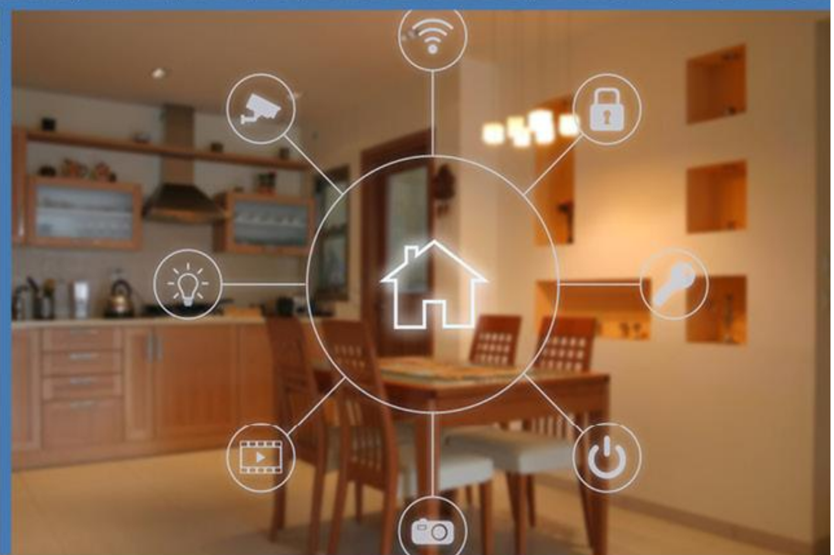

Advanced Strategies for Demand Flexibility Management and Customer DER Compensation

Energy Division White Paper and Staff Proposal

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California Public Utilities Commission

All staff listed below are with Energy Division

Retail Rates Team	Demand Response Team	Other Teams
Lead Authors: Achintya Madduri Masoud Foudeh Paul Phillips	Aloke Gupta	
Contributing Authors: Jenneille Hsu Ankit Jain Phillip Voris	Jean Lamming Andrew Magie	Josh Huneycutt (Transportation Electrification)

Reviewed By:
Dan Buch
Simon Baker

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Acronyms

Acronym	Definition
AAH	Availability Assessment Hours
AC Cycling	Air Conditioning Cycling
ACP	Alhambra Control Platform
ADR	Automated Demand Response
ADS	Automated Dispatch System
AP-I	Agriculture & Pumping Interruptible
AWE	CAISO's Alert, Warning, Emergency Declaration
BIP	Base Interruptible Program
BTM	Behind-The-Meter
BYOT	Bring Your Own Thermostat
CAISO	California Independent System Operator
CalFUSE	California Flexible Unified Signal for Energy
CBP	Capacity Bidding Program
CCA	Community Choice Aggregator
CDC	Coincident Demand Charge
CEC	California Energy Commission
CEV	Commercial Electric Vehicle
CP&S	Customer Program and Service Organization
CPM	CAISO's Significant Event Capacity Procurement Mechanism
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
DA	Day-Ahead
DAM	CAISO's Day-Ahead Market
DC	Demand Charge
D-CPP	Distribution Critical Peak Pricing
DER	Distributed Energy Resource
DR	Demand Response
DR RFO	Demand Response Request for Offers
DRAM	Demand Response Auction Mechanism
DRAS	Demand Response Automation Server

DRP	Demand Response Provider
DRRS	Demand Response Registration System
EAP II	2005 California Energy Action Plan II
ELCC	Effective Load Carrying Capability
ELRP	Emergency Load Reduction Pilot Program
ENS	Enterprise Notification System
EPM	Energy Procurement Management
ERCOT	Electric Reliability Council of Texas, Inc.
GCC	Grid Control Center
GHG	Greenhouse Gases
GMS	Generation Management System
HVAC	Heating, Venting, or Air Conditioning
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
kW	Kilowatt
kWh	Kilowatt-Hour
LBNL	Lawrence Berkeley National Laboratory
LMDR	Load-Modifying Demand Response
LMS	Load Management Standards
LSE	Load Serving Entity
MOO	Must Offer Obligation
MW	Megawatt
MWh	Megawatt-Hour
NCDC	Non-Coincident Demand Charge
NREL	National Renewable Energy Laboratory
ONC	Outage Notification Communication
PDR	Proxy Demand Resource
PFR	Petition for Rulemaking
PG&E	Pacific Gas & Electric Company
PLS	Permanent Load Shifting Program
PMax	Maximum Power (Capacity) of a Resource
PNNL	Pacific Northwest National Laboratory
POPP	Peak to Off-Peak Price Ratio

PSPS	Public Safety Power Shutoffs
PTR	Peak Time Rebate
PYD	Power Your Drive
QC	Qualifying Capacity
RA	Resource Adequacy
RAAIM	Resource Adequacy Availability Incentive Mechanism
RDRR	Reliability Demand Response Resource
RPS	Renewables Portfolio Standard
RTM	CAISO's Real Time Market
RTP	Real Time Pricing
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SDP	Summer Discount Program
SEP	Smart Energy Program
SSDR	Supply-Side Demand Response
Sub-LAP	Sub-Load Aggregation Point
TRC	Total Resource Cost (Cost-Effectiveness Metric)
TOU	Time Of Use
UDC	Utility Distribution Company
UNIDE	Unified, Dynamic, Economic Signal (former program name for CalFUSE)
VGI	Vehicle-Grid Integration

1 Executive Summary

1.1 Need for a Fresh Approach to Demand Flexibility

California's electricity system is undergoing rapid transformation on the pathway to 100% renewable power, with the expected high penetration of renewables, electrification of buildings and transportation, and deployment of behind-the-meter (BTM) distributed energy resources (DERs). Many stakeholders are concerned about potential adverse impacts of these trends on the State's power grid (see section 3.1) and agree that going forward it is essential for California to leverage demand response (also referred to as load or demand flexibility management) as a critical resource in integrated resource planning (IRP) to meet the State's aggressive GHG emissions reduction targets.

Demand Response (DR) continues to play an important role in achieving California's clean energy goals. The California Public Utilities Commission (CPUC) has a long track record in developing policies to promote DR. These policies can be broadly grouped into two main strategies: 1) CAISO market-integrated DR programs (also referred to as supply-side DR (SSDR), and 2) load-modifying DR (LMDR) based on a range of time-differentiated rates or utility managed load reduction programs.

Fortunately, some of the trends noted earlier, specifically the electrification of transportation and buildings and growth in customer deployment of BTM DERs, present significant demand-side potential (see section 3.2) to address the challenges associated with the State's energy transformation, help integrate renewables, reduce GHG emissions, improve system reliability, and reduce or minimize cost of service. These trends are driving a substantial and rapid increase in electric end uses that are capable of being flexible in terms of when energy could be consumed or generated. Some stakeholders suggest that the flexible demand/generation nature of the electrified end uses and BTM DERs, if aggregated, coordinated, and shaped properly at scale (that is, large-scale demand flexibility management), could play a major role in solving the anticipated challenges to the State's electricity system.

However, the CPUC's current approach to demand response (SSDR and LMDR) is complex and may not be well positioned to address emerging grid needs. Additionally, current policies may have become a barrier to scaling demand management solutions to the levels necessary to support California's clean energy goals.

With the experience gained through the CPUC's efforts to integrate SSDR programs with CAISO markets, stakeholders have noted concerns (see section 3.3.1) about the high degree of complexity in SSDR program implementation, high level of confusion, high transaction costs, and limited flexibility. With respect to LMDR programs, other stakeholders have suggested that a comprehensive review of the underlying electricity rates policies is needed to address a range of serious issues (see section 3.3.2), including the proliferation of "boutique" technology-specific rates (e.g., for solar, electric vehicles, and storage), incentives for uneconomical load management, non-equitable fixed cost recovery and related cost shifts, and inability to monetize DER capabilities. In several proceedings, parties have provided testimony to encourage the adoption of rates based on real-time grid conditions to provide both customer bill benefits and system cost benefits.

If the State is to fully capture the significant demand-side potential enabled by electrification and customer DERs, a key "chicken-and-egg" problem related to demand response and retail rates must be resolved. For large numbers of customers (both residential and commercial) to adopt flexible demand management solutions at the scale necessary to support the future electricity grid, automation technologies for controlling various end-uses and DERs must be inexpensive and ubiquitous. For this to be true, there must exist a robust and stable policy pathway that is standardized, easy to implement, and allows 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.

1.2 Staff Proposal

This Energy Division (ED) white paper proposes that the CPUC seek to significantly improve demand-side resource management through a more synergistic, scalable, and integrated demand response and retail rate strategy that can effectively address the emerging grid issues and opportunities associated with the growth of renewables, building and transportation electrification, and behind-the-meter DER deployment by electricity customers.

The paper proposes a comprehensive vision, guiding principles, and a policy roadmap to drive the development of a universal approach to flexible demand and DER management and compensation solutions available to all customers, initially on an opt-in basis,[1] throughout the state.

Accordingly, ED Staff recommends that the CPUC initiate a Rulemaking, as referenced in the DER Action Plan 2.0 as Track 1,[2] to take up this paper's proposal.

1.2.1 Vision Statement

This paper recommends that the CPUC establish an ambitious policy vision: To achieve widespread customer adoption of low-cost, advanced flexible demand and DER management and compensation solutions across the state (and beyond) via a unified, universally accessible, dynamic economic signal. Policies in pursuit of this vision should help in addressing the following issues associated with the ongoing transformation of the electricity grid:

1. Mitigate reliability and grid integration challenges associated with high growth in renewables, end-use electrification, and behind-the-meter DER deployment by customers,

[1] Note: Consistent with the objectives of Track 1 of the DER Action Plan 2.0, ED Staff recommends that CPUC explore whether and to what extent the demand flexibility framework proposed in this white paper should be adopted on an opt-out or default basis for certain customers at a later date following a conclusive evaluation.

[2] *See* CPUC DER Action Plan 2.0 at 8. (available at) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M467/K470/467470758.pdf.

2. Minimize short- and long-term cost of service associated with the rapidly evolving electricity infrastructure, and
3. Fully leverage capabilities of customer DERs to address grid needs while providing fair compensation for grid services provided by the DERs.

1.2.2 Guiding Objectives

In support of this policy vision, this paper proposes that the CPUC pursue the development of a policy roadmap or framework that should achieve the following objectives:

1. Enhances scalability via standardized, universal mechanisms to enable demand flexibility management.
2. Makes the value of energy and capacity services provided by the grid or DERs more transparent and based on real-time grid conditions.
3. Seamlessly accommodates different and evolving pricing policies of utility distribution companies (UDCs) and load serving entities (LSEs), both inside and *outside* the CPUC jurisdiction.
4. Ensures full recovery of costs associated with the infrastructure for electricity generation and delivery, consistent with cost-causation principles and avoidance of cost-shifts.
5. Offers options to all customers for bill and demand management choices, protection against bill volatility, and forward planning of energy usage or generation.
6. Encourages investment in BTM DERs, including vehicle-to-grid integration and microgrids, without cost-shifts to non-participating customers.

1.2.3 Policy Roadmap

In support of and consistent with the above vision statement and guiding objectives, this paper describes a comprehensive policy roadmap, the centerpiece of which is a unified, universally-accessible, dynamic, economic retail electricity price signal. The roadmap consists of a three-pillar structure addressing 1) the presentation of electricity prices to customers and smart devices, 2) electricity rate reform, and 3) customer options to optimize energy consumption and generation. For convenience, this whitepaper refers to the roadmap is as "CalFUSE" (California <u>F</u>lexible <u>U</u>nified <u>S</u>ignal for <u>E</u>nergy).[3] The proposed roadmap consists of six key policy elements, all intended to be available on an opt-in basis as follows:

ELEMENT 1: DEVELOP STANDARDIZED, UNIVERSAL ACCESS TO THE CURRENT ELECTRICITY PRICE

- Statewide, web-based portal to provide current electricity price specific to each customer.
- Accommodate different pricing inputs from UDCs and LSEs.

[3] Note: The policy roadmap was previously referred to by Staff and stakeholders as "UNIDE" (unified, dynamic, economic signal).

- Engage tech / industry ecosystem in educating customers and developing energy management solutions.

ELEMENT 2: INTRODUCE DYNAMIC ELECTRICITY PRICES BASED ON REAL-TIME WHOLESALE ENERGY COST

- Real-time pricing tied to CAISO locational marginal price, reflecting the marginal cost of energy.

ELEMENT 3: MODIFY ELECTRICITY PRICES TO INCORPORATE DYNAMIC CAPACITY CHARGES BASED ON REAL-TIME GRID UTILIZATION

- Capacity fixed cost recovery linked to the degree of congestion relative to the available infrastructure capacity for electricity generation and delivery.
- Implements the design principle that fixed cost recovery should be higher when the system utilization is higher.
- Shift fixed cost recovery onto load driving capacity upgrades based on marginal cost of adding incremental capacity, while ensuring collection of approved revenue requirements and minimizing unintentional cost-shifts.

ELEMENT 4: TRANSITION TO BI-DIRECTIONAL ELECTRICITY PRICES

- Customers import or export energy at the same dynamic composite price.
- Fair, transparent, and rational compensation for grid services provided by customer owned DERs linked to avoided marginal costs.

ELEMENT 5: OFFER A SUBSCRIPTION OPTION BASED ON CUSTOMER-SPECIFIC LOAD SHAPES

- Customers subscribe to a monthly load shape based on historic usage (and the associated hourly energy quantities) at a pre-determined monthly price.
- Protect against bill and revenue collection volatility, while still encouraging opportunistic, beneficial load shift.
- Ease customer transition from current rates to dynamic rate.

ELEMENT 6: ENABLE TRANSACTIVE FEATURES ALLOWING LOCK IN OF FUTURE ELECTRICITY PRICES

- Customer option to commit to future import or export of energy at pre-determined prices (based on forecasts) to control and optimize energy use or generation.
- Improved visibility for planning and operations (for CAISO, UDCs/LSEs, and customers & their service providers).

The Figure 1-1 below illustrates the overall policy roadmap described above, referred to as the "CalFUSE" framework in this paper.

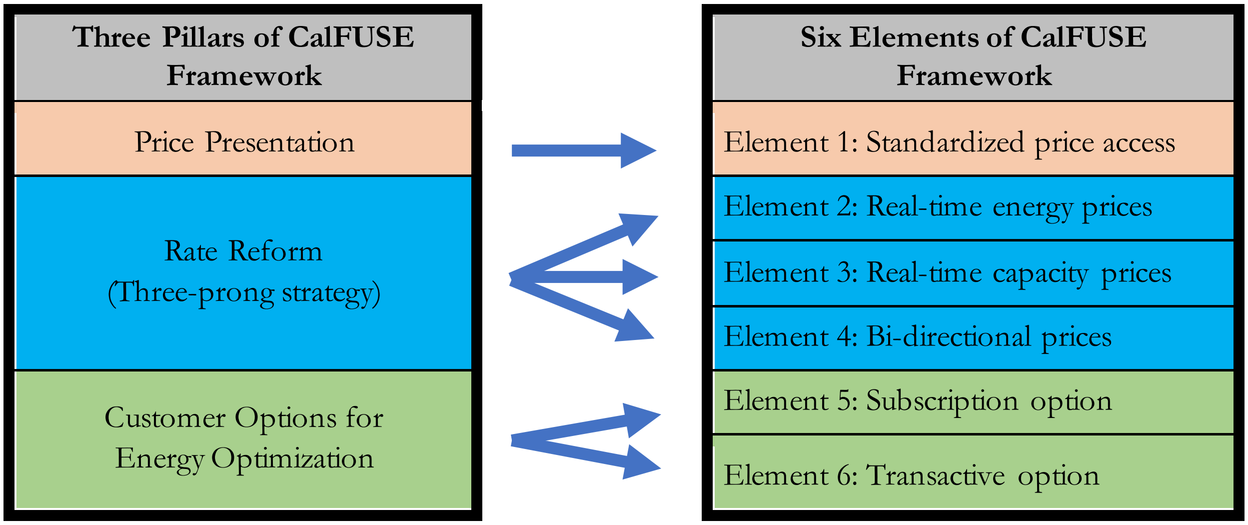

Figure 1-1: The CalFUSE Framework

1.3 Structure of This Paper

The remainder of this paper is organized as follows:

Chapter 2 summarizes the procedural background of policies in support of providing access to dynamic retail rates to customers and achieving greater demand/load flexibility.

Chapter 3 presents the problem statement in detail and outlines the need for a more effective, synergistic, and scalable demand response and retail rate strategy to better address the emerging issues associated with the transformation of California's electricity system.

Chapter 4 presents the staff proposal describing the vision, guiding objectives, and the policy roadmap focused on implementing a flexible, unified signal for energy in California (CalFUSE).

Chapter 5 discusses the potential impacts of implementing the CalFUSE framework.

Chapter 6 examines the learnings from various pilots and programs around the country that have implemented dynamic retail rates.

Chapter 7 concludes the white paper and offers Staff's recommendations for next steps in the implementation of a Statewide demand flexibility roadmap.

Chapter 8 (Appendix) summarizes the DER Action Plan 2.0 and stakeholder feedback in response to ED Staff's proposal previewed at the May 25, 2021, demand flexibility management workshop.[4]

[4] *See* https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops/advanced-der-and-demand-flexibility-management-workshop.

2 Procedural History

This section presents a brief overview of relevant procedural history, including proceedings, workshops, and studies undertaken at the behest of the CPUC and the CEC related to achieving greater demand flexibility through dynamic rates, demand charge reform, and demand response.

1. **CPUC Rate Design Principles**. In Rulemaking (R.) 12-06-013 the CPUC adopted an update to its rate design principles, which are benchmarks to measure the success of ratemaking proceedings. The update preserved the CPUC's commitment to conservation, equity, and marginal cost ratemaking, and reaffirmed the CPUC's commitment to the "Bonbright Principles".[5]

The 10 CPUC Rate Design Principles:

1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost.
2. Rates should be based on marginal cost.
3. Rates should be based on cost-causation principles.
4. Rates should encourage conservation and energy efficiency.
5. Rates should encourage reduction of both coincident and non-coincident peak demand.
6. Rates should be stable and understandable and provide customer choice.
7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals.
8. Incentives should be explicit and transparent.
9. Rates should encourage economically efficient decision-making.
10. Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates and minimizes and appropriately considers the bill impacts associated with such transitions.

2. **DER Action Plan 1.0 (2016)**. In 2016, the CPUC released its DER Action Plan 1.0 to serve as a roadmap to facilitate proactive, coordinated, and forward-thinking development of DER policy for decision-makers, staff, and stakeholders.[6] The DER Action Plan addressed strategies related to DER deployment using rates and tariffs, infrastructure and procurement, and DER market

[5] Bonbright, James C, "Principles of Public Utility Rates," Columbia University Press, 1961.

[6] California Public Utilities Commission, "DER Action Plan," May 3, 2017. (available at) https://www.cpuc.ca.gov/-/media/cpuc-website/Files/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/MichaelJPicker/DER%20Action%20Plan%205317%20CLEAN.pdf

linkages. It also incorporated the reforms of CAISO's 2006 Market Redesign and Technology Upgrade and the CEC's advances in real time price signal standards.[7]

3. **Advanced Rate Design Public Forum (2017).** Pursuant to DER Action Plan 1.0, the CPUC held its Advanced Rate Design public forum in 2017 to consider innovative rates and tariffs.[8] A key theme of this event was the incompatibility of demand charges (particularly non-coincident demand charges, or NCDCs) with the CPUC's commitment to cost-causation. Participants argued that locational, marginal, real-time pricing is an efficient means to assess distribution-level cost causation, and to minimize the cost of electricity service while providing widescale grid benefits.

4. **Petition for Rulemaking for RTP and Demand Charges (2019).** In November 2018, California Solar & Storage Association, California Energy Storage Association, Enel X, ENGIE Services, ENGIE Storage, OhmConnect, Inc., the Solar Energy Industries Association, and Stem, Inc., filed a Petition for Rulemaking (PFR) requesting the CPUC to open a rulemaking to address 2 topics: (1) to order state's 3 large IOUs to offer optional real time pricing tariffs to all customer classes, and (2) to request the CPUC to consider demand charge reform both for coincident and non-coincident demand charges.[9] The PFR was denied on procedural grounds, but the CPUC has encouraged the parties to bring up these topics in individual GRC proceedings.

5. **CPUC Load Shift DR Working Group (2019).** The CPUC Load Shift Working Group, established by (D.) 17-10-017, released a collection of product proposals intended to leverage CAISO market-based, i.e., "market-informed", mechanisms for inducing peak load reduction and peak generation offtake.[10] Common to these proposals was the use of unified signals for locational temporal prices and the incorporation of third parties to manage delivery of load change in conjunction with a utility price signal or other value proposition.

6. **LBNL DR Potential Study (2020).** Undertaken on behalf of the CPUC, this three-phase study was initiated in 2015 on the premise that meeting our clean energy and resource adequacy goals will fundamentally change the operational dynamics of California's grid. Over the course of this study, LBNL researchers have quantified the ability and the cost of using DR resources to help meet capacity needs at forecasted critical hours in the state.[11, 12] The study introduced the concepts of Shape, Shift, Shed, and Shimmy as distinct forms of DR that could be economically

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[7] California Energy Commission, "08-DR-01," January 2, 2008.

[8] California Public Utilities Commission, "2017 Electric Rate Forum - Presentations and Bios," December 11, 2017. (available at) https://www.cpuc.ca.gov/general.aspx?id=6442455548.

[9] California Public Utilities Commission, "P.18-11-004," February 8, 2019, 13.

[10] "Final Report of the California Public Utilities Commission's Working Group on Load Shift." January 31, 2019. (available at) https://gridworks.org/wp-content/uploads/2019/01/LoadShiftWorkingGroup_report_final.pdf

[11] Alstone, Peter, et al., "2015 California Demand Response Potential Study - Charting California's Demand Response Future. Interim Report on Phase 1 Results," April 2016, at 1, https://doi.org/10.2172/1421793.

[12] *Id.* at 2

incentivized, and assessed that fully 20% of load is potentially shiftable to time periods associated with low wholesale energy prices and energy curtailment.[13]

7. **LBNL Study on the Potential Impacts of Dynamic Electricity Tariffs (2021)**. Building upon the results and tools from the DR potential study, LBNL is conducting a study that will examine the bill and revenue impacts of a transition to a dynamic tariff based on the CalFUSE framework proposed in this paper. The dynamic tariff will incorporate wholesale energy market prices, and scarcity pricing to recovery utility generation and distribution capacity costs. The study will also assess the impact of subscriptions on customer bill volatility and revenue recovery, and the evaluate different methodologies to assess the shape of customer load shape subscriptions. LBNL will utilize the database of IOU customer load shapes that was developed during the course of Phase 4 of the DR potential study to model the impacts of a dynamic tariff on customer electricity bills, system load shapes, and utility cost recovery.

   The research study will address the following scenarios:

   a) Impacts of dynamic rate on customer bills under an inelastic scenario, where customers do not change consumption patterns.
   b) Impacts under an elastic scenario, where customers are price responsive, to assess the: (1) amount of DR resource could be captured, (2) the bulk power system load shape and wholesale electricity price impact, (3) effect of automation on load response, (4) impacts on power sector emissions and system costs.

8. **CPUC Energy Division's Advanced DER and Demand Flexibility Management Workshop (2021)**. On May 25, 2021, CPUC Energy Division Staff hosted a workshop to preview a Staff proposal for a comprehensive roadmap to facilitate widespread adoption of flexible demand management solutions while minimizing the cost of service through a unified, dynamic economic signal that is the focus of this white paper.[14] Stakeholder comments to this workshop are included in Appendix 8.2.

9. **DER Action Plan 2.0 (2021).** In December 2021, the first public draft version of the DER Action Plan 2.0 was released. It recognizes the role of the CPUC in coordinating policies across regulatory bodies and IOUs in service to our state decarbonization and affordable energy goals. Further, it sets target dates to implement vetted rate design solutions such as RTP, policies to enable private sector products such as pay for load shape, and mechanisms to integrate underutilized resources such as EVs.

[13] Gerke, Brian, et. al., "The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resource Through 2030," Lawrence Berkeley National Laboratory (LBNL), 2020.

[14] CPUC Energy Division, "Advanced DER and Demand Flexibility Management Workshop." May 25, 2021. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops/advanced-der-and-demand-flexibility-management-workshop.

10. **SDG&E Commercial EV & Real Time Pricing Proposals (2021).** On July 3, 2019, SDG&E filed Application (A.) 19-07-006 and proposed a new electric vehicle high power charging (EV-HP) rate to serve medium-duty/heavy-duty (MD/HD) commercial EV and direct current fast charging (DCFC). On April 24, 2020, the CPUC issued (D.) 20-04-009 to approve an interim rate waiver to serve separately metered MD/HD and DCFC electric vehicle customers of SDG&E. Subsequently, with (D.) 20-12-023, the CPUC approved (with modifications) SDG&E's proposal for a new rate for separately metered EV charging loads with an aggregated maximum demand of 20 kilowatts or greater, excluding single-family residential customers.

    On December 13, 2021, SDG&E filed A.21-12-006 for a Real Time Pricing Pilot Rate to be approved by the CPUC. In its application, SDG&E proposed a 2-stage pilot based on hourly day-ahead CAISO pricing. In stage 1 of its proposal, SDG&E proposes a pilot limited to M/L C&I customers only, with a minimum target of 25 participants and a cap of 100. CCA, NEM and DR customers are excluded from pilot participation. In Stage 2, SDG&E proposed to include all customers classes except for street lighting customers. SDG&E has proposed to implement stage 1 by end of 2022. For stage 2, SDGE has proposed to file a Tier 2 Advice Letter in Q2 2024 with final details, including eligibility, rate design, costs, and revenue requirement. This is an open proceeding.

11. **PG&E Commercial EV & Real Time Pricing Proposals (2021)**. In November 2018, PG&E filed A.18-11-003 for a new commercial EV (CEV) rate that included a "subscription charge" in lieu of NCDCs and proposed the creation of a new class of customers choosing to take service on the rate. The CPUC issued (D.) 19-10-055, approving the application, with modifications that substantially reduced the amount of the subscription charge included in the new rates. This Decision also required PG&E to file an application for a Real Time Pricing pilot within 12 months.

    In October 2020, PG&E filed the A.20-10-011 for a Real Time Pricing (RTP) pilot based on the CAISO hourly day-ahead market (DAM) for commercial EV customers. The CPUC issued (D.) 12-11-017, authorizing PG&E to offer an optional day-ahead, hourly RTP rate, not as a pilot limited to 50 customers as originally proposed, but as an optional rate for any customer that is eligible to enroll in the utility's Business Electric Vehicle rates. The proceeding remains open for an additional study that PG&E needs to complete before deciding on the rate design components of the new rate.

