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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues	Rulemaking 13-11-005

COMMENTS OF RECURVE ANALYTICS, INC. ON EMAIL RULING REQUESTING COMMENTS / PROPOSALS ON ENERGY EFFICIENCY TO ADDRESS GOVERNOR'S PROCLAMATION OF JULY 30, 2021

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."

Recurve has prepared these comments around one core programmatic solution, and several recommended rule changes, which we believe will accelerate projects across the board with embedded means of ensuring accountability. In summary, we recommend that 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

Commission:

- Adopt a **market-access model** rather than a winner-take-all paradigm for bringing in and deploying efficiency projects.
- **Suspend cost-effectiveness test screening** for two years and instead cap payments for delivered system benefits (determined using the approved ACC for energy efficiency and quantified at the meter.)
- Create a **fast-track pathway for Community Choice Aggregators to access energy efficiency and demand response program funds** when using a performance-based market-access model.
- **Redirect budgets** for closely related non-resource activities to fund the deployment of market access models and bring emergency energy savings and peak load reductions forward for 2022-2023.
- **Leverage existing population NMEC pay for performance programs** with peak incentives to target customers with the highest cooling degree days to deliver appropriate solutions from a wide range of technologies and available incentives.

I. Market-Access Model to Deliver Demand Flexibility by July 2022

One of the biggest challenges in meeting this call to action is the quick pace at which actual projects need to come online. In California, designing, reviewing, procuring, and finally launching a new energy efficiency program historically takes 3-4 years. Much of this timeline is driven by the expectation that large-scale third-party and statewide programs will be awarded to one firm. As a result, many firms capable of delivering resources (big or small) may be boxed out of the market and do not have a pathway to bring resources forward to support customers and the grid. In an emergency situation as described in the Governor's proclamation, we need market access models that bring all hands on deck to deploy new resources quickly.

To accelerate projects that are not currently anticipated within the system plans and that can deliver demonstrable impacts and meet the Governor's call to action, the Commission needs to focus on three key things:

- **Send a clear price signal:** The Avoided Cost Calculator (ACC) provides a direct system value/price signal that can be calibrated to the urgency of the resource need.

- **Align incentives:** Meter-based performance programs designed around Population NMEC rules align incentives to directly purchase the system value from customers.
- **Streamline Procurement Process:** Market-access models, like Demand FLEXmarket[2], can enable this direct purchase of system benefits grounded in performance-based accountability (only pay for the benefits delivered) with an audit trail to back it up.

A. Avoided Cost Calculator and Total System Benefit Provide a Base Price Signal

While the ACC is not without flaws and certainly needs to be updated, it is currently the Commission's best expression of how much it values demand-side resources. **The ACC offers a consistent and transparent underpinning of value that programs and projects should be directly built around**, and why we believe the Total Systems Benefit metric for assessing goals for the energy efficiency proceeding will be so revolutionary. We will not re-hash our comments here, but simply point out that the ACC and the TSB offer a streamlined way to consider and reconcile the multiple benefits realized by energy efficiency and other types of demand flexibility solutions. The Commission in this proceeding and the summer reliability proceeding is expecting projects to be able to deliver demand flexibility in the form of overall load shape reductions (via EE), load flexibility shifts, as well as responsive reductions in 2022 and 2023.

Recurve has made valuing projects based on their hourly metered impacts possible with the FLEXvalue calculation engine, which is an **open-source codebase that enables program administrators, and aggregators to assess the system benefits of projects.** Tracking the net hourly performance of portfolios of projects in relation to their system benefits is also viable today using CalTRACK, OpenEEmeter, and GRIDmeter **so Program Administrators can pay aggregators based on the actual load impacts (EE and DR) delivered.**

With this foundation for a price, the Commission has the flexibility to scale up or down

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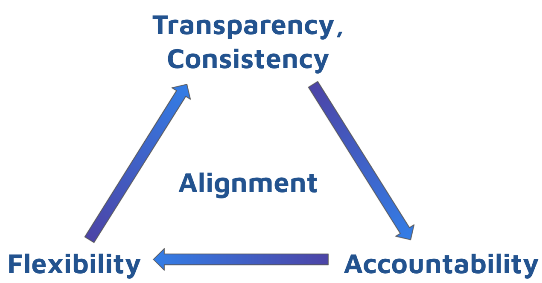
[2] The Demand FLEXmarket was first approved by the CPUC for implementation with MCE in the 2021 ABAL and East Bay Community Energy is also using the model to procure energy saving resources. A more detailed description of the model can be found on the Demand FLEXmarket web page. The appendix our comments included a full proposal description of model and answers the core questions posed in the ruling.

based on the urgency and potential risk of not having sufficient resources in 2022 and 2023. Instead of using the value currently prescribed for EE programs, **the Commission could apply an accelerant (a straight multiplier) to the ACC to communicate the urgency of near-term reliability to market actors and to motivate swift action**.

B. Meter-based Performance Designed around Population NMEC

Meter-based performance, vis-a-vis the population NMEC rules, offers the right balance of risk to reward for a significant acceleration of projects. Because payment is grounded in delivered savings, 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 aggregators are the point of settlement and can hedge risk across their portfolio of projects,



individual customers are shielded from the risk of shoddy installation. Requiring consistent, transparent, and repeatable measurement and verification mitigates the administrative overhead of having to review custom models. No change to the NMEC Rulebook is necessary to support acceleration of projects per the Governor's proclamation with the exception of the treatment of participant costs described later.

