model versus a single technology program model.

The Staff analysis is informed by the 2018 impact evaluation of the smart thermostat program that came out in 2020. If this analysis was embedded in the program, and there were performance instead of fixed incentives, the targeting solutions and program optimization may have already been underway. Regardless, we see targeting as a minimum expectation for all program implementation.

The evaluation report and staff summary point out the wide variation in incentives for smart thermostats depending on the program, and that it currently cost about $222 on average to get a smart thermostat installed given today's program designs, and the average rebate was $59. It also notes that these types of single technology energy efficiency programs " . . . *have been shown to provide limited energy efficiency savings in most climate zones in California*." The evaluation report also notes that "*The cooling load savings shapes, for instance, diverge substantially from the cooling load peak hours. Savings in the afternoon are relatively higher compared to early evenings, indicating that savings may be related to setpoint increases while* *occupants are at home in the evenings.*"[5] As such, the staff proposal to couple the thermostat program with required demand response programs may indeed improve both programs' effectiveness; but it could also be true that coupling smart thermostats with a myriad of other interventions could lead to improved household performance and greater savings impacts.

As described in the Demand Flex Market segment, if aggregators are presented with the value stream (a la the avoided cost calculator and additional triggers) they would have the flexibility to deliver the best combination of devices and behaviors to drive outcomes. That could perhaps even be a free smart thermostat coupled with any number of other technologies, like replacing inefficient air conditioners with heat pumps. A rebate is a one and done. A value stream that can build a cash flow from optimized performance builds businesses and services that will support the grid and deliver value to customers now and in the future.

Instead of mandating installations in climate zones with the highest cooling degree day (CDD) needs, we recommend the Commission instead put a premium value on delivering impacts from 4 to 9 pm that naturally motivates the selection of customers with the highest CCD. However, this signal amplifies all kinds of actions across the spectrum of technologies, not just smart thermostats. A portion of this value is already included in the avoided cost calculator, but it is largely invisible to aggregators, customers and programs focused on annual savings goals. Deploying technology alone does not facilitate the alignment of these incentives. Targeting could get them part way there, but without aligned incentives around performance it may only help on the margins.

It is also important to note that programs like TECH are explicitly designed to target customers with high cooling loads for air conditioner replacement. No fancy "*load disaggregation tools"* are needed. The TECH initiative is relying on CalTRACK, a weather dependent energy consumption model, to isolate heating and cooling loads of the entire residential population to identify solutions to maximize the delivery of system benefits on an hourly basis. TECH, as a market transformation initiative, is extremely well aligned with existing pay for performance programs at PG&E and with MCE's Peak Flex Market to reduce

[5] DNV-GL 2018 Smart Thermostat Impact Evaluation, 2020 at page 8

peak loads by accelerating the replacement of inefficient air conditioners with highly efficient heat pumps and to deliver these resources by July of 2022. In Appendix B we provide more detail on a proposal for synergizing these two programs to maximize impacts for 2022 and beyond.

We strongly advise against creating another state-wide single technology silo. The technology is quite mature, widely available, and integrates well with existing programs. The state already has too many single-technology programs that are not synergistic. Creative "incentive layering" schemes reflect the challenges of trying to overcome a single first cost market barrier. Instead we should focus on building markets that allow for "value stacking" which can drive market mechanisms that can continue to deliver as the specific technologies and viable solutions ebb and flow.

Rule change recommendation*: Do not limit targeting to Smart Thermostat programs. Mandate targeting for all resource programs to identify highest impact opportunities for 2022 and 2023 within the customer base and provide performance payment for delivering on that value.*

VII. Conclusion

We appreciate the opportunity to provide insights at this urgent time for California. We look forward to a continued engagement with all parties to identify the most effective solutions.

Dated: September 1, 2021

Respectfully submitted,

/s/

Carmen Best

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Appendix A. Proposal Breakdown: Demand Flex Market

Recurve has prepared this proposal according to the "Overall Guidance for Any Program or Policy Proposal Submitted" provided by ALJ Stevens in R.20-11-003. The same proposal was presented in the energy efficiency proceeding R.13-11-005.

1. **Identify any new program or modification to an existing program that could reduce demand or increase supply at net peak**

a. **General Program Design**

Recurve is pleased to present our response to the state of California's request for proposals to bring peak load reductions for the summers of 2022 and 2023. Recurve is accelerating the transition to a clean energy economy by supporting the full integration of demand-side resources into the emerging carbon-free energy grid. For this program, Recurve is proposing a Demand FLEXmarket solution that combines pay-for-performance with an open market of qualified aggregators delivering energy efficiency, load shifting, and demand response across the residential and commercial sectors.

The Demand FLEXmarket uses Recurve's platform and open-source industry-proven M&V tools to quantify energy savings at the specific AMI meter while converting actual MWh impacts into payable and claimable savings, all on an ongoing basis. This population NMEC program design will support the delivery of cost-effective savings and decarbonization to meet California's clean energy goals while optimizing energy usage for residential and commercial customers.

