

Demand FLEXmarket -- Creating a Market Access Model to Unleash Solutions Providers and Scale Demand Flexibility

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ABSTRACT

On December 2, 2021, the California Public Utilities Commission (CPUC) approved a unique solution to quickly deliver load reductions to the state in response to the Governor’s emergency call to action. In D.21-12-011, the CPUC allocated \$150 M to the newly named “Market Access” program as a primary means of addressing summer reliability concerns. The Commission cited the simplicity, flexibility, and scale that the program offers as reasons for adopting this model so quickly at scale. The origin of the “Market Access” program can be directly traced to the Demand FLEXmarket, which is a model for demand-side programs that combines pay-for-performance with an open market of qualified aggregators and implementers to deliver demand flexibility solutions to residential and commercial customers. Demand flexibility is energy efficiency, demand response, electrification, distributed generation, and storage working together to achieve a clean and stable grid. Demand FLEXmarket was first implemented with Marin Clean Energy (MCE) in 2021. The market saw its budget quintuple within the first year due to high aggregator interest and deal flow. This paper details the key attributes of the market access program that made it a compelling choice for emergency action and the details of the program design and implementation currently operating in California. This model delivers cost-effective savings without traditional prescriptive barriers. Payment is tied directly to Total System Benefits (avoided utility cost for each hour of the year). Utilities and other load-serving entities can design high-precision programs to achieve distributed energy integration, equity, and grid reliability goals. Incentivizing hourly impacts based on avoided costs creates value parity between demand flexibility and other grid resources as the time and locational value of energy savings moves to the forefront. In addition, the model is being applied directly to equity-focused programs by offering multipliers for income-eligible and hard-to-reach customers, incentivizing aggregators to target services to customer segments that have historically been ignored in traditional programs.

Introduction

With increased variable renewable generation, demand flexibility is a critical element for grid optimization. Demand flexibility, derived from energy efficiency and demand response, and coordination of other behind-the-meter distributed energy resources, can provide the time-delimited responsiveness for short and long-term load reductions. Meter-based quantification provides transparent, accessible analytics to track changes in consumption for both individual buildings and in aggregate. Reliable impacts support resource planning and facilitate performance-based transactions. When meter-based quantification is used in a market-based framework, it supports the ability to quickly scale by drawing in new market actors and improving accountability. Such market-based solutions for decarbonization and grid stability

have a unique ability to scale and ensure demand-side resources can make a meaningful contribution to the grid while still supporting policy goals of equity and market transformation.

Background

On July 30, 2021, California Governor Gavin Newsom issued an emergency proclamation¹ regarding the pending 3.5 GW shortfall of electricity resources in 2022 and 2023. In the proclamation, he called on all California state agencies responsible for energy policy to do everything they can 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." At the California Public Utilities Commission, several proceedings created special tracks to solicit ideas and deliberate on urgent emergency action. The long-standing energy efficiency proceeding (R.13-11-005) initiated the process with an Administrative Law Judge ruling on August 6, 2021.² Among the proposals, parties widely supported a relatively new model, the Demand FLEXmarket, for its ability to scale, bring new market actors to contribute to solving this urgent problem, and for its built-in accountability. It is being tested at scale in 2022 and 2023.

The Demand FLEXmarket, in its original and now emergency form, was designed to address three historic barriers to energy efficiency implementation in California. The FLEXmarket model also addressed discrete challenges of an emergency deployment of demand-side resources. Each component is described in more detail in this paper.

First, California's "winner-take-all" third-party procurement processes have become untenable. Procurement processes for statewide and utility-level implementation of programs require very long time frames due to stakeholder engagement requirements, independent review, and other factors. Implementers submitting proposals, as a result, take on the substantial risk of stranded costs if they are not a winning bidder. Ultimately, this process can lead to significant underutilization of qualified firms to deliver energy efficiency value. In addition, smaller utilities or load-serving entities like community choice aggregators face barriers to accessing innovative solutions for their customers due to their small footprint and budgets. As the options for customer energy management solutions continue to widen, program administrators are concerned about locking in solutions or vendors that may quickly become outdated. In a market-access model, like FLEXmarket, a wide range of aggregators and implementers can enter the market by demonstrating minimum qualifications and get started delivering demand flexibility of almost any sort. All market participants are paid based on their aggregate performance at the meter, based on the hourly fixed base price for grid value.