The proclamation is another opportunity for the Commission to **fulfill the obligations of SB350 to focus on NMEC as the default mode of resource acquisition.** SB350 states that *"The energy efficiency savings and demand reduction reported for the purposes of achieving the targets established pursuant to paragraph (1) shall be measured taking into consideration the overall reduction in normalized metered electricity and natural gas consumption where these measurement techniques are feasible and cost-effective."* NMEC is most certainly feasible and cost-effective for a majority of the resource acquisition programs.

When deployed via a market access model like the Demand FLEXmarket, it can drive third-party, performance-driven, meter-based impacts and aligns with the new Total Systems Benefit adopted by the Commission this year. In addition to providing accountability for tracking outcomes of emergency spending, this model also supports an actuarial feedback loop to provide a more reliable and dependable analysis for forecasting and for coordinating the combined potential of efficiency and demand response impacts in the future.

C. The Market-Access Model is Available Today to Scale and Deliver Resource by 2022 and Beyond

In contrast to the protracted procurement process for a single implementer that we see in third-party energy efficiency programs, with a **market access model, all qualified providers can be bringing projects forward to build a portfolio**. A Demand Flexibility Marketplace or Demand FLEXmarket, is an example of this model, and is already part of MCE's approved commercial energy efficiency portfolio. More specific detail about this market access model is provided in Appendix A.

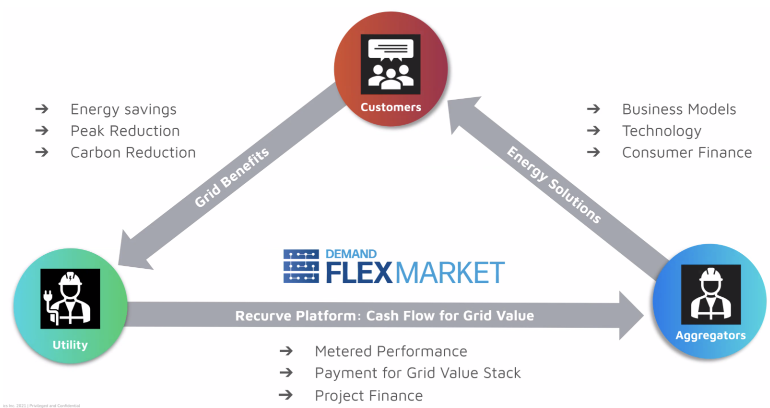
In summary, a standardized contract ("Flexibility Purchase Agreement"), articulates the terms for payment, including the measurement and verification for establishing performance. The base price per kWh is formulated from the system benefits (avoided cost value) with a deduction for administration and the embedded measurement and verification of projects. MCE has also launched a demand response version of the program called Peak FLEXMarket that provides a fixed payment for demand reductions from 4 PM - 9 PM and aggregators are eligible for up to 12 days (60 hours) of 'Resiliency Events' paid out in the price range of $200-$800 per MWh, depending on the grid constraints and costs at the point in time.

A market access model like Demand FLEXmarket **enables single aggregators to deliver both efficiency and demand response impacts as load modifying resources**, which has not been effectively done to date, and opens up demand response to a new class of energy service providers. As a recent ACEEE study demonstrated, Integrated Demand Side Management (IDSM) efforts in California have a poor record of achieving this objective – largely because of siloed regulatory objectives, budgets, and misaligned value propositions which in some cases are even pitted against one another.[3] Funding to date has not been tracked to resource acquisition and

[3] *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

hence had no real incentive to deliver on savings objectives. Many of these programs have been discontinued the exception of a few programs classified as IDSM among REN providers.

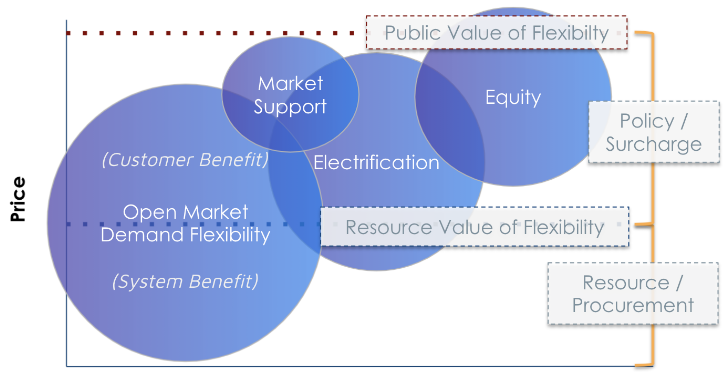
In contrast to typical program procurement, **aggregators in a flexibility market can sign on quickly, with minimal contractual headaches, and start delivering projects almost immediately**. It is not inconceivable that projects can start flowing within days of signing and FPA. The FLEXmarket may be one of the most straightforward and timely ways for program administrators and aggregators to "cut to the chase" to identify projects that can deliver by July 2022 and beyond July 2023.