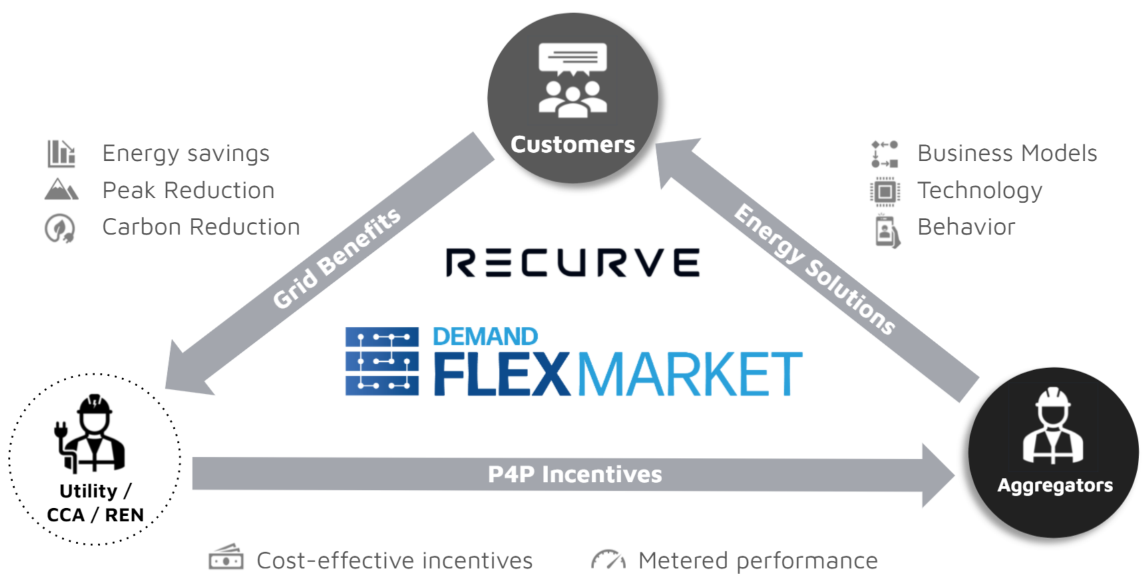


Figure X: Demand FLEXmarket Concept

The FLEXmarket model overcomes the traditional barriers to entry for qualified aggregators and validates the savings impacts for both end customers and the grid. This creates a tighter connection between program investments and the grid impacts that drive value for ratepayers including the following value streams:

- Maximizing energy savings delivered by aligning aggregator incentives with desired outcome through performance-based compensation.
- Supporting climate goals by targeting customers with the highest potential for GHG reductions and applying the right measures to deliver results.
- Improving the lives and livelihoods of the communities served through efficiency and effectiveness of service delivered by enabling aggregator business models best in line with specific customer needs.

i. Program trigger

The Demand FLEXmarket combines long-term energy assets and short-term controllable load shifting and demand response assets into a single VPP. Energy efficiency measures can be viewed as long-term, non-dispatchable virtual power plants, with load shifting and demand response taking the form of short-term virtual power plants with varying startup times. Similar to physical power plants, different technologies and business models will also have varying marginal costs and operational characteristics.

Energy Efficiency projects are "triggered" upon enrollment/installation and are incentivized to deliver optimal load shapes for the state of California based on the avoided cost curve. Controllable load shifting and demand response projects can be installed alongside energy efficiency projects, or utilize existing infrastructure that adapts operation to deliver MWh reductions during peak hours. Ideally, routine load shifting windows are identified in advance, such as summer weekdays from 4-9 PM, with shorter term demand response windows identified < 24 hours in advance. Program participants are notified through the Recurve platform and email notices to ensure event awareness.

Recurve methods can identify and separate long term energy efficiency impacts from short term demand response impacts at the same meter through the use of long term and short term baselines. This allows for a separate incentive rate ($/MWh) to be used between long term efficiency and short term demand response.

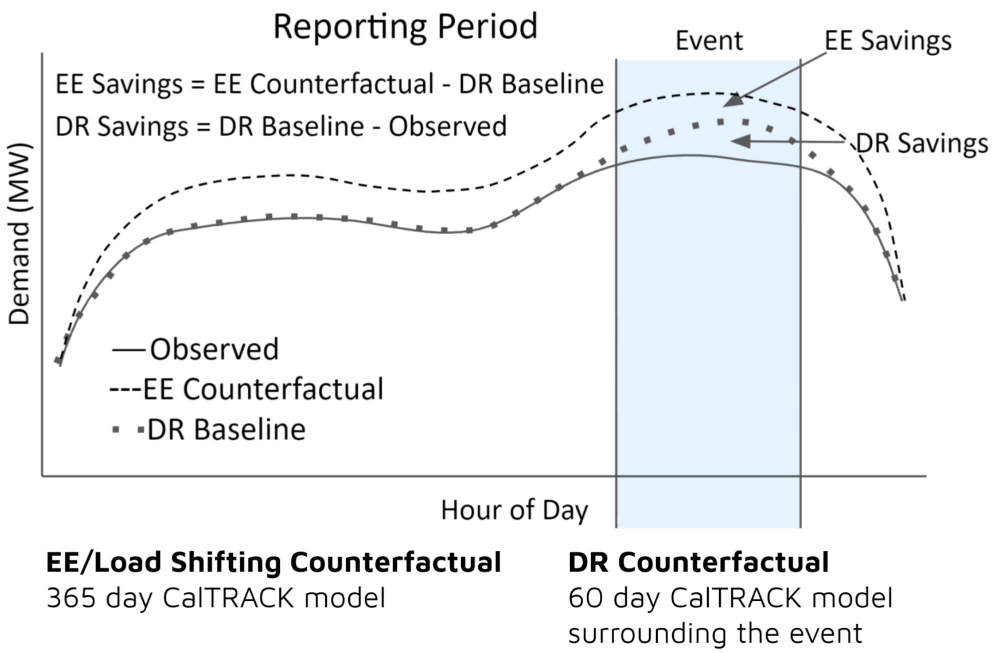


Figure X: Separating Energy Efficiency and Demand Response Savings

ii. Demonstration that program will deliver benefits during net peak

The Demand FLEXmarket does not rely on deemed values to demonstrate net peak energy savings, and instead utilizes a Population NMEC approach to develop consistent and transparent baselines for each meter. Energy usage is tracked to demonstrate impacts relative to the baseline energy consumption. Recurve has performed meter-based savings analysis on past and current programs that demonstrate the impacts of energy efficiency and demand response measures during net peak periods. In fact, measured savings from common efficiency measures such as insulation and HVAC upgrades have demonstrated large impacts on energy reduction during peak periods.