    In addition to the above RTP rate for Electric Vehicles, PG&E as part of its GRC Phase 2 application, has filed an application for a general RTP rate open to multiple customer classes. The decision for that portion of the proceeding is expected by July 2022.

12. **Summer Reliability Rulemaking and Authorized Dynamic Rates Pilots (2021).** In response to the August 2020 rolling outages, the CPUC expanded the role of demand response

resources and dynamic rates in addressing mid-term reliability concerns.[15] It established a 5-year pilot Emergency Load Reduction Program (ELRP) as a pay-for-performance demand response program that compensates voluntary incremental load reduction provided by a participating customer during a program event triggered in response to CAISO-declared grid emergencies. Program participation includes directly enrolled non-residential customers, virtual power plant aggregators, customers with Rule 21 exporting DERs, non-residential aggregators, EV/charging station aggregators (including both V1G - vehicle charging and V2G - vehicle discharging into the grid) and directly enrolled residential customers.

Additionally, to test the efficacy of dynamic pricing rates to facilitate load shift, the CPUC directed PG&E and SCE to pilot rate designs based on the Staff's CalFUSE Proposal—previewed at the May 25, 2021, workshop and described further in this white paper—with locational- and marginal cost-based hourly dynamic rates that pass through real-time generation, capacity, and other costs to incentivize participants to shift consumption away from peak periods.

13. **CEC Load Management Standards Update (2021).** The CEC initiated a rulemaking (CEC Docket Number 21-OIR-03) to amend existing load management standards (LMS) in order to address the concern that "existing demand response programs are incapable of shifting loads to periods of high renewable generation, and thus are inadequate for supporting the carbon-free grid of the future."[16]

    As part of its updates to the LMS, the CEC has created an online, universally-accessible customer rate database, the Market Informed Demand Automation Server (MIDAS), and has proposed to adopt regulations to "form the foundation for a statewide system of granular time and location dependent signals that can be used by automation-enabled loads to provide real-time demand flexibility on the electric grid."[17] The proposed regulations will be considered and possibly adopted at a CEC Business Meeting in Q2/Q3 of 2022. The regulations will require utilities, including IOUs, CCAs, POUs and other LSEs, to:

    a) Develop retail rates that change at least hourly and reflect locational marginal costs, within one year of the effective date of the regulations (2023).

    b) Update the time-dependent rates in the CEC MIDAS database, within 3 months after the effective date of the standards (2022).

    c) Implement a standardized method for providing automation service providers with access to customers' rate information, within one year of the effective date of the regulations (2023).

[15] *See* CPUC Rulemaking (R.) 20-11-003, (D.) 21-12-015, issued on December 2, 2021

[16] California Energy Commission. "Analysis of Potential Amendments to the Load Management Standards," 21-OIR-03 Final Staff Report, November 2021. (available at) https://efiling.energy.ca.gov/GetDocument.aspx?tn=241067&DocumentContentId=74898

[17] *Ibid.*

d) Develop a list of cost-effective automated price response programs for each sector and integrate information about time-dependent rates and automation technologies into existing customer education and outreach programs, within 18 months after the effective date of the standards (2024).

e) Offer voluntary participation in a marginal cost rate or cost-effective demand flexibility program for all customers, within 3 years of the effective date of these regulations (2025).

14. **CEC Flexible Demand Appliance Standards (2021).** SB 49 required the CEC to set minimum standards for appliances sold or leased within California to promote flexible demand, support grid operations, and reduce greenhouse gas emissions by scheduling, shifting or curtailing appliance operations with customer consent, while maintaining feasibility and cost-effectiveness.

    The CEC is updating flexible demand appliance standards in a series of phases for thermostats, pool pump controls, dishwashers, clothes dryers, electric storage water heaters, behind the meter batteries, and electric vehicle supply equipment. The CEC took public comment in the fall of 2021 on their initial staff proposal and may issue a draft report before a formal rulemaking opens. [CEC Docket Number 20-FDAS-01].

15. **CPUC 2022 Affordability Rulemaking Phase 3 En Banc**. The CPUC held an Affordability En Banc (February 28-March 1, 2022) to consider proposals to limit and/or mitigate future electricity and gas rate increase from a diverse panel of experts from academia, the energy industry, the environmental justice community, and consumer advocates.[18] Multiple electric rate reform proposals advocated for the use of real-time and marginal cost-based rates to incentivize electrification and contain costs.[19, 20] In addition, the en banc explored opportunities for non-ratepayer funding strategies as well as financing mechanisms for easing the transition away from natural gas and greater electrification. This portfolio of reforms was examined using the metrics developed in this proceeding, including the affordability ratio, as well as evaluation criteria for assessing rate impacts and the feasibility of implementation.

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[18] CPUC 2022 Affordability Rulemaking Phase 3 En Banc, held on February 28-March 1, 2022. En Banc materials available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability.

[19] *See* Brad Heavner (California Solar and Storage Association), "Reforms to Contain Utility Costs and Rate Growth," February 28, 2022. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/en-banc/heavner-slides-w-alt-image-and-link-texts.pdf.

[20] *See* Frank Wolak (Stanford University), "Retail Electricity Rate Reform," February 28, 2022. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/en-banc/wolak-slides-w-alt-image-and-link-text.pdf.

3 A Fresh Approach to Demand Flexibility

This chapter makes a three-part case for a novel approach to demand flexibility management, expanding on the need described in the introductory section of the Executive Summary, as follows:

1. The challenges associated with the ongoing transformation of the electricity system resulting from the expected high penetration of renewables, electrification of buildings and transportation, and deployment of behind-the-meter (BTM) distributed energy resources (DERs),
2. The significant opportunity involving demand-side flexibility enabled by widespread electrification and customer DER deployment, and its potential to integrate renewables and reduce GHG emissions, improve system reliability, and reduce or minimize cost of service, and
3. The limitations associated with the traditional approach to demand response and retail rate design that curtail the demand-side potential described above, suggesting a need for a fresh approach.

3.1 Challenges Associated with the Ongoing Transformation of the Electricity System

3.1.1 Increasing Penetration of Renewable Resources

A. INCREASED CURTAILMENT OF RENEWABLE ENERGY

California's climate goals will require the electric sector to transition to 100% clean electricity by 2045. The least-cost pathway for achieving California's climate goals based on the 2019-2020 IRP model plans for a substantial increase in the building of renewable resources).[21] As more renewable resources are added to the supply portfolio, California's system operator and utilities will be required to manage a grid with an increasingly dynamic supply profile and curtail growing amounts of renewable energy when supply exceeds demand or when ramping needs exceed the available flexible resources. Curtailment is already a year-round phenomenon, with average daily curtailment in 2020 at about 4.3 GWh per day (Figure 3-1). By 2030, CAISO projects a rapid increase in renewables curtailment (Figure 3-2) due to export and ramping limitations.[22] The average daily curtailment is estimated to increase by a factor of four to about 15 GWh by 2030 (and 100 GWh by 2045).

[21] Note: The IRP results referenced in this section were finalized in CPUC (D.) 20-03-028 in Rulemaking16-02-007, including detailed outcomes from the publicly available version of the RESOLVE model used to support the rulemaking.

[22] Mark Rothleder, "Briefing on Post 2020 Grid Operational Outlook," CAISO, 2019. (available at) https://www.caiso.com/Documents/BriefingonPost2020GridOperationalOutlook-Presentation-Dec2019.pdf

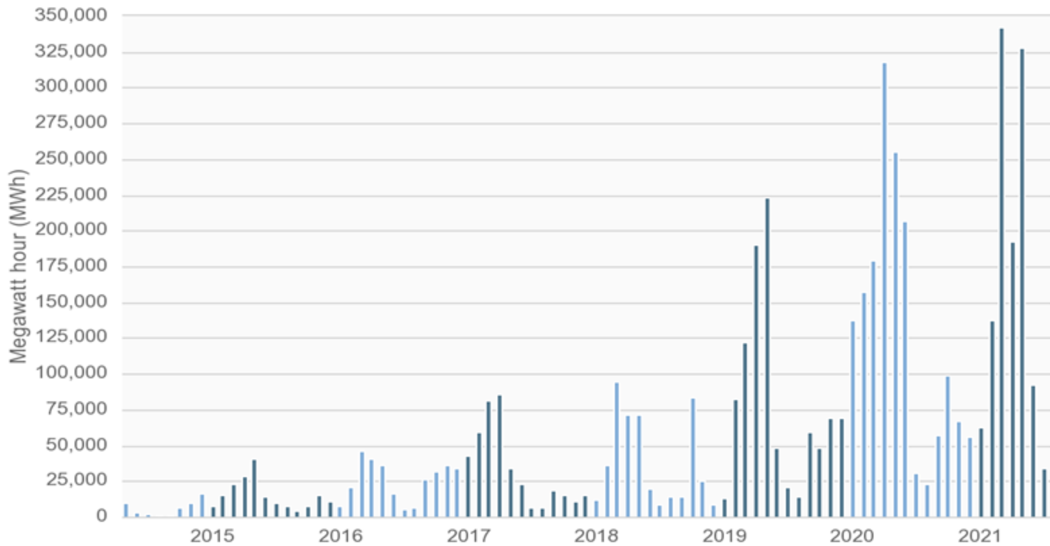

Figure 3-1: Monthly curtailment of wind and solar recorded by CAISO.[23]

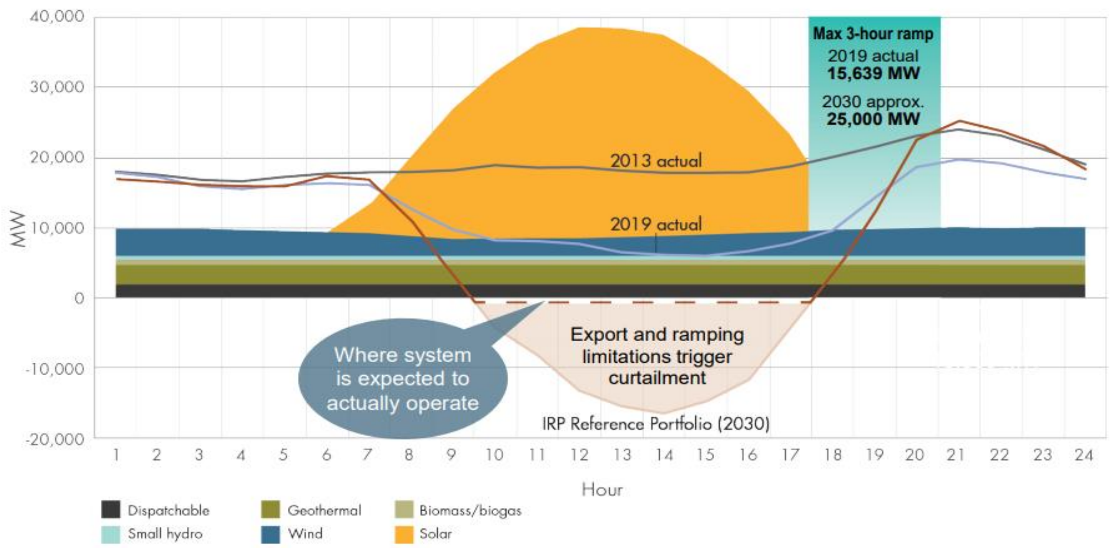

Figure 3-2: CAISO's outlook for projected curtailment and max 3-hour system ramp in 2030.[24]

Large scale curtailment represents a significant opportunity cost in terms of both energy and system capacity. However, with widespread adoption of demand flexibility management equipment and

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[23] *See* "California ISO - Managing Oversupply". (available at) http://www.caiso.com/informed/Pages/ManagingOversupply.aspx

[24] Mark Rothleder, "Briefing on Post 2020 Grid Operational Outlook," CAISO, 2019. (available at) https://www.caiso.com/Documents/BriefingonPost2020GridOperationalOutlook-Presentation-Dec2019.pdf

techniques, customers would have the potential to shift significant load to counterbalance the projected curtailments. This could provide significant support to California's clean energy goals by: (a) increasing renewable integration and reducing GHG emissions, (b) reducing system ramping requirements and improving system reliability, and (c) reducing or minimizing cost of service system-wide.

B. SYSTEM RELIABILITY UNDER DURESS

In addition to the widespread curtailment of renewable energy, the ability of the bulk system operator to ensure system reliability is also under duress, due in large part to:

1. **Increasingly steep system ramping needs**. The CAISO forecasts a 60% increase in the maximum three-hour ramp of system net load, from 15,600 megawatts in 2019 to 25,000 megawatts in 2030 (Figure 3-2).
2. **Increasing reliance on use-limited and intermittent supply resources**. The penetration of use limited resources, such as energy storage or SSDR resources, and intermittent resources, such as solar or wind, is growing rapidly. This, combined with adverse climate change impacts, such as extreme heat waves and drought, has contributed to increasing reliability challenges for California's grid. The 2020 rotating outages and the increasing frequency of grid emergencies called by CAISO could be considered manifestations of these reliability challenges, at least in part.[25]

3.1.2 Increasing Electrification of End Uses

A. TRANSPORTATION

Senate Bill 350[26] (de León, 2015) requires the CPUC to accelerate statewide transportation electrification.

Governor Newsom's Executive Order (N-79-20[27]) directs California to require all new cars and passenger trucks sold by 2035 to be zero-emission vehicles. The recently issued CEC staff report, *Assembly Bill (AB) 2127 Electric Vehicle Charging Infrastructure Assessment*[28], notes that 1.2 million EV

[25] *See* California ISO, "Summary of Alert, Warning, Emergency, and Flex Alert Notices Issued from 1998 to Present." (Updated 1/19/2022). (available at) https://www.caiso.com/Documents/FlexAlertNoticesIssuedFrom1998-Present.pdf

[26] California State Senate, "SB 350 Clean Energy and Pollution Reduction Act of 2015," 2015, https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB350

[27] *See* https://www.gov.ca.gov/2020/09/23/governor-newsom-announces-california-will-phase-out-gasoline-powered-cars-drastically-reduce-demand-for-fossil-fuel-in-californias-fight-against-climate-change/.

[28] Alexander, Matt, et. al., "Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment: Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030 – Revised Staff Report," California Energy Commission, May 2021, Publication Number: CEC-600-2021-001-REV.

chargers will be needed by 2030. Moreover, the state's transportation electrification goals are projected to drive an increase of net load by more than 10% by 2030.[29]

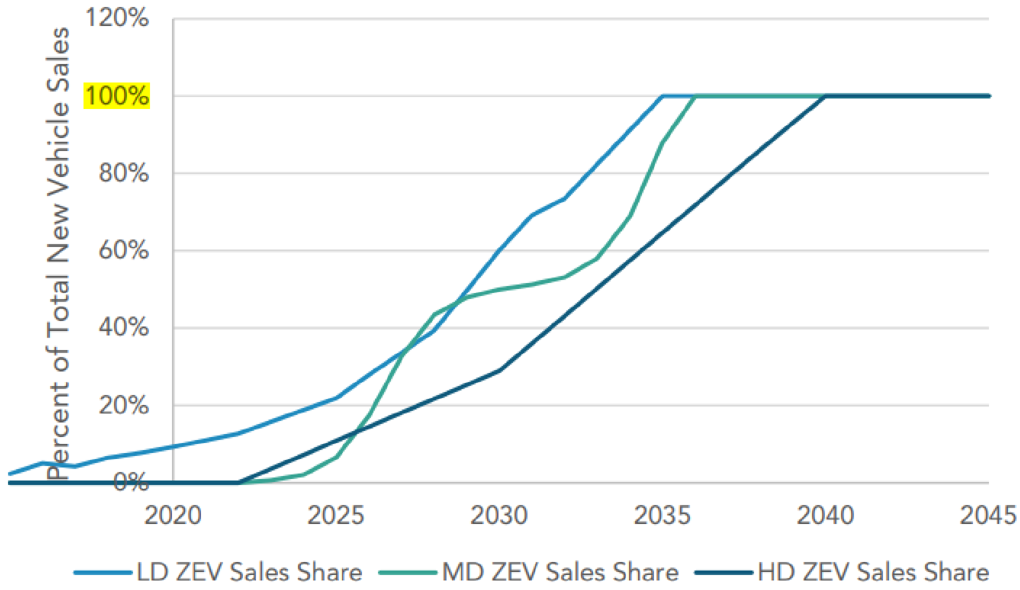

Figure 3-3: Transition of on-road vehicle sales to zero-emission vehicle technology in the CARB Draft 2022 Scoping Plan Proposed Scenario.[30]

The expected increase in load from zero-emission vehicles, if not managed properly, could increase stress on the grid, aggravate reliability concerns, and drive up the cost of electric service, with utilities spending heavily to procure additional resources to ensure adequate supply and upgrade the grid itself to maintain reliability. This concern is highlighted in the CEC staff report, calling for greater alignment between pricing design, renewable electricity, and charging behavior:

> Charging millions of PEVs will introduce significant new load onto the electric grid. CEC models project that electricity consumption in 2030 from light-duty vehicle charging will reach around 5,500 megawatts (MW) around midnight and 4,600 MW around 10 a.m. on a typical weekday, increasing electricity demand by up to 25 and 20 percent at those times, respectively. While current results indicate that nonresidential charging demand will generally align with daytime solar generation, more than 60 percent of total charging energy will still be demanded when sunshine is not abundantly available. Further, a projected surge of charging demand around midnight when off-peak electricity rates take effect may strain

[29] Kavya Balaraman, "This will change the nature of load: what California's zero emission vehicle order means for the power sector", Utility Dive, September 23, 2020. (available at) https://www.utilitydive.com/news/this-will-change-the-nature-of-load-what-californias-zero-emission-vehi/585793/

[30] *See* CARB Draft 2022 Scoping Plan Update, May 10, 2022, at 149. (available at) https://ww2.arb.ca.gov/sites/default/files/2022-05/2022-draft-sp.pdf.

local distribution infrastructure. **To fully realize the economic, air quality, and climate benefits of electrification, California must pursue greater vehicle-grid integration, or coordination of charging with grid needs, to ensure that charging is better aligned with clean, renewable electricity without sacrificing driver convenience.**[31]

Simultaneous or "lockstep" price response behavior is another example of potential negative consequences of rapidly growing vehicle charging if not addressed properly. Since EV TOU rates incentivize charging beginning at midnight, a host of pre-scheduled smart chargers may simultaneously begin charging in lockstep to take advantage of the lower price. This instantaneous spike in load could stress distribution circuits and create challenges for the generation system as well.

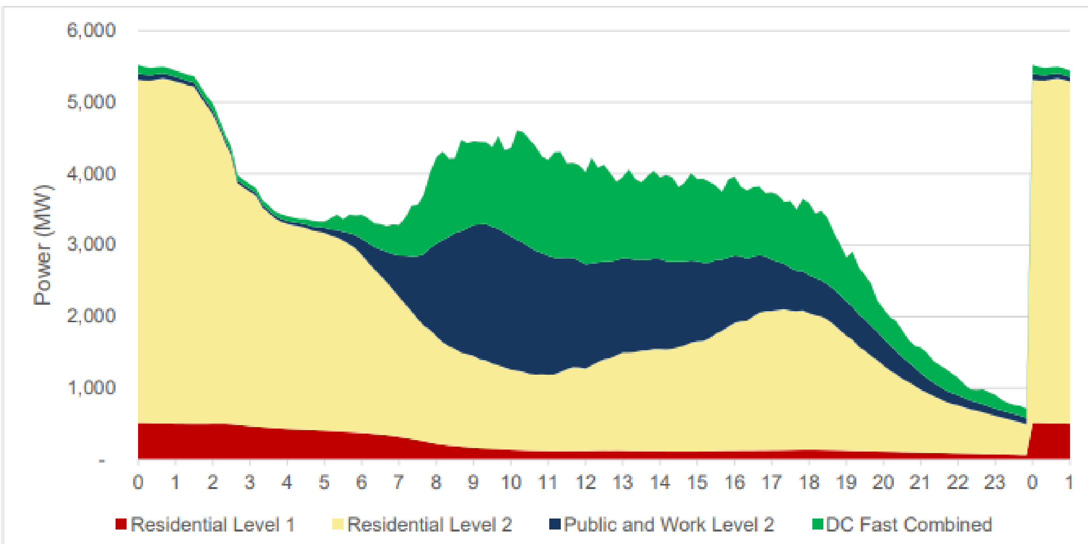

Figure 3-4: Projection of 2030 Statewide charging patterns of light-duty vehicles under current rate structure and incentive schemes on a typical weekday.[32]

Charging management strategies beyond TOU rates may be necessary to align EV charging with daytime solar generation. Additional coordination between residential chargers and the distribution system may also be necessary to mitigate the lockstep charging response that can occur at the onset of the super off-peak period (midnight).

The imperative to pursue more effective vehicle-grid integration (VGI) is also a statutory obligation: the Legislature in Senate Bill 676 (Bradford, 2019) has directed the CPUC to "consider how, or if,

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[31] Alexander, Matt, et. al., "Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment: Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030 – Revised Staff Report," California Energy Commission, May 2021, Publication Number: CEC-600-2021-001-REV.

[32] *Ibid.*

electric vehicle grid integration can mitigate any generation, transmission, or distribution costs, or increase the economic, social, or environmental benefits associated with transportation electrification." The legislature defined VGI broadly to include "any method of altering the time, charging level, or location at which grid-connected electric vehicles charge or discharge, in a manner that optimizes plug-in electric vehicle interaction with the electrical grid and provides net benefits to ratepayers."[33]

B. BUILDINGS

Assembly Bill 3232 (Friedman, 2018) requires the CEC to work with other state agencies, including the CPUC, to assess how GHG emissions in buildings can be reduced, primarily by fuel switching from fossil fuels to electricity as the primary source of energy.[34] Studies indicate that as customers adopt electrified end-uses (such as electric HVAC, heat pump water heaters, electric cooking, etc.), this could lead to a 60% increase in electric sales and a 40% increase in peak load by 2045.[35] As more and more customers adopt smart home technologies and storage, cost-based rates that facilitate these goals, and leverage their DR capabilities, are needed.

3.1.3 Deployment of Customer BTM DERs

California has led the nation in adoption of customer-sited BTM DERs including rooftop solar PV and energy storage, with more than 11,000 MW of solar PV capacity and 700 MW of energy storage capacity installed to date (Figure 3-5).[36]

Analysis from CEC's 2020 Integrated Energy Policy Report Update (IEPR) forecasts Statewide BTM PV production to grow from 21,000 GWh in 2021 to 41,200 GWh in 2030, and BTM energy storage capacity to grow from 700 MW in 2021 to 2,600 MW in 2030.[37] Along with the anticipated growth in EVs that was highlighted above, there is a pressing need to integrate the forecasted DERs and EVs in a cost-effective manner.

Stakeholders have highlighted the need for a scalable, long-term strategy for aligning the dispatch of customer DERs to both contain utility costs and address the challenges of a high renewables grid.[38] In the adopted Version 2.0 of its DER Action Plan, the CPUC has presented its goal of ensuring

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[33] California State Senate Bill No. 676, Bradford, "Transportation electrification: electric vehicles: grid integration", October 02, 2019.

[34] California State Assembly Bill No. 3232, Friedman, "Zero-emissions buildings and sources of heat energy," September 13, 2018.

[35] *See* "Pathway 2045: Update to the Clean Power and Electrification Pathway," Southern California Edison, November 2019. (available at) https://www.edison.com/home/our-perspective/pathway-2045.html

[36] *See* California Distributed Generation Statistics. (Accessed on March 15, 2022). (available at) https://www.californiadgstats.ca.gov

[37] *See* CEC Self Generation and Overall Electricity Demand Forecast Update – Commissioner Workshop on Updates to the California Energy Demand 2019-2030 Forecast. (available at) https://www.energy.ca.gov/event/workshop/2020-12/session-2-self-generation-and-overall-electricity-demand-forecast-update

[38] *See* Brad Heavner (California Solar and Storage Association), "Reforms to Contain Utility Costs and Rate Growth," 2022 CPUC Affordability Rulemaking Phase 3 (R.18-07-006) En Banc. (available at) https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability.

that DERs can be more effectively and equitably integrated into the grid through cost-based dynamic rates that improve grid resource utilization.[39]

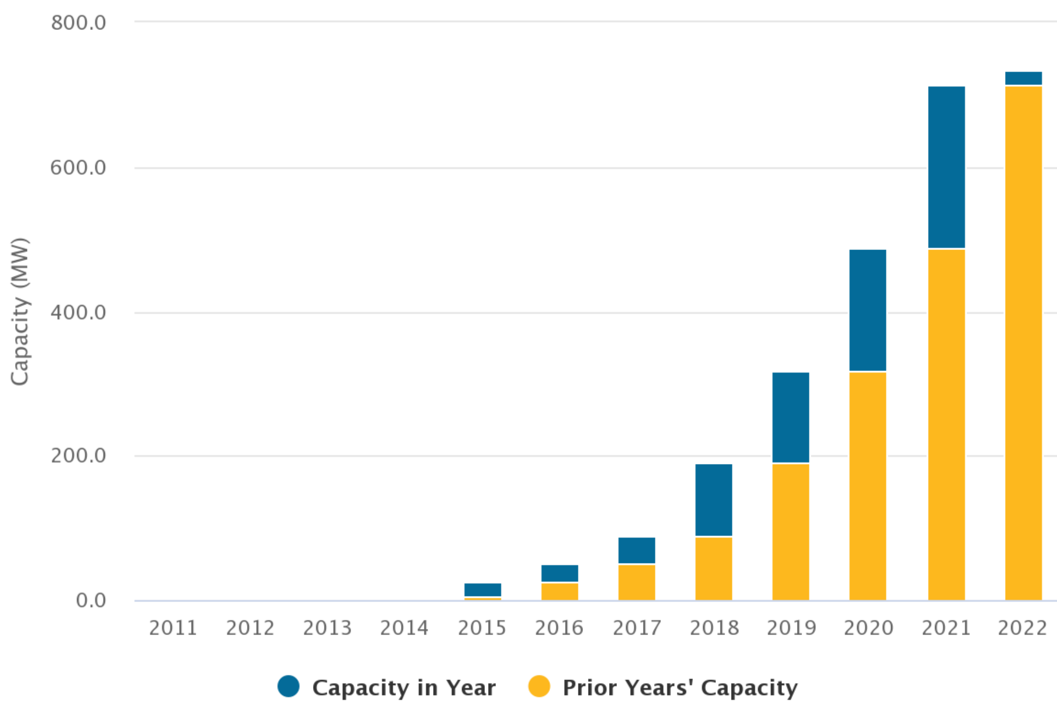

Figure 3-5: Customer-sited energy storage installed in California as of March 2022.

3.2 Growing Potential for Demand Flexibility

3.2.1 Growth in Flexible Loads

Recent studies[40] that have analyzed the costs and benefits of DERs, and flexible resources show that a co-optimized system—i.e., a system that optimizes both the planning and dispatch of DERs—can

[39] Note: Summary of DER Action Plan 2.0 is described in the Appendix, Section 2.1.