Participating aggregators project the estimated savings impacts of their projects based on their interactions with customers. Among the suite of prospecting tools like targeting and co-branding, aggregators have access to a version of the FLEXvalue calculator that allows them to assess the avoided cost value of their proposed projects and scope out business plans for targeted market segments. The market manager ensures projects are eligible based on a data sufficiency check and track and monitor savings once enrolled in the program. Payment to aggregators is made based on one year of demonstrated performance and potentially shorter time intervals for demonstrated peak impacts.

Since aggregator payments are calculated directly from the system benefits delivered (i.e. avoided cost value), these projects are tied right back to the CPUC's price signal. The Commission can amplify the value (i.e. price signal) by putting a premium on the short-term delivery of projects to meet the urgency of system reliability in the next two years. The Commission could establish that any project completed in the next two years would be eligible for payments of 2-10x of value in the current ACC given the urgency. This value accelerant could just be applied to the peak time period 4-9 PM or a combination of overall plus peak accelerant could be established. The right number for the accelerant depends on how much system instability will likely cost the state in the next two years.

Similarly, **an accelerated value could be applied to ensure that customers eligible for Energy Savings Assistance, Tribal Communities, or other designated communities are fully included in any emergency response**. The Commission can establish that projects with demonstrated impacts for these eligible populations would be worth 2-10X of system benefits. Whatever the chosen value, it would be stacked on top of the value of urgency and near-term resilience. As noted in the illustration, each objective of the portfolio has value. All of the potential value can be stacked for a given project and portfolio to accelerate the best outcomes for all. Added project value can attract existing or new aggregators to deliver services to these otherwise underserved markets and also align with grid value.



The system benefit and any additional benefits the Commission recognizes could be forecasted by identifying pre-calculated load shapes for core measures or projected load impacts. The final payment would be for the delivered value based on actual load shapes and, where applicable, in response to load shedding events. Records of each transaction are maintained for audit purposes. **A dedicated ledger for any Demand FLEXmarket ensures accountability into the system, delivering revenue-grade confidence in the impacts achieved and the associated payments**.

The Demand FLEXmarket model is a great candidate for the Governor's call to action because **program administrators can directly buy the resource, not a program**. It can be scaled in a timely fashion, is directly tied to the base value the Commission has already identified for system benefits and has built-in accountability to ensure payments are only made for delivered savings. Taken together, Demand FLEXmarketplace offers the widest range of aggregators the maximum flexibility to aggressively pursue projects across the state on behalf of load-serving entities.

The accountability chain to delivered load shapes has to flow all the way to reporting impacts to the Commission. **One barrier for this market access model, and all population NMEC programs, is that as of today actual load shapes still cannot be claimed** with the current Cost-Effectiveness Tool (CET). Recurve requests that the Commission grant permission in this emergency for program administrators to use the open-source FLEXvalue calculation engine for calculating savings claims for population NMEC programs. Since outputs of the FLEXvalue calculation engine are fully compatible with CET outputs all necessary data would still be archived in CEDARS per the data specification.

Recommendation: *Utilize existing population NMEC guidelines as the default pathway for responding to the governor's proclamation. Enable the deployment of new market-access models derived from the Rulebook that:*

1. *Apply M&V consistently using open-source methods,*
2. *Mitigate risk to ratepayers with performance payments to aggregators based on system benefit delivered and include peak incentives*
3. *Provide an audit trail of change in energy consumption and record of payment for projects implemented.*
4. *Are eligible to claim all value streams in the current ACC (including low GHG refrigerants) and could accelerate implementation if an additional value is recognized for the urgency of resiliency identified in the Governor's proclamation.*
5. *Would make savings and total system benefits claims based on actual, delivered load shapes calculated in FLEXvalue and uploaded to CET.*

II. Suspend the cost test for two years; cap payments for delivered system benefits (per approved ACC and any adders the CPUC recognizes) quantified at the meter

The Governor's proclamation clearly lays out the urgency of system reliability in the short term. Demand-side resources need to deliver meaningful load reductions at scale for the State of California. To reach scale, the framework for deciding, parsing, and paying for system benefits from customers has to fundamentally change - but spending should go unchecked either. **Instead of using cost tests to control spending, capping payments to the value signaled by the Commission offers a streamlined, yet effective safeguard against ratepayer risk and allows a means of proper balancing with benefits.** If the Commission is paying no more than the system benefit for a project and it is paid upon delivery, the risk of non-cost effective implementation is limited.

Recurve has submitted extensive comments on how the Total Resource Cost test creates a penalty for co-investment and puts undue negative downward pressure on investments in energy efficiency. The **TRC's biggest flaw is that it discourages co-investment in energy efficiency**. Straightforward, logical programs like on-bill financing or home upgrades that leverage external capital are hobbled within utility programs because they illogically hamper portfolio cost-effectiveness. The governor's proclamation, as well as economic recovery initiatives that have emerged after the COVID-19 pandemic, highlight the importance and urgency of leveraging external resources for investments in infrastructure. A cost test that discourages this kind of collaboration will mean California's customers (participant ratepayers and non-participant ratepayers) will miss out on an important opportunity.