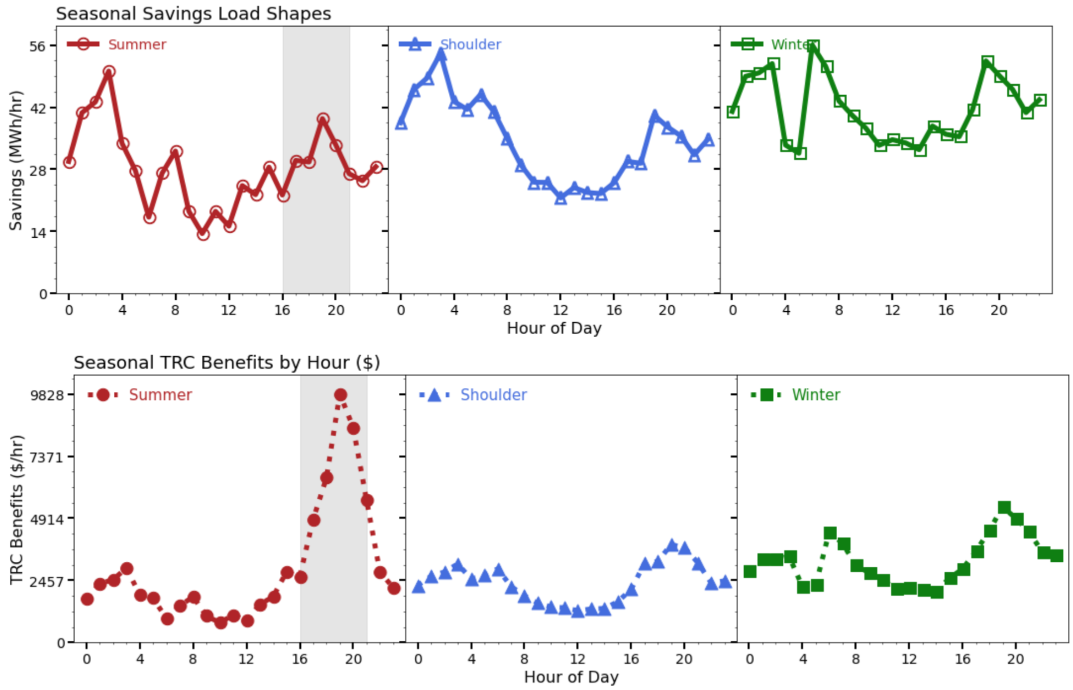


Figure X: Measuring Energy Efficiency Impacts at the Meter

In addition to efficiency measures, there are many existing resources and energy service companies that have the capacity to shift load, but do not have a reliable price signal to organize behind. A recent study by Berkeley Lab indicated that there are several GWH of existing load shifting potential waiting to be unlocked, with a large portion representing residential and commercial HVAC. A routine shift of this load has the potential to reduce day to day renewable curtailment and net peak at the same time. The rapid growth of behind the meter storage has the potential to contribute greatly as well. This program plans to provide a stable price signal that aggregators and customers can plan load shifting and demand response operations around.

iii. **Program performance requirements**

Participants in the market are compensated based on metered energy savings throughout the year and during load shifting/demand response windows. Aggregators are not compensated until delivery of metered MWh savings. A goal of the program is to align incentives along the entire value chain. Aggregators are incentivized to deliver MWh savings, and Recurve is incentivized to recruit aggregators and projects, with a portion of the program administration budget based on results delivered.

iv. **Compensation structure**

The compensation structure for this program involves paying aggregators for the reduction of load throughout the year and during peak hours. Energy efficiency projects are incentivized based on the avoided cost curve and cost effectiveness requirements. Load shifting projects are incentivized with a flat, long term and predictable $/MWh rate, with demand response events signaled with higher $/MWh incentives based on grid conditions. Aggregator load reductions and payments owed are tracked throughout the entire program in a transparent and auditable fashion. The program administration budget requires fixed cost components, but is also structured to align with the amount of MWh reductions delivered.

v. Program eligibility and enrollment

This program aims to be as inclusive as possible while navigating potential dual participation issues by performing site/project eligibility checks, including but limited to the following:

- The customer must be located in the LSE territory defined by the program.
- Requires a minimum of 12 consecutive months of energy usage data in order to construct the baseline counterfactual.
- The meter must have a model fit < 1.0 CVRMSE, indicating a strong correlation between the counterfactual baseline and meter data.
- The customer cannot be currently participating in an ongoing demand-side program (such as load shifting or demand response).
- The customer cannot be currently participating in the CAISO market or an existing RA or LMR program.[1]
- If a customer has participated in a past energy efficiency program, the most recent measure installation must have been installed >12 months ago to establish a clean energy usage baseline and demonstrate incrementality.
- If there is a solar installation on-site, it must have been completed more than 12 months prior to any energy-efficiency intervention.

vi. Measurement and verification, if needed

The program utilizes open-source population Normalized Metered Energy Consumption (NMEC) methodologies for both energy efficiency projects and event-based load shifting and demand response. This is combined with the use of comparison groups to remove exogenous grid impacts (such as Flex Alerts or COVID-related behavior shifts).

Recurve's incoming data pipelines connect resource, dispatch, and site data to energy savings calculations to create portfolios of projects. An aggregated view provides a consistent metric of portfolio performance for each aggregator and the VPP as a whole. Recurve will receive meter data directly from load serving entities to perform M&V for each meter compared to the counterfactual baseline usage calculated using the CalTRACK methodology. This streamlines the meter data collection process and M&V methodology for the VPP as a whole so that aggregators can focus on dispatch and delivering results at the meter.

Recurve combines historical baseline creation with comparison group tracking through the GRIDmeter platform and methodology. This allows us to account for exogenous factors occurring on the grid that are not captured with a historical baseline by creating comparison groups that closely reflect customers enrolled in the program. Comparison groups have counterfactual models created alongside the treatment group, and an hourly "difference-of-differences" percentage calculation determines the final savings. This is particularly important during events or situations not captured in a historical

[1] This program component is in compliance with existing rules. If the Commission were to adopt an option for incrementally demonstrating impacts that are locally targeted or net of CAISO settlement this criteria could be adjusted to expand eligibility.

baseline, such as extremely high temperatures or changes in consumption due to the COVID pandemic.

