Rate Rhythms: Orchestrating Solar, Storage, and Load Shifting Under Dynamic Pricing

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ABSTRACT

Emerging near–real-time dynamic retail rate structures such as California's CalFUSE proposal offer a pathway to better align energy use with grid conditions while accelerating the deployment of distributed energy resources. This paper investigates how load battery storage paired with solar photovoltaics can respond to dynamic pricing signals.

Using an hourly simulation framework applied to representative residential building archetypes, we develop price-responsive dispatch strategies that optimize both storage dispatch and load control against forecasted real-time rates. This approach enables flexible loads and storage assets to shift consumption away from high-price periods and absorb excess renewable generation when prices are low.

We quantify customer bill impacts by comparing tariff expenditures under static and dynamic rate schedules. Greenhouse gas emissions are assessed by mapping marginal emissions factors to hourly consumption, revealing how flexible operations influence environmental outcomes. Utility system benefits are evaluated through avoided costs and reductions in peak demand. This study highlights conditions under which rate designs can unlock multiple value streams for end-users and utilities.

Our findings will inform rate designers, technology developers, and policymakers on structuring dynamic tariffs to catalyze distributed resource integration. The paper concludes with practical recommendations for grid–interactive controls implementation, identifying key considerations for pilot programs and large-scale deployment strategies.

Introduction

The rapid expansion of distributed energy resources (DERs) across California's electricity system has exposed fundamental limitations in traditional retail rate structures. Flat and tiered volumetric rates, designed for an era of passive consumption, provide neither the price granularity nor the temporal signals needed to coordinate the growing fleet of rooftop solar, behind-the-meter storage, electric vehicles, and smart appliances that increasingly populate the distribution grid. As California pursues its mandate of 100 percent clean electricity by 2045, the mismatch between static pricing and dynamic grid conditions is becoming a central obstacle to both reliability and decarbonization. (CEC 2021).

California's response to this challenge has unfolded through two parallel but increasingly intertwined regulatory tracks: the gradual maturation of time-varying retail rates and the emergence of a more ambitious transactive pricing architecture known as the California Flexible Unified Signal for Energy, or CalFUSE.

From Time-of-Use to Real-Time Pricing

California's engagement with time-differentiated retail rates spans several decades. Early time-of-use (TOU) pilots for large commercial and industrial customers in the 1980s and 1990s established the basic principle that price signals could elicit load response, though adoption remained limited by metering constraints and the complexity of customer-facing rate structures. The deployment of advanced metering infrastructure across the state's major investor-owned utilities (IOUs) in the late 2000s and early 2010s—covering the service territories of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)—removed the technical barrier to hourly pricing for mass-market customers and set the stage for broader rate reform.

The California Public Utilities Commission's (CPUC's) residential rate reform proceeding, initiated under Assembly Bill 327 (2013), accelerated TOU adoption by authorizing default TOU enrollment for residential customers. By the late 2010s, all three major IOUs had implemented or were piloting default TOU rates, and real-time pricing (RTP) experiments for commercial and industrial customers had demonstrated meaningful load response in response to price variation. Yet these efforts remained constrained by rates that reflected temporal differentiation without capturing the full marginal cost of serving load at each location and hour, including the distribution capacity costs that increasingly dominate utility cost structures as DER penetration rises.

The CalFUSE Framework

The conceptual foundation for CalFUSE emerged from CPUC Energy Division staff work on advanced demand flexibility management, published in a white paper released in June 2022 (CPUC 2022). The framework was designed as a policy pathway intended to be "standardized, easy to implement, and allow the industry to develop low-cost, flexible demand management capabilities and integrate them into smart end-use devices and DERs by default for use by all customer classes." Rather than layering additional program overlays onto existing rate structures, the staff proposal envisioned a six-element architecture that would progressively deepen the alignment between retail prices and real-time grid conditions. The six elements are:

1) standardized, universal access to the current electricity price;
2) dynamic electricity prices based on real-time wholesale energy cost;
3) modified electricity prices incorporating dynamic capacity charges based on real-time grid utilization;
4) transition to bidirectional electricity prices;
5) a subscription option based on customer-specific load shapes; and
6) transactive features enabling customers to lock in future electricity prices.