We have also clearly articulated why the Program Administrator Cost test (simply Total System Benefits divided by PA cost) is a more accurate reflection of how administrators could directly buy resources from the market. **As the concept of demand flexibility and the role of distributed energy resources matures, the limits of current cost tests to meet the objectives have been laid bare**. In 2019, a comprehensive paper on the issues of the total resource cost test was published[4] and since then other articles[5] have made compelling arguments and practical suggestions for updating this framework for the future. This emergency proclamation opens a window for truly unleashing potential when ratepayer funds are amplified with private clean energy capital investment.

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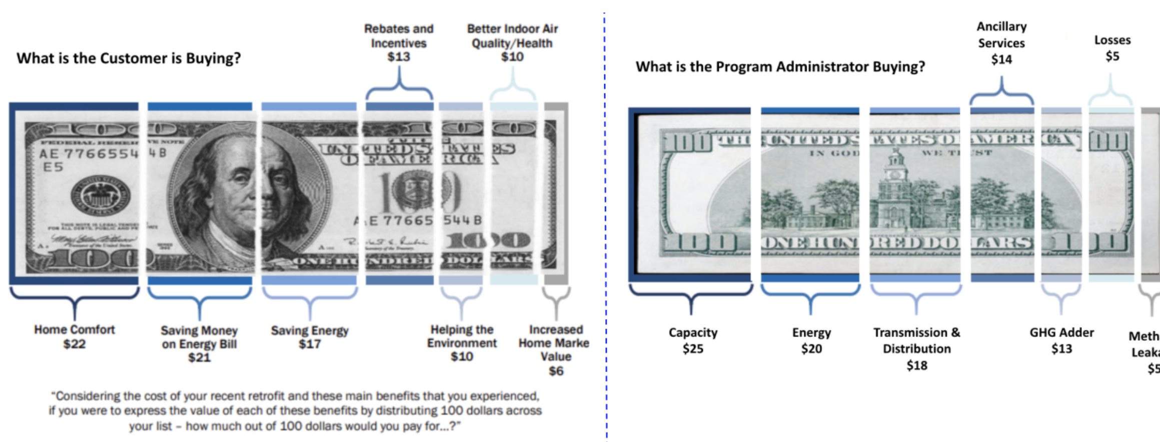
[4] Evolving Cost-Effectiveness Policy and Tools to Enable Modern Energy Efficiency and Demand-Side Management, Adam Scheer, 2019. Available at this link: https://www.recurve.com/blog/rethinking-cost-effectiveness-to-meet-the-needs-of-the-modern-grid

[5] Why a Bandage Fix for Cost-Effectiveness Testing Isn't Enough, Posted by Adam Scheer, Jake Millette, Olivia Patterson, and Julie Michals, Advanced Energy Perspectives https://blog.aee.net/why-a-bandage-fix-for-cost-effectiveness-testing-isnt-enough

Cost tests are primarily used to define budgets to procure forecasted resources (ex-ante basis), but they also have a role in understanding "did we get what we paid for" (ex-post basis). **In this expedited scenario of bringing resources online in the next year, incremental to the existing plans, the cost test could presumably play no role in an extended forecasting exercise.** The Commission must identify available budgets (or new funding streams) and point them toward a market access model of procuring efficiency and demand response resources. Alternatively, if the Commission needs to establish a new funding stream, like authorize utilities to create a memo account, they could initiate spending and performance payments (tied to system benefits) could serve as the basis for recovering the costs in future rate cases.

In the Demand FLEXmarket model, **aggregators are paid only up to the system benefit delivered**. As such, they are encouraged to leverage limited ratepayer-funded incentives to bring in private capital to make up the remainder. They are motivated to settle with customers at the lowest price point to stretch system benefits payments as far as possible for each project so they can maximize the size of their portfolio, because they are paid most when maximum performance of their portfolio is achieved at the lowest cost.

Because **customers will only be willing to pay up to the value of their bill savings, comfort, and other intrinsic and extrinsic motivations, aggregators have to meet them where they're at**. No centralized potential study, incentive program, or cost test can find this balance point on its own. Savings or demand impacts may be the same electrons, the value proposition to the customer versus the system are clearly delineated between parties:



The **cost of procuring the system benefit is competitively discovered** in the market. Take a similar example from D.21-05-031. The Commission recognized that competitively solicited third-party contracts should be exempted from zero-based budgeting requirements because 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 has to reconcile all of that against the system benefits rate paid based on portfolio performance.** Population NMEC programs shift risk to aggregators and their portfolio functions as a virtual power plant creating a cash flow anchored to the total system benefit. This payment 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.

The Commission also affirmed in D. 21-05-031 that their requirement to capture all cost-effective demand-side resources is the floor, not the ceiling, of potential necessary investments. **Suspending the cost test for performance-based programs with market price discovery will not unleash unjustified expenditures.** It will simply streamline the ability for program administrators to buy incremental resources from the market.

Recommendation: *Suspend the cost test for 2 years for population NMEC market access models; limit payments to delivered system benefits as defined in the approved ACC for energy efficiency with an accelerant value approved for the near-term urgency and for targeting specific market segments.*

III. Create a fast-track pathway for Community Choice Aggregators to Access Energy Efficiency and Demand Response Program Funds For Deploying 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. There are a number of potential explanations for this, but one 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.