[40] Reeve, Hayden, et. al., "Distribution System Operator with Transactive (DSO+T) Study Volume 1: Main Report," Pacific Northwest National Laboratory (PNNL), 2022. (available at) https://doi.org/10.2172/1842485.

achieve significant long-term cost savings and partially mitigate the curtailment of renewable resources (Figure 3-6).

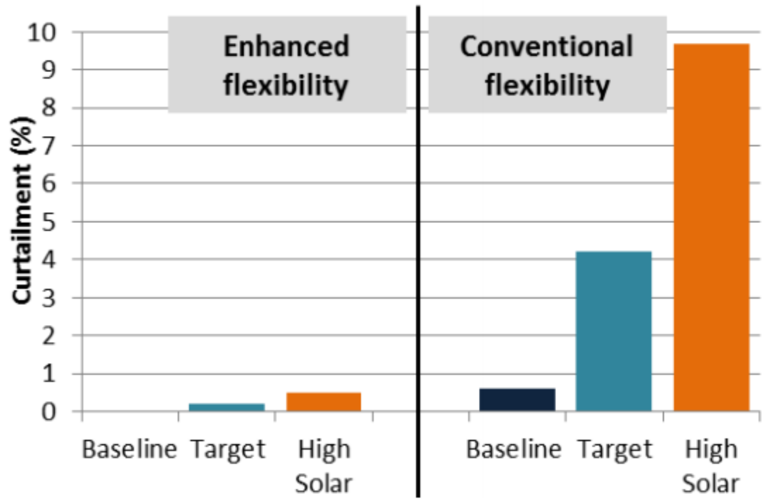

Figure 3-6: The impact of enhanced flexible resources (e.g., DERs, EV charging, DR, BTM storage) in reducing the curtailment of projected renewable generation in California in 2030.[41]

Lawrence Berkeley National Laboratory's (LBNL's) California DR Potential Study Phase 3 Report found that the quantities of flexible loads available at low cost would be sufficient to significantly reduce the amount of renewable energy that is curtailed:

> In 2020, the [potential Shift] resource that is available at or below the battery benchmark amounts to 5.3 GWh of Shift resource, primarily provided by commercial HVAC, industrial process, and agricultural pumping loads. A single dispatch of this entire resource would be sufficient, in principle, to utilize much or all of the otherwise-curtailed energy on an average day in spring 2019 […] The available Shift resource could also shrink the typical evening generation ramp by as much as 50%, reducing the need for costly flexible generation resources.[42]

The LBNL DR Potential Study found that by 2030, California could shift 2-5% of daily load (10-20 GWh) and save $200-500 million (2015$) in annual costs associated with curtailing renewable generation (Figure 3-7). Analysis of the 2019-2020 IRP model showed that without DERs and customer load shift resources providing necessary demand flexibility, installing additional renewable resources will lead to higher levels of curtailment and more extreme ramping requirements.

[41] Brinkman, Gregory, et.al. "Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California." No. NREL/TP-6A20-64884. National Renewable Energy Laboratory (NREL), 2016.

[42] Gerke, Brian, et. al., "The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resource Through 2030," Lawrence Berkeley National Laboratory (LBNL), 2020.

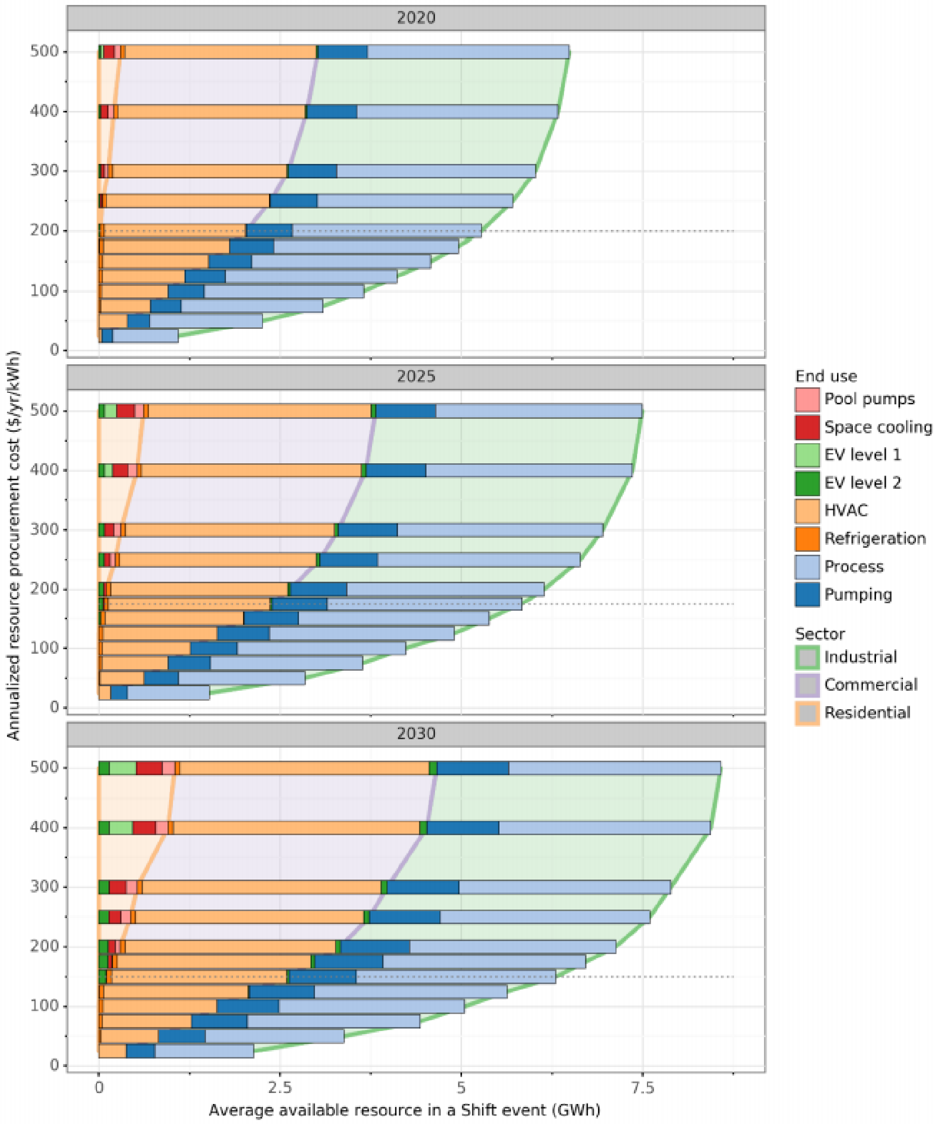

Figure 3-7: Potential Shift resources identified by end use and sector in LBNL's California DR Potential Study Phase 3.[43]

3.2.2 Transportation Electrification Potential

The potential of EVs to provide system-wide benefits is further enhanced if EVs can also sell back their stored energy to the grid (i.e., vehicle-to-grid or V2G). V2G can be used as a reliability resource during high-demand periods. For example, stakeholders have highlighted the ability of

[43] *Id.* Note: The dotted grey horizontal lines show the cost of BTM battery storage for each year. The available quantity of shift resource is shown as the amount of energy (in GWh) that is available per average shift event. There can be multiple shift events in a day.

medium/large vehicles (e.g., school buses in summer months) to be mobile storage resources that can be dispatched to provide locational grid support during critical events. However, export limitations in current utility tariffs need to be addressed along with assessing the appropriate time and location-varying prices that reduce the potential for cost-shift from EV owners to non-owners.

3.2.3 Potential of Buildings and Other End Uses

California has an aggressive set of building and end-use electrification goals to further decarbonize major end-uses of energy in the state. Multiple cities and counties have adopted building codes that require new buildings and/or retrofits to existing buildings to reduce their reliance on gas for heating, cooking, and other end-uses. The use of electric heat pumps for both water heating and HVAC systems is expected to grow significantly. These resources can significantly enhance customer demand flexibility, especially if integrated with smart home or automation technologies.

3.2.4 Conclusions

California's climate goals achieved through electrification will significantly increase the use of electricity for a variety of end-uses and create new classes of loads with significantly more flexibility. End-use electrification provides opportunities to reduce household energy costs. Electrified buildings can store energy by pre-cooling/pre-heating and can reduce customer energy bills by responding to the price of energy to schedule their HVAC and water heating operations. The scheduling of electric water pumping can be a major source of load shift in the agricultural sector. Managed charging (V1G and V2G) of EVs and optimized dispatch of energy storage can provide system-wide benefits while reducing customer energy bills.

It is important to highlight that most of the load shift potential discussed in this section should be available at little or no reduction in the value of service or comfort to consumers. Traditional load shedding programs that are focused on a limited number of events for the year typically involve a trade-off between the available incentive through the DR program and the utility or comfort of the end-use load. Load shift through pre-cooling/heating buildings or scheduling of EV charging does not impact the value of the service associated with the loads. As the LBNL report notes:

> For many shiftable end-uses, a multi-hour shift can often be executed with a minimal impact on the customer's perceived level of energy service: for instance, delaying the operation of an appliance for a few hours, or pre-cooling a building to enable an evening load reduction, may not have noticeable impacts on customer convenience or comfort.[44]

As discussed in the next section, the current approaches to most DR programs and rate structures are unlikely to provide a streamlined path to unlocking the full value-stack of end-use electrification.

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[44] Gerke, Brian, et. al., "The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resource Through 2030," Lawrence Berkeley National Laboratory (LBNL), 2020.

3.3 Issues with Current DR Strategies and Retail Rates

As noted earlier, there appears to be some stakeholder sentiment that the current bifurcated approach to demand response policies (SSDR and LMDR) taken together has become overly complex and confusing, is not well positioned to address the emerging grid needs and is a barrier to scaling demand management solutions to the levels necessary to support California's clean energy goals.

3.3.1 Critical Issue Areas for Supply-Side Demand Response

Over the last 20 years, the CPUC has pursued a multipronged approach to demand response and worked systematically to improve its reliability and scale.

Perhaps one of the most significant milestones in the CPUC's evolution of demand response came in 2015 with the development of the supply-side DR (SSDR) pathway involving the integration of utility load shed programs into the CAISO's wholesale energy market, allowing them to compete directly on an economic basis with conventional fossil-based generation. Working closely with the CAISO, which developed market models to allow DR resources to participate in the CAISO market, the CPUC developed Rules 24 & 32 governing retail customer participation in wholesale markets via DR market products.

In addition, a "click-through" tool was developed by the IOUs for customers electing to enroll in competing DR programs offered by third-party DR providers and grant those third-party DR providers access to their data while protecting customer privacy. Complementing this was the cultivation of a competitive ecosystem of third-party DR providers through the Demand Response Auction Mechanism (DRAM), and IOU "all source" solicitations where DR and other clean energy resources compete against conventional generation. More recently, Community Choice Aggregators (CCAs) have become active in procuring SSDR resources.

Tremendous accomplishments have been achieved in the development of supply-side demand response over several years. However, experience with SSDR programs has revealed significant challenges and costs and DR capacity procurement has not scaled as hoped. At the same time, the needs of the grid have evolved significantly, and there are indications that the market integrated DR products may have limited flexibility in addressing the emerging grid challenges.

Some stakeholders have expressed concerns that the incentive based SSDR pathway appears inherently limited in scalability. As further elaborated below, major issues with the SSDR framework include high complexity, high costs, misalignment between system needs and customer expectations, and limited flexibility.

While the SSDR program portfolio is expected to continue playing an important role in system reliability, the proposed CalFUSE framework described in Chapter 4 is designed to scale demand flexibility to the levels needed to address emerging grid challenges discussed earlier in this chapter.

A. HIGH COMPLEXITY

Stakeholders have noted concerns about high complexity associated with SSDR resource procurement mechanisms and program implementation.

Procurement Mechanisms

The SSDR procurement landscape in California has been evolving and has been criticized as complex and confusing. Below is a summary of the various mechanisms currently in play to procure SSDR resources among CPUC jurisdictional service areas.

Programs administered by IOUs include:

a) Emergency programs (with participation by directly enrolled customers or third-party aggregators), which can be dispatched by the CAISO for emergencies only.

b) Capacity bidding programs (with participation by third-party aggregators enrolling mostly commercial customers), where the DR resources are bid into the CAISO market by the IOUs on an economic basis in competition with generators.

c) A/C cycling programs (with participation by directly enrolled customers), which can be dispatched for emergencies or bid economically by the IOUs into the CAISO market.

d) All-source solicitations run by the IOUs to procure longer term (multi-year) contracts (e.g., Local Capacity Requirement contracts) for resource adequacy capacity to address projected insufficiency in supply portfolio - SSDR resources offered by third-party aggregators are eligible to compete in the solicitations and have sometimes been selected.

Programs administered by third-party DR providers[45] include:

a) DR resources selected and contracted by the IOUs via the DR Auction Mechanism (DRAM) to meet short-term resource adequacy obligations. DRAM has been in progress for 8 years as a pilot program, with its ultimate future to be decided by the CPUC in a pending DR proceeding.

b) DR resources selected and contracted by the Community Choice Aggregators (CCAs) to meet their resource adequacy obligations.

c) DR resources contracted bilaterally by the IOUs, pursuant to the summer reliability decision D.21-12-015.

Each procurement vehicle listed above involves various evolving policies (such as eligibility, incrementality, dual participation, etc.), different program design elements, including incentive structure and dispatch parameters, variations in performance & penalties, and unique contractual terms and conditions.

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[45] Note: A key difference between third-party DR aggregators and third-party DR providers is that the CAISO market bidding strategy for resources offered by aggregators is controlled by the IOUs. In the latter case, the market bidding strategy for the underlying resources is controlled by the third-party.

This patchwork procurement situation creates confusion in the marketplace and complexity for market participants and fails to inspire confidence that any single procurement mechanism (or all mechanisms in aggregate) could scale DR to the level needed to address the evolving grid needs associated with high renewables, electrification, and DER deployment.

Program Implementation

In addition to the differences in policies and rules associated with different mechanisms to procurement SSDR resources, many aspects of SSDR program implementation could be perceived as highly complex by market participants, including (but not limited to):

a) ex-ante qualifying capacity determination,

b) customer enrollment and disenrollment processes,

c) integration with CAISO and IOU processes and IT systems, including challenges in access to customer data,

d) demand response resource integration with and participation in CAISO markets,

e) ex-post performance measurement and settlement processes, and

f) regulatory compliance with CPUC, CAISO, and CEC policies and processes, etc.

Limited Growth

As a result of above complexities involving SSDR procurement and implementation, the learning curve required to participate in the California market is perceived to be steep for potential DR providers. This discourages new market entrants and reinforces market concentration, limiting growth in the DR market.

B. HIGH COSTS

The complexities discussed above contribute to high transaction costs involving substantial efforts in customer education and marketing to recruit customers and maintain customer enrollment, and substantial investment in IT systems and staff resources to support the complex program administration and implementation. Below are some areas where costs add up for DR providers (DRPs), which could be an IOU or third-party DR provider, as they integrate a program with the CAISO market:

a) A DRP must either hire a scheduling coordinator[46] or become one.

b) A customer cannot participate in more than one CAISO demand response "resource," and all customers within the resource must be located within a single sub-LAP[47], limiting

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[46] Note: Only scheduling coordinators are certified to transact business directly with CAISO. *See* http://www.caiso.com/Documents/SCCertificationOverview.pdf.

[47] Note: A sub-LAP is an area within a default load aggregation point (LAP) that group buses with similar grid impacts. *See* http://www.caiso.com/Pages/glossary.aspx

the size of a DR resource aggregation, meaning integration costs are spread over a smaller resource.

c) The DRP must navigate a multi-step technical process to register a resource aggregation with the CAISO.

d) A third-party DRP must pursue a parallel process with the utility distribution company to obtain customer authorization for release of data and then secure that data on an ongoing basis for settlement of customer performance.

e) Expanding the capacity of IOU IT systems to accommodate more Rule 24/32 CAISO registrations, and data provision, has required the CPUC to authorize ongoing upgrades at incremental costs.

Counterfactual assessment and settlement: this ongoing complex process uses baselines derived through stakeholder working groups and CPUC proceedings and involves substantial investment in data collection and IT systems.

Determination of DR resource qualifying capacity eligible for resource adequacy: Program administrators must follow an annual rigorous load impact protocols process to report ex-post resource performance. This exercise typically forces a DRP to contract with highly specialized independent program evaluators and incur significant expense in the process.

The accumulation of costs associated with various aspects of market integrated DR could be regarded as a serious issue in limiting the scalability of DR programs.

C. MISALIGNMENT BETWEEN SYSTEM NEEDS AND CUSTOMER EXPECTATIONS

While SSDR programs directly compete with conventional generation to meet electricity demand, the SSDR resources are inherently different. Unlike a generator, these resources are clean, have no startup time, have no minimum runtime, and are not affected by transmission failures or line losses. However, customers providing demand response may experience temporary disruption or reduction in service level or inconvenience from turning down lighting, HVAC and other end uses – sometimes referred to as being "hot and dark." This disruption is often associated with customer complaints and attrition.

Capacity payments for SSDR programs can be an attractive incentive to customers for inducing them to be available on call to reduce demand when the system experiences high prices or stress. However, available energy payments associated with program dispatches can fail to incentivize the customers ongoing participation in events if the customers perceive the compensation to be low relative to the service degradation experienced by them (that is, customers may perceive their marginal or opportunity cost to be higher than the compensation). To minimize attrition, program operators seek to avoid dispatch and mitigate service disruption to the customer by bidding high prices into the CAISO market, which in turn reduces the value and effectiveness of the SSDR resources from the CAISO's perspective.

D. LIMITED FLEXIBILITY

Looking forward, the SSDR pathway appears to be limited in flexibility. Stakeholders have identified at least three limitations discussed below.

Limited Load Management Potential Beyond Highest Cost Hours

The SSDR programs focus primarily on load shed during perhaps 30 to 60 hours of highest market prices in the year and are not readily adaptable to encourage the 8760-load shape and shift, the type of DR needed to address the grid challenges identified earlier. The lack of flexibility is highlighted by the CEC's recently initiated rulemaking (CEC Docket Number 21-OIR-03) to amend existing load management standards (LMS). The related CEC Staff Report notes that the rulemaking intends to address the concern that "existing demand response programs are incapable of shifting loads to periods of high renewable generation, and thus are inadequate for supporting the carbon-free grid of the future."[48] This observation is particularly notable given Lawrence Berkeley National Laboratory's estimation of an annual average potential of 5.3 GWh of non-battery Shift DR as of 2020 in California IOU service territories, at a cost equivalent to or less than that of BTM batteries – a resource they estimate could shift over several hours, and be utilized twice per day to mitigate both the morning and evening ramps.[49]

Limited Reach in Addressing Local Conditions

While SSDR programs respond to CAISO system needs, they lack the flexibility to address local distribution needs even though prices, scarcity and congestion vary throughout the system, and customers may be able to respond dynamically to local conditions.

Barriers to Compensation of DER Services

Presently, available SSDR pathways involve various barriers that prevent customer DERs from fully monetizing their capabilities. For example, as some parties have noted, "Most DERs are interconnected under Rule 21, and the only CAISO tariff for these resources is PDR, which does not credit energy exported to the grid."[50]

3.3.2 Critical Issue Areas for Load-modifying Demand Response and Retail Rates

Parallel to the development of SSDR, the CPUC has pursued the development of the load-modifying DR (LMDR) pathway involving time varying rates, encouraging customers to reduce electricity use during events with energy price spikes or shift consumption from periods of higher energy prices to periods of lower energy prices. The use of time differentiated rates on a large scale

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[48] California Energy Commission. "Analysis of Potential Amendments to the Load Management Standards," 19-OIR-01 Final Staff Report, November 2021, at iii. (available at) https://efiling.energy.ca.gov/GetDocument.aspx?tn=241067&DocumentContentId=74898.

[49] Gerke, Brian, et. al., "The California demand response potential study, phase 3: final report on the shift resource through 2030," LBNL, 2020. at 64.

[50] Joint Solar/Storage Parties (SUNRUN, CESA, CALSSA, TESLA, CEERT, VOTE SOLAR, AND ENELX) Track 4 Proposal, January 28, 2021, at 4, in R.19-11-009.

was enabled by the deployment of over 13 million electric smart meters by the California IOUs between 2008 and 2014 at the direction of the CPUC, making them the first utilities in the nation to install smart meters. The IOUs began rolling out mandatory time-of-use (TOU) rates for non-residential customers in 2009. By 2010, the utilities implemented event-based rates for nonresidential customers, referred to as Critical Peak Price (CPP), offering relatively low energy prices during most hours with markedly high prices during a limited number of events.

As noted earlier, stakeholders have suggested that a comprehensive review of the electricity rates policies underlying the LMDR approach is needed to address a range of serious issues, including the proliferation of "boutique" technology-specific rates (e.g., for solar, electric vehicles, and storage), incentives for uneconomical load management, non-equitable fixed cost recovery and related cost shifts, and inability to monetize DER capabilities. The proposed CalFUSE framework described in Chapter 4 is designed to address these issues.

A. INACCESSIBILITY, INEFFICIENCIES, AND CONFUSION ASSOCIATED WITH PROLIFERATION OF SPECIAL PURPOSE RATES

In recent years, the retail electric rates ecosystem has experienced a proliferation of specialized rate structures to support disparate policy goals, and the manner in which this has occurred can fairly be characterized as ad-hoc and piecemeal. Customers and service providers face challenges in navigating tariff options and discovering the appropriate price signals to respond to due to a lack of transparency and availability. Customer choice in establishing the right rate offering based on consumption patterns is an important goal, but the eventual phasedown, elimination or consolidation of older tariff offerings will be required to minimize confusion and promote accessibility, scalability, and uniformity of price signals and cost recovery mechanisms.

A proliferation of rate structures can result in increased overhead (e.g., in revenue cycle services, maintenance and adaptation of rate schedules, migration of customers) that translates to an incremental fixed cost. While maintaining an appropriate menu of rate options is a longstanding ratemaking goal for the CPUC, managing an ever-expanding slate of tariff options across IOUs can be burdensome and carry unintended consequences.

Furthermore, the confusion associated with rate structure proliferation impedes customer awareness of the current electricity prices as well as automation options and wider-scale adoption of demand flexibility solutions. Most utility customers in California do not have any access to the current price of electricity (Figure 3-8). Traditional tiered retail rates further remove the link between the actual price of electricity and the cost to serve a specific customer. Certain programs enable select customer segments access to some real-time information. For instance, the Self-Generation Incentive Program (SGIP) provides customer access to a real-time GHG signal, though not real-time prices. In addition, this program is limited in scope with a small userbase.

Staff suggests that universal access to the current price of electricity is a critical step in enabling customer load shift, load management practices and other behaviors that are needed to meet the state's climate goals reliably and economically. The state should promote electricity pricing information via a standardized platform with machine-readable prices and technologies that support automation of load management, including smart inverters and EV charging hardware.[51]

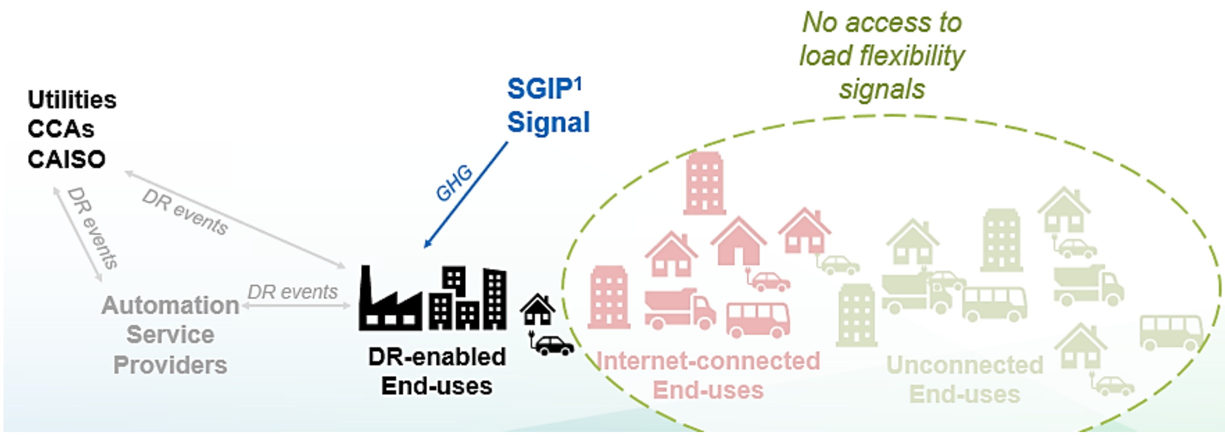

Figure 3-8: Present status of load management in California.[52]

B. MISALIGNMENT BETWEEN RETAIL RATES AND GRID ECONOMICS

Most retail rates deployed currently in California do not reflect real-time, locational energy costs or grid conditions such as scarcity or congestion in utilization of capacity limited infrastructure (e.g., distribution circuits and generation portfolio). Hence, the actual economic cost to deliver reliable and low-carbon electric service is not conveyed in price signals. This encourages customers to pursue economically *inefficient* demand management in response to the price signal, potentially raising the cost of service. In addition, distribution and system peaks can occur at different times; some circuits can peak during super off-peak hours. The lack of a locationally-informed price for capacity cost recovery encourages inefficient outcomes, such as EV charging while circuits are already peaking, resulting in sub-optimal grid utilization, which in turn leads to adverse and inequitable impacts on cost of service.

Historically, there was limited motivation to consider the responsiveness of demand-side resources because there was limited BTM flexibility that could significantly impact operations and planning at the circuit or system level. In addition, conventional supply-side resources were able to operate flexibly to meet system demand. As variable output renewable resources have started to become a larger share of the available generation mix, conventional (centrally-dispatchable) supply-side grid flexibility has become more constrained, and system reliability has been stressed during peak demand periods and extreme weather events.[53] However, the proliferation of renewable generation has also been accompanied with the adoption of demand-side resources that, as highlighted in prior sections, can be more flexible than in the past and can modify a customer's net load profile. Multiple

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51 Note: The CEC has outlined a vision for a universal price portal (MIDAS) as part of the LMS proceeding.

52 See CEC staff presentation from Workshop on Draft Load Management Standards Staff Report on April 12, 2021. https://www.energy.ca.gov/proceedings/energy-commission-proceedings/load-management-rulemaking.

53 D.21-12-015, at 5-6.

Staff analyses[54], stakeholder testimonies[55], and research studies[56] have attested to the fundamental disconnect between grid economics and current retail rates. Aligning the incentives of supply-side and demand-side resources can unlock the huge potential of a transformed grid where renewable resources are balanced through responsive loads and DERs. A guiding principle that merits repeating is:

> Rate design should ensure that the choices a customer makes to minimize its own bill are consistent with the choices it would make to minimize system cost.[57]

C. INCONSISTENT COMPENSATION POLICIES FOR BTM DER ENERGY EXPORTS

California's climate policies have encouraged widespread adoption of a variety of BTM DERs that can export energy to the grid (e.g., rooftop solar, energy storage, EVs) and these technologies will play a crucial role in the success of meeting the state's climate goals. However, as has been highlighted in the prior sections, there is also a danger of increased grid instability and cost of service if DER operations are unmanaged and/or mis-incentivized. Ensuring that retail rates are cost-based and appropriately compensate DERs for their grid services are key elements to sustainably grow the adoption of DERs.