Together, these elements are designed to be available on an opt-in basis, allowing customers to selectively engage based on their capabilities and risk tolerance while ensuring that price signals remain grounded in actual system costs.

Following a public workshop on the white paper in July 2022, the CPUC voted unanimously on July 14, 2022, to open a formal rulemaking—R.22-07-005—to advance demand flexibility through electric rates. CA CPUC Decision D.23-04-040, issued in May 2023, adopted updated electric rate design principles and demand flexibility design principles, establishing the procedural framework for translating the CalFUSE concepts into utility tariffs. The proceeding's second phase has been developing specific rate designs for each customer class, with individual IOU rate applications expected to flow through general rate case proceedings.

Pilots and Demonstrated Performance

Even before the formal CalFUSE rulemaking, early pilots were generating evidence on the feasibility and customer response to real-time pricing. The CPUC authorized SCE to use TeMix's RATES (Retail Automated Transactive Energy System) platform for a three-year dynamic pricing pilot from 2022 to 2024, approving $2.5 million for the effort. The pilot was designed to demonstrate the CalFUSE dynamic pricing concept across multiple use cases, assessing how the framework's three-part policy approach could deliver standardized price access, dynamic electricity prices linked to real-time grid conditions, and customer options to manage energy use and costs. Participating customers received composite hourly price signals reflecting both CAISO locational marginal prices (LMPs) and distribution capacity utilization, while remaining on their otherwise applicable tariff for billing purposes during the initial phase.

The pilot demonstrated that dynamic pricing combined with third-party automation and aggregation services could enable load response, with battery storage dispatch showing particular promise under dynamic transactive rates compared to business-as-usual operation. Valley Clean Energy's AgFIT pilot, serving agricultural pumping customers in PG&E territory, provided complementary evidence on the value of transactive features: customers were able to pre-purchase predicted usage based on week-ahead price forecasts, achieving a degree of billing certainty that proved important for commercial acceptance of the dynamic rate concept.

SDG&E pursued a parallel path, proposing a two-stage commercial and industrial RTP pilot anchored to day-ahead CAISO pricing, while PG&E developed a commercial EV day-ahead RTP rate authorized in late 2023. Across these efforts, a consistent finding emerged: the combination of automated devices, third-party aggregators, and hourly price signals could produce meaningful load shifts and bill savings, but customer enrollment and technology integration remained rate-limiting factors requiring deliberate program design.

Regulatory Timeline and Implementation Pathway

The broader mandate for dynamic retail rates derives from the California Energy Commission's (CEC’s) updated Load Management Standards (LMS), which took effect in April 2023. As of April 1, 2023, PG&E, SCE, SDG&E, SMUD, LADWP, and large community choice aggregators are required to develop retail electricity rates that change at least hourly to reflect grid costs and greenhouse gas emissions. The LMS call for large utility customers to have access to these optional rates by January 1, 2027. CA

A central enabling infrastructure for this transition is the CEC's Market Informed Demand Automation Server, or MIDAS. Load-serving entities are required to maintain the accuracy of existing and future time-varying rates in the publicly available, machine-readable MIDAS rate database, develop standard rate information access tools to support third-party services, and submit locational rates that change at least hourly to reflect marginal wholesale costs. CA Rate Identification Numbers (RINs), now appearing on utility bills across the state, allow smart devices and third-party providers to query MIDAS and retrieve the customer-specific price signal applicable at any hour—a foundational step toward the automated demand response ecosystem envisioned by CalFUSE.

The CPUC has issued guidance for IOUs to design their dynamic hourly rates in preparation for the 2027 milestone, with individual rate proposals flowing through each utility's general rate case. PG&E, SCE, and SDG&E have each submitted LMS compliance plans outlining their pathways to full-scale RTP, though the parallel requirement for FERC approval of dynamic transmission rate components introduces additional procedural complexity and potential schedule risk for meeting the statutory deadline.