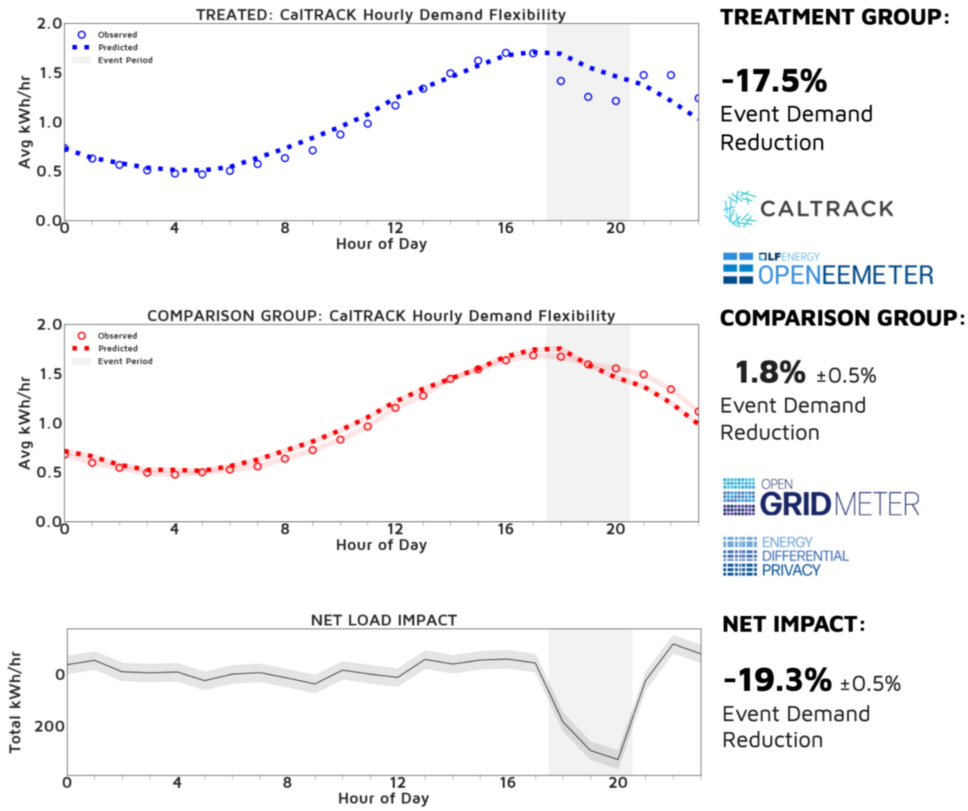


Figure X: Savings Calculation and Comparison Group Adjustment

b. **Program Administration (including who would administer the program)**

Recurve would be responsible for full program design, administration, and management activities. The program will be assigned dedicated resources, including a Marketplace Program Manager, Customer Success Specialist, Customer Solutions Manager, and Engineering Lead. Upon contract sign, Recurve will schedule and facilitate a project kickoff meeting with applicable LSE's and key stakeholders to align key tasks and considerations, including program goals, design, incentive structures, M&V plan, schedule, and general marketplace operations. Routine check-in meetings will be held on a weekly basis or mutually agreed upon frequency.

Upon program launch, Recurve will utilize existing Flexibility Purchase Agreements (FPAs) with aggregators to onboard them to new marketplaces, while continuing recruitment of new aggregators into the marketplace. The Recurve team will perform all progress reporting duties for LSEs and CPUC stakeholders. Recurve will configure a unique instance of the platform in which authorized stakeholders can log in and track real time progress of program metrics including savings and incentive payment tracking.

The general program lifecycle flow can be seen below, from eligibility checks to performance tracking and quality assurance.

Program Lifecycle Flow

	Eligibility	Qualification	Enrollment: Pre-Intervention	Enrollment: Post-Intervention	Performance Tracking	Quality Assurance
Program Implementer	Identify eligible customers for program. Engage customers to participate in the program.	Review baseline analysis for eligible customers to determine appropriate measures. Make notes on project. Group projects by contractor cohort	Review recently scheduled projects	Review recently completed projects	Monitor ongoing portfolio performance after update to ensure on track to meet savings goals. Download KPIs for reporting.	Periodically examine disqualifed projects and look for outliers which may negatively effect portfolio peformance.
Recurve Platform	Pull authorized customer, site and historical meter data into platform. Verify eligibility w/meta data.	Create placeholder-project for each eligible customer. Batch customers and ETL to complete baseline analysis for each.	Update project intervention date and status to scheduled. Remove customer from eligibility table.	Update project intervention date and status to completed.	Batch completed projects/new data to ETL and run meters at set frequency e.g. monthly.	Use portfolio settings to detect NRE's and identify outliers.
Program Channel		View cohort of eligible projects to see suggested measures and info for each customer. Use list for customer outreach.	Sell intervention to customer. Use enrollment form to update project with scheulded intervention date and set status to scheduled. Upload required contracts & info.	Complete intervention. Use enrollment form to update project with actual intervention date and set status to completed.	Examine program performance to see if projects peformed as expected.	Identify outliers and examine their meta data to understand how to improve performance.

Figure X: Demand FLEXmarket Program Lifecycle Flow

c. Program marketing, outreach and education

The overall marketing, outreach, and education approach is to combine top-down awareness campaigns with bottom-up aggregator customer recruitment to maximize the customer pipeline. Many aggregators participating in Demand FLEXmarket are recruiting customers on a day-to-day basis, regardless of energy efficiency programs. The program is designed to tap into the existing aggregator recruitment flow and provide incentives for projects that provide grid value for total system benefit. Recurve anticipates that the best time to engage a customer on an energy efficiency upgrade is when they are already speaking with aggregators regarding service or repair. Through constant aggregator recruitment, Recurve aims to serve as many customers as possible with market coverage and saturation.

Recurve supports aggregators in outreach efforts by analyzing meter data to identify customers that can deliver outsized impacts for certain measures. The identification of key load shapes will allow us to target individual customers that offer the most potential for grid services based on specific technologies and business models. Customers that exhibit high summer peak period usage and steep evening ramps will be of particular interest. In addition, Recurve will provide support with an awareness campaign to funnel end customers towards the program.

d. Program budget, including breakouts for administrative costs, marketing, evaluation, and breakouts for startup costs, incentive payments (if applicable), and ongoing program administration

The following budget breakdown indicates estimated spend by category aligned with CPUC cost definitions. The FLEXmarket program design streamlines many administration functions, allowing a high percentage of total budget to be allocated to customer incentives. The budget total is an **indicative** example, and the program can be scaled up or down depending on the total budget and number of load serving entities participating. However, the percentage breakdown for each category remains relatively consistent.

Cost Category	Budget	% of Total Budget
Non-Incentive		
Administration ● Administrative labor ● Reporting ● Data Request Responses ● Ad-hoc support ● Etc.	$1,250,000	5%
Marketing & Outreach ● Preparing and distributing collateral ● General awareness and outreach support ● Advertising ● Etc.	$625,000	2.5%
Direct Implementation - Non-Incentive ● Processing project submittals ● QA/QC ● Education/Training of Aggregators ● Project Management ● Program Development & Design ● Recurve Platform ● Etc.	$4,375,000	17.5%
Non-Incentive Subtotal	***$6,250,000***	***25%***
Incentives		
Direct Implementation - Incentives ● All payments made directly to aggregators based on delivered MWh at the meter	$18,750,000	75%
Incentives Subtotal	***$18,750,000***	***75%***
Total Budget	**$25,000,000**	***100%***

Figure X: Indicative Demand FLEXmarket Budget

e. **Implementation timeline (must demonstrate program can be designed and fully implemented such that it can deliver demand reduction or increase supply at net peak for June 2022, and if not on this timeline, why the proposed timeline still provides benefit in addressing the summer net peak reliability need)**

After contract sign, Recurve will begin work on platform setup, data transfer pipelines, and program documentation and requirements finalization. Recurve anticipates that this process can be completed within 8-16 weeks, depending on speed of data transfer. This leaves more than enough time to begin delivery of demand reduction by June 2022. The program setup process can be completed in parallel for multiple load serving entities.