Second, cost-effectiveness tests that penalize participants' private capital contributions have led to underinvestment in energy efficiency as a grid resource in California and presented a significant risk to taking action in an emergency. In the Demand FLEXmarket, prudent spending is managed by limiting the direct payment to the aggregator against the Commission's approved value stream minus the administrative costs. In the non-emergency implementation of the program, the participant investment must still be considered. Still, project cost-effectiveness is visible to aggregators upfront so the program can be designed with a cap at a prescribed cost-

¹ EXECUTIVE DEPARTMENT STATE OF CALIFORNIA PROCLAMATION OF A STATE OF EMERGENCY, July 30, 2021. <https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf>

² August 6, 2021 Administrative Law Judge E-MAIL RULING REQUESTING COMMENTS/PROPOSALS TO ADDRESS GOVERNOR'S PROCLAMATION OF JULY 30, 2021 <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M398/K290/398290583.PDF>

effective level. In this model, it is also possible to waive the cost-effectiveness test and instead cap payments at delivered system benefits (determined using the approved avoided cost value for energy efficiency and quantified at the meter.) Waiving the cost test was the path adopted by the CPUC for the emergency implementation of the market access program and is well aligned with treating demand flexibility as a “purchasable” resource. Capping payments at net benefits may be exceptionally suited to jurisdictions that set goals or performance payments based on net system benefits instead of annual savings.

Third, integrating distributed energy resource solutions for customers has proven difficult. Several years of Integrated Demand Side Management programs have not managed to “crack the nut.” Since the Demand FLEXmarket quantifies demand flexibility consistently and transparently across energy efficiency, demand response, electrification, electric vehicle charging, battery storage, or all combined, it helps break down the valuation silos. With a common valuation stream and accounting framework, the Demand FLEXmarket offers a means of operationalizing the vision of integrated demand-side resources for customers and the grid. This common accounting was enabled in California with the passage of SB350 and AB802 in 2015³ paving the way for meter-based accountability for energy efficiency in California, but the majority of the portfolio continues to rely on deemed incentives and savings estimation. Demand FLEXmarket offers a program design that more effectively supports the critical attributes of Normalized Metered Energy Consumption (NMEC) adopted in the legislation as it is technology agnostic, directly aligned with peak value, and mobilizes direct market action.

Facilitating Market Access to Scale Demand Flexibility

One of the biggest challenges facing regulators and utilities alike is when they are called on to quickly accelerate their savings goals or decarbonization impacts. The pace at which actual projects need to come online can be daunting, especially when facing an emergency energy shortfall. In California, complying with third-party procurement protocols means designing, reviewing, procuring, and finally launching a new energy efficiency program can take three or even four years. Much of this timeline is driven by the expectation that large-scale third-party and statewide programs will be awarded to one firm and the caution associated with “getting it wrong” when millions of contract dollars are at stake. 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 facing an emergency, the California Public Utilities Commission pointed out their preference for the streamlined deployment of resources and accountability. The Demand FLEXmarket proposal was generically called the “Market Access” program in the final decision. The market access model offered a solution that could bring all hands on deck to deploy new resources quickly:

“The concept behind this program is that it utilizes population-level [Normalized Metered Energy Consumption] NMEC rules and a [pay for performance] PFP concept to incentivize implementers to find energy efficiency projects that deliver measurable peak or net peak demand savings.”

³ [SB-350 Clean Energy and Pollution Reduction Act of 2015. \(2015-2016\)](#) and [AB-802 Energy efficiency. \(2015-2016\)](#)

AND

“The major benefits of the program are that funds are only expended for portfolios of projects that deliver verifiable energy savings at peak times. In addition, any implementers that can deliver those savings and meet standardized eligibility criteria will be able to participate in this type of standardized program.” CPUC in D.21-12-011

Key Attributes of the Market Access program model

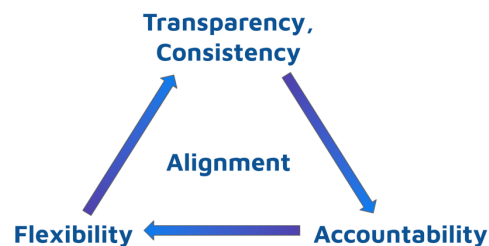
Three core attributes help to define the market access model and its predecessors:

1. **A clear price signal:** In California, the Avoided Cost Calculator (ACC) provides a direct system value/price signal that can be calibrated to the urgency of the resource need and augment other value streams recognized in the jurisdiction (i.e., equity, environmental justice, health, etc.)