Purpose and Scope of This Paper

Despite this regulatory momentum, significant analytical gaps remain. The customer-facing economics of dynamic rates—particularly for residential customers with solar, storage, and flexible loads—have not been comprehensively characterized across the range of rate designs and technology configurations now entering the market. Evaluations of bill impacts, greenhouse gas outcomes, and utility system benefits have been conducted largely in isolation, making it difficult to assess the full value stack available under dynamic pricing and to identify the conditions under which rate design choices enhance or constrain that value.

This paper addresses those gaps through an hourly simulation framework applied to representative residential building archetypes. Using proxy CalFUSE price signals developed by Verdant and derived from CAISO market data and CPUC avoided cost schedules, we model the price-responsive dispatch of battery storage paired with solar PV and other load-shifting technologies. We quantify bill impacts under static and dynamic tariff scenarios, evaluate avoided costs and peak demand reductions from the utility perspective, and synthesize these streams into a comprehensive cost-effectiveness analysis. The findings are intended to inform rate designers, technology developers, and policymakers as California moves from pilot-scale demonstration toward broad deployment of dynamic retail rates.

Methodology

The foundation of our modeling approach is data collected and insights gleaned from annual impact evaluations of California's Self-Generation Incentive Program (SGIP) (Verdant, 2023). We begin by selecting load shapes that are representative of typical SGIP participants, since our modeling should be representative of current DER adopters. Implicit in this choice is also the assumption that future DER adopters have similar consumption behaviors to past DER adopters. Starting with SGIP customer consumption data, we then added back solar PV generation and battery charge/discharge to arrive at an underlying consumption shape. SGIP participants in our metered sample were grouped into 33 bins as follows:

- By IOU: PG&E, SCE, and SDG&E
- By climate zone: inland / coastal / desert as applicable for each IOU
- By customer size
- In the San Joaquin Valley DAC or not

- With or without an electric vehicle

Grid benefits in this analysis are measured using the CPUC's avoided cost calculator (ACC) (E3, 2024). The ACC is a standardized framework used by the CPUC to estimate the long-term monetary value of energy and capacity that utilities avoid when customers deploy DERs like solar panels and batteries. The calculator determines the value of DERs by modeling these key avoided costs:

- Generation Energy: Power generation costs the utility avoids buying on the wholesale market.
- Generation Capacity: Costs avoided by not needing to build or procure new power plants to meet peak demand.
- Transmission and Distribution (T&D) Capacity: Infrastructure upgrades avoided or deferred by reducing strain on local grids.
- Ancillary Services & Environment: Costs avoided for grid balancing and complying with California's decarbonization and greenhouse gas (GHG) emission limits.

The load shapes were adjusted to reflect the same weather conditions as the ACC.

Modeling Scenarios and Assumptions

Based on our review of literature and existing programs, we developed a suite of scenarios that represent the range of potential DER Futures. We modeled both existing baseline conditions and hypothetical future conditions, which gives us the flexibility to compare any two scenarios, to model the impact of applying different interventions to different cohorts of customers (e.g., moving solar PV customers under Net Energy Metering (NEM) 2.0 to the net billing tariff (NBT) and adding storage, or moving NBT customers to a real-time dynamic rate). The modeled scenarios are:

- **Standalone solar PV on NEM 2.0.** This scenario is not considered as a potential intervention but rather used as a baseline scenario to compare changes in bills and avoided costs after applying the other interventions listed below.
- Solar PV paired with storage on NEM 2, performing solar self-consumption. This scenario is referred to in subsequent figures as (**SC NEM**) and is representative of observed dispatch from the majority of NEM solar and storage (PV + battery energy storage system (BESS) in figures) customers in SGIP currently.
    - Additional sensitivity included where the battery performs emergency dispatch, defined as full battery dispatch during the top 36 avoided cost hours of the year. This scenario is referred to as **Emergency Dispatch** and it builds on the SC NEM case with dispatch during the most critical hours of the year, representing enrollment in a program like Demand Side Grid Support (DSGS), Emergency Load Reduction Program (ELRP), or other utility emergency demand response programs.
    - Additional sensitivity included where the battery dispatches during the top two consecutive highest hours of avoided cost each weekday. This scenario is referred to as **Daily Dispatch** and it represents a coordinated dispatch, either by a utility or

an aggregator, that overrides the daily discharge for self-consumption or rate optimization and instead discharges the battery during the highest value hours each day. It's not a fully optimized dispatch against avoided costs.