D. TOU RATES ARE NOT SUFFICIENT TO FULLY SCALE FLEXIBLE LOAD MANAGEMENT

TOU rates are designed to encourage customers to modify their usage to take advantage of the price differential between the peak and off-peak periods. To the extent the customer is able to shape or shift load in response to the TOU rate, some bill savings can be achieved by the customer, while also yielding beneficial results for the overall system in the form of a modest reduction in system peak demand. The average summer peak load reduction impact in the statewide TOU pilots was measured at 4.6%.[58] At the end of 2021, more than half of California IOU ratepayers were on a time-varying rate.

The rollout of mandatory non-residential and default residential TOU rates across all IOU service territories over the last few years has been essential in introducing consumers to the concept of time varying rates. Evaluations demonstrated statistically significant summer peak period load impacts, resulting in some incremental system savings and grid efficiencies.[59, 60] However, by design, current

[54] "Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future." CPUC Staff White Paper, 2015.

[55] "Final Report of the CPUC's Working Group on Load Shift", January 2019. (available at) https://gridworks.org/initiatives/initiatives-archive/load-shift-working-group/.

[56] Borenstein, Severin, et. al., "Designing Electricity Rates for An Equitable Energy Transition", Next 10 Report, February 2021. (available at) https://www.next10.org/electricity-rates.

[57] Linvill, Carl, and Jim Lazar. "Smart non-residential rate design: Aligning rates with system value." The Electricity Journal 31, no. 8, 2018, at 1-8.

[58] George, Stephen, et. al., "California Statewide Opt-in Time-of-Use Pricing Pilot: Final Report", Nexant, March 2018.

[59] Bell, Eric, et. al., "2020 Load Impact Evaluation of Southern California Edison's Default Time-of-Use Pilot," Nexant, April 1, 2021

[60] Hansen, Daniel, and David Armstrong, "2020 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-of-Use Rates," Christensen Associates Energy Consulting, April 1, 2021.

TOU rates are necessarily coarse insofar as they consist of average blocks of differentiated price signals. Consequently, the rates do not go far enough in providing a full range of economic incentives for customers to align their energy consumption (or generation) with the dynamic needs of the electricity system. An analysis of 2019 SDG&E prices conducted by Joint Advanced Rate Parties (JARP) and Enel X NA shows that 57% of the highest-priced intervals for wholesale energy prices fell outside the TOU on-peak period.[61] This observation alone offers a persuasive rationale for bringing retail rate structures closer to the dynamic nature of wholesale market conditions and pricing if the state is to capture the grid and prosumer benefits of increasingly flexible end uses and greater elasticity of demand in the electric sector.

Ultimately, TOU rates typically feature two or three period rate designs, which are ostensibly too blunt of a pricing instrument to maximize voluntary customer engagement in opportunistic (price-responsive) load shift. TOU periods and pricing differentials are fixed and determined in advance through a long-term rate design process, while RTP rates fluctuate as a reflection of wholesale market conditions and the dynamic equilibria of supply and demand. Thus, any changes to grid conditions, including those driven by emergency events called by CAISO, are not reflected in TOU rates, unless the customer participates in a Critical Peak Price (CPP) program. Analysis comparing the CPUC Avoided Cost Calculator (ACC) to TOU rates highlights the limitations of the TOU rate in capturing utility costs (Figure 3-9). Indeed, the divergence between TOU rates and utility costs grows even more acute when wholesale market energy prices are incorporated into comparisons.

A dynamic rate structure that is updated based both on the variability of renewable resources (both seasonal and diurnal) and the real-time constraints of the electric system can encourage load shift that reduces long-term system costs and provides reliability benefits to the grid.

[61] *See* Supplemental Testimony of Joint Advanced Rate Parties (JARP) for SDG&E Application A.19-03-002 at 6. (available at) https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1007009/3039/345925598.pdf.

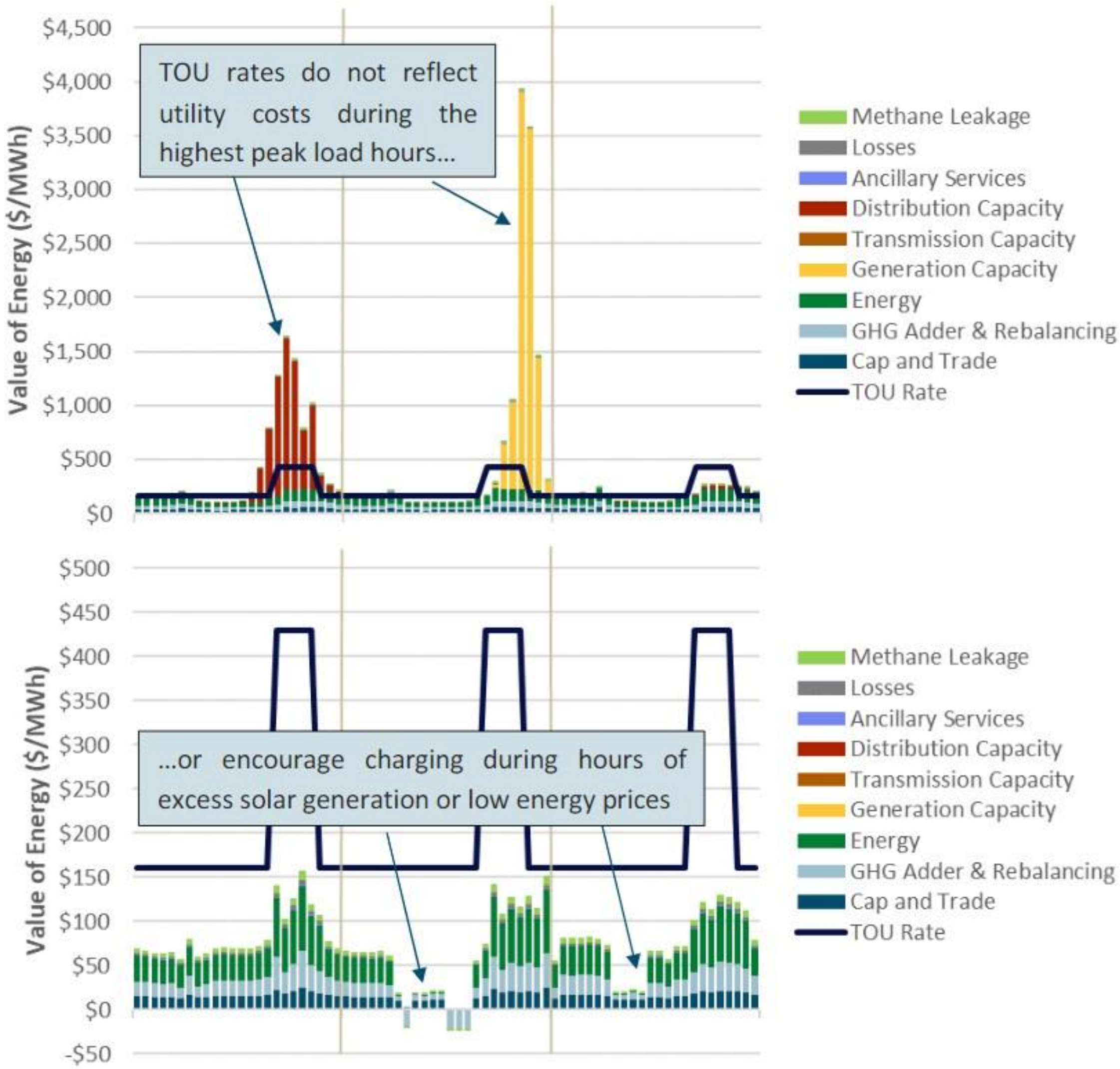

Figure 3-9: 2025 CPUC Avoided Costs Compared to TOU EV Rate (Top: 3 days in September. Bottom: 3 days in June).[62]

[62] Note: Based on CPUC Avoided Costs in 2025 for Climate Zone 9 (Los Angeles) and SCE TOU-D-PRIME Rate for EVs. *See* Eric Cutter, et. al., "Design Principles and Options for Retail Tariffs that Support Vehicle-Grid Integration." E3, October 2020. (available at) https://willdan.app.box.com/v/VGIRatePaper.

E. COUNTERPRODUCTIVE DEMAND CHARGES INHIBIT LOAD SHIFT AND REQUIRE REFORM

The current method of capacity cost recovery through coincident and non-coincident demand charges for many non-residential customers reduces incentives for economically efficient customer demand management, energy conservation, and investments in BTM DERs.

Background

Demand charges are one of the key pillars[63] of rate design for fixed cost recovery used by California IOUs for medium and large commercial customers,[64] and they often constitute a significant portion of non-residential customer bills. They were originally intended to reflect a utility's costs to support a reliable grid with sufficient capacity to meet the maximum demand of non-residential customers.

Some stakeholders consider these capacity-based charges to be a legacy of a bygone era in utility ratemaking in which commercial and industrial customer demand (load) was flatter, more predictable, and relatively inelastic, with little penetration of BTM renewable resources, energy storage and other DERs.

Demand charges are based on peak electricity consumption measured monthly in kilowatts (kW). In other words, demand charges represent the intensity of demand for power that each individual customer uses at a single point in time (the shortest metered time interval) and reflect the capacity cost needed to meet that customer's maximum consumption levels.

There are currently two types of demand charges in commercial and industrial rates: Coincident Demand Charge (CDC)[65], which reflects the highest individual customer demand measured during system peak hours, and Non-Coincident Demand Charge (NCDC), which reflects the highest individual customer demand any time of the day. Currently, the California IOUs utilize monthly demand charges that are measured based on the customer's highest 15 minutes of usage during the month. Utilities recover generation, distribution capacity, and, for a few specific large customers, transmission costs through demand charges (

63 Note: Along with fixed charges and volumetric charges.

64 Note: Residential customers currently do not pay demand charges in California.

65 Note: Sometimes called Peak Demand Charge.

Table 3-1). Utility tariffs often have maximum allowable power demand restrictions, which forces customers to be on schedules with higher rates and higher demand charges.

Table 3-1: How California IOUs Recover Generation, Transmission, and Distribution Capacity Costs for Non-Residential Customers.[66]

Revenue Component	Recovery Mechanism
Generation	• Recovered through both per kW and per kWh components. • Per kWh components are TOU. • Per kW components reflect generation capacity costs and are typically recovered using CDCs. Some utilities apply CDCs only during summer peak periods.
Distribution	• Monthly per-meter fee that reflects customer-specific costs, such as final line transformer, hookup, and service (metering, billing, etc.), predominantly for non-residential customers. • NCDCs and CDCs that may be differentiated by season and voltage levels. The split between NCDCs and CDCs varies across the IOUs.
Transmission	• NCDCs for most Medium/Large customers. • Revenue requirement is determined through FERC approval. CPUC has encouraged IOUs to file with FERC to move to time-dependent rates.[67] In 2008, SDG&E was approved by FERC to collect a portion of transmission revenues for Medium/Large commercial customers through seasonally differentiated CDCs.

Issues with the Current Implementation of Demand Charges

Researchers have identified several problems with the way demand charges are currently implemented. For example, a detailed discussion of the limitations of demand charges is presented in the 2017 Regulatory Assistance Project (RAP) report: "Smart Non-Residential Rate Design."[68] A quick overview of some of these limitations is presented below:

1. **Demand Charges, as currently designed, impede BTM DER and EV charging infrastructure deployment.** Demand charges, by effectively ignoring the grid's temporal needs, promote inefficient deployment and dispatch of energy storage and EV charging. Demand charges can also undercut the financial benefits of building and transportation

[66] Linvill, Carl, et. al., 'Smart Non-Residential Rate Design," Regulatory Assistance Project, 2017.

[67] *See* D.14-12-080 at 21; or D.17-08-030 at 92, ordering paragraph 34.

[68] Linvill, Carl, et. al., "Smart Non-Residential Rate Design," Regulatory Assistance Project, 2017.

electrification since electrified end-uses can increase a customer's peak load. As such, demand charges are incompatible with State GHG reduction and electrification goals.

2. **CDCs do not incentivize customer peak load reductions when most needed by the system.** As currently implemented, CDCs are based on a customer's single 15-minute peak demand over a month during a predefined peak period window. However, a customer's single peak measurement may not occur on a day when the net system demand is at peak, which is typically on hot summer days.

3. **NCDCs arguably represent a deviation from the cost causation principle and can lead to increased GHG emissions.** NCDCs, by penalizing demand even when timed to be beneficial to the grid, can send an economically inaccurate and inefficient signal that is disconnected from the factors that drive system costs. For example, to reduce its NCDC, a customer with a natural mid-day peak load (normally the most favorable time in California from a system perspective) might shift some of that consumption into hours when the remainder of the system is on peak or using GHG-emitting resources. This problem was identified early in the Self-Generation Incentive (SGIP) Program.[69] To address this situation, program rules were modified to provide a GHG-emission signal that energy storage controls systems could use to guide the dispatch of the storage devices such that the charging period is better aligned with local solar generation, improving the likelihood of overall emissions reduction.[70] But these measures are merely proxy solutions that do not comprehensively resolve the fundamental misalignment between grid economics and the rate structure.

4. **Demand charges can perversely incentivize customers to worsen grid conditions.** Monthly demand charges can result in counter-productive behavior. Once a demand charge has been incurred, the incentive to conserve is removed; the customer will pay the demand penalty regardless of usage for the remainder of the month.

In compliance with SB 1000[71], the CPUC has been considering rate strategies that can reduce the effect of demand charges on EV drivers. The EV rates that have been approved by the CPUC for each of the 3 large electric utilities are examples of the CPUC's policy in this regard. In D.18-05-040, the CPUC approved an EV rate for SCE customers for the first five years that does not include any demand charges. In the SCE rate, the demand charges would be introduced annually in year six, increasing to full cost by year 11. Similarly, the CPUC approved a Commercial Electric Vehicle rate for PG&E[72] and an Electric Vehicle High Power rate for SDG&E.[73] In the latter two rates, the demand charges are reduced and converted to monthly "subscription charges", where customers choose a subscription level based on their forecasted maximum EV charging demand, in order to

[69] 2017 SGIP Advanced Energy Storage Evaluation Report, at 1-9.

[70] D.19-08-001 at 11.

[71] Pub. Util. Code §740.15(a)(2). SB 1000 (Stats. 2018 Ch. 368).

[72] D.19-10-055.

[73] D.20-12-023.

promote EV adoption. Note that the "subscription charge" is similar to a demand charge in its rate design, however it is discounted relative to traditional demand charges.

In summary, maintaining demand charges as a primary mechanism to recover capacity costs from non-residential customers is counter-productive to California's long-term conservation and climate goals and is no longer aligned with grid economics.

Demand Charge Case Studies

1. **Case Study #1: Electric School Buses.** The example of electric school buses is often discussed to highlight the limitations of existing rate structures. Electric school buses (and other Medium/Large Duty EVs) can have a seasonal usage pattern. School buses are used less often during the summer months. There is potential to use these vehicles as storage resources during months when net demand flexibility is needed due to reliability concerns. However, NCDCs and export limitations can prevent the actualization of the value stream. NCDCs may disincentivize charging of the bus fleet even at times when renewables are plentiful, energy costs are low, and the system may have excess network capacity. Research from NREL shows that demand charges force EV fleet managers to deploy on-site storage to reduce on-site peak load, which is not coincident with system peak load.[74] Energy export limitations are especially problematic during summer months when there is very limited on-site load to displace at a school. These structural barriers are at cross-purposes with system optimization and cost minimization, preventing monetization of potential grid services and increasing the transition costs of transportation electrification for fleet owners.

2. **Case Study #2: DC Fast Chargers.** In order to promote EV adoption, Senate Bill 350 mandated that public EV charging must be competitive with fossil fuel prices.[75] However, demand charges, especially NCDCs, are a major financial obstacle to economic EV and fleet charging, particularly for public high-powered DC fast charging (DCFC) stations.[76] For example, DCFCs with low customer utilization but high instantaneous power demand can be difficult to sustain financially, as high demand charges are spread over a lower volume of electricity sales. This is an issue for equitably promoting widespread transportation electrification, as serving remote or underserved communities without access to home charging often means operating stations with lower utilization rates. In A.20-10-011, PG&E's commercial EV RTP pilot proceeding, many stakeholders have raised the concern that demand charges can result in high average cost per kWh for commercial EV charging providers.[77] As part of this proceeding's testimony, EPRI interviewed numerous stakeholders about Commercial EV rate design and consistently found that stakeholders were the most concerned about the uncertainty and financial risk that demand charges

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[74] "Transportation & Mobility Research: Electric Vehicle Smart Charging at Scale." National Renewable Energy Laboratory (NREL). (available at) https://www.nrel.gov/transportation/managed-electric-vehicle-charging.html.

[75] PUC Section 740.12 (a) (1) (H), added by SB 350, De León: Clean Energy and Pollution Reduction Act of 2015.

[76] "From Gas to Grid", RMI. (available at) https://rmi.org/wp-content/uploads/2017/10/RMI-From-Gas-To-Grid.pdf.

[77] *See* PG&E's supplemental testimony for CPUC proceeding A.20-10-011. (available at) https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=645708.

introduce, weakening the business case for public EV charging. In the same proceeding, stakeholders have stated that DCFCs with integrated storage have the capability to reduce the curtailment of renewable energy by charging the BTM storage during off-peak hours and using the stored energy for EV charging during peak hours.[78] However, demand-charge related constraints have been highlighted as inhibiting the potential of DCFC-coupled storage.

3.3.3 Conclusions

Current SSDR and LMDR (retail rates programs) do not provide sufficient incentives to manage DER dispatch and EV charging, nor do they provide customer bill savings that are aligned with system cost savings. In aggregate, a lack of proper incentives could compromise California's ability to cost-effectively meet its decarbonization goals due to excess spending on distribution infrastructure and generation resources to meet the demands of unmanaged electrification.

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[78] *See* Electrify America, LLC.'s brief for CPUC proceeding A.20-10-011. (available at) https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M392/K633/392633820.PDF.

4 Energy Division Staff Proposal

4.1 Summary

CPUC Staff proposes an integrated economic signal as a more effective strategy to address the suite of grid challenges associated with the ongoing transformation of California's electric grid and aforementioned shortcomings of the existing approaches to demand flexibility.

4.1.1 Proposed Vision

This paper recommends that the CPUC establish an ambitious policy vision: To achieve widespread customer adoption of low-cost, advanced flexible demand and DER management and compensation solutions across the state via a unified, dynamic economic signal. Policies in pursuit of this vision should help in addressing the following issues associated with the ongoing transformation of the electricity grid:

1. Mitigate reliability and grid integration challenges associated with high growth in renewables, end-use electrification, and behind-the-meter DER deployment by customers,
2. Minimize short- and long-term cost of service associated with the rapidly evolving electricity infrastructure, and
3. Fully leverage capabilities of customer DERs to address grid needs while providing fair compensation for grid services provided by the DERs.

4.1.2 Proposed Guiding Objectives

In support of the vision, this paper proposes that the CPUC pursue the development of a policy roadmap or framework that should achieve the following objectives:

1. Enhances scalability via standardized, universal mechanisms to enable demand flexibility management.
2. Makes the value of energy and capacity services provided by the grid or DERs more transparent and based on real-time grid conditions.
3. Seamlessly accommodates different and evolving pricing policies of utility distribution companies (UDCs) and load serving entities (LSEs), both inside and *outside* the CPUC jurisdiction.
4. Ensures full recovery of costs associated with the infrastructure for electricity generation and delivery, consistent with cost-causation principles and avoidance of cost-shifts.
5. Offers options to all customers for bill and demand management choices, protection against bill volatility, and forward planning of energy usage or generation.

6. Encourages investment in BTM DERs, including vehicle-to-grid integration and microgrids, without cost-shifts to non-participating customers.

4.1.3 Proposed Policy Roadmap

The centerpiece of the Staff proposal is a unified, universally-accessible, dynamic, economic retail electricity price signal that is supported by six key policy elements organized in three pillars of the CalFUSE framework as summarized below and illustrated in Figure 4-1.

1. **Price Presentation** of the electricity rates in the form of CalFUSE price signal to customers and their devices to enable automated demand flexibility solutions,
2. **Rate Reform** involving a three-prong strategy to create the CalFUSE price signal for encouraging the development of demand flexibility solutions, and
3. **Customer Options** to optimize and manage bills and energy imports and exports in response to the CalFUSE price signal to encourage wide-scale adoption of automated demand flexibility solutions.

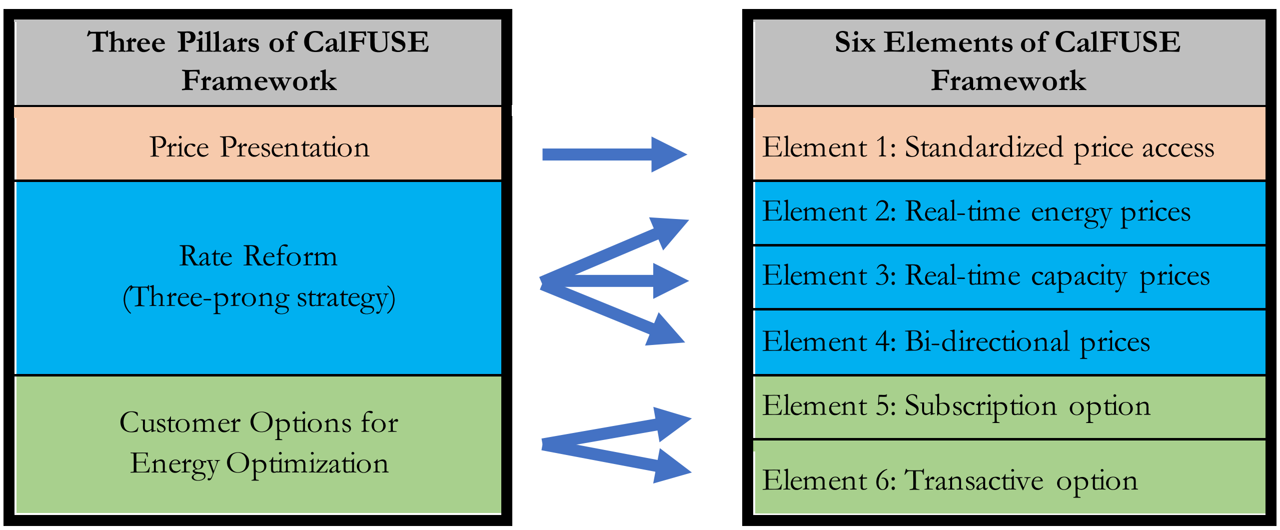

Figure 4-1: The CalFUSE Framework

The six elements (collectively referred to as the "CalFUSE policy roadmap") are summarized below and discussed in further detail later in this chapter:

1. **Develop standardized, universal access to the current electricity price**. A statewide internet-based price portal provides the composite electricity price specific to each customer at any point in time. This portal enables access to the customer-specific current (and forecasted) composite electricity price generated by the "price machine" (see Element 2) based on the price determinant inputs provided by the customer's electricity providers (i.e., the LSE and UDC).

2. **Introduce dynamic electricity prices based on real-time wholesale energy cost.** The commodity energy cost component of the composite electricity price is tied directly to the locational marginal price (LMP) in the CAISO energy market to reflect the localized marginal cost of energy. This cost component is combined by the "price machine" with other price components computed by that price machine based on the price determinant inputs (related to the cost recovery of the grid infrastructure and other fixed costs) to provide the composite electricity price applicable to a particular time, location (or service area), customer, and accessible through the price portal described above.
3. **Modify electricity prices to incorporate dynamic capacity charges based on real-time grid utilization.** The grid infrastructure capacity fixed cost recovery portion of the composite electricity price is dynamically modified based on the real-time utilization level of the locally available capacity infrastructure for electricity generation and delivery, based on the design principle that capacity cost recovery should be higher when the system utilization is higher. The capacity cost recovery price components are computed and combined with other price components by the "price machine" to determine the composite electricity price applicable to a particular location, time, and customer, and accessible through the price portal described above.
4. **Transition to bi-directional electricity prices**. Customers import and export energy based on the same dynamic, composite prices based on cost-causation. This avoids uneconomic arbitrage[79] and enables fair, transparent, rational compensation for grid services provided by customer owned DERs.
5. **Offer a subscription option based on customer-specific load shapes.** Customers may subscribe to a monthly load shape based on historic usage (specified energy quantity for each hour of the day) that is billed at a pre-determined price. This option allows customers to hedge against the volatility of dynamic prices and pay a predictable, pre-determined price for a customer-specific hourly usage profile (i.e., load shape), easing customer transition from legacy rates to the CalFUSE price signal. Customers still have the flexibility to opportunistically modify or to shift their usage (or export energy) based on the dynamic CalFUSE price and maximize their bill savings.
6. **Enable transactive features allowing lock in of future electricity prices.** Customers can execute contracts to import or export energy at some future time at a pre-determined price. This provides customers with additional options to control and optimize energy demand or generation. This also allows greater visibility into future grid conditions, enabling service providers to improve load forecasting, planning and operations.

The elements of the CalFUSE framework are intended to be offered on an opt-in basis to all customer classes. Over time, the CPUC could consider defaulting certain subsets of customers or DERs on to the CalFUSE framework to advance various policy goals.

[79] Note: Symmetric, bi-directional prices can ensure that customer exports are dispatched predominantly in response to grid conditions rather than customer-specific load conditions, or past customer usage history.

4.1.4 Role of Third Parties in Implementation of CalFUSE Framework

Staff anticipates that various third parties will play a major role in the successful implementation of the CalFUSE framework. These third parties in the CalFUSE "ecosystem" could include:

1. Application developers focused on making the CalFUSE price signal accessible to customers and devices,
2. Device manufacturers integrating the necessary functionality to enable the devices to interact with the CalFUSE price,
3. Automation service providers layering intelligent algorithms or artificial intelligence to optimize device behavior in response to the CalFUSE price,
4. Energy management service providers offering services to customers for managing multiple smart devices and optimize customer's bills, and
5. DER operators or aggregators pooling together and leveraging multiple customers and their devices as a resource and offering services to LSEs or UDCs, etc.

It is likely some entities will choose to combine multiple roles as a one-stop service to customers. Collectively, these third parties will have an essential role in managing the customer experience and value proposition for BTM resources. Staff envisions that the CalFUSE framework will unlock the ability of BTM resources to automatically (i.e., without the need for manual customer intervention) respond to the dynamic prices and provide grid benefits while reducing customer energy bills. The automated/ managed response of customer loads, driven by third parties for most residential and small commercial customers, is necessary to achieve the full scale and impact of the CalFUSE framework in terms of widespread adoption of demand flexibility solutions.