With a streamlined path to aggregation, through the market-access model described in the first part of this proposal, **CCAs could quickly target, launch and contribute to meeting this emergency obligation with projects that would reduce load overall** via efficiency investments tied to the system benefit value, and build extra capability within the state to respond to events and improve reliability. CCAs could use similar criteria for events to extend the reach of efforts like the Emergency Load Reduction Program (ELRP) or to meet their own needs.

Eligibility criteria can ensure that participants are not already enrolled in system-wide DR aggregations that CAISO is counting on and the outcomes of these efforts would be quantified and available for consideration in the qualifying capacity considerations of the CEC to forecast load into the future.

Recommendation: *Suspend requirements for fully developed business plans for CCAs who wish to access funding for DSM programs. Proposals for a streamlined market access program model can be approved via Tier 2 Advice Letter (staff approval) for any CCA.*

IV. Redirect Budgets from Non-Resource Programs that Directly Align With the Emergency Order

Several non-resource program budget categories could justifiably be redirected to fund the emergency action called for in the Governor's proclamation and fund direct procurement via market access models. We cite three here, recognizing there may be more, with the rationale for deploying these budgets in an emergency toward delivering actual project savings in 2022 and 2023.

Integrated Demand Side Management (IDSM) historically has been a non-resource program. The purpose of the program has always been to address and overcome barriers to implementing integrated energy efficiency and demand response programs. In the current budget filings, many of the initiatives are already testing projects with RENs and CCAs. We propose that any statewide funds that are unspent in this category be redirected to fund projects for 2022 and 2023. For IDSM deployed locally, we encourage them to orient toward a performance design and report impacts achieved in 2022 and 2023 to contribute to the emergency response.

The **Emerging Technologies** program's mission is aligned with the emergency proclamation in two ways. First, the **purpose of the emerging technologies effort is to identify new and promising ways to capture energy savings for the future**. The market access model outlined in these comments is a great example of a new innovation. It also by its very nature of providing maximum flexibility to aggregators to deliver system benefits, attracts innovation by serving as a testbed. All of these new ways to optimize efficiency and demand response impacts for customers and for the grid are tracked and monitored at the meter to know what is working and what might not be delivering. The total 2021 Budget Filing was $15,868,567.

The **evaluation budgets** are another category of portfolio spending that is closely aligned with the Governor's proclamation. With a fixed percent budget (4% of the portfolio) one of the key objectives of these funds is to inform the California Energy Commissions load forecast. **Just a one year allocation of the evaluation budget could make a significant impact on delivering efficiency and demand reductions for this emergency.** If deployed using the market access model, program administrators and Energy Division staff could have first-hand experience in understanding how this model improves accountability, transparency and creates a streamlined feedback loop to the CEC's load forecast, not to mention comprehensive results. Energy Division staff could potentially have secure permissioned access to a market settlement platform to track the performance of the portfolios. [2021 Budget Filing: $24,376,998]

I. Leverage Existing Population NMEC Programs & Comments on Staff proposal for Smart Thermostats and Targeting

The staff proposal for Smart Thermostats (issued in R.20-11-003 but is directly relevant to energy efficiency issues) provides an interesting example to juxtapose and illustrate 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. It is interesting to consider that **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, that it currently costs about $222 on average to get a smart thermostat installed given today's program designs, and that 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.*"[6] As such, the staff proposal to couple the smart thermostat program with required demand response programs may indeed improve effectiveness by more fully utilizing their capabilities of smart thermostats. However, 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 illustrated in the Demand FLEXmarket model, 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 combination could perhaps even be a free smart thermostat coupled with any number of other technologies, such as replacing inefficient air conditioners with heat pumps.

In other words, a rebate-based program 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.

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

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 selection of customers with the highest CCD**. This approach sends a signal that 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 and customers. Programs focused on annual savings goals and technology deployment alone does not facilitate the alignment of these incentives. Targeting could get them partway there, but without aligned incentives around performance, it may only help on the margins.

It is also important to note that programs like Technology and Equipment for Clean Heating (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 the 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 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.

In the appendix we have include two proposals beyond the Demand FLEXmarket proposal that we believe will push more energy efficiency and peak impacts in 2022 and 2023.

These are both enabled through targeting, performance based payments, and integration of technologies across programmatic silos.

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

V. Conclusion

We are at a critical inflection point. Demand-side resources have been called to action to meet system reliability needs and our ability to respond, or not, will set the stage for our role in the future of a clean energy grid.

We believe that the core recommendation to establish a strong market-access oriented approach to procuring system benefits is one of the only ways to bring resources forward for the upcoming two years and will also have the benefit of setting precedent for a future of less bickering, lower overhead costs, and more demand-flexibility available to meet the needs of a decarbonized grid as well as provide the multitude of benefits to customers and the economy that we expect.

Recurve Analytics, Inc. appreciates the opportunity to comment and respectfully requests the Commission to consider the concerns raised herein. Please note that Recurve is submitting similar comments to the Commission via the R.20-11-003 proceeding summer reliability.

Dated: August 31, 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. Recurve is using the more detailed form to present the same proposal for expanding the market access model, Demand Flex Marketplace to parties in the energy efficiency proceeding as well as the summer reliability proceeding.

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.