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 around which programs and projects can be directly built. Since California has already adopted Total Systems Benefit as the key metric for assessing goals for the energy efficiency proceeding starting in 2024, beginning to use the ACC value for program design now supports this transition. The ACC and the TSB offer a streamlined way to consider and reconcile the multiple benefits realized by energy efficiency and other demand flexibility solutions. The expectation to deliver demand flexibility in the form of overall load shape reductions, load flexibility shifts, and responsive reductions in 2022 and 2023 mean the total system benefits metric is one of the only ones available to track impacts accurately.

2. **Aligned incentives:** Meter-based performance programs designed around Population NMEC rules⁴ align incentives to purchase the system value from customers directly.

Meter-based performance, implemented 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 bear performance risk across their portfolio of projects, aggregators are motivated to ensure proper and effective installation. Requiring



⁴ The NMEC Rulebook is available on the CPUC's Rolling Portfolio Guidance page: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/rolling-portfolio-program-guidance>

consistent, transparent, and repeatable measurement and verification (in an open-source code-base) mitigates the administrative overhead of having to review custom models. No change to the NMEC Rulebook was necessary to support the acceleration of projects per the Governor's proclamation, except for the treatment of participant costs described later.

Embedded measurement and verification provides accountability for tracking outcomes of spending. Meter-based tracking also supports an actuarial feedback loop to provide a more reliable analysis for forecasting and coordinating the combined potential of demand flexibility (efficiency and demand response) impacts in the future. These concepts are not new, but are optimized in the Demand FLEXmarket because of the tight connection between performance payment and program optimization.

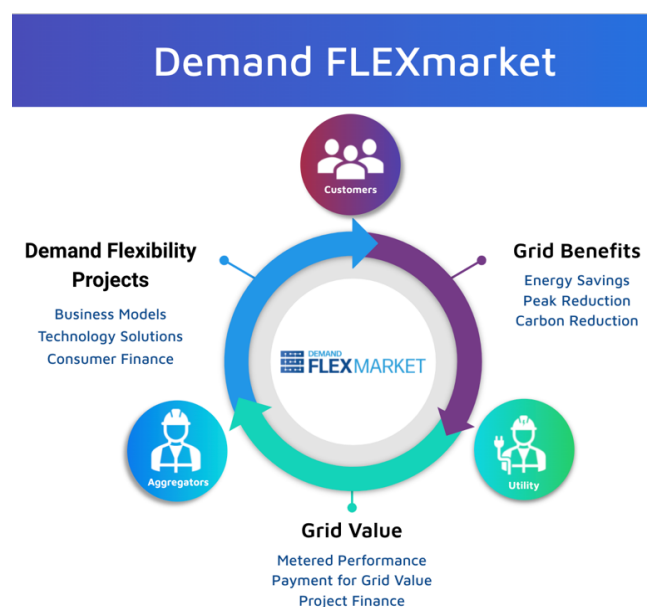
- 3. Facilitate Direct Purchase of Demand Flexibility:** Market-access models, like Demand FLEXmarket, enable utilities or other program administrators to purchase system benefits directly. Impacts can be dependable, as they are grounded in performance-based accountability (only paying for the benefits delivered) and have an audit trail to document each intervention and the resultant outcomes.

Operations of a Demand FLEXmarket

In a Demand FLEXmarket, an implementation of the market access model, all qualified providers can submit projects to build a portfolio. MCE, California's first Community Choice Aggregator, pioneered the deployment of this model in 2020. Facing challenges with delivering cost-effective commercial programs, recruiting implementers, and wanting customers to have greater access to innovation, MCE proposed and was approved to launch the Commercial Flexibility Marketplace as part of their commercial energy efficiency portfolio.⁵ A low barrier to entry, therefore, was essential to success.

Pricing and contracting

Aggregators sign a standardized contract ("Flexibility Purchase Agreement"), that articulates the terms for payment, the pre-defined and standardized measurement and verification for establishing performance.⁶ In the original program design, the base price per kWh was



⁵ The original implementation plans and M&V plans for MCE's Commercial Marketplace are available on the California Energy Efficiency Coordinating Committee review page see MCE's plans presented November 2020. <https://www.caeccc.org/draft-implementation-plans-for-revi>

⁶ Per [Population NMEC rules](#) the M&V plans are filed with the program plan and must be applied consistently to all projects in the portfolio.

formulated from the system benefits (avoided cost value) with a deduction for administration, tracking and monitoring of projects per the M&V plan. Adaption of the model to address emergency reliability will include a significantly larger incentive for load reductions that happen from 4PM – 9PM from June to September, as prescribed in the Commission decision. An example price curve is illustrated in Figure 1.