- Solar PV paired with storage on NBT, performing solar self-consumption (**SC NBT**). This is the same scenario as (SC NEM) above but under the NBT.
- Solar PV paired with storage on NBT, performing rate arbitrage (**TOU NBT**). In this scenario, the customer is on the NBT and discharging the battery exclusively during the on-peak TOU period.
- Scenarios where the battery is dispatched against a dynamic rate modeled after the CalFUSE principles, with the following subscription amounts:
    - The customer's total annual consumption is enrolled in a subscription in the Otherwise Applicable Tariff (OAT), but the solar PV and storage are fully exposed to the dynamic rate. (**CalFUSE PV + BESS**)
    - The customer's total annual consumption and solar PV generation is enrolled in a subscription on NBT in the OAT and only the storage is fully exposed to the dynamic rate. (**CalFUSE BESS**)
    - The customer's total annual consumption, solar PV, and storage is completely billed on the OAT, NBT, but the storage is dispatched to follow the dynamic rate price signals. (**CalFUSE NBT**)

Table 1 summarizes the scenarios and modeling assumptions.

Table 1. Summary of Modeling Assumptions

Scenario Name	Battery Dispatch	Customer Billing
TOU NBT	Time-of-use arbitrage, charge from solar, discharge on peak	Net billing tariff
SC NEM	Self-consumption, charge from solar, discharge to zero net load	NEM 2
SC NBT	Self-consumption, charge from solar, discharge to zero net load	Net billing tariff
Emergency Dispatch	Self-consumption, charge from solar, discharge during 36 highest avoided cost hours	NEM 2
Daily Dispatch	Self-consumption, charge from solar, discharge daily during two highest avoided cost hours	NEM 2
Calfuse PV + BESS	Optimized dispatch against CalFUSE price signal	Consumption charged at NBT, solar and storage billed at CalFUSE rate

Scenario Name	Battery Dispatch	Customer Billing
Calfuse BESS	Optimized dispatch against CalFUSE price signal	Consumption and solar charged at NBT, storage billed at CalFUSE rate
Calfuse NBT	Optimized dispatch against CalFUSE price signal	NBT

Scenarios with solar PV were modeled assuming the solar PV is sized to deliver 100% of a customer's annual consumption for NEM 2 cases, and 80% of annual consumption for NBT cases. PV generation was simulated with system and site-specific parameters (including location, tilt, azimuth, system size, and actual weather data) using PVLIB v 0.12.0 (Anderson, 2023). These simulations were calibrated to closely reflect the outputs of PVWatts (NLR 2026) and their accuracy for residential systems has been verified in previous work.

Each scenario with energy storage was modeled with either one PowerWall 3 system (11.5 kW, 13.5 kWh), or two PowerWall 3 systems (27 kWh). We chose the PowerWall 3 as it is the most ubiquitous energy storage system in the SGIP today, however the modeling should be considered illustrative of any battery storage system of similar size. A minimum state of charge of 20% was set for all scenarios. Scenarios where the battery is dispatched against the CalFUSE dynamic price signal were modeled using Verdant's linear optimization battery dispatch model.

Results

For each scenario listed above we modeled impacts on customer bills and utility avoided costs. Figure 1 shows the average first year outcomes if an illustrative small to medium sized PG&E customer has no DER installed and adopts any of the eight scenarios modeled.

Figure 1: Modeling Results for New PV and Storage Customers

In general, the scenarios with the highest bill savings are the NEM PV + Storage self-consumption scenario (SC NEM) and the self-consumption NBT scenario (SC NBT) at $4,269 and $3,401 respectively. The CalFUSE PV + BESS scenario, where the customer's consumption is billed on an otherwise applicable tariff (OAT) but the solar PV and energy storage are billed against CalFUSE, has the lowest bill savings at $1,430.