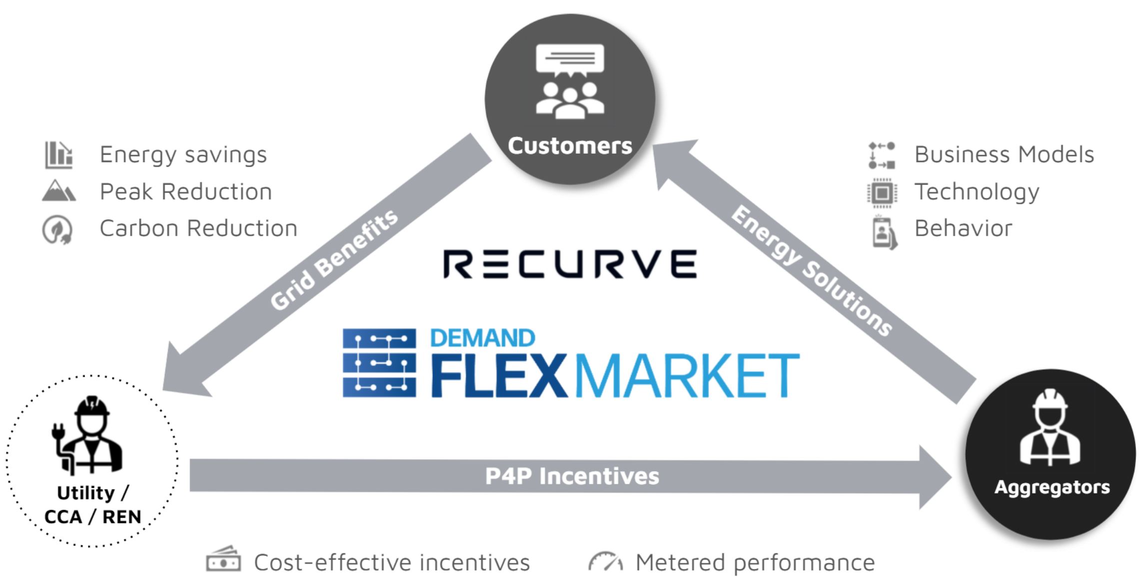


Figure X: Demand FLEXmarket Concept

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.

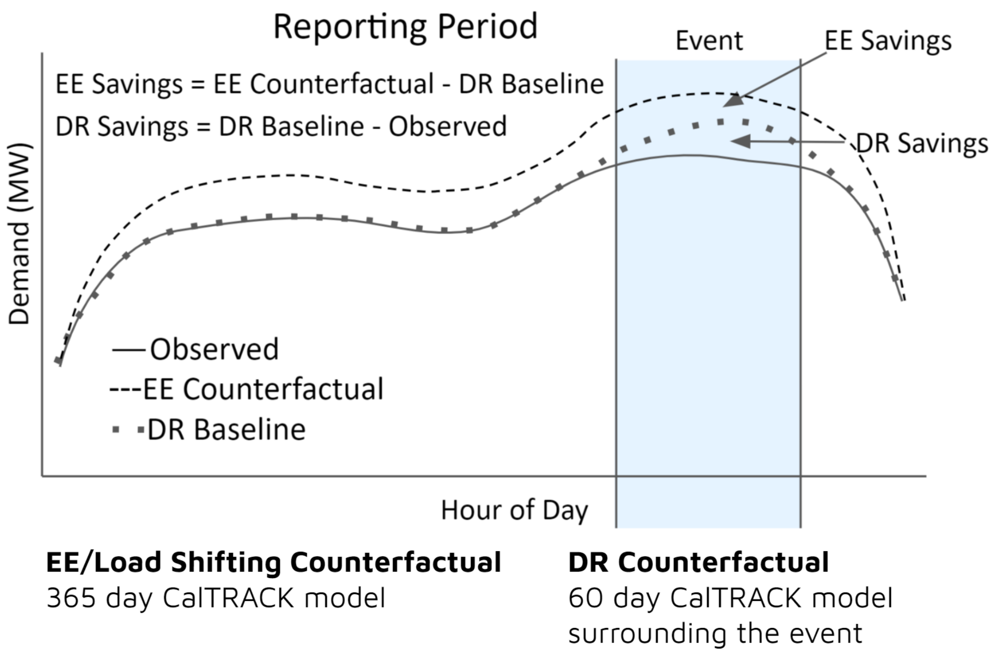


Figure X: Separating Energy Efficiency and Demand Response Savings

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.