4.2 Element 1 – Develop Standardized, Universal Access to the Current Electricity Price

A statewide internet-based price portal provides the composite electricity price specific to each customer at any point in time. This portal enables access to the customer-specific current (and forecasted) composite electricity price generated by the "price machine"[80] based on the price determinant inputs provided by the customer's electricity providers (i.e., the LSE and UDC).

4.2.1 Summary

Staff suggests that easy discovery and wide-spread awareness of the current (and forecasted) electricity price applicable to a customer's energy imports and exports is a necessary pre-requisite to achieving the vision. In the current environment, however, customer awareness of electricity prices is generally poor across the state (even for a simple TOU rate design), and there is no easily accessible and straightforward mechanism that allows customers or their third-party service providers to discover the current and anticipated electricity prices. For example, a simple query on widely available consumer smart home platforms (e.g., Google Nest, Apple Home, Amazon Alexa) fails to provide any useful or actionable information on current electricity prices, in contrast to widely available information on weather conditions, traffic, financial markets, etc.

The lack of visibility into electricity prices could be remedied by establishing a standardized, statewide, internet-based price portal that provides customers and third-party energy management and DER service providers access to the current (and forecasted) electricity price anywhere in the state regardless of their specific electricity service provider.

CEC staff recently released a staff report, along with proposed amendments to the Load Management Standards (LMS), as part of the 2022 Load Management Rulemaking.[81] This report highlighted the need for a statewide price portal:

> Staff and stakeholders [including CPUC, California ISO, utilities, CCAs, automation service providers, and equipment manufacturers] agreed on the need for a statewide real-time signaling system that enables automation markets to coalesce around agreed upon principles and technologies for demand flexibility. Once completed, customers and automation service providers will be able to link flexible loads to this database, enabling the automation of customer end-uses in real time.

[80] *See* "price machine" description in section 4.2, Element 2.

[81] *See* CEC Docket 21-OIR-03.

4.2.2 CEC MIDAS Rate Database

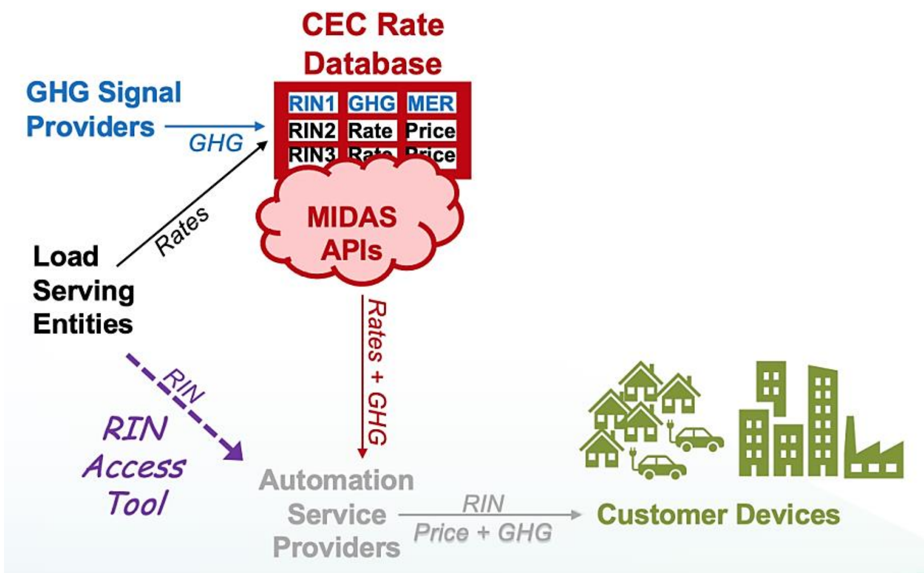

Figure 4-2: CEC proposed MIDAS Rate Database allowing end-users and service providers to access the customer-specific hourly prices.

CEC is currently developing the Market Informed Demand Automation Server (MIDAS - see Figure 4-2 with details described in CEC Staff Report[82]), in support of its load management initiatives outlined in the CEC 2022 Load Management Rulemaking[83], as well as the CalFUSE roadmap. The MIDAS system could potentially serve as the statewide price portal recommended above. CEC staff envisions that the MIDAS database will allow customers access to the applicable rates and electricity prices and enable third-party service providers to automate the response of flexible loads in response to the prices.

CEC staff described their vision for MIDAS in the "Analysis of Potential Amendment to the Load Management Standards Staff" report:

> The CEC has developed the Market Informed Demand Automation Server (MIDAS) Rate Database. The web-based service provides access to time-varying rates in a standard machine-readable format using an application programming interface (API). This allows device manufacturers and California customers to automatically access customer rate information for use in automating price responsive load shifting.

[82] California Energy Commission. "Analysis of Potential Amendments to the Load Management Standards," 21-OIR-03 Final Staff Report, November 2021. (available at) https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-OIR-03

[83] *See* CEC Docket 21-OIR-03.

> The CEC's MIDAS platform was created to enable demand automation through time-varying rates and marginal grid signals. Once fully developed, the MIDAS platform will receive, aggregate, and distribute 5-minute locational price and greenhouse gas emissions data from multiple sources. The system will use APIs to enable statewide access to electricity rates using standard Rate Identification Numbers or RINs. The goal of this effort is to facilitate mass-market load flexibility to lower customer bills and/or greenhouse gas emissions. The MIDAS system is being designed to be scalable to the national or international level.
>
> RINs use standardized codes for country and state; distribution and energy company (co.); rate; and location, so every rate has its own unique RIN. With the use of RINs, customers, utilities, ASPs, and others can match automation devices to the relevant electricity prices or GHG signals, ensuring appropriate load management for the customer at that site.

4.2.3 Key Implementation Considerations

The proposed statewide price portal should incorporate the following:

A. INTERNET-BASED ACCESS

The electricity price information of interest to the customer should be accessible from the portal via the internet anywhere in the state with a standardized URL and/or API, regardless of the specific electricity provider serving a customer. Additional communication options to obtain prices, such as FM radio, could be considered or added later.

B. CURRENT COMPOSITE ELECTRICITY PRICES

The portal should provide access to the current retail electricity prices applicable to a customer's energy imports and exports, regardless of the specific rate type the customer may be enrolled in, such as flat rate, TOU, CPP, or "CalFUSE" based rate described below. Some type of a unique identifier (account number, "rate code", etc.) may need to be entered into the portal by the customer to access the customer-specific rate. At minimum, the current electricity price should be updated on the portal every hour (but sub-hourly granularity could be considered or added at a later time).

C. FORECASTED ELECTRICITY PRICES

The portal should provide forecasted electricity prices, at least 24-hour ahead. More frequent forecast updates or longer-term (such as, week ahead) forecasts could also be considered or added at a later time.

4.2.4 Key Implementation Questions

1. **What processes, systems, or entities are necessary to facilitate the development and maintenance of the statewide price portal as described above**?

What process or regulations are required to ensure that a customer (or their authorized third-party service provider) of any LSE in the state is able to obtain, via the price portal, the composite electricity price specific to that customer? Note that the LMS amendments proposed by the CEC LMS Staff Report require each "utility"[84] (including CCAs) to upload its time-dependent, composite electricity rate to the MIDAS database.

2. **What should be the timeline to implement the statewide price portal?**
   The proposed CEC LMS amendments include a compliance and implementation timeline for the State's LSEs, which would require each LSE to upload its time-dependent composite electricity rates applicable to its customers to the MIDAS database no later than 3 months after the effective date of the proposed LMS standards amendments. The CPUC DER Action Plan 2.0 anticipates that, by 2023, the CPUC initiates consideration of proposals to ensure that customers, technology vendors, and third-party service providers have access to pricing information through a pricing platform.[85] Stakeholder input has been solicited by the CEC for the LMS regulations.

3. **Should the price portal be available by default to all customers of all LSEs in the state?**
   Providing default access to the price portal to all customers could allow automation or third-party service providers to provide services (for example, price-responsive automation and alerts) on a larger scale, while minimizing administrative overhead.

[84] *See* CEC Docket No. 21-OIR-03 Proposed Regulatory Language for Section 1621 (b) of the Load Management Standards, where utility is defined to include Los Angeles Department of Water and Power, San Diego Gas and Electric Company, Southern California Edison Company, Pacific Gas and Electric Company, and Sacramento Municipal Utility District, as well as any Community Choice Aggregators (CCA) operating within the service area and receiving distribution services from the foregoing electric utilities.

[85] Note: On April 21, 2022, the CPUC adopted Version 2.0 of its DER Action Plan. *See* Appendix 8.1 for additional details.

4.3 Element 2 – Introduce Dynamic Prices Based on Real-time Wholesale Energy Cost

The commodity energy cost component of the composite electricity price is tied directly to the locational marginal price (LMP) in the CAISO energy market to reflect the localized marginal price of energy. This cost component is combined by the "price machine" with other price components computed by that price machine based on the price determinant inputs (related to the cost recovery of the grid infrastructure and other fixed costs) to provide the composite electricity price applicable to a particular time, location (or service area), customer, and accessible through the price portal described above.

4.3.1 Summary

A range of issues with the current retail rate regime were described in Section 3.3.2. As one part of the CalFUSE three-pronged rate reform strategy (see Figure 4-1), Staff proposes that the CPUC introduce a CalFUSE price signal that incorporates a variable commodity energy price-based CAISO wholesale Locational Marginal Price (LMP). This variable commodity energy price would reflect the locational and temporal constraints of the bulk power system (generation and transmission capacity) and provide an economic incentive to customers to shift their energy usage and manage their DERs in response to the recurring variations in energy market prices.

A transition to dynamic retail electricity prices linked to CAISO market energy cost would encourage development of demand flexibility solutions and incentivize BTM DERs to optimize operations, yielding substantial system and customer benefits by:

1. Encouraging load shift to or increased usage during hours with low energy prices.
2. Reducing energy procurement costs. Energy prices tied to the wholesale market have been shown to provide bill savings to participating customers.[86,87]
3. Reducing curtailment, evening ramp, emissions. Shifting demand to reduce the curtailment of renewable resources, which is often correlated with negative real-time wholesale electricity prices, will also reduce evening ramps and greenhouse gas emissions in the electric sector at the lowest cost possible.
4. Enhancing reliability. Shifting demand and reduced curtailment helps reduce system supply ramps and volatility, which improves system reliability.
5. Complementing anticipated updates to CEC's Title 20 (Load Management Standards)

The variable commodity energy price would be just one component of the CalFUSE composite electricity price at a particular time/location (or service area)/customer. Other components of the CalFUSE price signal, like any retail energy price, are related to the cost recovery of generation,

[86] *See* New Jersey PSE&G TOU&CPP pilot program. Participants experienced average savings of $160 over the course of the pilot.

[87] *See* ComEd's RTP pilot program. Participants reduced their electricity bills by an average of 10%.

distribution, and transmission services and other fixed costs, which would be determined by the rate design policies adopted by the applicable customer's electricity providers (LSE and UDC).

4.3.2 Key Implementation Considerations

A. PRICE MACHINE

Consistent with Guiding Principle 3, the CalFUSE framework incorporates the concept of a flexible "price machine" to accommodate the pricing policies of different LSEs and UDCs. The price machine could be a cloud-based IT platform to which the LSEs and UDCs upload their respective rates designed to recover the cost of generation, distribution, and transmission services and other fixed costs), along with the machine receiving the dynamic LMPs from CAISO representing the cost of the energy commodity. The price machine is designed to combine the various cost components to compute the composite electricity price applicable to a particular time/location (or service area)/customer across the state and provide it to the price portal described above for access by customers and their authorized third-party service providers.

The price machine functionality could be integrated with the price portal as a single statewide system, or it can be maintained separately. The latter case allows for multiple price machines across the state feeding electricity prices into the price portal. For example, each UDC could maintain a price machine that receives price inputs from all the LSEs served by that UDC, along with the dynamic LMPs from the CAISO.

The CalFUSE framework relies on LSEs and UDCs to provide customer-specific and time-varying energy and capacity prices. The CEC-proposed amendments to the Load Management Standards require LSEs and UDCs to upload hourly prices to the MIDAS price portal, to enable price accessibility to customers, devices, and third-party integrators. Alternatively, there may need to be a separate independent entity to manage the price machine for computing customer- specific price given that unbundled customers receive their generation service (and prices) from their LSE (e.g., CCA) and their distribution service from their UDC (e.g., IOU).

B. LEADTIME AND TEMPORAL GRANULARITY OF LMP COMPONENT OF THE CALFUSE SIGNAL.

The CAISO Day-Ahead market for wholesale energy provides hourly prices for the next day based on bids to sell energy placed by generators to find the least cost of energy to meet expected demand at each "pricing node" (location on the grid where transmission lines and generation interconnect) throughout the CAISO balancing area, while incorporating bulk system constraints. At the closing of the day-ahead market each day, the next day hourly prices applicable to each pricing node are published. CAISO also operates 15-min and 5-min real-time energy markets, where energy prices at each pricing node are determined as required to balance supply and demand deviations in real-time relative to day-ahead commitments.

A comparison of average prices on all the CAISO markets is shown in Figure 4-3. The average prices paid on the day-ahead market are higher than the spot 5-minute market, but the spot market tends to have higher variability—especially during emergency grid conditions.

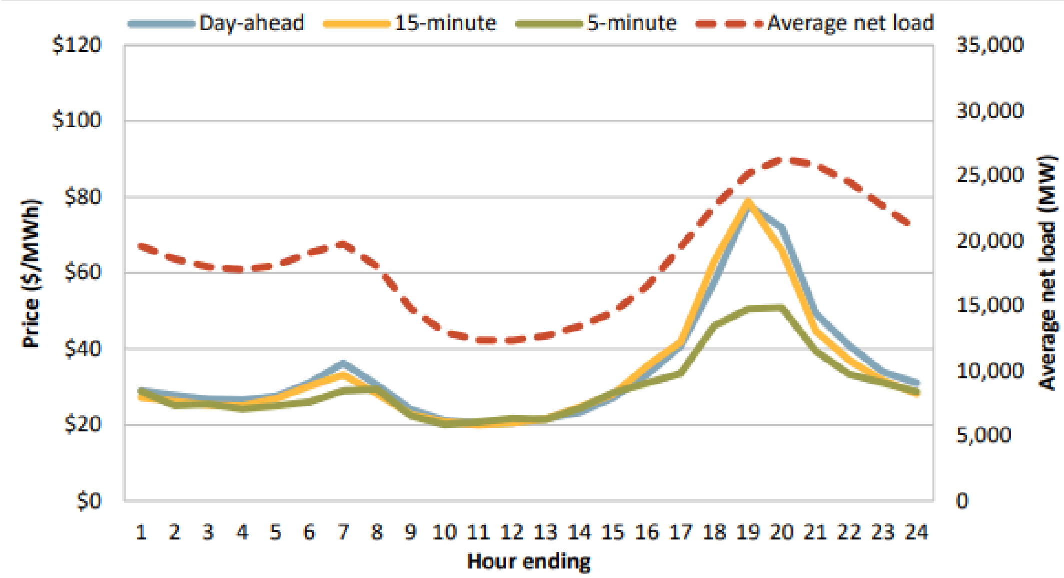

Figure 4-3: CAISO energy prices in the day-ahead and real-time markets follow the shape of the net load curve.[88]

In its comments to the May 25, 2021, ED Staff demand flexibility workshop, Cal Advocates recommended that the variable commodity energy prices should be linked to the day-ahead market (DAM) prices, rather than the prices produced in the real-time imbalance market, as "the DAM would be beneficial for customers by offering the best risk/reward ratio".[89] On the other hand, having energy prices linked to the real-time markets could create additional economic opportunity and enable customer BTM DERs to capture more value while meeting high-value system needs during times when the grid may experience extreme stress. But this opportunity would need to be balanced with consumers protections against extreme market conditions. Notably, other elements of the CalFUSE proposal discussed later (Elements 5 & 6) could help provide such protection.

Staff recommends that the demand flexibility potential and impacts - on system reliability, bills, and revenue stability - of DAM hourly energy pricing be compared to that of the real-time markets as part of a stakeholder workshop and/or stakeholder comments.

[88] *See* CAISO 2020 Annual Report on Market Issues & Performance, at 7.

[89] *See* Cal Advocates Comments to CPUC Staff advanced DER and demand flexibility management workshop on May 25, 2021. Summarized in Appendix, Section 8.2.4.

C. SPATIAL GRANULARITY OF LMP COMPONENT OF THE CALFUSE SIGNAL

CAISO's market calculates LMPs at each pricing node (Pnode), where an injection (i.e., generation) or withdrawal (i.e., demand) of energy is modeled and for which a LMP is calculated and used for financial settlements. There CAISO market includes 9,700 distinct Pnodes. Each utility's service territory is comprised of many different Pnodes, and a weighted average of the LMPs at each Pnode in a utility's service territory is used to calculate the default load aggregation point (DLAP) price. The DLAP price at a particular time represents the price that a utility pays for the energy needed to meet its aggregate demand at that time.

DLAP prices are publicly posted on CAISO's website and have been used as the energy price for many RTP pilot projects. Pnode LMPs tend to be clustered close to the DLAP LMPs under most conditions. In a 2015 report on the difference between Pnode and DLAP LMPs on the day-ahead hourly market, CAISO Staff stated that:

> Nodal [Pnode] price dispersion across the system and variation from the DLAP LMPs are minimal. With the exception of the Greater Fresno area, the observed price dispersion and variation was sporadic and not contiguous enough to be used to efficiently create more granular load zones. The congestion-driven pricing observed will likely dissipate as already approved transmission enhancements become operational in the future.[90]

However, the report also noted that more granular node pricing does have the potential to provide benefits,

> Benefits related to more accurate price signals to incent investment, congestion revenue rights, and more efficient market outcomes have been estimated to range between $1.08 million and $2.75 million annually.[91]

The analysis highlighted that average Pnode prices from 2011-2014 ranged from $25-52 per MWh with 90% of nodal prices averaging between $35-44 per MWh. More locational granularity—at a sub-LAP or Pnode level - could provide the opportunity for flexible loads and DERs to provide added system benefits and reduce the need for capital intensive transmission system upgrades. However, this must be balanced with other policy considerations including the complexity of implementing more granular dynamic pricing and the potential impact of differential pricing within a service area.

It is important to consider that the analysis above relates to the DAM and that variations in nodal prices can be higher on the real-time spot markets. The higher variability has the potential to incentivize additional opportunistic load shift and more beneficial DER dispatches. Staff

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[90] "CAISO Load Granularity Refinements, Draft Final Proposal", March 24, 2015. (available at) http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedClosedStakeholderInitiatives/LoadGranularityRefinements.aspx.

[91] *Id.* at 3.

recommends that the tradeoffs of more versus less granular LMPs be explored through stakeholder comments.

D. CUSTOMER TRANSITION TO A DYNAMIC CALFUSE PRICE SIGNAL

Staff proposes that all customers and customer classes should have access, on an opt-in basis, to CalFUSE price signal that includes the energy commodity cost in the form of LMPs linked to the CAISO wholesale market. In conjunction with Element 5 (subscription option) described later, the responsiveness of these subsidized technology means that customers receiving them have a high likelihood of benefitting themselves and the energy system if they are enrolled in a rate schedule with an RTP-based CalFUSE price signal.

4.3.3 Key Implementation Questions

1. **What processes, systems, or entities are necessary to facilitate the development, operation, and maintenance of the price machine as described above?**
   There are several factors to consider in the implementation of a price machine that can accept inputs from multiple sources (price functions from LSEs and UDCs, real time data from CAISO and local grid conditions) to compute the dynamic, composite, customer specific CalFUSE price. Should the price machine functionality be integrated with or separated from the price portal? Should the CalFUSE framework be based on a single, statewide price machine or accommodate multiple price machines for more flexibility?

2. **What should be the time base for the LMP component of the CalFUSE signal that represents the variable commodity energy cost?**
   The CAISO operates different markets including distinct day-ahead and real-time markets. The day-ahead market is based on a network model, which analyzes transmission and generation resources to find the least cost energy to serve demand at each individual node. The majority of the energy is scheduled in the day-ahead market on an hourly basis. The real-time market is a spot market in which buyers and sellers purchase/sell as needed to balance deviations (relative to forecast) in demand or supply not covered in their day ahead schedules. Therefore, potential options for the time granularity of the CalFUSE signal include:
   a) Hourly day-ahead market,
   b) Hourly real-time (e.g., average of prices in four consecutive 15-minute real-time market intervals,
   c) 15-minute real-time market, or
   d) 5-minute real-time market.

3. **What locational granularity should be used for the LMP component of the CalFUSE signal?**
   As was noted above, the CAISO market includes 9,700 P-nodes. These P-nodes can also be aggregated into larger geographies for various purposes. Each of these aggregations is a potential option for the real-time energy component of the CalFUSE signal:

a) **DLAP.** The DLAP price is the weighted average of all the P-nodes in a utility's service territory.
b) **LCA**. There are ten "Local Capacity Areas" in CAISO's balancing area and CAISO performs annual studies to inform local RA requirements for each LCA.
c) **Sub-LAP**. The "sub-Load Aggregation Points" are defined by CAISO based on relatively continuous geographic areas that do not include significant transmission constraints within the area. There are multiple sub-LAPs within each utility's service territory that represent the most granular level of geographic detail where generation capacity planning for reliability can be done.
d) **LSE boundary**. The LSE boundary represents all the P-nodes that correspond to a single LSE.
e) **P-node**. The P-node is the most granular level at which LMPs are available.

4. **How should the expense for utility distribution system losses be recovered?** Transmitting power through the power grid results in electrical losses that are primarily driven by the load in the distribution system, and secondarily impacted by certain environmental conditions (such as temperature). Electrical losses are higher when distribution circuit loads are higher and scale quadratically. LSEs need to procure additional energy than what is consumed (metered) by customers due to system losses, typically 8-10% on an annualized basis. Likewise, UDCs need to oversize their circuit capacities by a loss factor to have the necessary capacity to meet peak circuit loads. Potential options for recovery of the energy component (LSE) include:
   a) **Utilization-based loss recovery**. In the TeMix/SCE Rates pilot[92] the delivery component for the price signal was modified to include a price adder that recovers for distribution system losses. Loss recovery was linked to distribution system utilization such that more revenue was recovered during high utilization periods.
   b) **Flat loss factor applied to energy prices**. It is also possible to apply a flat proportional loss factor to energy prices for all hours. However, this may not reflect the cost causation of these losses as precisely or appropriately as the above option.

[92] *See* section 4.4.2, item C for additional pilot details.

4.4 Element 3 – Modify Electricity Prices to Incorporate Dynamic Capacity Charges Based on Real-time Grid Utilization

The grid infrastructure capacity fixed cost recovery portion of the composite electricity price is dynamically modified based on the real-time utilization level of the locally available capacity infrastructure for electricity generation and delivery, based on the design principle that capacity cost recovery should be higher when the system utilization is higher. The capacity cost recovery price components are computed and combined with other price components by the "price machine" to determine the composite electricity price applicable to a particular location, time, and customer, and are accessible through the price portal described above.

4.4.1 Summary

The retail electricity price consists of multiple price components to recover the cost of various elements required to generate and deliver electricity, as illustrated in Figure 4-4 below.

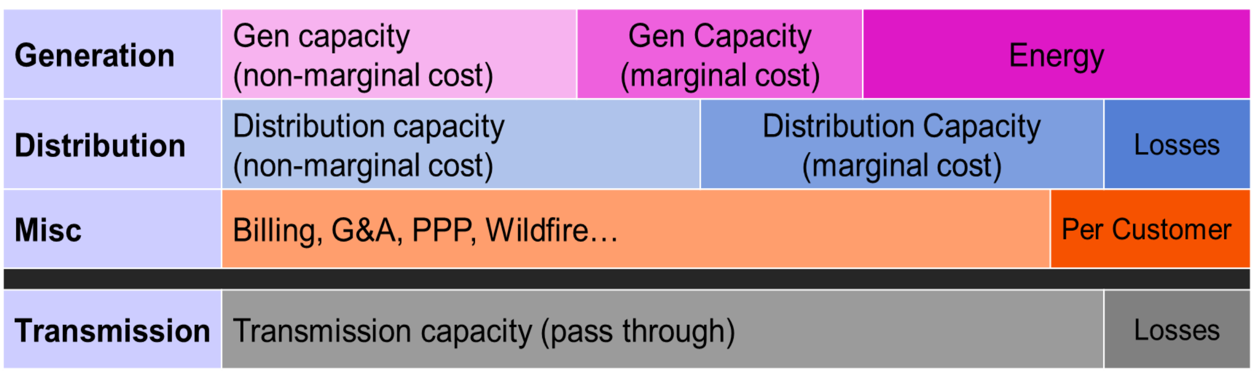

Figure 4-4: Illustration of costs components of an electric utility's cost of service (i.e., cost to generate and deliver electricity).

This chapter focuses on the CalFUSE framework's mechanism to recover the infrastructure capacity costs and other fixed costs required to support system demand and the distribution grid.

The traditional methods for recovering infrastructure costs and other fixed costs include the following: (1) for residential customers, a combination of monthly fixed charges and static volumetric rates, which could be time-variant or based on monthly consumption (inclining blocks or tiered pricing); and (2) for non-residential customers, a combination of monthly fixed charges, static volumetric rates, and monthly demand charges based on *customer's* peak demand (both NCDC and CDC).

Chapter 3 highlights deficiencies in traditional fixed cost recovery methods, including ineffective price signals and incentives to manage loads, reduce system costs, and decrease greenhouse gas emissions. With respect to demand charges specifically, the concerns raised include:

a) Non-coincident demand charges, as currently implemented, do not effectively incentivize load shifting from peak to off-peak periods,

b) Demand charges can provide perverse incentives for DER dispatch, and

c) Demand charges can be argued to poorly reflect the cost causation principle.[93]

The inefficiencies of traditional fixed cost recovery methods will likely lead to increasing systems costs over time as loads increase with electrification and more customers deploy DERs.

To enable access to a unified economic price signal via simplified and scalable price portal (described in Element 1), Staff proposes to require that the composite CalFUSE electricity price (and its component prices) be time-based and volumetric. In other words, the price components should *not* be dependent on historical or current customer-specific consumption (such as tiered rates) or customer-specific demand (NCDC, CDC, $/kW).