Figure 2 below looks at changes in avoided costs and bill savings relative to a baseline where the customer has already installed standalone solar PV on NEM 2 and is adding energy storage. The scenario with the most dramatic change to customer bills is where the customer is transitioned to the CalFuse PV + BESS scenario, where the customer's consumption is billed on an otherwise applicable tariff but the solar PV + energy storage is billed against CalFuse. Notably, in all cases, the customer bills will increase except for the scenario where the customer stays on NEM 2 but adds battery storage performing solar self-consumption (SC NEM). All other scenarios create modest improvements in avoided costs and moderate increases in customer bill payments. Due to the reduction in bill savings, an incentive program may be needed to encourage a customer to transition off NEM 2 onto a different rate such as NBT or a dynamic rate.

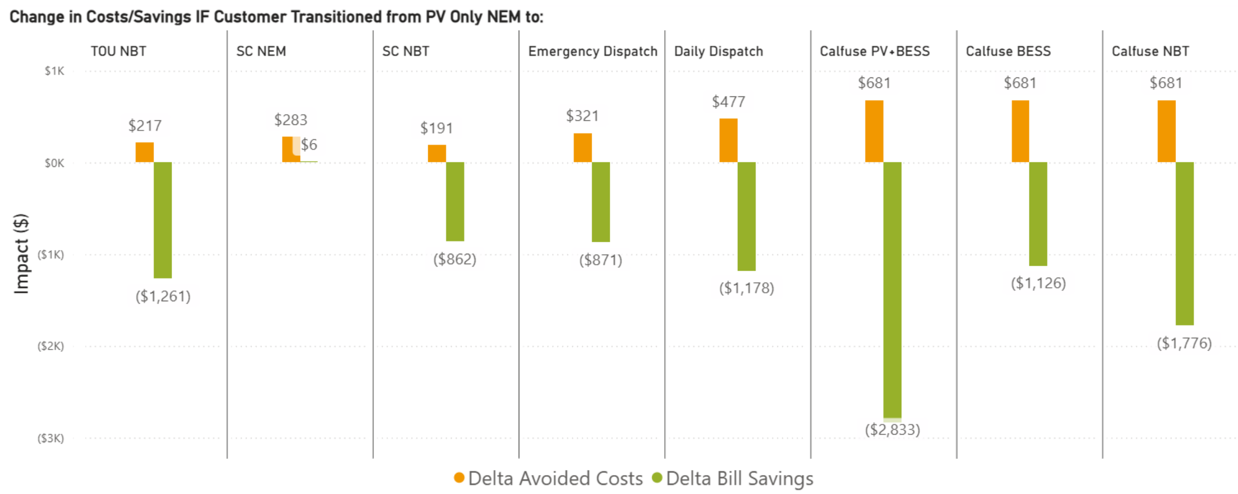

Figure 2: Modeling Results for an Existing NEM 2 PV Customer Adding Storage

Figure 3 below looks at changes in costs/savings relative to a baseline where the customer has already installed solar PV paired with storage and is either on the NBT (left) or on NEM 2 (right). The results are directionally similar to the case where the customer has standalone solar PV on NEM. Generally, the delta avoided costs are smaller when compared to the standalone NEM 2 customer as the customer is already using the existing storage for self-consumption.