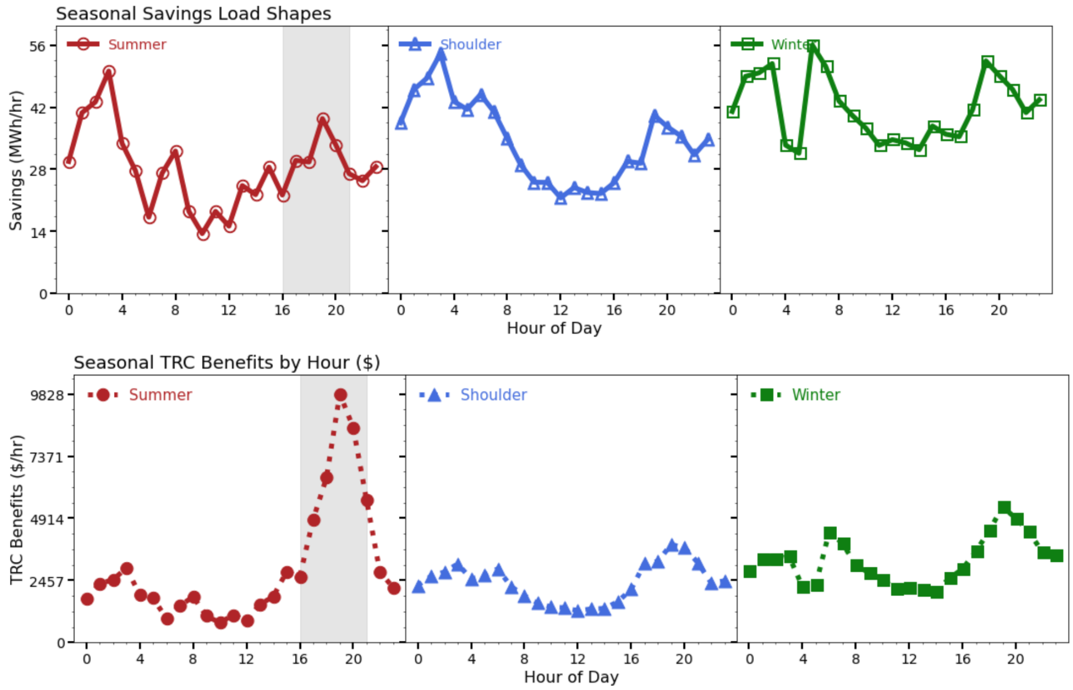


Figure X: Measuring Energy Efficiency Impacts at the Meter

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.

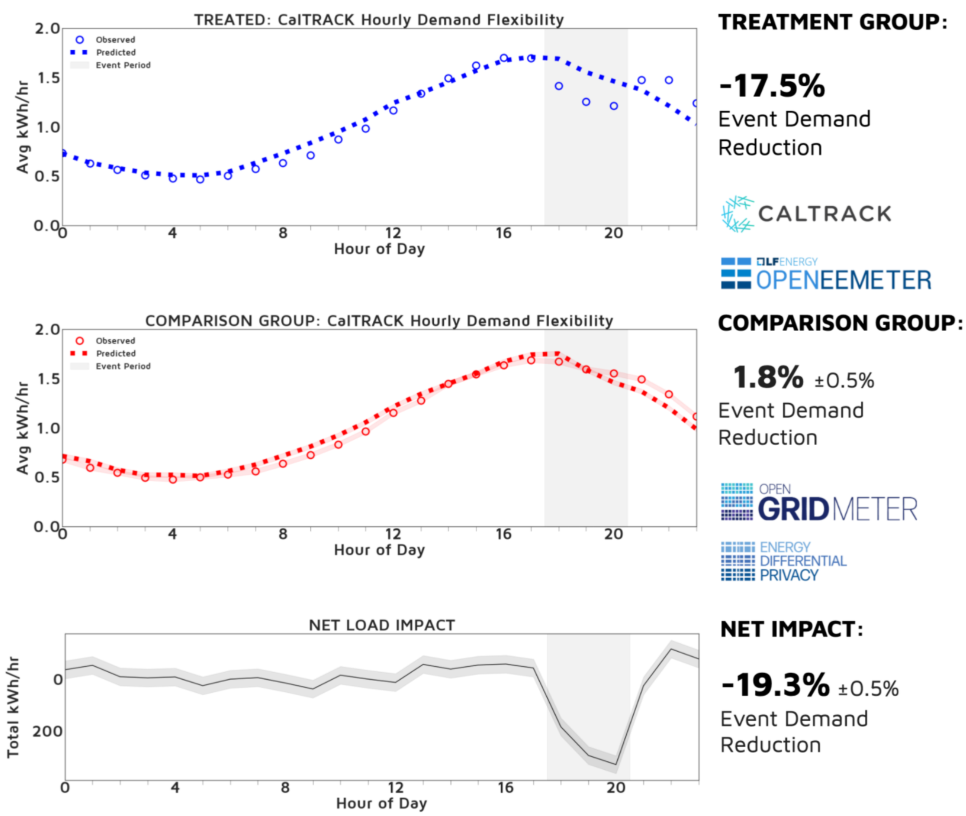


Figure X: Savings Calculation and Comparison Group Adjustment

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.