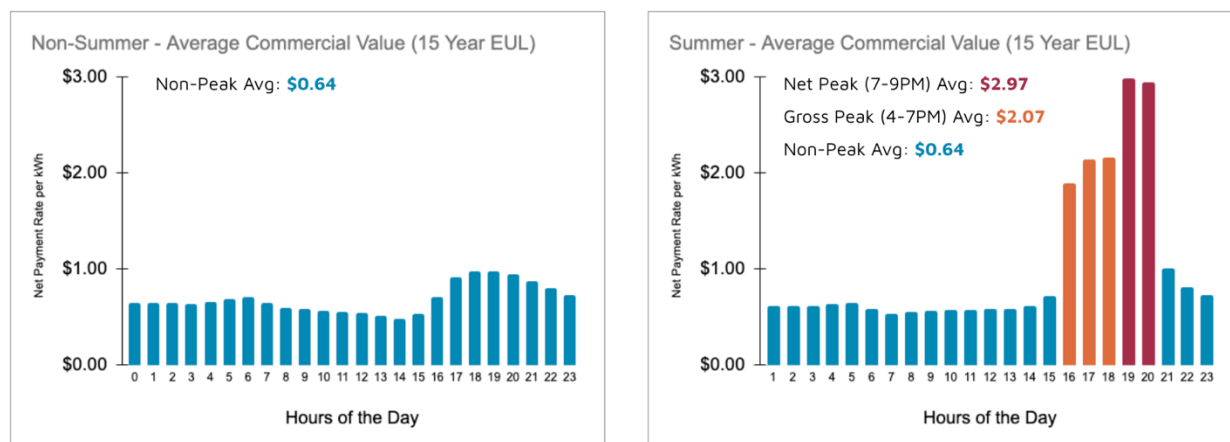


Figure 1. Illustration of the price distribution for typical long term project (actual price varies by market)

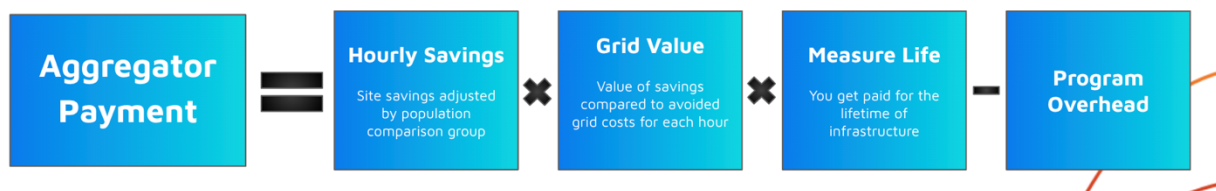


Figure 2. Basic Aggregator Payment structure

In a Demand FLEXmarket, a single aggregator can deliver both efficiency and demand response impacts and be compensated for the combined effect of load reduction and load shifting in relation to the avoided cost curve. This approach opens the opportunities for demand response and energy efficiency providers to expand the scope of their customer services based on the value delivered to the customer and the grid.

With the streamlined, standardized pricing and ease of contracting, 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 a Flexibility Purchase Agreement (FPA). The FLEXmarket currently has over 50 aggregators with signed FPAs and roughly 30 are actively preparing projects to be online in time to support summer reliability in California. The market access model may be one of the most straightforward and timely ways for program administrators and aggregators to identify and deliver projects in a short time frame.

Forecasting and other resources for aggregators

Forecasting likely impacts at the project level are the responsibility of participating aggregators in the market. Aggregators actively assess the potential via audits or past similar projects as they interact with customers. Translating these forecasted impacts into a dollar value

and a projected cash flow is facilitated with tools that are accessible to the aggregators once they've signed an FPA. For valuation, aggregators have access to a project value estimator that allows them to quickly assess the avoided cost value of their proposed projects and scope out business plans for targeted market segments. More detailed analysis used to forecast portfolios is available by using a cost-effectiveness calculation engine. The FLEXvalue calculation engine⁷ is an open-source cost-effectiveness code base, that enables program administrators and aggregators to assess the forecasted and delivered system benefits of projects in direct relation to the cost effectiveness rules applicable to the program. It is designed with comparability and compatibility with the Cost Effectiveness Tool (CET) required by the California Public Utilities Commission for final cost effectiveness calculations for savings claims.