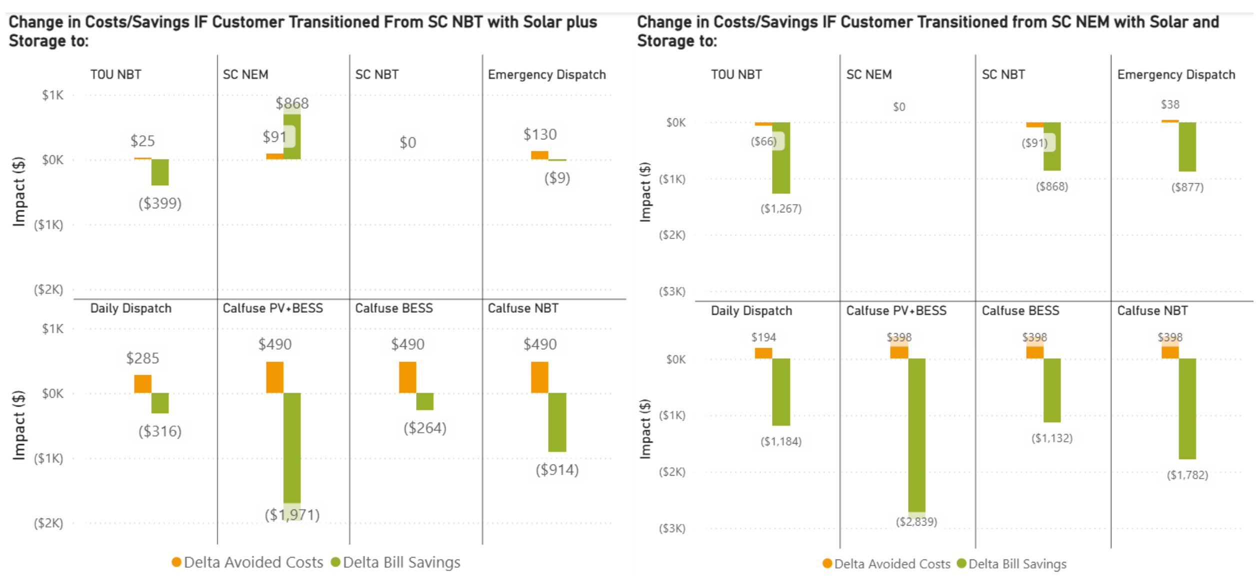

Figure 3: Modeling Results for an Existing Solar PV + BESS Customer on NBT (Left) and NEM 2 (Right)

Conclusion

This paper examined the performance of solar PV, behind-the-meter battery storage, and other load-shifting technologies under dynamic pricing structures modeled after the CalFUSE framework, using an hourly simulation approach grounded in empirical consumption data across representative residential archetypes in the PG&E, SCE, and SDG&E service territories. Our results offer several findings with direct relevance to rate designers, technology developers, and policymakers preparing for California's 2027 deployment milestone.

Summary of Key Findings

The analysis confirms that dynamic retail rates can unlock meaningful utility system benefits—in the form of avoided costs and peak demand reductions—that are not reliably captured under static TOU or NEM-era structures. Battery dispatch optimized against CalFUSE-proxied price signals consistently outperformed business-as-usual self-consumption strategies on avoided cost metrics, reflecting the ability of price-responsive load flexibility technologies like storage to align discharge with the highest-value hours for the grid. Based on our modeling, a customer with a battery dispatched optimally against CalFUSE-proxied price signals provides approximately $1,132 in annual avoided cost benefit, compared to a customer performing self-consumption which provides approximately $642 - $734 in avoided cost benefit.

However, the customer bill picture is more nuanced. For customers transitioning from an existing NEM 2.0 solar installation to a dynamic rate exposure, bill savings under most CalFUSE scenarios are lower than under continued NEM 2.0 participation—in some cases modestly so, and in others significantly. The CalFUSE PV + BESS scenario, in which both solar generation and storage are fully exposed to the dynamic rate, produces the greatest improvement in avoided costs ($398 per year) but also the greatest erosion of customer bill savings relative to the NEM 2.0 baseline (bill increase of $2,839 per year). This tension between system-level value and customer-level economics is a central design challenge for regulators and program administrators seeking to catalyze transitions off legacy rate structures.

The subscription-based CalFUSE configurations—where a customer's baseline consumption remains anchored to the otherwise applicable tariff while only the storage or PV-plus-storage margin is exposed to dynamic pricing—offer a more favorable customer bill outcome while still delivering improved avoided cost performance (in the scenario where only the storage is exposed to dynamic pricing, avoided costs increase by $398 and bills increase by $1,132 per year). This finding supports the graduated, opt-in enrollment pathway envisioned in the CalFUSE framework's six-element architecture and suggests that subscription structures may be an important bridge for customers who are risk-averse about bill exposure under real-time pricing.