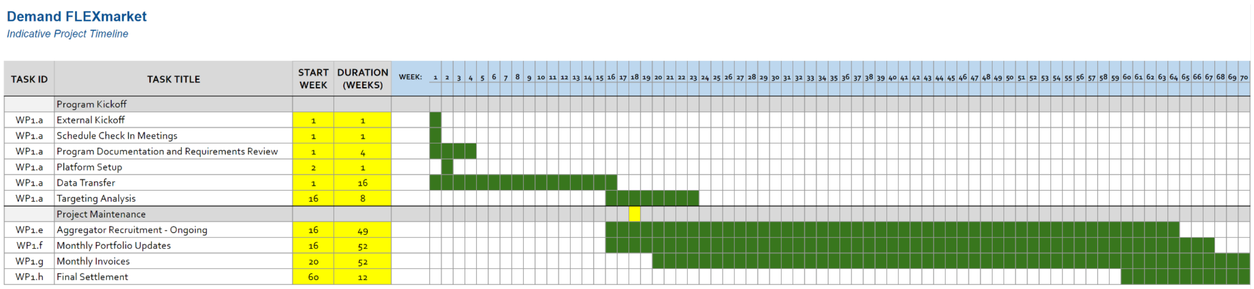


Figure X: Indicative Demand FLEXmarket Schedule

f. **Program duration**

The Demand FLEXmarket is a program that can be extended in perpetuity. Qualified aggregators are continuously welcome to enter the market and bring resources that can reduce demand, particularly summer during net peak hours.

g. Estimated megawatt contribution/load impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs)

The exact MWs delivered during net peak will depend on budget, the number of load serving entities participating, and the price signals sent to the market. Incentives will be calculated based on the California avoided cost curve (or multiplier thereof) and cost effectiveness requirements. The avoided cost curve already highly values load reductions during summer net peak hours of 4-9 PM, and the incentive design could be adjusted to further emphasize this value. Upon program authorization, Recurve would develop a forecast based on finalized program design and aggregator feedback on resource availability.

While recognizing the many caveats, current experience with MCE suggests that a Peak FLEXmarket model (load shifting / DR focus) could potentially deliver 30 MW of enrolled capacity for a given CCA by 2023 with funding in the range of $10M. This is not including the additional long term savings co-impacts. The Commercial Demand Flex Market (long term EE focus) for MCE, for example, is slated to deliver 5,224,085 kWh, 273 kW, and 0.09 MM Therms based on the 2021 Annual Budget Advice Letter for energy efficiency.

The Demand FLEXmarket is designed to be fully incremental, and we do not anticipate any impact reduction to existing programs.

h. Potential interaction with other existing programs (i.e., dual participation issues)

This program navigates potential dual participation issues by performing eligibility checks as described above. Sites participating in this program cannot be participating in existing RA or LMR programs. In addition, sites that have participated in past energy efficiency programs must have had measures installed over one year prior to Demand FLEXmarket participation in order to establish a baseline for incremental savings.

i. **Prior similar program experience in California or elsewhere**

MCE Clean Energy has implemented an ongoing Demand FLEXmarket within their service territory that revolutionizes traditional programs in a way that guarantees cost-effectiveness and lowers energy usage during the most critical times for the grid. The MCE Demand FLEXmarket is currently focused on the commercial sector for energy efficiency, but there is also an ongoing load shifting and demand response component available to all sectors, including residential. Initially funded with a budget of $1 MUSD, the program budget was expanded to $5 MUSD annually due to encouraging project submission and pipeline flow.

The Demand FLEXmarket combines the benefits of pay-for-performance programs with the innovation of an open marketplace. Qualified aggregators can enroll into the platform by accepting the Flexibility Purchase Agreement and M&V terms. From there, aggregators can enroll projects and submit them for approval. Once approved and installed, Recurve tracks the hourly energy savings relative to the baseline model prior to the project. Aggregators are then paid according to the M&V terms set forth by MCE Clean Energy and Recurve. This straightforward enrollment process creates an open market where results are rewarded, regardless of technology.

With hourly tracking, MCE Clean Energy is able to incentivize participants based on time of day. A price signal tells aggregators exactly what energy savings during each hour of the year are worth. For example, energy savings between 4-9 PM in the summer can be valued over 3X compared to typical hours throughout the year.

The Demand FLEXmarket has been expanded to include demand response measures, integrating energy efficiency, load shifting, and demand response into a coherent price signal to the market. This leads to engagement from the most innovative technology providers and helps to address grid issues by flattening peak energy usage and reducing MCE Clean Energy's market exposure.

j. **Program funding and cost recovery mechanisms**

Program funding could come from several sources, including identifying appropriate pools of non-emergency energy efficiency budgets. Emerging Technologies and the Evaluation budgets for **one** year would total roughly $40 million. In 2021 alone, the Commission allocated $15,868,567 to Emerging Technologies and $24,376,998 to evaluation. Both of these pools of funds will not result in any demand reductions or energy savings in 2022 or 2023, but their mission could be directly captured in the Demand FLEXMarket model, which spurs innovation, assesses performance, and will deliver impacts in the near term as well as the long term as an emerging market model.

CCA's and other load serving entities wishing to launch a Demand FLEXmarket model could apply for these funds via a Tier 2 advice letter. Alternatively, utilities could be authorized by the CPUC to establish Memo Accounts to track expenditures and recover costs via the next general rate case. Since most of the cost is based on performance, this would minimize risk of costs to ratepayers to sink costs without demonstrated impacts.

k. **Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk**

A possible risk associated with Demand FLEXmarket is a slow project submission flow from aggregators that hampers the ability to meet program savings goals and deadlines. Recurve mitigates this risk by aligning our payment with aggregator project submission. This means that if aggregators are not submitting projects, a portion of Recurve's non-incentive budget is held back. Ultimately, Recurve is incentivized to motivate and coach aggregators in submitting projects, and aggregators are incentivized to maximize MW and MWh savings.