Other prospecting tools and support for aggregators include the review of consumption data (only with proper data security clearance) to prioritize customer targets and, if desired, utility co-branding. A 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 quarterly based on seasonal performance for peak impacts and trued up with one year of demonstrated performance.

Tracking performance and delivered value

Once projects are enrolled, the market manager tracks the net hourly performance of portfolios of projects in relation to their system benefits. Tracking every enrolled project and its progress is viable today using the open-source measurement suite of CalTRACK, OpenEEmeter, and GRIDmeter comparison groups all of which have grown out of industry best practice in measurement and verification.⁸ The final payment in the Demand FLEXmarket is for the delivered value based on actual load impacts.

By design, the utility, regulator, and aggregators all have a clear audit trail of each project and the full portfolio of delivered impacts. This provides a solid basis for program administrators to pay aggregators based on the actual load impacts delivered. Records of each transaction are maintained for audit purposes. A dedicated ledger for the Demand FLEXmarket ensures accountability in the system, delivering revenue-grade confidence in the impacts achieved and the associated payments. This structure provides built-in accountability to ensure payments tied to delivered impacts which is fully auditable by the program administrator or their regulators.

Since aggregator payments are calculated directly from the system benefits delivered (i.e. avoided cost value), the performance of these projects is tied right back to the CPUC's approved value for grid impacts. As noted in the pricing section, the Commission, in D.21-12-011, allowed program administrators to propose amplified value (i.e. price signal) for the short-term delivery of system reliability in 2022 and 2023. The Commission capped the payments at the current Total System Benefit but allowed re-distribution of value from "off" hours to be pushed into the summer peak hours. The additional value creates an extra incentive for aggregators to deliver impacts from peak 4-9 PM and even more at net peak 7-9 PM. Each market establishes its price for those periods to calibrate it to its "right number" based on the cost of potential system instability and other market factors that may motivate aggregators.

⁷ More information about the FLEXvalue calculation engine and the operational work book is available at: <https://flexvalue.recurve.com/>

⁸ The full suite of open-source methods and code base can be accessed at: <https://www.recurve.com/open-source>

Some non-emergency Demand FLEXmarkets operating in California offer an accelerated value to ensure that customers in targeted communities are fully included in the clean energy future. Program administrators add kickers into the project value for aggregators when customers in designated “Disadvantaged Communities” or “Hard to Reach” populations are enrolled. In addition, some program administrators that also have economic development goals and are considering offering premium value for locally based contractors and aggregators. The value assigned is up to the program administrator and can be coupled with other funding sources they may have at their disposal. The grid value or Total System Benefit serves as the base price, and the cost for achieving other policy objectives is stacked on top. As noted in the illustration (Figure 3), each portfolio objective has value. The potential value can be stacked for a given project and portfolio to accelerate the best outcomes. Added project value can attract existing or new aggregators to deliver services to these otherwise underserved markets and align with grid value.