Implications for Rate Design

These results carry several practical implications for the rate design applications currently moving through the CPUC's general rate case proceedings ahead of the 2027 LMS deadline.

First, the degree to which customers benefit under dynamic rates is highly sensitive to the scope of their rate exposure. Rate designers should consider partial exposure mechanisms—including subscription options anchored to historical load shapes—as tools for managing customer bill risk during the transition from legacy rates, particularly for the existing NEM 2.0 population where the alternative baseline carries substantial embedded value.

Second, the availability and accuracy of the price signal itself matter enormously for dispatch optimization. Scenarios modeled with optimization against the CalFUSE proxy signal demonstrated stronger system benefit performance than those using simplified dispatch heuristics, underscoring the importance of timely, machine-readable price delivery through the MIDAS infrastructure and Rate Identification Number (RIN) framework. Investment in the quality and accessibility of the price signal—not just its design—should be treated as a co-equal implementation priority.

Third, incentive structures will likely be necessary to bridge the customer economics gap for NEM 2.0 customers considering enrollment in dynamic rates. The modeling indicates that, absent incentive support, most existing NEM customers face higher net bill costs under dynamic rate scenarios. Policymakers designing transition mechanisms should consider how existing programs — Self-Generation Incentive Program (SGIP), Demand Side Grid Support (DSGS), and successor demand response frameworks—can be structured to offset this transition cost while rewarding the improved grid-interactive performance that dynamic dispatch enables.

Recommendations for Pilot Program Design and Deployment

As California's IOUs and CCAs move from current pilot-scale operations toward broader deployment, several design considerations emerge from this analysis. Pilot programs should be structured to capture sufficient data on actual dispatch behavior under real (not shadow-billed) dynamic rate conditions, as simulation-based estimates of customer response will inevitably diverge from observed behavior once customers bear actual financial exposure. Evaluation frameworks should track bill impacts, avoided cost realization, and enrollment persistence jointly, not in isolation.

While not explicitly shown in this paper, the underlying data used in this analysis show that the geographic and demographic diversity captured in our 33-bin archetype structure highlights that outcomes vary meaningfully across climate zones, customer size, and disadvantaged community status. Pilot and program designs should intentionally sample across these dimensions to avoid overgeneralizing from results concentrated in a narrow customer segment. Equity safeguards — including bill protection mechanisms for income-qualified customers and community-based outreach to ensure access to enabling technologies—should be integrated from the outset rather than retrofitted after early enrollment patterns emerge.

Finally, the role of third-party aggregators and automation service providers deserves explicit attention in program rules. The strongest system benefit outcomes in this analysis are associated with optimized dispatch strategies that, in practice, require algorithmic control rather than manual customer response. The CalFUSE ecosystem's envisioned role for automated services platforms is therefore not peripheral to the rate design—it is central to realizing the value proposition that justifies the transition. Pilot program structures should actively enable and evaluate third-party participation, and rate tariff language should be designed with machine-readable price delivery and automated dispatch as first-class use cases.

Looking Ahead

California's approach to dynamic retail rates represents one of the most ambitious attempts by any jurisdiction to align mass-market electricity pricing with the real-time economics of a high-DER grid. The analytical framework developed here—integrating customer bill impacts, marginal emissions, avoided costs, and cost-effectiveness metrics across a diverse set of technology configurations and tariff scenarios—offers a template for the kind of comprehensive evaluation that rate designers and regulators will need as deployment scales. The findings presented here are necessarily illustrative rather than definitive, reflecting the constraints of simulation-based analysis and the absence of large-scale behavioral data under actual dynamic rate conditions. This analysis is also limited to battery storage paired with solar PV – future research should explore bill and rate impacts from other load flexibility technologies like load shifting water heaters and managed charging of electric vehicles. As California's IOUs file their LMS-compliant rate applications and pilot results accumulate through 2025 and 2026, this modeling framework can be updated with observed dispatch data and refined price signal representations to sharpen the guidance available to policymakers navigating one of the most consequential rate design transitions in the state's history.

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