Instead, the CalFUSE price signal would recover grid infrastructure costs through dynamic, volumetric ($/kWh) composite prices linked to marginal costs. Note that the following discussion from the CPUC's decision from PG&E's 2021 GRC phase 2 proceeding, (D.) 21-11-016, defines marginal costs as follows:

> Marginal costs consist of generation capacity costs ($/kW), generation energy costs ($/kWh), customer access costs ($/customer hookup), and distribution capacity ($/kW) costs. These marginal costs are the incremental cost to serve one additional kW or kWh of demand or an additional customer.[94]

The above analysis leads to the second part of the three-prong rate reform strategy. Staff proposes that the capacity cost recovery portion of the composite CalFUSE price be:

1. **Linked to marginal capacity costs**. Marginal costs represent the "long-run" cost for building additional generation capacity and distribution capacity to meet future load growth. The use of marginal costs to design rates is already part of the CPUC's preferred policy of marginal cost-based rate design.[95] Prices that convey the temporal variability of marginal costs provide a signal for customers to shift load away from congestion and thereby help defer or avoid future capacity upgrades.

2. **Dynamically modified**. Prices should be based on the real-time (hourly) utilization level of the locally available capacity infrastructure for electricity generation and delivery. This means that more revenues are recovered when system utilization is higher, and the dynamic price serves as a scarcity price function.

3. **Scaled to recover required revenues.** The dynamic composite price can be scaled to collect revenues required to cover capacity infrastructure costs using a scaling method such

[93] *See* Section 3.3.2 – Counter-Productive Demand Charges.

[94] *See* CPUC decision from PG&E's 2021 GRC Phase 2 proceeding, D.21-11-016 at 75.

[95] D.21-11-016 at 6.

as the Equal Percentage of Marginal Costs (EPMC) allocation. This methodology is consistent with the CPUC precedent of scaling up rates based on marginal costs to recover embedded (non-marginal) costs.[96]

The integration of the above concepts can serve as the basis for determining the hourly capacity cost recovery prices of the CalFUSE signal.

The capacity infrastructure price functions driving the CalFUSE signal would be designed by the responsible regulatory entity (i.e., UDC or LSE), with the current utilization level of the localized capacity infrastructure as the independent variable (or input). The scarcity price function should be:

a) Designed such that the hourly volumetric price increases at a faster rate as the aggregate demand-driven utilization level of the localized infrastructure approaches the capacity limit (saturation), and

b) Scaled, as needed, to collect the appropriate revenues for the capacity infrastructure costs based on forecasted load over 8760 hourly intervals.

Pricing functions that are linked to "long-run" marginal costs and scaled to collect the appropriate revenues required to recover the capacity infrastructure costs encourage economically efficient decision-making, both short-term and long-term, by consumers, third-party service providers, and operators of BTM DERs.

A key benefit of the above architecture is that the capacity-related cost recovery burden is shifted onto the load during the hours that drive congestion on, or saturation of, the available infrastructure capacity (and eventually force capacity upgrades), while ensuring collection of the approved revenue requirements and minimizing unintended cost-shifts. Other beneficial aspects of the proposed architecture are as follows:

a) Encourages load to shift to lower cost and lower utilization hours,

b) Minimizes long-term costs of infrastructure upgrades, supporting electrification,

c) Allows flexible rate design options to accommodate different policy choices by different regulatory entities (e.g., the functional relationship between system utilization and prices, the revenue recovery targets for the various capacity infrastructure price functions, etc.),

d) Accommodates multiple pricing functions with different cost allocations and recovery rate or different price volatility limits by customer class, which can be done through the scaling factor of the price functions,[97] and

e) Enables more frequent or granular updates to the pricing function as needed to maintain revenue collection on target and reflect changing system conditions and demand profile.

[96] *Id.* at 76.

[97] Note: This is analogous to CPUC precedent, where revenues are allocated to customer classes (via EPMC scalars) based on the class contribution to calculated marginal costs. *See* D.21-11-016 at 76.

Consistent with the CPUC's cost causation principle, it should be emphasized that a scarcity pricing design updated on a frequent (annual, quarterly) basis will incorporate a more dynamic and accurate reflection of changes to grid utilization (load factors) across the system. Consequently, the incremental efficiencies and cost savings realized for utilities and LSEs and customers would in turn be reflected in annual adjustments to marginal generation and distribution capacity costs (and therefore scaling factors). This in turn should help mitigate concerns about cost-shifting or cross-subsidies between participants and non-participants.

The framework presented in this white paper includes additional design elements for mitigating cost-shifting concerns. These include recovery of some fixed costs outside the volumetric dynamic price via other mechanisms, such as the subscription option or monthly fixed charge as described in sections 4.5.2 and 0.

4.4.2 Key Implementation Considerations

A. DESIGN OF SCARCITY PRICE FUNCTION FOR CALFUSE CAPACITY FIXED COST RECOVERY COMPONENT

Staff recommends that total capacity fixed cost recovery of the CalFUSE price signal be composed of three separate "localized" capacity infrastructure cost elements:

a) **Generation Capacity** (driven by "local" Resource Adequacy requirement);

b) **Flexible Generation Capacity** (driven by Flexible Resource Adequacy requirement); and

c) **Distribution Capacity** (driven by "local" distribution system capacity limits, such as at the circuit/substation level).

The actual scope of the geography included in the "local" capacity infrastructure is a policy choice determined by the regulatory entity responsible for that infrastructure (UDC or LSE) and could be different for each capacity component.

More specifically, the scarcity price curve for fixed cost recovery of each capacity element could be a polynomial function (e.g., a quadratic function). In this case, the rate design in a GRC Phase 2 proceeding (for IOUs), or equivalent process for non-IOU entities, would consist of establishing the methodology and inputs necessary to derive capacity price functions that satisfy the constraints noted earlier: capacity limits, approved long-run marginal cost of adding new capacity, and the appropriate revenue recovery. A test year with 8760 hours of forecasted aggregated demand is used to derive the shape and scale of each scarcity price function such that the revenue collection resulting from the sum of the products of the (a) hourly CalFUSE prices generated by a price function related to a capacity element, and (b) the hourly forecasted usage, is equal to the appropriate revenue recovery desired for that capacity element.

B. DETERMINATION OF CALFUSE DYNAMIC PRICES

In practice, the price machine described earlier senses the "local" grid conditions each hour in terms of the current utilization level (via updates provided by SCADA equipment or some other process) relative to the capacity limit of each of the three types of capacity infrastructure. The price machine then computes the respective hourly capacity fixed cost recovery price via the prescribed scarcity price function and sums them with the current LMP-based energy price received from the CAISO. If necessary, the price machine can further add other components related to transmission[98] and other fixed costs (i.e., non-generation and non-distribution), and determine the composite electricity CalFUSE price applicable to a particular location/time/customer that is accessible through the price portal.

C. IMPLEMENTATION EXPERIENCE WITH SCARCITY PRICE FUNCTION

The scarcity pricing approach to capacity cost recovery described above has been implemented in the Retail Automated Transactive Energy System (RATES) pilot project[99] funded by CEC-EPIC and operated by TeMix.[100] The project involved 100 customers served by the Moorpark substation in SCE territory.

In the RATES pilot project, utilization-based, scarcity pricing curves (Figure 4-5) were formulated such that if the system and circuit usage matched forecasted usage, the scarcity prices would collect the approved revenue required for distribution capacity, generation capacity, and flexible generation capacity costs. Note that the scarcity price revenue targets can either be class-based or can incorporate multiple classes.

The methodology described above ensures that the hourly capacity and energy price components reflect cost causation, recover approved revenues, and incentivize responsive load management during peak, capacity-constrained hours.

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[98] Note: Transmission cost recovery is under FERC jurisdiction and the associated charges are volumetric for the most small/medium customers. For those customers, the volumetric rate would be passed as an input to the price machine with no modification.

[99] Note: The RATES project was funded by CEC EPIC Grant GFO-15-311. Project presentation available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=231538&DocumentContentId=63345

[100] Note: An approach similar to that of the "RATES" pilot was also adopted for the two CalFUSE-based dynamic rates pilots ordered by the CPUC in R.20-11-003. Both pilots are expected to be launched by June 2022.

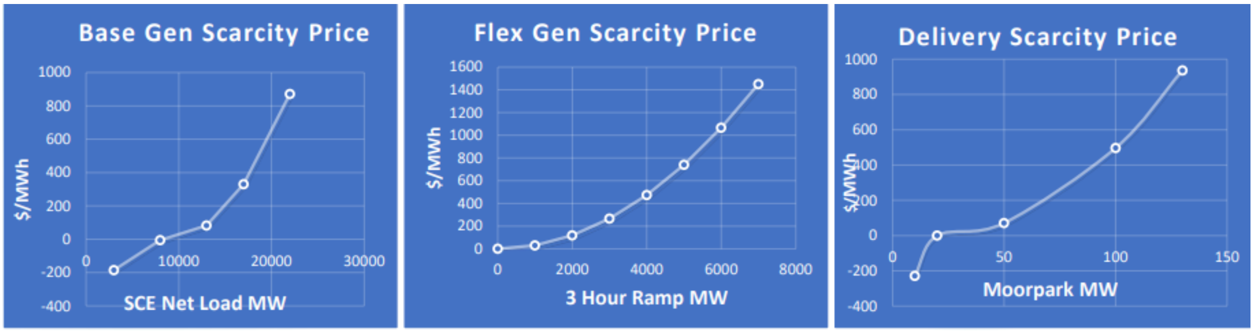

Figure 4-5: Scarcity price curves for System Generation Capacity (left), 3-hour Flexible Generation Capacity (center), and Distribution Capacity (right).

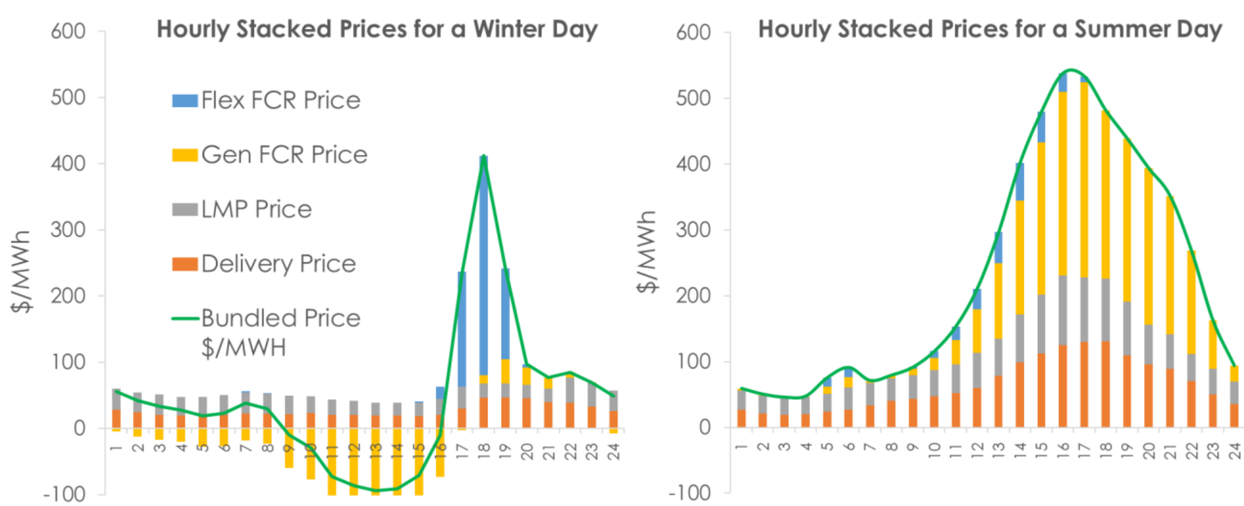

Figure 4-6: Hourly energy (LMP) and capacity (flexible capacity, generation capacity, and distribution/delivery capacity) prices from the SCE/TeMix RATES pilot.[101]

The individual capacity fixed cost recovery components (for distribution, generation, and flexible generation) were determined based on the measured demand and thereby created a variable price signal that incentivized flexible loads and DERs to respond to dynamic grid conditions (Figure 4-6).

While the scarcity prices for system generation and flexible capacity are uniform across an LSE's service territory, the distribution scarcity prices can have more geographic granularity; this makes them more effective in reducing the need for distribution system upgrades. As implemented in the RATES pilot, the distribution capacity (delivery) prices were based on the load of the Moorpark Substation. The annual hourly load profile of the substation was used to scale the prices such that

[101] Note: FCR means Fixed Cost Recovery

without any change in the load profile, the delivery prices would recover the same revenue as an otherwise applicable tariff.

This approach ensures that even if parts of a utility's distribution system have load profiles that are different from one another, the revenues recovered for each distribution system segment are still based on the same, traditional, system-wide average distribution price. In other words, different segments of the distribution system will have price profiles that vary from one another and may have price components that peak at different times of the day/year, but each segment will recover the same annual revenue as before, which socializes the cost recovery across all utility customers.

The detailed mathematical formulation of the scarcity price functions for recovering capacity costs is described in next section.

D. DERIVATION OF CAPACITY FIXED COST RECOVERY SCARCITY PRICING CURVES

This section is optional for most readers and intended for those familiar with the nuts and bolts of rate design, who wish to dig deeper into the mathematical formulation of CalFUSE scarcity price functions to recover costs of the required infrastructure (generation capacity, flexible ramping capacity, and distribution capacity). The derivation of the capacity fixed cost recovery price curves that were implemented by the SCE/TeMix RATES transactive energy pilot and will be implemented in the upcoming dynamic rate pilots authorized in (R.) 20-11-003, is described below.

For this pilot, scarcity pricing curves were derived for:

a) Distribution Capacity, $G_{delivery}$;

b) Generation Capacity, $G_{generation}$; and

c) Ramp Capacity, G_{ramp}.

Each of the pricing curves (Figure 4-5) provides a capacity price (in $/MWh) as a function of the of either a specific circuit or the LSE's net load (in MW) as follows:

a) $G_{delivery}$ is a function of the circuit load measured at the substation, $U_{circuit}$;

b) $G_{generation}$ is a function of the LSE's net load, U_{LSE}, which includes the dispatch of grid connected renewables; and

c) G_{ramp} is a function of the LSE's 3-hour net ramp, U_{ramp},—i.e., the difference between current net load and the net load measured 2 hours prior.

A quadratic function was used as the shape of the scarcity pricing curves to reflect the physics of electrical losses ($Losses \propto I^2 \times R$).[102] Equations for the pricing curves are shown below:

[102] Note: The shape of the price function is a judgement call made by the LSE, subject to regulatory approval. There are a variety of shapes that can be used, which would spread the cost recovery of capacity costs differently between peak and off-peak hours. As there

$$G_{delivery}(U_{circuit}) = \begin{cases} C_{delivery} \times \left(\dfrac{U_{circuit} - U_{inflection,ckt}}{U_{\max,\mathrm{ckt}} - U_{inflection,ckt}} \right)^2, & if\ U_{circuit} > U_{inflection,ckt} \\ -C_{delivery} \times \left(\dfrac{U_{circuit} - U_{inflection,ckt}}{U_{min,ckt} - U_{inflection,ckt}} \right)^2, & if\ U_{circuit} < U_{inflection,ckt} \end{cases}$$

$$G_{capacity}(U_{LSE}) = \begin{cases} C_{capacity} \times \left(\dfrac{U_{LSE} - U_{inflection,LSE}}{U_{max,LSE} - U_{inflection,LSE}} \right)^2, & if\ U_{LSE} > U_{inflection,LSE} \\ -C_{capacity} \times \left(\dfrac{U_{LSE} - U_{inflection,LSE}}{U_{max,LSE} - U_{inflection,LSE}} \right)^2, & if\ U_{LSE} < U_{inflection,LSE} \end{cases}$$

$$G_{ramp}(U_{ramp}) = C_{ramp} \times \left(\frac{U_{ramp}}{U_{max,LSE}} \right)^2, \quad if\ U_{ramp} > 0$$

Where UDC/LSE-specific inflection points, and minimum/maximum load levels are used to incorporate circuit and system constraints related to low-load and high-load conditions. The cost factors, $C_{delivery}$,$C_{capacity}$, and C_{ramp} (\$/MWh) are scaling term that are calibrated to ensure that the pricing curves recover the GRC approved revenue target (i.e., annual utility cost for each capacity element) as described below.

An hourly net load profile (8760 hourly system usage) was extracted from a test year and used to scale the cost factors such that the revenues recovered from each of the pricing functions match the revenues for distribution capacity, generation capacity, and ramp capacity. The hourly demand profile of the Moorpark substation, $U_{circuit}$ (MW), was used to scale $C_{delivery}$, the hourly net LSE demand profile, U_{LSE} (MW) was used to scale $C_{capacity}$, and hourly 3-hour net load ramp for the LSE, U_{ramp} (MW), was used to scale G_{ramp}. The following set of equations illustrates how the annual revenues are calculated to ensure that the pricing curves are scaled appropriately to avoid over/under collection:

$$R_{annual,ckt} = \sum_{t}^{8760} G_{delivery}[U_{circuit}(t)] \times U_{circuit}(t) \quad (\$/\mathrm{yr})$$

$$R_{annual,gen} = \sum_{t}^{8760} G_{capacity}[U_{LSE}(t)] \times U_{LSE}(t) \quad (\$/\mathrm{yr})$$

$$R_{annual,ramp} = \sum_{t}^{8760} G_{delivery}[U_{ramp}(t)] \times U_{LSE}(t) \quad (\$/\mathrm{yr})$$

is a significant amount of subjectivity in the notion of the "ideal" price curve, in this white paper CPUC Staff is merely highlighting the subjective decision made by TeMix and SCE in the design of the tariff for the RATES pilot. Other price function shapes (linear, cubic, sigmoidal, heat-rate derived, etc.) may be favored by individual LSEs.

Where:

a) $R_{annual,ckt}$ is the annual revenue recovered for distribution capacity costs—normalized by the annual substation load to match the distribution revenues appropriate to the substation;[103]

b) $R_{annual,gen}$ is the annual revenue recovered for generation capacity costs; and

c) $R_{annual,ramp}$ is the annual revenue recovered for flexible capacity costs.

4.4.3 Key Implementation Questions

1. **What geographical scope (or aggregation point) should be used to define the "localized" available infrastructure (that serves as the basis for determining real-time utilization level) for the different capacity elements of CalFUSE?**
   As an example, potential aggregation points for distribution capacity could be the substation (as was the case in the TeMix/SCE RATES pilot) or different feeder circuits downstream of a substation that have their own unique load profile and capacity constraints.

2. **Are there existing grid technologies or processes available that would help determine the hourly system utilization level of the "local" capacity infrastructure required as an input to the price machine (so that it could compute the capacity cost components of the CalFUSE signal via the prescribed scarcity price functions)?**
   In the VCE/PG&E agricultural pumping dynamic rate pilot approved in (D.) 21-12-015, PG&E has engaged a third-party contractor to create 7-day forecasts for the UDC distribution system utilization (on a circuit-level).[104] These forecasts, which will be updated daily, are integrated into the pilot price generation platform (the TeMix RATES platform). In SCE's dynamic rate pilot, which was also approved in (D.) 21-12-015, SCE is also utilizing similar forecasts at the substation level.[105] Both these pilots will provide valuable information regarding the existing technologies or processes for forecasting distribution system capacity utilization levels and integrating those forecasts into dynamic capacity prices.

3. **Are there other approaches that should be considered for dynamic capacity cost recovery? What are the pros/cons of these alternatives vs. the architecture proposed in this section?**

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[103] Note: Each distribution substation/circuit's scarcity price curve is scaled by the load profile of that particular substation/circuit. This ensures that the distribution capacity prices are locationally informed—i.e., each substation/circuit's peak prices/hours are based on the substation/circuit's net load shape and peak capacity.

[104] PG&E AL 6495-E at 6.

[105] SCE AL 4684-E at 7.

Note that other proposals for dynamic capacity cost recovery have been proposed in IOU RTP applications including in the PG&E and SDG&E RTP proposals.[106]

4. **Should all fixed costs be recovered via a dynamic volumetric rate or only generation and distribution capacity costs?**
   Many approaches to fixed cost recovery have been proposed both in academic studies as well as IOU RTP pilot applications. Some approaches suggest that the retail volumetric electricity price should be designed to recover only long run marginal capacity costs that can be deferred through efficient system utilization, and all other fixed costs should be recovered through progressive monthly fees (independent of energy usage level).[107, 108]

   The CalFUSE composite price as described in this section presents a blended approach to cost recovery, where scarcity prices are used to recover all generation and distribution capacity infrastructure costs. However, there are other utility fixed costs which are not included in the CalFUSE composite price as described in the section above, including: customer-specific meter and final-line transformer (customer access costs), labor and administration, public purpose programs and wildfire mitigation costs[109]. Staff proposes multiple approaches for the recovery of these fixed costs, including: (a) customer load shape subscriptions (see Element 5 below in Section 4.6), (b) monthly fixed charges as described in the preceding paragraph, or (c) volumetric prices, which can either be flat or scarcity prices. The CalFUSE approach is compatible with all three options for fixed-cost recovery. There may be policy reasons, such as equity, for choosing a specific option or combination of options. However, Staff also recommends that the dynamic capacity price should, at minimum, recover utility marginal cost revenues to ensure that the dynamic price effectively reduces the long-term expenses.

5. **Should the scarcity price curves be customer class specific?**
   It would be possible to use a class-specific demand profile and revenue target and create class-specific scarcity price curves. However, there may be certain implementation challenges with a customer specific approach, such as the challenge of forecasting class-specific system/circuit utilization on a dynamic basis.

[106] *See* D.21-11-017 at 36-41 for discussion of PG&E's proposed Marginal Generation Capacity Cost (MGCC) calculation methodology using the Peak Cost Allocation Factor (PCAF) approach to develop a marginal capacity price signal.

[107] Borenstein, Severin, et.al., "Designing Electricity Rates for An Equitable Energy Transition", Next 10 Report, 2021. (available at) https://www.next10.org/electricity-rates.

[108] Wolak, Frank and Ian Hardman, "The Future of Electricity Retailing and How We Get There," Program on Energy and Sustainable Development, Stanford, 2020.

[109] Note: Public purpose program costs and certain wildfire related costs were classified as non-bypassable charges by the CPUC in D.16-01-044.

4.5 Element 4 – Transition to Bi-directional Electricity Prices

Customers import and export energy based on the same dynamic, composite prices based on cost-causation. This avoids uneconomic arbitrage and enables fair, transparent, and rational compensation for grid services provided by customer owned DERs.

4.5.1 Summary

Staff proposes that as part of the CalFUSE rate reform strategy, the retail price differential between customer imports and exports should be eliminated, with the dynamic CalFUSE price signal functioning as a bi-directional (symmetric) rate. During any time-interval, the customers would have the option to either buy (import) or sell (export) energy at the same real-time, location-specific retail price.

A bi-directional price requires that the cost of importing energy and the credit for exporting energy is linked directly to the cost-causation principle. Linking the price to: (a) the real-time market informed commodity energy value (Element 2), and (b) capacity values informed by real-time system utilization levels (Element 3), ensures that any dispatch of a customer's BTM DER resource for export is aligned with grid needs. Staff suggests that the bi-directional CalFUSE price signal could have several potential benefits, including:

1. Encourages economically efficient decision-making in terms of customers (predominantly through automated price-response) both shifting demand and optimizing DER dispatch, which helps maximize both customer and system benefit.
2. Provides an easily discoverable, transparent, predictable, market-informed compensation for exports by customer DERs, without customers needing to participate in a complex market-integrated program.
3. Opens up opportunities for price-responsive technologies (e.g., energy storage, vehicle-to-grid, etc.) to export to the distribution grid during hours with high prices, resulting in downward pressure on the CalFUSE price for all customers.
4. Promotes distributed, price-responsive, self-dispatch of customer DERs, which may be a more efficient pathway for scaling to large volumes of DERs in comparison to alternatives that involve command & control regimes for dispatching BTM DER aggregations.
5. Potentially opens up a pathway for third-party BTM DER service providers and LSEs or UDCs to explore contracting opportunities based on the embedded capacity value (to reduce peak demand or defer capacity upgrades), with the DER dispatch driven by a market informed CalFUSE price signal.

4.5.2 Key Implementation Considerations

A. BIDIRECTIONAL, SYMMETRIC PRICES ALLOW FOR SCALABLE DISPATCH OF FLEXIBLE EXPORTS

As customers adopt resources that have the capability to control their exports to the grid, it is essential to dispatch flexible exports at times when those exports have the highest system value. An export price that accurately reflects grid value is one part of the equation. However, it is also very beneficial for the export and import price to be symmetric to maximize the scalability of price-based dispatch of customer resources. A non-symmetric price substantially increases the complexity of optimizing the dispatch behavior of customer devices or DERs.

For example, when import and export prices are non-symmetric, each customer device needs visibility into a variety of external parameters associated with other customer devices (such as, the current and anticipated device dispatch profile, rate of energy consumption or generation) and the current and predicted aggregate net load of the customer premise in order to optimize its own dispatch behavior. When prices are symmetric, there is no need for devices to coordinate their behavior or to be aware of the net building load. Each device uses the price as the only optimization decision variable. The simplicity of symmetric prices can enable device manufacturers to easily automate price-responsive behavior. As noted earlier in this paper, widespread and automated price-responsiveness is a crucial element of maximizing the system impact of demand flexibility.

B. MITIGATING POTENTIAL COST SHIFT CONCERNS ASSOCIATED WITH BTM EXPORTS

Anytime a rate design contemplates compensation for BTM exports by customer owned DERs, the potential for cost shift needs to be considered. As experience with various rates authorized by the CPUC has accumulated over time, it is apparent that there are at least two structural sources that lead to adverse cost shift in some legacy rates: 1) poor linkage between the rate design and cost causation associated with dynamic grid conditions, and 2) recovery of all fixed costs through a constant adder embedded in the volumetric rate, distorting the economic signal perceived by customer DERs.

It is important to highlight key aspects of the CalFUSE framework that differentiate it from legacy BTM export compensation policies in addressing the above structural sources of potential cost-shift. These include:

1. **Market-informed energy (commodity) price**. The commodity component of the current CalFUSE price is derived explicitly from the wholesale market in real-time. This ensure that the commodity-portion of the price paid for BTM exports at any time is linked to the marginal cost of an LSE's procurement of energy from the wholesale market at the same time.

2. **Capacity prices based on marginal costs**. The distribution and generation capacity components of the CalFUSE price are linked to marginal costs of adding incremental

capacity and recover associated revenues through scarcity prices that are based on capacity utilization. This ensures that capacity related prices are incentivizing dynamic shifts in demand away from periods of high utilization to periods of low utilization. This, in turn, reduces or defers the need for distribution system upgrades and reduces an LSE's incremental generation and flexible capacity procurement needs.

3. **Reduced fixed costs embedded in volumetric CalFUSE rate**. There are multiple levers available to recover fixed costs under the CalFUSE framework while still maintaining a bidirectional symmetric dynamic price. These include: (a) scaling the capacity scarcity prices to recover the non-marginal infrastructure costs;[110] (b) a fixed charge embedded in customer-specific subscription price (see Element 5 below) based on historic usage billed at legacy rates;[111] (c) monthly fixed charges outside the volumetric dynamic price or subscription; and (d) shifting of some fixed costs to non-ratepayer sources of funding. These levers present options to the CPUC that can help balance key policy considerations (such as, equity in cost allocation, minimizing cost-shift, fair compensation for grid services provided by customer DERs, encouraging DER adoption, etc.).