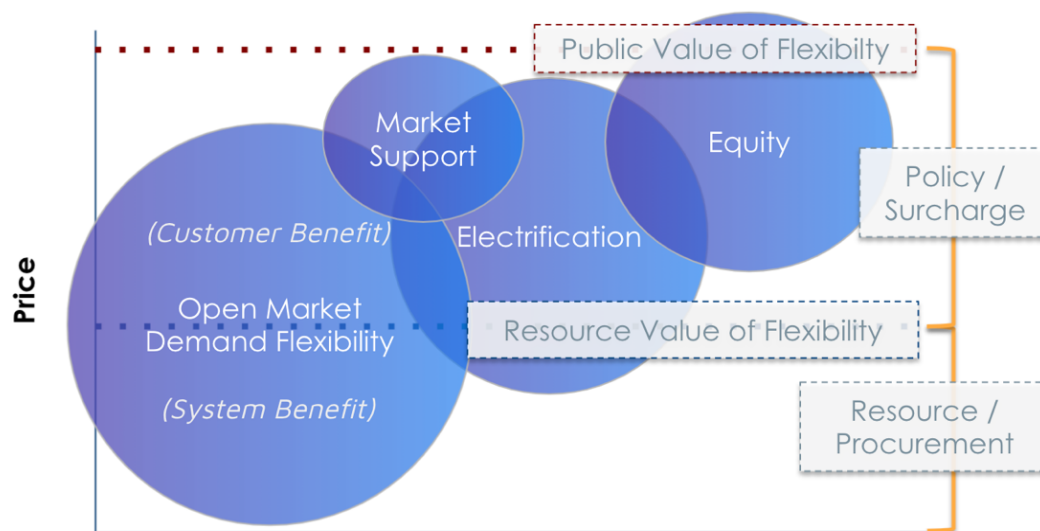


Figure 3. Stacking value for performance beyond grid benefits

Market Access Model Balances Costs and Benefits

One of the reasons MCE initially adopted the Commercial Flexibility Marketplace was to leverage a program design that offered more predictability in achieving cost-effectiveness targets. Since the original program was still bound by the Total Resource Cost test, which in California discounts participants’ private contributions against the benefits, they needed a way to have greater confidence their portfolio would not keep coming up short for ratepayers based on this metric.

Optimizing the cost test

MCE adopted a payment model in which the minimum efficiency payment was based on the forecasted fixed rate of the projected value (avoided cost benefit net of customer and administrative costs) of projects in the portfolio divided by the portfolio savings. Aggregators are paid for their portfolio per kWh or therm achieved in the first year following project completion

based on the metered savings achieved and the deemed load shape. The efficiency payment was set at net of the upfront customer contribution to the cost of the project and administrative costs to support cost-effectiveness. A second, flexibility payment was available to aggregators that demonstrated that the actual savings and actual load shape deliver higher net benefits than the deemed forecasted value. The flexibility payment is also net of the upfront customer contribution to the cost of the project and administrative costs to support cost-effectiveness. The Aggregator was not eligible for either the efficiency or flexibility payment if the net benefits from their portfolio did not exceed the corresponding costs, including the energy-related customer (participant) cost and implementation costs. In sum, payment for a project will never exceed the net total system benefits delivered by a project and therefore is effectively guaranteed to stay under a 1.0 benefit/cost ratio.

The payment structure has since evolved to simply be a single payment. The payment is based on the value of any hour on the avoided cost curve, with discrete, amplified incentives for peak periods, but the foundational principle that payments can never exceed the system benefits delivered stays intact. Having a mechanism for costs not to exceed benefits in the program's operation is a significant advance in mitigating ratepayer risk for delivered value from demand flexibility programs. It offers a much more streamlined means of directly purchasing grid value from customers without trying to parse the value accruing to customers versus value accruing to the system.

Waiving the cost test

One of the most striking concepts adopted in the emergency Market Access program in California was the CPUC's decision to waive the use of the cost tests. The CPUC chose instead to cap payments at the Total System Benefits to control spending. This solution offered a streamlined yet effective safeguard against ratepayer risk and allowed a means to balance payments with benefits properly. The Commission reasoned that as long as rate-payers pay no more than the system benefit and only pay for it upon delivery, the risk of runaway or wasteful spending is limited. No other program solution offered in the emergency proceeding had such a safeguard on delivered value.

Many jurisdictions have adopted a Program Administrator Cost test to better reflect how utilities or load serving entities could directly buy resources from the market. But with the market access model, it may be worth considering the potential limits of current cost tests (TRC, PAC or otherwise) to meet the objectives of market integrated demand flexibility. In 2019, a comprehensive paper on the issues of the total resource cost test was published, and since then, other articles have made compelling arguments and practical suggestions for updating this framework for the future.⁹ This emergency proclamation opened a new opportunity for unleashing potential by allowing ratepayer funds to be effectively combined with private, clean energy capital investment.

⁹ 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> AND 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>

Traditionally, cost tests are 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). The cost test could presumably play no role in an extended forecasting exercise in an expedited scenario of bringing resources online in the next year. Suppose utilities or Commission can have budgets or identify new funding streams for decarbonization or resiliency. In that case, they could leverage a market access model to deploy as many demand flexibility resources as the value stream allows, up to the budget cap. Given the typical delays in program design and launch, this more nimble approach may also be extremely useful when budget surpluses are identified and targeted at clean energy. This mechanism may also be amenable to hesitant Commissions that only want to fund delivered value. In such cases, Commissions could authorize utilities to create a memo account, to allow initial spending and performance payments (tied to system benefits) but then apply to recover the costs in future rate cases based on the delivered performance. No complicated cost test is necessary in either case.