However, the Demand FLEXmarket directly address risks commonly associated with many traditional programs, including:

- Poor realization rates and impact evaluations.
- High administrative and project management costs, leading to small incentive pools.
- Rigid and prescriptive requirements that increase transaction cost and slow project flow.
- Struggle with scale as one implementer tackles an entire territory.

The Demand FLEXmarket inherently addresses many of these issues in the foundational design, including ongoing M&V, which enables enabling mid-program adjustments to influence performance metrics, low administrative costs increasing budgetary allocation for incentives, solution flexibility, and allowing for an open marketplace of qualified aggregators to ensure future scale can be achieved in-line with budget increases.

2. **Identify any new policy or modification to an existing policy that could reduce demand or increase supply at net peak (for example a rule, regulation, incentive, penalty)**

The drag of participant costs associated with the use of the Total Resource Cost test significantly hobbles energy efficiency projects. We recommend using no cost test and paying directly for system benefits delivered from efficiency or using a Program Administrator Cost test that does not have a co-investment penalty.

a. **Duration – temporary or permanent:** Permanent

b. **Justification or demonstration that policy will support the delivery of reliability benefits during net peak**: The potential savings using a PAC test are about 25% higher than the Low TRC test in the Commission's latest potential and goals study. By leveraging co-funding, the state can accelerate the installation of projects that both lower energy use overall, and drive reliability benefits during net peak. Performance incentives tied to hourly performance can further ensure that increased co-investment will drive impacts where needed.

c. **Estimate of policy's impact (megawatts)**: Based on the efficiency potential study, the estimated potential based on PAC is about 40% higher than the low TRC scenario. The actual MW resulting from this policy change are not known and are dependent on several factors.

d. **Implementation requirements, including whether other state agencies or CAISO must approve:** The CPUC can make a unilateral decision on what cost test to apply in the energy efficiency proceeding.

e. **Potential risk of proposal**: Programs drive toward customers and initiatives that can augment ratepayer funding and increase overall impacts. Value streams to overcome cost barriers for customers with fewer means should be tracked with equity budgets. Market-based performance programs are best suited for this transition.

f. **Statutory and/or regulatory justification and history (especially if recommendation is to change an existing policy)**: The Commission has recognized that the requirement to capture all cost-effective energy efficiency is a floor, not a ceiling. It has also been recognized in recent decisions that certain initiatives (like market transformation, and building electrification) should not be subject to a cost test. The Commission has recognized that costs for third-party providers are "per se reasonable" because they are revealed via a competitive process.

Performance-based program models designed around population NMEC, wherein program administrators are directly buying aggregated systems resources, are in a unique position to fill this role. However, they are caught up in a deemed reporting paradigm that is not appropriate for their actual operation as a virtual power plant (VPP). The program costs for these competitively delivered resources should be considered per se reasonable and at the boundary of the aggregator payment in the same way third-party programs are considered reasonable. Extending this logic for population NMEC with a marketplace deployment model will enable significant scaling of these investments, which will also deliver time-valued efficiency (i.e. EE-DR co-benefits) to meet aggressive targets and support the grid as soon as 2022.

In D.21-05-031 the Commission recognized that competitively solicited third-party contracts should be exempted from zero-based budgeting requirements. Since the budgets were established via a competitive process, the program costs represent the market rate for procuring that resource and as such are "per se" reasonable.

> "*Implementation costs associated with competitively-solicited third-party contracts shall be considered per se reasonable, without the program administrator needing to justify the costs using a zero-based approach."* D.21-05-031 Ordering Paragraph 21

By extension, population NMEC programs with direct payments to aggregators for system benefits are likewise representing the "per se" reasonable market rate for procurement of the resource. Aggregators are leveraging competitive market forces to finance projects, settle willingness to pay price points with customers, and may augment projects with other capital sources. The aggregator must reconcile all of this against the system benefits rate paid based on portfolio performance. Furthermore, in the case of population NMEC programs that shift risk, both measurement and payment are settled directly with the aggregator based on their portfolio of projects. Their aggregated portfolio functions as a virtual power plant creating a cash flow that represents the total system benefit, isolated from the customer benefits and costs that are being delivered and paid for by each building owner. Hence, the only cost that needs to be accounted for in this measurement boundary is the cost of procuring the resource from the aggregator's portfolio and any other justification of cost, to achieve the system benefit, is unnecessary.

3. **Procurement mechanisms/Resources not previously accepted in this proceeding**

a. Proposals for programs, procurement mechanisms, or resources not authorized in the previous decisions in this proceeding, with additional details that address any related concerns (proposals should also include any applicable details identified in section 1 above).

We are proposing the Demand Flex Market as a program proposal that also serves as a procurement mechanism. Most resources provided would be additional load modifying resources with CCAs but could also be procured via utilities or even non-LSE partners like local governments.

Appendix B. Proposal Breakdown: TECH Focused Acceleration of Existing Pay for Performance Program

Recurve is submitting this proposal in partnership with ICF following the form requested for proposals in R.20-11-003. The same proposal was presented in the energy efficiency proceeding R.13-11-005.

1. Identify any new program or modification to an existing program that could reduce demand or increase supply at net peak

General Program Design

The supplemental approach begins with expanding the current measure list of PG&Es HEOP (pay for performance) program to include the installation of Heat Pumps and other home performance measures. Based on the expanded measure list, ICF will recruit trade allies (e.g., HVAC and Home Performance contractors) to participate in the program and install (at a minimum) a TECH qualified variable-capacity heat pump (VCHP) in place of a standard HVAC unit. Contractors are free to install other home performance measures as they wish as part of their normal course of business.

Contractors will be provided with a targeted customer list (developed in support of the TECH initiative) and will be incentivized only when they install qualified measures at a customer on the targeted list.

Program trigger - as primarily an efficiency value proposition no particular triggering event is necessary, beyond program launch.

Demonstration that program will deliver benefits during net peak – The demand associated with Variable Capacity Heat Pumps is documented to be less than the demand associated with a standard HVAC system. This reduction in unit demand across approximately 2,500 customers will deliver benefits during the summer peak.