4. **Incentive to export limited to hours beneficial to the system.** With the combination of above factors, the CalFUSE price signal (as illustrated in Figure 4-6 above) limits the incentive for customer DERs to export to hours where the exports provide clear system benefits. In hours when supply is abundant and system capacity is not stressed, the prices will be low and likely disincentivize BTM exports. The hours during which BTM exports would result in net financial benefits for customers are also hours where exports would provide net system benefits by reducing stress on generation and delivery infrastructure, and improving system reliability.

4.5.3 Key Implementation Questions

1. **How should the CPUC's net billing policies be aligned with the CalFUSE price signal?**
2. **Are there any statutory constraints or jurisdictional concerns that impact the rate design aspect of the CalFUSE price signal?**
3. **Are the existing metering technologies, usage data collection and processing, and IT & billing systems adequate to enable settlements with the dynamic CalFUSE signal?**
4. **Are the existing customer data access policies, systems, processes (in conjunction with the Element 1 price portal) adequate to allow third-party service providers of**

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110 Note: This approach was illustrated in Section 4.4 above. However, it is also possible to only include marginal costs in the volumetric CalFUSE price and use other mechanisms (fixed charges, subscriptions) to recover non-marginal costs.

111 *See* Georgia Power's two-part RTP rates, which are described further in Section 4.6 below. For example, Georgia Power Real Time Pricing – Day Ahead Schedule, "RTP-DA-5".

BTM DERs and automated energy management tools to fully leverage the CalFUSE signal to maximize benefits for their customers?

5. **Are there any initiatives that the CPUC needs to pursue in other policy domains and proceedings (such as, IRP, Resource Adequacy, DRP, Interconnection, etc.) in support of the CalFUSE roadmap?**

4.6 Element 5 – Offer a Subscription Option Based on Customer-Specific Load Shapes

Customers may subscribe to a monthly load shape based on historic usage (specified energy quantity for each hour of the day) that is billed at a pre-determined price. This option allows customers to hedge against the volatility of dynamic prices and pay a predictable, pre-determined price for a customer-specific hourly usage profile (i.e., load shape), easing customer transition from legacy rates to the CalFUSE price signal. Customers still have the flexibility to opportunistically modify or to shift their usage (or export energy) based on the dynamic CalFUSE price and maximize their bill savings.

4.6.1 Summary

Staff's proposal for the CalFUSE signal includes a load shape subscription option with two features, as follows:

The first feature allows customers to purchase an hourly, customer-specific, load shape – i.e., energy quantities (kWh) for each hour of a bill period based on their historical usage – at a pre-defined tariff, such that customer with subscriptions are billed at a cost effectively equivalent to the cost of their bills on the pre-subscription TOU or Tiered rate (see solid line in Figure 4-7), assuming their actual usage is aligned with the subscribed load shape.

The second feature allows customers the discretion to deviate from the subscribed load shape, with the change in energy quantity billed at the current CalFUSE price. During each hourly (or sub-hourly) interval, customers can: (1) buy additional energy as needed to meet actual demand, and (2) sell back any unused or excess energy relative to the quantity pre-purchased through the subscriptions. The buy/sell transactions are charged/credited at the current CalFUSE price, as determined by Elements 2, 3, and 4 (see dotted line in Figure 4-7). This feature encourages customers to seek opportunistic load shift in response to the dynamic CalFUSE price when it is financially advantageous to do so.

To summarize, a subscription load shape is billed at the "legacy" rate and any deviation from the subscription load shape is billed/credited to the customer based on the CalFUSE price signal.[112]

[112] *See* subscription as a hedging product was proposed by CalSSA for SDG&E GRC Phase 2 at Workshop on Dynamic Rates and Real Time Pricing. (available at) https://www.cpuc.ca.gov/General.aspx?id=6442462894.

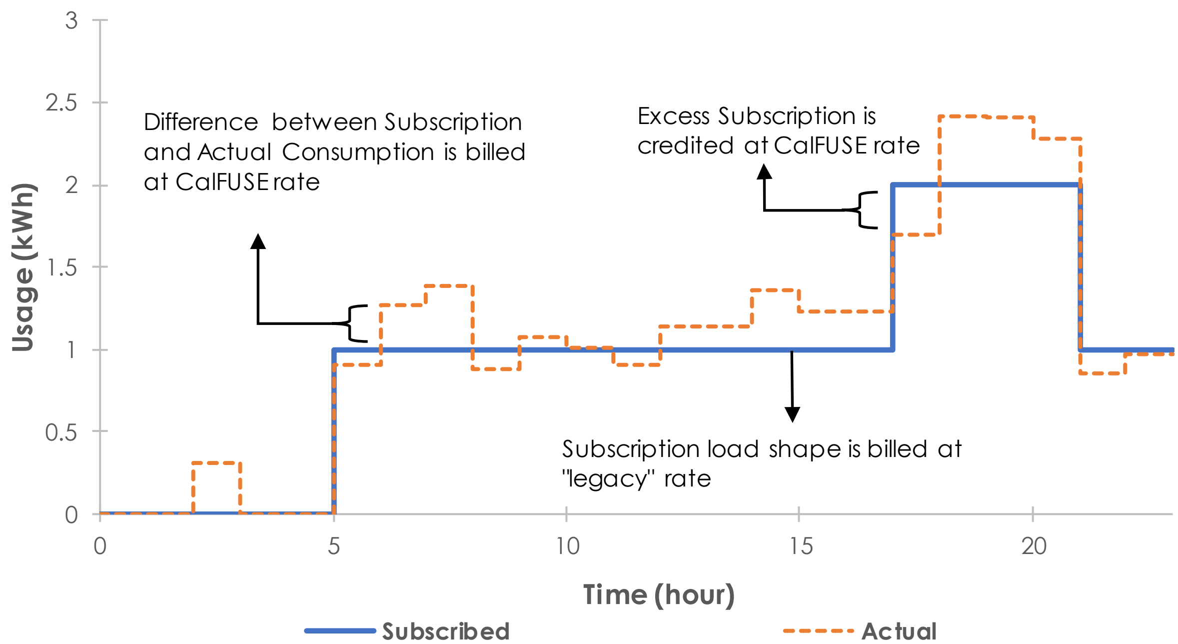

Figure 4-7: Example of a CalFUSE subscription as a hedging product.

This approach of applying a subscription overlay on a dynamic tariff is a key feature of Georgia Power's long-standing RTP tariff offerings, which include a subscription amount referred to as the customer baseline load (CBL) and is described as follows for Georgia Power's RTP Day Ahead ("RTP-DA-5") schedule:

> The CBL represents a customer's normal operation for billing under its conventional tariff. The CBL is initially developed using either customer-specific hourly firm load data or monthly billing determinant data that represents the electricity consumption pattern and level agreed to by the customer and Georgia Power. Changes in consumption, measured from the CBL, are billed at RTP-DA prices. The CBL is the basis for achieving revenue neutrality with the appropriate non-RTP-DA firm load tariff on a customer-specific basis. Mutual agreement on the CBL is a precondition for use of RTP-DA.[113]

In the past, the term subscription has been used to describe a variety of different products, including: (1) a fixed monthly fee for essentially unlimited usage of electricity, or (2) an alternative to traditional NCDCs where customers can pre-purchase a demand capacity (kW) at a discount. This is not what is being proposed by Staff in this paper – an "all you can eat" subscription option is antithetical to the principles of cost causation, energy conservation and economic decision-making.

[113] *See* Georgia Power Real Time Pricing – Day Ahead Schedule: "RTP-DA-5." (available at) https://www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/rates-schedules/RTP-DA-5.pdf.

The CalFUSE subscription option proposed here is a simple forward-hedge: it allows customers and LSEs/UDCs to reduce their bill and revenue recovery uncertainty while still incentivizing economically efficient load shift. Table 4-1 provides an overview of the benefits of fixed load shape CalFUSE subscriptions.

Table 4-1: Benefits of fixed load shape subscriptions

Protection	Flexibility	Predictability
• Protect customers against bill volatility by allowing a forward contract based on predictable prices. • Ease customers transition to real-time prices.	• Accommodate changed home conditions. • Encourage opportunistic load shift.	• Stabilize revenue recovery for UDCs, LSEs, etc.

4.6.2 Key Implementation Considerations

A. DESIGN OF MONTHLY SUBSCRIPTION LOAD SHAPES AND TARIFFS

In addition to the key goal of the subscription option to provide bill/revenue stability, it is important to ensure that customers who choose this option are still sufficiently incentivized to optimize demand flexibility and BTM DER dispatches to maximize benefits to themselves and the system.

For the Georgia Power RTP tariffs, the subscription amount, which is referred to as the customer baseline load (CBL), is billed on a conventional otherwise applicable tariff (OAT), and is designed as follows:

> For customers with Existing Load, the CBL will initially be developed from either historical metered half-hourly (1/2) interval data for a customer's specific location or from a Template scaled to the historical monthly energy and monthly peak demands.
>
> For customers with New Load, the CBL will initially be based on 100% of a Commercial customer's total projected load or 60% or greater of an Industrial customer's total projected load. A new Commercial or Industrial customer can establish a CBL less than its projected level provided that the customer can Demonstrate its desired CBL level or the CBL is based on a Footprint. In no case shall this CBL be less than the minimum CBL level established by Georgia Power for that specific location. Since no historical data exists for a new location, the

> CBL can be developed from a Template, or from a similar customer's load shape, scaled to the expected usage pattern of the New Load.[114]

Another approach to designing monthly subscriptions was demonstrated by the TeMix/SCE RATES pilot, which provided subscriptions based on the otherwise applicable tariff for each customer.[115] This approach allowed for policy and equity decisions that are embodied in a customer's otherwise applicable tariff (e.g., CARE, FERA, Medical Baseline) to be "transferred" over to the subscription "rate". Customers on TOU rates were offered a subscription based on the average of their hourly usage of the prior 3 years.

In this example, a customer that used the same monthly energy—on an hourly basis—as the prior years would pay the same amount as their TOU-based historic bill. Any deviation from the subscribed amount was billed/credited at a dynamic composite rate that, similar to the CalFUSE framework, was based on the wholesale commodity prices and hourly, usage-based capacity cost recovery scarcity price curves. Analysis of customer bill impacts for the subscription methodology in the RATES pilot showed that a completely inelastic customer (i.e., a customer that was entirely non-responsive to the dynamic prices) experienced an annual bill impact *of less than 4%*.

There are various methodologies for subscription offerings that could be considered. Staff highlights the following two options:

1. A customer-specific subscription profile based on a projection from prior year(s) usage, as was done in the TeMix/SCE RATES pilot, which ensures revenue-neutrality on a per-customer basis; and
2. A class-based, climate-zone-specific / that is scaled to match a customer's total annual peak period usage, which results in the subscriptions being revenue-neutral on a customer class basis.

Subscriptions offered at the otherwise applicable tariff reduce the potential for revenue shortfalls and both inter- and intra- class cost shift, which strikes a balance between stabilizing bills/revenues while still providing incentives to respond to real-time grid conditions through the CalFUSE price signal. As customer usage patterns may change in response to the CalFUSE price signal, these subscription levels can be adjusted annually. The appropriate methodology to determine the subscription shape and tariff for each customer/class will need to be assessed in further detail through stakeholder feedback.

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114 *Ibid.*

115 *See* Details for the Retail Automated Transactive Energy System (RATES), available at: https://rates.energy/.

B. RECOVERING OTHER "NON-CAPACITY" FIXED COSTS VIA SUBSCRIPTIONS

Traditionally, volumetric rates for residential customers are designed to recover:

a) Energy costs based on wholesale commodity market costs

b) Capacity fixed costs (generation, distribution, and transmission), that each have an associated marginal cost; and

c) Other "non-capacity" fixed costs, including utility or LSE retail operations and administration, low-income and public purpose programs (e.g., CARE, Medical Baseline, energy efficiency programs, etc.), and wildfire mitigation costs.

The third category of costs do not have a clear marginal cost basis, that is, they do not scale with usage and cannot be avoided by changes in customer usage and demand. Note that customer access costs (meter and final line transformer cost) are not explicitly listed above. For the purposes of this section, customer access costs are considered "non-capacity" fixed costs, as these costs are typically recovered through a monthly fixed charge (e.g., $ per meter per day).

Staff proposes that load shape subscriptions be used to recover these other "non-capacity" fixed costs and ensure that the CalFUSE price approaches a true real-time, cost-based price. Alternatively, "non-capacity" fixed costs could be recovered through a monthly, fixed charge on customer bills. In either case, it is important for these other fixed costs to be recovered equitably without distorting the dynamic volumetric price signal. This advances the cost causation principle and reduces the concerns of under/over collection of required revenues or cost-shifts.

A customer-specific or scaled class-based subscription where a customer's subscription load shape is billed at an otherwise applicable tariff (e.g., TOU or Tiered rate) ensure that a customer's total bill is revenue neutral relative to a customer's previous firm non-RTP tariff. Any incremental energy used (or unused) relative to the subscribed quantity should be billed/credited at the real-time CalFUSE price signal computed by the price machine via scarcity price functions with the non-capacity fixed costs portion of cost recovery *removed*.

C. SUBSCRIPTIONS FOR REACTIVE POWER USAGE

Industrial loads with rotating, inductive machinery can draw large quantities of Reactive Power. Reactive Power (Var) is the component of electric power that is "out-of-phase" with respect to Real Power (W), which is the actual power consumed when electrical energy is converted into work. Loads that draw a large amount of Reactive Power in proportion to Real Power are described as having a low Power Factor (PF). Even though Reactive Power is not "consumed" by a load, there is still a cost – in energy lost due to line losses – when loads with a low PF are served. Stakeholders have noted that for certain customers, managing their Reactive Power usage is just as financially important as managing their Real Power usage. Staff suggests that it may be possible to incorporate Reactive Power payments/compensation into the CalFUSE/subscriptions framework. To develop this idea further, detailed modelling and stakeholder discussion should be pursued in the course of the recommended rulemaking.

4.6.3 Key Implementation Questions

1. **What other approaches for designing monthly subscription profiles and tariffs should be considered?**

2. **How should customer subscription profiles be updated/revised?**
   To ensure that subscriptions appropriate represent a customer's monthly demand, it may be necessary to periodically update/revise each customer's hourly load shape. For example, Georgia Power's RTP tariffs allow for revision to the CBL (customer subscription amount) to reflect the changes due to new equipment or energy efficiency improvements that "result in a measurable reduction in electric power demand and/or energy usage." [116] However, CBL revisions are not allowed to be revised due to other factors, including RTP price response, or weather.

   For the CalFUSE framework, the subscription levels could be updated periodically to reflect adjustments to customer load profiles in response to weather-conditions, customer BTM investments (e.g., DERs, energy efficiency, EVs, etc.), as well as potential reductions in the cost of service resulting from improved system utilization.

3. **In implementing the CalFUSE framework, how can the role of third-party energy managers and service providers be best leveraged? How can companies with large consumer facing platforms (Google, et.al, tech ecosystem, telecom companies, cable service providers, etc.) be engaged in support of CalFUSE?**
   The robust ecosystem of third parties, including service providers, DER integrators, and aggregators, can enable customers to save on their monthly bills by providing and managing price responsive devices. Multiple studies have shown the importance of automated response in enabling sustained and measurable load shift. Third parties have been successful at recruiting and enrolling customers into existing DR programs. Staff expects that third parties will have a critical role in managing customers energy usage and DERs in the CalFUSE framework as well to maximize customer bill savings. Leveraging machine learning and other predictive algorithms to provide an optimization/management service can help ensure that customers are able to optimize their savings, while monetizing DER capabilities by providing grid services.

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[116] *See* Georgia Power Real Time Pricing – Day Ahead Schedule: "RTP-DA-5." (available at) https://www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/rates-schedules/RTP-DA-5.pdf.

4. **What best practices should be considered for educating customers about CalFUSE price signal and subscription offerings?**

   Customer marketing, education, and outreach (ME&O) is important in the success of the CalFUSE initiative, with its subscription option, being effective in driving customer adoption of demand flexibility solutions. The rollout of default TOU rates was accompanied with a thorough ME&O program. A clear message about the benefits of CalFUSE would need to be developed, along with a customer rate comparison tool that predicts the bill impacts of the CalFUSE/subscription rate (as has been required for transitioning customers to TOU rates),[117] including modeling of opportunistic load shift, to showcase the potential bill savings.

   Third party energy management services will play a material role in aiding critical customer segments in navigating CalFUSE tariff offerings. Staff anticipates that these third-party services as well as IOU-specific ME&O programs that borrow from the essential learnings of CPUC's default TOU implementation process will be evaluated and developed over the course of the recommended rulemaking, informed by a working group process.[118]

[117] D.15-07-001 at 172 (and surrounding discussion).

[118] Note: A post-mortem capstone report and press release on the accomplishments and learnings from programmatic milestones of the default TOU implementation process is under way and will be available to inform a CalFUSE framework ME&O program by the end of 2022.

4.7 Element 6 – Enable Transactive Features Allowing Lock in of Future Electricity Prices

Customers can execute contracts to import or export energy at some future time at a pre-determined price. This provides customers with additional options to control and optimize energy demand or generation. This also allows greater visibility into future grid conditions, enabling service providers to improve load forecasting, planning and operations.

4.7.1 Summary

Staff proposes that customers should be able to purchase and sell energy based on future (e.g., week-ahead, day-ahead, hour-ahead, etc.) prices offered by the LSE or UDC.

Transactive features and the concept of "transactive energy" have been studied extensively since 2000 through Department of Energy (DOE) funded research projects conducted by US National Labs.[119, 120]

To be clear, in proposing the transactive element as part of the CalFUSE framework, Staff is not suggesting or advocating any of the concepts listed below:

a) Peer to peer trading,
b) Forcing customers to become market traders, or
c) Electricity prices set by supply / demand bids (market trading).

The transactive element is intended to offer an additional tool for customers and smart DERs to optimize energy management and bills by enabling customers to make decisions to purchase or sell energy in advance of when the energy transfer needs to occur (could be a few hours or a few days in advance). Large, sophisticated customers are able to do this in the wholesale energy market. With rapidly advancing machine learning and artificial intelligence becoming accessible in common consumer devices, Staff suggests that it is reasonable to make the transactive capabilities available to customers for use at their discretion and encourage further energy management innovation in the industry.

The transactive element of the CalFUSE framework does not need to be implemented at the same time as the other elements. Certain customer segments (e.g., large C&I and agricultural pumping customers) may be best suited to be the early adopters of the transactive option.[121] These early adopters could pave the way for the more advanced elements of the CalFUSE framework to be incrementally scaled to other customer segments as desired by the CPUC.

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119 *See* Pacific Northwest National Laboratory (PNNL), "Transactive Energy." (available at) https://www.pnnl.gov/explainer-articles/transactive-energy.

120 *See* National Institute of Science and Technology (NIST), "Transactive Energy: An Overview." (online) https://www.nist.gov/el/smart-grid-menu/hot-topics/transactive-energy-overview.

121 Note: As highlighted in D. 21-12-015 at 91, VCE's agricultural pumping customers have expressed interest in the transactive system as it allows them to schedule their operations on a weekly basis. VCE has started its 3-year dynamic rate pilot as of May 2022.

A brief description of how a transactive system (yet another cloud-based platform) would work within the CalFUSE framework (see Figure 4-8) follows:

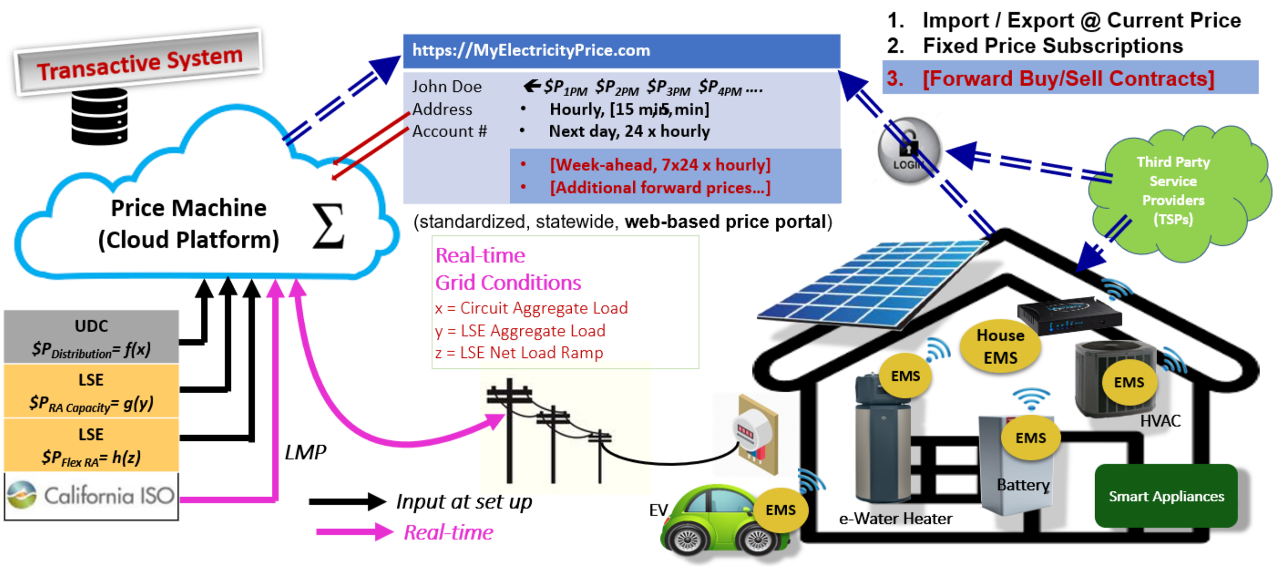

Figure 4-8: Graphical illustration of the CalFUSE framework, including the transactive elements.

A transactive system involves transactions between an LSE and the customer's DERs (or an energy management service provider representing the customer). A transactive bid (aka tender, proffer) is a one-way, offer to sell/buy a specified quantity of energy during a specified future time interval at a specified forward price. A customer's acceptance of a transactive bid results in a binding transaction. More specifically:

1. Based on its demand forecast, an LSE issues a set of bids, or tenders, (e.g., hours-ahead, day-ahead, week-ahead, etc.). When a customer (or the customer's smart device/DER) accepts a bid, the customer executes a binding contract to buy/sell the specified quantity of energy during the specified time interval in the future at the specified price.
2. For each time interval, only a limited number of bids (tenders) are offered and may be accepted by customers (e.g., on a first come first served basis). The aggregation of the transactions can provide the LSE (and the UDC) with greater visibility into the expected load and allows it to adjust its planning and operations to serve that load.
3. Customers who accept the transactive bids lock-in a specific price for energy for a future time interval ahead of time. This can help the customer manage and schedule device operations (e.g., EV fleet charging, agricultural pumping, battery discharge, etc.) to optimize their energy/demand management, via the device's or integrated, transactive-focused,

artificial intelligence algorithms, and maximize financial benefit consistent with customer preferences or needs.

4. The transactive system can automatically create new bids that reflect updated information regarding the overall system supply and demand. If the customer imports or exports energy without an underlying transaction, the imported/exported energy is settled at the applicable CalFUSE price. As the transactive system is constantly updated with the latest bids accepted by customers over a variety of time horizons, there should be multiple stabilizing feedback loops that may lead to the efficient balancing of supply and demand at both distribution and wholesale levels.[122]

Note that a subscription load shape is a special case of a transactive bid from an LSE accepted by the customer.

Given the proposed functionality of a transactive system, it is probably best set up as a cloud-based platform separate from the price portal and the price machine described in earlier Elements.

To the extent, customers engage in energy transactions within a transactive system[123] in the context of the CalFUSE framework (as described above), several upsides or benefits could be realized, resulting in a win-win-win beneficial outcomes for customers, UDCs/LSEs, and CAISO. Potential benefits include:

1. **Price certainty**. Allows customers to lock-in price certainty by purchasing future quantities of energy based on prices offered by the LSE.

2. **Energy optimization**. Provides additional options for customers and devices to optimize energy management and reduce costs.

3. **Load forecast accuracy**. Reduces load forecast error for the system operator by providing greater demand-side visibility through aggregate transaction data.

4. **Visibility**. Improves an LSE's (or UDC's) operations as needed to support the expected load and longer-term capacity planning.

5. **System stability**. Reduces the potential of instability driven by over-response[124] of flexible loads to a sharp change in price.

Staff suggests that the load shape subscription (Element 5) and transactive elements (Element 6) of CalFUSE enable bill and revenue stability through their design. Subscriptions to baseline quantities at existing tariffs as a pay-for-load-shape option can ensure that as ratepayers transition to dynamic locational electricity pricing, their bills are stable relative to their historical usage. Similarly, LSEs are

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122 Reeve, Hayden M., et. al., "Distribution System Operator with Transactive (DSO+T) Study Volume 1: Main Report,". PNNL, 2022. (available at) https://doi.org/10.2172/1842485.

123 Note: A bid or tender-based transactive energy project was piloted by TeMix, inc. in SCE territory, and was funded by the CEC-EPIC program. Details for the Retail Automated Transactive Energy System (RATES) are available at: https://rates.energy/

124 Note: A pertinent example is synchronized charging of EVs in response to the TOU step change, leading to a large, potentially, de-stabilizing load spike (see Chapter 3).

also assured that the bulk of electric sales are billed at rates effectively equivalent to existing tariffs and revenues are stable relative to historical baselines. The use of transactive tenders extends the hedging protection offered by subscriptions and allows for both customers and LSEs to optimize their bills and revenues.

Transactive retail markets (a more advanced version of the proposed CalFUSE Element 6) have been studied in detail over the past 10 years. A recent DOE-funded study performed by Pacific Northwest National Laboratory (PNNL) demonstrated the potential of a transactive retail market as follows:

> The dynamic coordination of flexible customer assets can save a region the size of Texas $3.3–5.0B **(12-19% of electrical costs) per year** [emphasis added]**,** even under a range of future renewable generation, DER deployment, infrastructure growth, and market price assumptions.[125]

The above PNNL study is discussed in further detail in Chapter 5.

4.7.2 Key Implementation Considerations

A. ENABLING CONSUMER ACCESS TO TRANSACTIVE FUNCTIONALITY

Customers smart devices, DERs, other end-use equipment, or homes/buildings could interact with and execute transactions with a transactive system via embedded, autonomous, automated "agents" (or energy management systems, aka EMS) or through a cloud-based control platform (for example, a virtual power plant) The role of these agents is described below:

> The [agents] are lightweight artificial intelligence and machine learning models that reside on an electrical consuming device controller, in the cloud, or on an edge-gateway. The agents perform optimization routines, unique to each device, to determine the most beneficial operation of the device based on the device owner's preference for that device to provide comfort vs. savings, current tender prices, usage forecast, and other variables such as weather.[126]

A third-party entity (e.g., an aggregator, an energy management service provider, a DR provider) could manage the buying/selling transactive tenders and the control of flexible customer-sited resources (e.g., storage, smart thermostats, EVs) that leverage their flexibility to take opportunistic advantage of dynamic prices.