A natural balance for price discovery

In the Demand FLEXmarket model, aggregators are paid only up to the system benefit delivered. As such, aggregators 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 and maximize the size of their portfolio. They are paid most when the 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 independently. Savings or demand impacts may be the same electrons, but the value proposition to the customer versus the system is clearly delineated between parties:

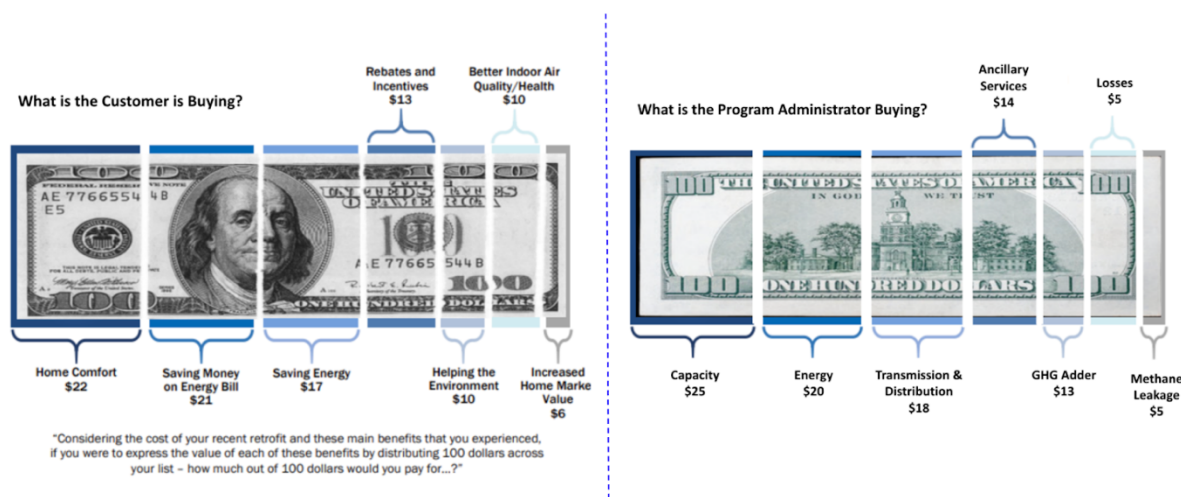


Figure 4. Benefits to Customers and Benefits to Program Administrators

The cost of procuring the system benefit is competitively discovered in the market, even though the regulatory body fixes the total value via the avoided cost calculator assumptions. Much like the logic applied in [D.21-05-031](#) where 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 likewise represent the "per se" reasonable market rate for resource procurement. 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 those factors alongside the system benefits rate paid based on portfolio performance.

It is important to acknowledge that 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 is isolated from the customer benefits and costs 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. 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 necessary potential investments. Suspending the cost test for performance-based programs with market price discovery will not unleash unjustified expenditures. It will simply streamline the ability of program administrators to buy resources directly from the market. It is a unique feature of this program design and may make it more synergistic with other programs.

A path for technology-agnostic demand flexibility

In the Demand FLEXmarket, the demand side management industry has a pathway for delivering integrated flexibility solutions. The market incentivizes outcomes, not specific technologies. The value of improved thermal resilience and avoided energy use, for example, could be captured with insulation and windows or perhaps just one of these elements. Similarly, the wide variety of grid value from electric vehicles can be captured via managed electric vehicle charging, backup power, and coupled (or not) with any number of other solutions to take customers on a grid-supportive decarbonization journey.

Early models of the Demand FLEXmarket have largely been constrained and contained by their funding "home" of energy efficiency. While the options to engage with any given customer are almost infinite, payments and rebates allowable in any program silo are typically limited. The initial implementation of the Commercial Demand Flexibility Marketplace with MCE did not prescribe technologies but defined "anchor" technologies to establish the price per kWh given a deemed load shape. Aggregators are allowed to implement multiple efficiency measures but do not offer incentives for battery storage or managed electric vehicle charging. The emergency adaptations of the Demand FLEXmarket in California have expanded the scope of possible interventions to optimize payment against the peak enhanced avoided cost curve. Interventions can include energy efficiency and demand response together or alone. However, if they are funded through different streams, the impacts must be differentiated to mitigate dual

payment. Specifically, the Commission directed program implementers to include in their plans:

Description of any plans to integrate long-lasting energy efficiency deployment with other opportunities like demand response, and including a description of how measurement of energy efficiency and other savings will be disaggregated and paid for;
D. 21-12-011 at p. 29.