Program performance requirements – ICF will utilize an engineering calculation to determine the demand reduction associated with the installation. ICF will be compensated based on this calculated demand reduction.

The performance of savings measures will be determined using meter-based CalTRACK methodology. Aggregators/Trade Allies will be compensated based on meter-based savings.

Compensation structure - ICF will be compensated for its services on a $/kW reduced basis. kW will be calculated based on the reduction in load from the current baseline conditions (standard HVAC) compared to the improved conditions (with a VCHP and smart Tstat). Contractors will be compensated on a quarterly basis for the first year, based on the kWh savings of the home as determined through the application of the CalTRACK NMEC methodology.

Program eligibility and enrollment – To be eligible for participation, customers must be on the targeted customer list developed for the TECH program and meet the eligibility requirements of the HEOP program, which generally include the following:

- Must have an active service account for at least the past 13 months
- No solar or EV charging unless sub-metered
- No previous participation in programs that offered the same measures

Measurement and verification, if needed - The program will utilize population-based NMEC methodologies (i.e. CalTRACK, OpenEEmeter, GRIDmeter) for M&V of savings

Program Administration (including who would administer the program) - The program would be administered by PG&E, the current administrator of the HEOP program, and implemented by ICF.

Program marketing, outreach, and education -

- Marketing materials will include an expansion of the program website, the development of a one-page program handout and a variety of branded emails to support the outreach campaign
- Outreach will be conducted through multiple channels including the direct outreach conducted by participating trade allies as part of their business-as-usual marketing tactics. The program will generate leads for participating trade allies primarily through email-based campaigns

Program budget, including breakouts for administrative costs, marketing, evaluation, and breakouts for startup costs, incentive payments (if applicable), and ongoing program administration –

	2022	2023	Total
Admin	$200,000	$200,000	**$400,000**
Marketing	$225,000	$225,000	**$450,000**
DINI	$1,500,000	$1,500,000	**$3,000,000**
Incentive	$2,000,000	$3,000,000	**$5,000,000**
Total	**$3,925,000**	**$4,925,000**	**$8,850,000**

Implementation timeline (must demonstrate program can be designed and fully implemented such that it can deliver demand reduction or increase supply at net peak for June 2022, and if not on this timeline, why the proposed timeline still provides benefit in addressing the summer net peak reliability need)

		2021	2022					
Task	Duration (days)	Dec	Jan	Feb	Mar	Apr	May	Jun
Authorization to Proceed	1	★						
Modify measure mix	3w							
Develop technical requirements	4w							
Develop Marketing Materials	4w							
Modify program intake tools	8w							
Trade Ally Recruiting and Training	ongoing							
Begin Installations						★		

Program duration – The program will span the two summers identified in the ruling. We anticipate the program should begin by 1/1/22 in order to maximize the impact on the summer 2022 peak and can be terminated in October 2023 after the 2023 peak has passed.

Estimated megawatt contribution/load impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs) - ICF has determined that a VCHP, controlled by a smart Tstat (EcoBee+, etc), could reduce the cooling demand load by 0.085-0.25kW during peak periods. This range is dependent on the size of the heat pump and how aggressively the Tstat is controlling setpoints.

For the budget presented in this proposal, we estimated a total of 2,500 projects could be installed and operational prior to the summer peak of 2023, totaling approximately 500 kW in demand reduction. In addition to the demand reduction, the proposal will have significant additional benefits supporting state-wide goals for electrification, GHG reduction and energy efficiency.

Potential interaction with other existing programs (i.e., dual participation issues) - The program is proposed as a supplement to ICFs current Pay for Performance pilot implemented for PG&E. Projects will be enrolled in accordance with pilot eligibility requirements and energy savings compensation will be incorporated into the current contract.

Prior similar program experience in California or elsewhere – ICF implements over 15 HVAC programs across the nation where heat pumps and standard HVAC systems are installed for the purposes of decreasing energy use.

Program funding and cost recovery mechanisms - Cost recovery could be pursued related to the avoided cost of energy purchases which may cover 20 – 40% of the program costs.

Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) **with discussion of each potential risk** – The greatest risk to program success is being able to consistently enroll customers. Our tactic to overcome this risk is to leverage trade allies that are already conducting HVAC or Home Performance work and providing them with upfront and savings-based incentives to offset some portion of the project cost.

2. **Identify any new policy or modification to an existing policy that could reduce demand or increase supply at net peak (for example a rule, regulation, incentive, penalty)**

Duration – temporary or permanent – the proposed approach is envisioned as temporary

Justification or demonstration that policy will support the delivery of reliability benefits during net peak - Policy currently supports the TECH program and the Pay for Performance pilot.

Estimate of policy's impact (megawatts) - NA

Implementation requirements, including whether other state agencies or CAISO must approve - Due to the leveraging of existing programs, we do not anticipate and significant implementation concerns.

Potential risk of proposal - The greatest risk is associated with being able to promptly enroll customers into the program. The use of incentives for both demand and savings will help to minimize this risk.

Statutory and/or regulatory justification and history (especially if recommendation is to change an existing policy) - no policy changes needed.

3. **Procurement mechanisms/Resources not previously accepted in this proceeding**

Proposals for programs, procurement mechanisms, or resources not authorized in the previous decisions in this proceeding, with additional details that address any related concerns (proposals should also include any applicable details identified in section 1 above). – We propose that ICF's current contract with PG&E could be used as the procurement mechanism for this work. ICF would be happy to develop a firm scope of work and related budget for further evaluation as needed.

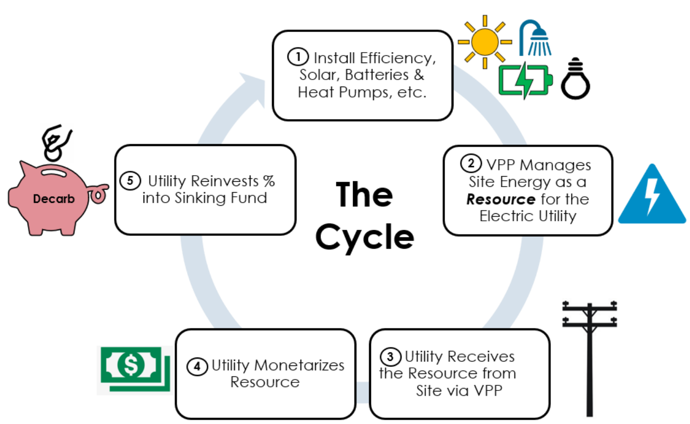
Appendix C. Proposal Breakdown: Multifamily Virtual Power Plant

Recurve is sharing this proposal in partnership with San Francisco Environment using the form requested in the energy efficiency proceeding R.13-11-005.