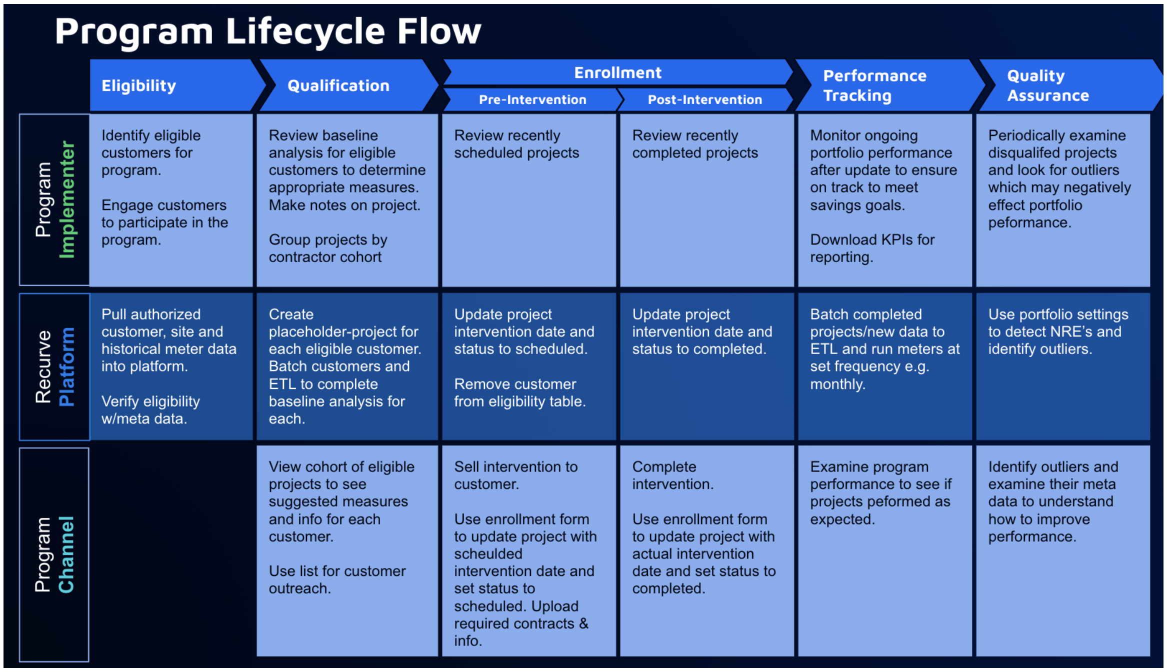


Figure X: Demand FLEXmarket Program Lifecycle Flow

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.

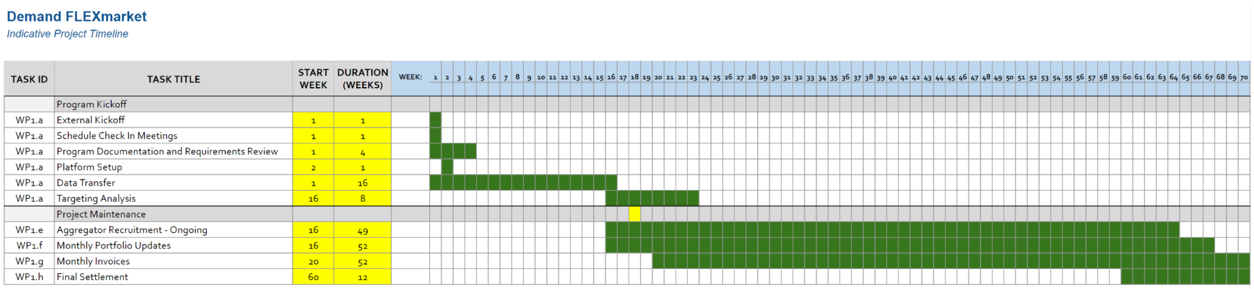


Figure X: Indicative Demand FLEXmarket Schedule

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. We use the more detailed form from the request for comments in R.20-11-003 to present the same proposal for expanding existing pay for performance programs and focusing on integration with TECH incentives.

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.

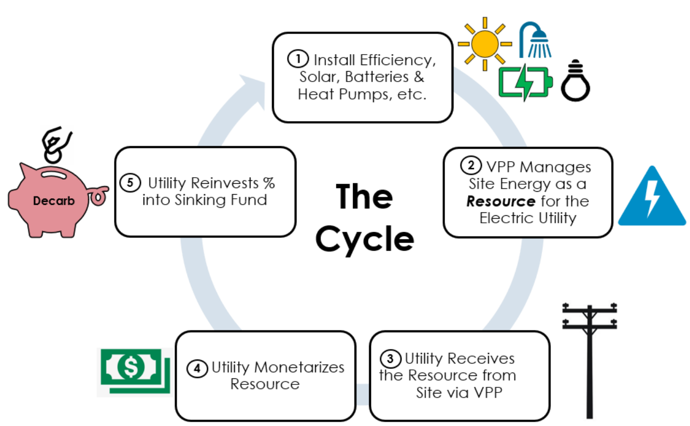
Appendix C. Proposal Breakdown: Multifamily Virtual Power Plant

Recurve is sharing this proposal in partnership with San Francisco Environment using the form requested in the energy efficiency proceeding.

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 program 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.

San Francisco Environment (SFE) intends to deploy the approach like a Virtual Power Plant (VPP). In this proposal, the market access model (Demand Flex Marketplace) would be augmented with an energy aggregators' software platform and services that can manage load directly. The initiative would be targeted at a portfolio of affordable, multifamily buildings. In this model, Recurve will partner with a local government entity (SFE), an affordable multifamily operator, and an energy aggregator to administer and implement the platform designated to enable the operation of the VPP.

The initiative 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.



To operationalize the proposed VPP concept enclosed herein, initially a single energy aggregator would 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 CPUC 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 marketplace reducing the performance risks associated with a single aggregator solution. Recurve and SFE can further define this future path in collaboration with the CPUC.

In summary, this VPP proposal initially provides a single aggregator transactional VPP pilot with a line of sight to expand into a multi-aggregator market-based solution 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.