MCE¹⁰ tackled this question with a phased approach. In the first phase (year 1) they will identify load reductions occurring during specified Peak FLEXmarket demand response event days, and will be blacked out from M&V of MCE's energy efficiency marketplace programs. Savings and value recorded from event participation will be measured and compensated through Peak FLEXmarket. They will not compensate aggregators under the efficiency market programs for these days, just the peak program.

In the second phase (year 2), on Peak FLEXmarket's DR event days, DR impacts will be disaggregated from energy efficiency impacts using comparison group selection, meter level energy efficiency baselines, and adjusted counterfactuals in the same way as would be done for energy efficiency-only projects. However, a separate DR counterfactual is generated via the FLEXmeter methods¹¹ (using the 45-day pre-event and 15-day post-event data with blacked out event days). In this approach, hourly efficiency savings are determined as the difference between the energy efficiency counterfactual and the demand response counterfactual. The load reduction assigned to the demand response intervention is then the difference between the demand response counterfactual and observed usage. The disaggregation method selected will be based on factors such as energy efficiency intervention start dates relative to demand response event periods and the timeline for supporting software development. The figure (5) below provides a schematic to delineate the components of a combined efficiency and demand response saving calculation.

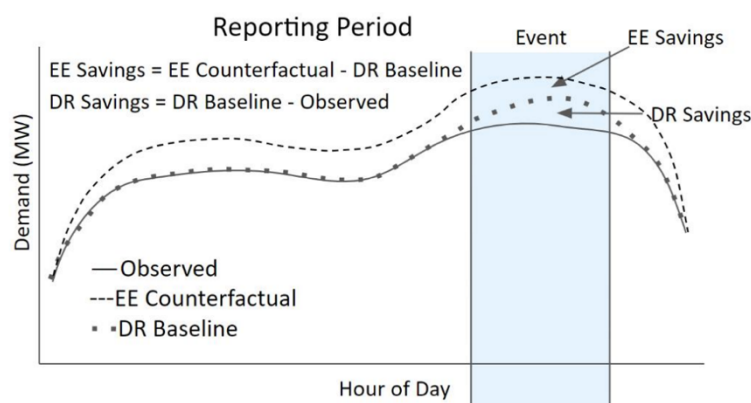


Figure 5. Disaggregating energy efficiency and demand response impacts

¹⁰ See MCE's Commercial M&V Plan MCE Commercial Marketplace Implementation and M&V Plan, May 2022. <https://cedars.sound-data.com/programs/MCE02d/details/>

¹¹ Glass, Joe, et. al. *Demand Response Advanced Measurement Methodology: Analysis of Open-Source Baseline and Comparison Group Methods to Enable CAISO Demand Response Resource Performance Evaluation*, CAISO - Recurve, 2022 <http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=F6490091-F3AC-4F36-AB16-FA212D5EB0D1>

In addition to harmonizing energy efficiency and demand response, other distributed energy resources that are typically cordoned off to other programs may also be funded under the emergency versions of the FLEXmarket. Battery storage, EV charging, electrification, and combinations of other technologies may be deployed together to maximize performance against the common avoided cost curve. While energy efficiency investments can still qualify for payment of the lifecycle value of the intervention, other technologies that are focused on managing usage are eligible for single-year performance payment with the option to re-enroll.

For future demand flexibility, procurement options that enable multi-technology solutions for customers will be essential. To date, this barrier has been largely insurmountable and may continue to be so if regulators and program administrators are constrained to single-technology-focused program silos.

Conclusion

The Demand FLEXmarket is in its nascent stages of implementation. The future will hold many lessons for the effective deployment of the model. However, the core barriers to program administration and implementation it is designed to overcome will not go away on their own. The California Public Utilities Commission's bold action to test the model in response to an emergency will be a chance also to push the boundaries of core policies and practices that have become the mainstays of the energy efficiency implementation and evaluation industry. Centralized program planning with little accountability for outcomes, overwrought technical specifications with hyper stringent cost-effectiveness limitations, and barriers to integrated solutions for customers will not scale in the future. This model offers direct strategies to streamline and animate a wide range of targeted interventions needed to optimize grid performance.

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