Description of programmatic approach or value proposition:
Pilot a market-based solution to fund building decarbonization while increasing energy efficiency (EE), distributed energy resources (DER), and demand response (DR) for existing multifamily buildings. The approach is to *monetize the value from these resources* and *re-invest the money into a Sinking Fund to be used for ongoing building decarbonization.* The Sinking Fund is a pool of money set aside to pay for future building decarbonization projects. Over time, this approach is expected to reduce the reliance on ratepayer funds by allocating the decarbonization savings back into the program.

The pilot will target low-income and affordable housing, which will support the State's climate goals and will help address summer reliability needs by reducing load in 2022 and 2023 and beyond. It can ultimately be scaled to provide decarbonization incentives to a range of multi-family building types.

The foundation of this pilot is the deployment of Recurve's Demand Flexibility Market (DFM). The DFM is the market access model which would be augmented by the participating energy aggregators' DERMs platform and services that manage electricity inputs and outputs in a portfolio of affordable, multifamily buildings to enable delivery of a Virtual Power Plant (VPP). With funding, Recurve will partner with local government entities (SFE), an affordable multifamily operator, and an energy aggregator to administer and implement the pilot.



To operationalize this proposed VPP concept, a single energy aggregator would initially be selected to participate as the VPP provider and deliver projects. The aggregator would provide and have access to a DERMS platform to enable direct control of site energy consumption by managing equipment to reduce electricity use when it's the most expensive. In parallel, the Recurve platform would provide the infrastructure to enable the VPP transaction by automating administrative efforts such as project eligibility and enrollments, provide ongoing revenue-grade measurement and verification of energy savings, and streamline settlement through the calculation of energy savings stacked against the California avoided cost curve to quantify the total system benefits to the utility and enable payments owed to the aggregator. The utility provider benefits by avoiding having to purchase electricity during peak times – resulting in a net reduction in energy use while providing a cost-benefit. Utility staff will then be able to monetize this benefit and re-invest a portion *into a Sinking Fund that will finance* future decarbonization projects – and the cycle continues.

Once the initial budget is deployed, the pilot concept comes to fruition, and results are verified, additional funding will be requested to expand the VPP into a multi-aggregator DFM reducing the performance risks associated with a single aggregator solution. At full deployment, the Recurve Platform managing the DFM sends a price signal incentivizing participation energy aggregators which operate the distributed energy resources. These signals encourage the management of equipment and site to optimize grid and customer economics. Similar to the pilot, the DFM will measure savings and assign a value against the California avoided cost curve to monetize and re-invest in a *Sinking Fund*. Recurve and SFE can further define this future path in collaboration with the CPUC.

This pilot can leverage existing State-funded energy efficiency and self-generation programs, such as the California Low Income Weatherization Program, Bay Area Regional Energy Network's Multifamily rebate program, Self-Generation Incentive Program, and Solar on Multifamily Affordable Housing. Through these programs, participants can already install energy efficiency and electrification equipment (e.g., heat-pumps) and renewable energy systems and battery storage.

In summary, the pilot proposal initially provides a single aggregator transactional VPP pilot with a line of sight to expand into a multi-aggregator DFM during the full concept roll-out. The proposed solution will allow building decarbonization to be used to unlock the full capabilities of demand-side energy resources through grid-interactive technologies and potentially a revolving funding mechanism to support continued decarbonization.

Specific measures or technologies:

1. The VPP manages and operates with grid-enabled devices such as DHW heat pumps, demand-response equipment, and charge battery-storage systems.

2. The aggregator is paid based on the performance of the projects installed via a Demand Flexibility Market model.

3. This pilot will develop a value matrix that monetizes the avoided costs for the local utility of buying expensive electricity from the market. A portion of the avoided cost will be deposited into the Sinking Fund.

4. The Sinking Fund (for decarbonization) is a financial resource for the participating affordable multifamily operator to draw from to fund electrification projects for the rest of its building portfolio.

Building type:
The building type includes a portfolio of high-rise, century-old, affordable multifamily and mixed-use buildings. Specific buildings and communities can be defined in more detail with further collaboration with the CPUC.

Customer market segment:

Owners and operators of affordable, multi-family residential buildings for the 9 counties surrounding the San Francisco Bay Area defined by SFE's service territory. Customers with the highest propensity to save will be defined and prioritized through advanced customer targeting to ensure the right solutions are delivered cost-effectively to the right customers.

Incremental funding needs, if any;
Funding is required to develop the data platform that will calculate the real-time value of energy and the algorithm for directing energy management (i.e. when to add load to the grid, and when to reduce load.) The SFE portion of the pilot would be about $110,000 to launch and potentially $1.4 million could support the project across multiple local governments. In the proposed VPP, over 70% of the project budget will be allocated to direct incentives to drive the desired load reductions. Additional funds will be requested in alignment with CPUC key stakeholders to develop a VPP expansion path into a multi-aggregator Demand Flexibility Marketplace defined in the main body of this abstract.

Estimated energy savings and/or peak demand savings during the 4-9 p.m. time period;
As primarily a fuel substitution measure, the estimated energy savings of transitioning from natural gas to electric is anticipated to be 6,000 MMBtu/year.

Whether the program/approach can be implemented by June 1, 2022 or June 1, 2023 (or both), with specific needs for each time period;
The VPP can be fully implemented by June 1, 2023. The first 12 to 16 months will include installing the heat pumps, developing the pricing matrix, and gathering at least twelve months of monitoring and reporting data from participating buildings.

A demonstration that the program or project is incremental to and not captured by existing programs or processes
Presently there is no program offering for a VPP that simulates the packaging and dispatching of distributed energy outputs from a portfolio of *existing* multifamily and mixed-use buildings to the electrical grid. In addition, while many California municipalities are adopting building decarbonization goals, there is currently no ongoing mechanism to provide long-term funding to support the electrification of existing buildings.

Additionally, the open-Source CalTRACK methods proposed as the backbone for this program's measurement and verification, allow for the quantification of incremental load reduction savings between long-term, predictable efficiency savings and incremental savings during peak periods from resiliency event responses.