The third-party service provider could offer a service contract to customers, wherein they manage the transactions and electricity bill of an individual customer in exchange for a set monthly fee. The monthly fee could be based on the customer's historic usage and flexible resources. In return the

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[125] Reeve, Hayden M., et. al., "Distribution System Operator with Transactive (DSO+T) Study Volume 1: Main Report,". PNNL, 2022. (available at) https://doi.org/10.2172/1842485.

[126] *See* TeMix Inc. website. https://temix.com/temix-transactive-energy-services/get-started-with-temix/

customer would allow the third-party provider to control a set of flexible loads to optimize their response to the dynamic CalFUSE price and buy/sell transactive tenders on the customer's behalf.

The interactions between the agents/EMS and the transactive system will require development of appropriate standards and protocols.

B. GENERATING LSE BIDS IN THE TRANSACTIVE SYSTEM

Recall that a combination of Element 2 (real-time energy commodity prices linked to CAISO locational marginal price) and Element 3 (real-time, dynamic capacity cost components linked to marginal capacity cost via a utilization-based scarcity price function) define the real-time, composite, volumetric CalFUSE retail prices. And with respect to Element 4 involves a customer's pre-purchased subscription based on a fixed load shape linked to the otherwise applicable tariff.

With respect to formulating bids (tenders) prices in the Element 6 transactive system, one option is to define the bid's prices based on system and circuit forecasts using the same dynamic price formulas as defined above. The LSE, in coordination with the UDC (if necessary), can use load forecasts on a variety of time horizons (week-ahead, day(s)-ahead) for the bids. Based on the quantity of bids accepted by customers, the LSE/UDC can update forecasts and create additional bids based on the updated forecasts.

Another possibility is that the bids are set dynamically by an LSE. Customers (or more likely, the energy management firms that represent them) participating in a transactive system are not obligated to accept bids offered to them. The customers would already have access to a forward hedge in the form of the subscription option. Thus, an LSE utilizing a transactive system is incentivized to offer bids at prices that customers are willing to accept. In other words, the LSE is incentivized to offer bids that are competitive with anticipated CalFUSE prices adjusted by a customer's perceived risk premium to procure sufficient BTM resources to optimize their operations.

C. CLEARINGHOUSE FOR TRANSACTIONS

The transactive element of the CalFUSE framework requires an entity that provides a clearinghouse function for the transactive tenders. This entity could be contracted by the IOUs or LSEs to provide and account for the transactive tenders that allow customers to lock in usage/load reductions or BTM generation for a pre-defined price. The LSEs/IOUs would in turn gain greater certainty in their load forecasts and can secure commitments from customers that can reduce their projected system/circuit load and lead to efficiency improvements from a resource adequacy and resiliency standpoint. The function and relationship of the entity managing the transactive clearinghouse will need to be explored by stakeholders or pilot programs.

4.7.3 Key Implementation Questions

1. **What entity or entities should operate and manage the transactive system?**
2. **Should there be one system for the whole state, or should there be multiple systems (perhaps one per UDC, or one per LSE)?**
3. **What are the processes, agreements, and understandings that are necessary between UDCs and LSEs to facilitate the transactive elements of CalFUSE?**
4. **What standards, rules, and regulations are required to facilitate a robust, secure, and efficient transactive system? What regulatory oversight is required?**
5. **What factors should an LSE consider in deciding how to formulate bids in a transactive system?**
6. **If the CPUC were to pursue the implementation of the CalFUSE framework, how should/could the CPUC seek the support of CCAs in supporting the CalFUSE framework and facilitate, manage, or oversee the collaborative work needed between the UDCs (IOUs) and LSEs (CCAs)?**

5 Analysis of the Energy Division Staff Proposal

This chapter analyzes the potential impacts that the Energy Division Staff CalFUSE proposal will have on the system benefits of and compensation for DERs and flexible loads and discusses the customer protections and equity benefits of the CalFUSE framework.

To ground the analysis presented in this chapter with data, the results from two relevant studies are presented. First, results from simulations of storage dispatch to a CalFUSE price signal are shown to discuss the economic and GHG emissions impacts of response to dynamic prices as prescribed by the CalFUSE framework. Second, results from Department of Energy (DOE) funded Distribution System Operation with Transactive (DSO+T) study are shown, which assessed the system and customer benefits of a dynamic rate coupled with transactive mechanisms to simulate the large-scale dispatch of flexible DERs in coordination with the operation of the electric power system.

5.1 Study 1: Modeling Energy Storage with CalFUSE Proxy Signal

This section presents modeling results from an open-source energy storage dispatch optimization tool, OSESMO.[127] OSESMO was developed by the SGIP GHG Signal Working Group to create a tool that could evaluate the dispatch (charge/discharge) of energy storage to evaluate the GHG emissions of an energy storage project.[128] Note that the dynamic prices used for the purposes of this study are the same as the prices used by TeMix/SCE in their RATES pilot, which was mentioned in Chapter 4 and will be discussed further in Chapter 6. The dynamic prices present a proxy for the CalFUSE price, and as such, there may be differences in the formulation and magnitude of the composite prices from what is presented in Chapter 4. Therefore, while these bill impact results provide a basis for comparison between the dispatch of energy storage under a CalFUSE price vs a TOU price, the absolute magnitude of the bill impacts is less informative compared to the relative bill impacts. However, the GHG reduction impacts are much more important to highlight and form a basis for comparing the actual GHG emission reduction benefits of dispatch driven by business-as-usual TOU rates versus the Staff CalFUSE proposal.[129]

[127] *See* "OSESMO: Open-Source Energy Storage Model", (available at) https://github.com/RyanCMann/OSESMO.

[128] *See* "SGIP GHG Signal Working Group Final Report", 2018, for R.12-11-005. (available at) https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy/energy_programs/demand_side_management/customer_gen_and_storage/ghg-working-group-report-09-06-18-corrected.pdf.

[129] Note: Staff acknowledges that the simulation toolset used for the analysis in this section was developed in consultation with Ryan Mann (Enel X) and Ed Cazalet (TeMix).

5.1.1 Methodology

The OSESMO tool incorporates an "optimization-based model" for energy storage that optimizes the control of the energy storage. The tool attempts to maximize a customer's bill savings across multiple, often competing, economic value streams, such as demand charge reduction and time-of-use energy charge arbitrage.

A. INPUTS

The inputs to each OSESMO simulation include:

1. Historical load profile data for a customer.
2. Tariff information, including demand charges for non-residential customers.
3. Battery characteristics, including cost, cycle life (degradation cost per charge-discharge cycle).

B. OUTPUTS

The outputs from each OSESMO simulation include:

1. Optimized storage dispatch profile.
2. Monthly customer bill for baseline load on input tariff.
3. Monthly customer bill with optimized storage dispatch.
4. Monthly GHG emissions impact from storage dispatch profile.

C. PARAMETERS

For this study, the following input parameters were used:

1. **Customer load profiles**: The 2020 SCE Residential and Commercial customer load profiles.[130]
2. **Customer tariffs**:
    a) **Residential:** SCE TOU-D-PRIME[131]
    This is a residential rate that currently restricts participation to customers with the following technologies: EV/PHEVs, batteries, electric heat pump systems. The off-peak volumetric price for this rate is lower than other TOU residential rates ($0.20 vs $0.30 per kWh).
    b) **Commercial:** SCE TOU-8[132]
    This is the mandatory rate for large commercial customers (>500kW). The rate includes TOU periods, monthly customer charges, and coincident and non-coincident demand charges.
    c) **Dynamic (CalFUSE proxy)**: A dynamic rate with the same design principles as the SCE/TeMix RATES pilot rate updated to incorporate 2020 energy market prices.

130 *See* https://www.sce.com/regulatory/load-profiles/2020-static-load-profiles.

131 *See* https://www.sce.com/residential/rates/Time-Of-Use-Residential-Rate-Plans.

132 *See* https://www.sce.com/business/rates/large-business.

3. **Battery characteristics**: Size, efficiency, and cycle cost.
    a) **Residential**: 5.8kW and 13.5kWh
    b) **Commercial**: 250kW and 500kWh

5.1.2 Results

The results from the OESMO simulations are shown in Table 5-1 below. As was noted above, while the bill impacts can form a basis for relative comparison, it would not be accurate to compare the absolute values of bill savings under TOU rates to bill savings under the CalFUSE proxy rate. However, Staff believes that the GHG emission results present an accurate basis for an absolute comparison between the TOU rates and the CalFUSE composite price as described in Chapter 4.

The first column of Table 5-1 lists the rate that was used as the input for generating the results. The second column calculates what each customer's annual base bill is when billed at the input rate, where the base bill is the bill for a customer's annual load without storage. The third column shows what a customer's annual bill is when energy storage is installed and the dispatch is optimized to the customer's retail rate, and the fourth column shows the bill savings with storage dispatch optimized. The fifth column shows the annual GHG emissions reduced from the optimal dispatch of storage. The last column displays the total number of charge/discharge cycles for the energy storage dispatch profile.

Table 5-1: Results from OSESMO storage dispatch optimization with residential and commercial customer that compare the bill and GHG impacts of storge dispatch optimized to TOU rates and to a (proxy) CalFUSE price signal

Class	Retail Rate	Annual "Base" Bill w/o Storage	Annual Bill with Storage	Annual Bill Savings with Storage	Annual GHG Emissions Reduced (metric tons)	No. of Cycles
Residential	SCE-TOU-D Prime	$1,849	$1,397	$447	**0.25**	150
Residential	CalFUSE	$1,644	$725	$919	**0.36**	201
Commercial	SCE-TOU-8 (includes NCDC)	$542,991	$512,990	$33,165	**3.78**	332
Commercial	CalFUSE	$589,656	$523,178	$66,478	**28.43**	393

For residential customers, we find that CalFUSE prices encourage batteries to cycle more often, and the resulting increased cycles result in 44% more annual GHG emissions reduced. CalFUSE prices do encourage additional cycles for residential customers, however, even when GHG emissions are normalized on a per cycle basis, CalFUSE prices are more effective at reducing GHG emissions, with 7% more emissions reduced on a per cycle basis. This picture is much more dramatic for commercial customers. As was discussed in Chapter 3, optimizing energy storage to reduce NCDCs prevents energy storage dispatch from reducing GHG emissions. The results show that commercial customers who optimize their dispatch to CalFUSE prices reduce 7.5x as many (650% more) GHG emissions than commercial customers on a TOU rate. Comparing the bill impacts, commercial customers reduce their bills by 11.3% by optimizing their energy storage dispatch in response to CalFUSE price compared to 6.1% for the TOU rate.

5.1.3 Conclusions

Demand charge reform has been a consistent concern with stakeholders, especially commercial EV fleet operators and charging station operators. Hourly, location-specific demand charges that reflect system distribution and generation capacity constrictions allow flexible loads to fully respond to low system prices while reducing their impact on capacity during peak periods.

In summary, Staff suggests that these results showcase the potential of CalFUSE to enhance demand flexibility, reduce GHG emissions at scale, and provide customer bill benefits through appropriate incentives.

5.2 Study 2: DSO with Transactive Mechanism (DSO+T)

The DSO+T study, funded by the Department of Energy (DOE) and conducted by the Pacific Northwest National Laboratory (PNNL), simulated and analyzed the use of dynamic rates and transactive energy mechanisms to incentivize the large-scale deployment of flexible distributed energy resources (DERs), such as air conditioners, water heaters, batteries, and electric vehicles, in the operation of the electric power system.[133] The DSO+T study's problem statement affirms the goals of this Staff proposal:

> There is a need for a solution that integrates the coordination of demand flexibility into everyday grid operation, ensures it is automated, puts the customer in control of how much or little they participate, and fairly compensates them for the level of flexibility they provide to the grid.

[133] Reeve, Hayden M., et. al., "Distribution System Operator with Transactive (DSO+T) Study Volume 1: Main Report,". PNNL, 2022. (available at) https://doi.org/10.2172/1842485.

5.2.1 Overview

This study used the Electric Reliability Council of Texas (ERCOT) region as the basis for its analysis and was conducted using a highly integrated co-simulation and valuation framework that encompassed the entire electrical delivery system from bulk system generation and transmission, through the distribution system, to the modeling of individual customer buildings and DERs. The financial impacts on each type of entity involved (grid operators and customers) were evaluated in detail. The assessment framework has three key elements (as shown in Figure 5-1): an integrated simulation model; a transactive coordination and market integration scheme; and an economic valuation method.

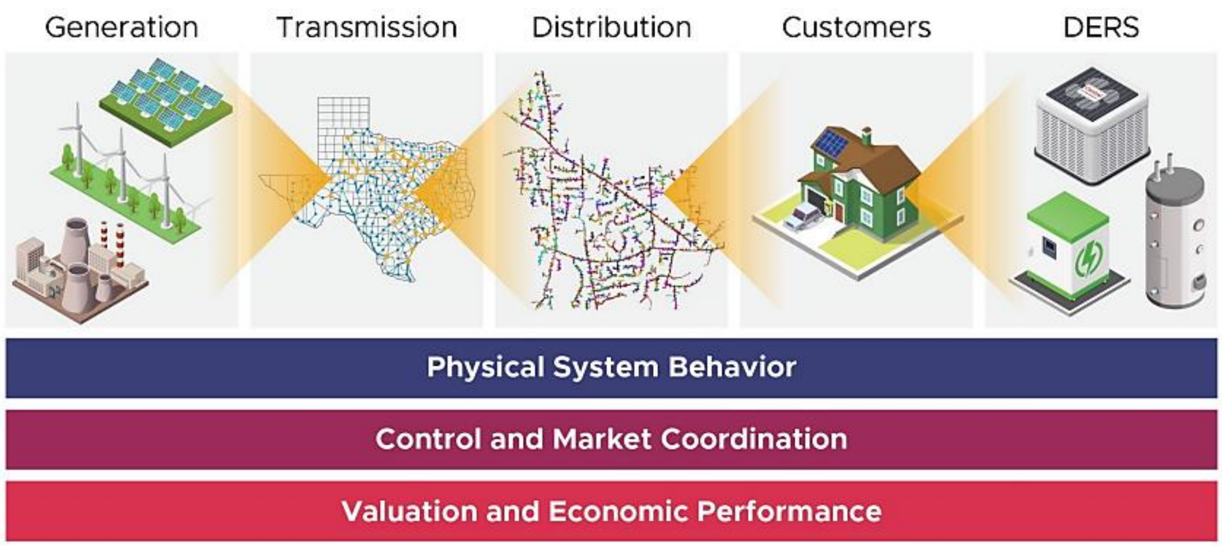

Figure 5-1: Overview of the PNNL DSO+T study's scope.

The DSO+T study, which simulates both the granular physics of the electrical system at small time scales to the economic performance of the wholesale market over multiple years, uses a more advanced version of a transactive framework than what is proposed in Element 6 of Staff's CalFUSE proposal, where a transactive retail market operated by a DSO is simulated for participating customers who have price responsive flexible resources. Note that while this framework includes a more dynamic retail transactive market, the fundamental principle is very similar to what Staff proposed in Chapter 4. As in the Staff proposal, price responsive devices that choose to participate receive bids using forecasts of available supply and demand and those bids are the basis for binding buy/sell agreements between the DSO and the customers. As was proposed in the Staff proposal, in addition to wholesale market prices, the transactive prices include distribution constraints (such as substation capacity limits) to ensure that the composite retail price supports the management of local distribution system constraints. The transactive rate structure for the study was as follows:

$$Bill = EnergyCost + CongestCost + DistributionCost + MeterCharge$$

Where:

a) $EnergyCost$ is the wholesale market (day-ahead and real-time) commodity cost plus distribution losses
b) $CongestCost$ is the marginal peak capacity (system and distribution circuit/substation) congestion cost.
c) $DistributionCost$ is a volumetric distribution system cost that collects revenues associated with operations and maintenance costs.
d) $MeterCharge$ is a constant (monthly) charge for customer specific costs (e.g., meter costs).

5.2.2 Results

The study demonstrated that a transactive framework with dynamic prices significantly shift energy use from high demand periods to low price periods. For the medium-renewables scenarios, the study found **9-15% lower peak load and 20-44% lower daily load swings**, with similar reductions in wholesale price variation (see Figure 5-2). Larger load reductions were seen in high-renewables scenarios.

The study also quantified the cost impact of demand flexibility on overall system operating costs. Some of the key takeaways from the cost analysis were that wholesale costs were lower, and less generation capacity was needed as well. The study also quantified the savings from deferred transmission system and substation upgrades. The benefits from both reduced wholesale energy costs and deferred infrastructure costs resulted in a **net annual benefit of $3.3-5.0 billion (12-19% of total system costs for ERCOT)**.

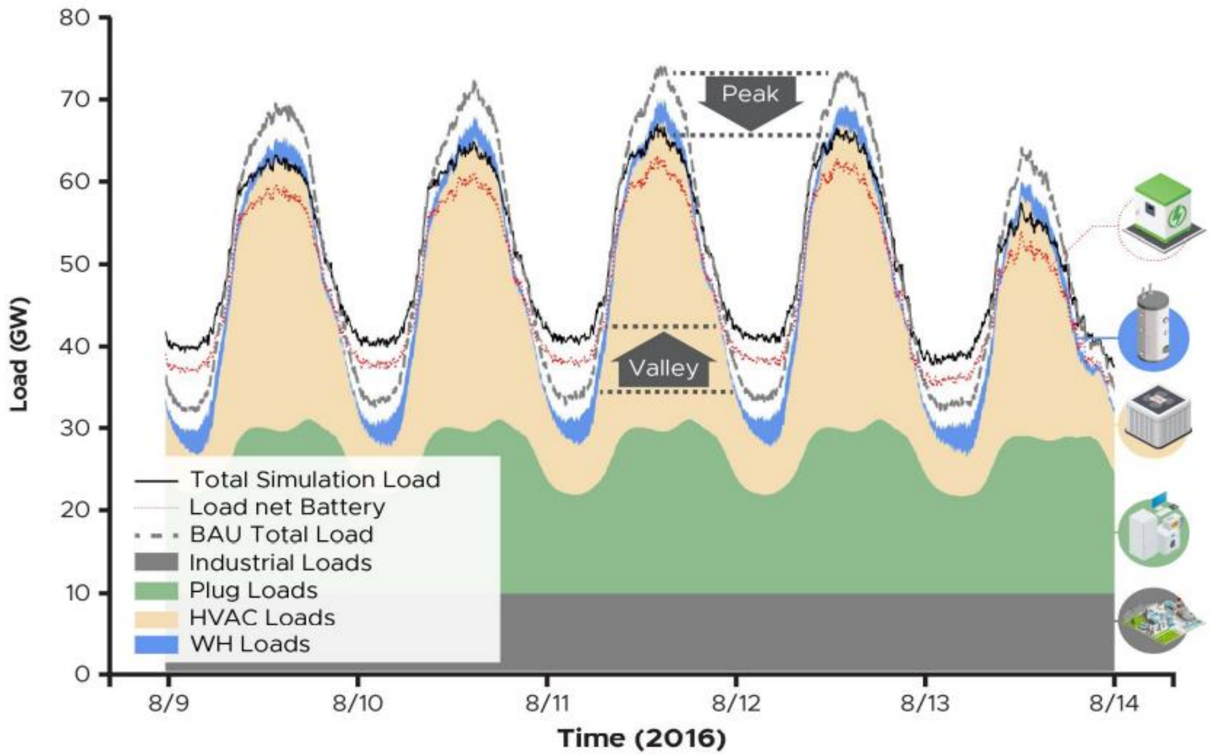

Figure 5-2: Example of peak load reductions observed by DSO+T study showing battery dispatch under a dynamic transactive rate compared to BAU.

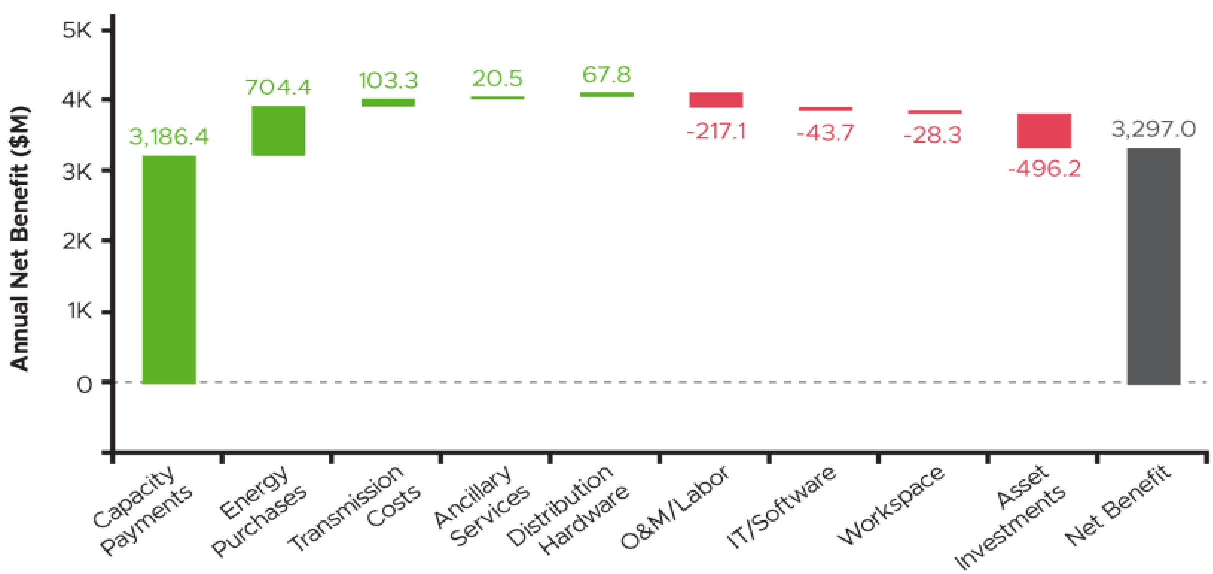

Figure 5-3: Annual net benefits for battery dispatch optimization using dynamic transactive prices (for a moderate renewables growth scenario).

5.2.3 Equity impacts

One of the most important results from the study was the fact that there were sustained **bill savings for both participating (14-16% savings) and non-participating (10-14%) residential customers due to the reduced overall costs that benefit all customers** (see Figure 5-4).

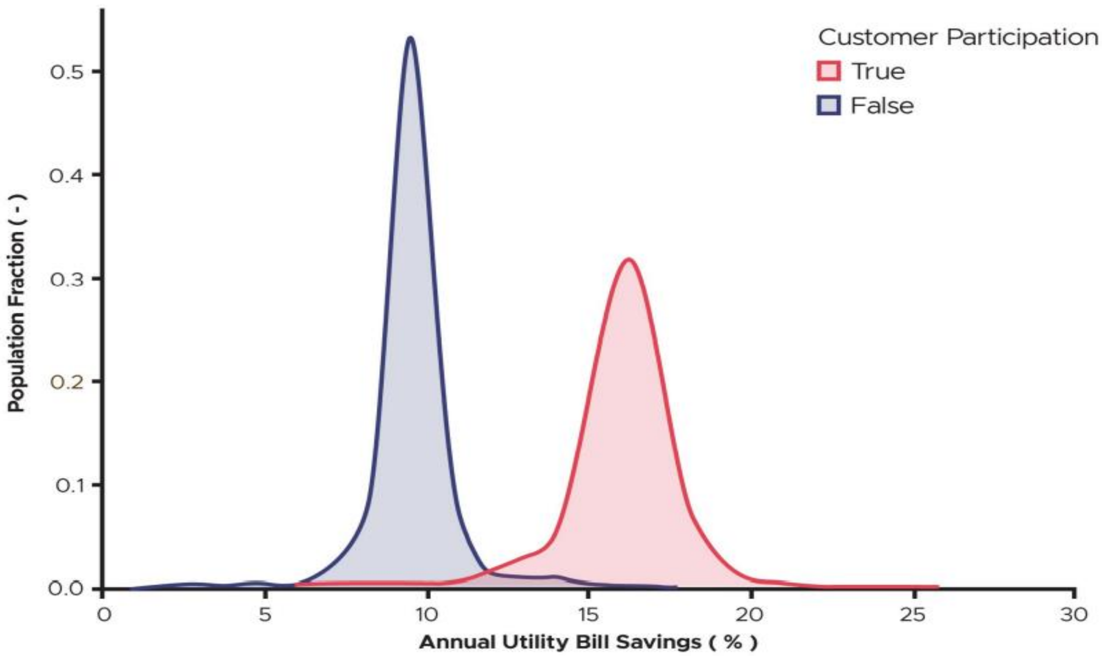

Figure 5-4: Comparison of residential annual bill savings to business-as-usual (for a moderate renewables growth scenario).[134]

5.2.4 Conclusions

The PNNL DSO+T study demonstrated the value of enhanced demand flexibility unlocked by a dynamic transactive retail market, which shares many key characteristics of the Staff CalFUSE proposal. This study reinforces one of the key motivations behind Staff's proposal, enhancing demand flexibility, especially in a high renewable future, can significantly reduce system costs while enhancing system reliability.

Most importantly, the benefits of such a proposal would be broad based, benefiting both participants and non-participants. Staff suggests that the demonstrated equity benefits of aligning

[134] Note: The red curve (true) represents customers that were simulated as participating in the transactive system, and the blue curve (false) represents customers that were simulated as non-participants (i.e., were on their OAT).

demand flexibility with system needs should be a crucial consideration in implementing the CalFUSE framework for California's electric customers.

5.3 Customer Protections and Equity Considerations

As California undergoes the ambitious transition necessary to decarbonize its economy, the CPUC has a stated goal of ensuring that the affordability of electric rates does not impede the adoption of DERs, and transportation and building electrification technologies among low-income and the environmental and social justice (ESJ) communities.[135] The various elements of the CalFUSE proposal are designed to work in concert to ensure that shiftable resources, including storage and EVs, are incentivized to optimize in such a way that the cost of service is minimized.

It is important to examine the equity considerations of a proposal in comparison to the equity implications of the status quo. The problems associated with current retail rate structures, which include: (a) the high-price of average rates that inhibits adoption of electrified end-uses,[136] (b) uneconomic demand charges that lead to inefficient dispatch of BTM resources,[137] and (c) the fundamental disconnect between traditional retail rate structures and marginal prices due to a reliance on volumetric recovery of non-marginal costs, have led to an inequitable rate burden on customers who are not able to manage their load, and especially low-income customers. The CalFUSE proposal is designed to address these and other issues with the status quo to achieve a more equitable outcome.

5.3.1 Reducing System Costs and Removing Unintended Cost-Shifts

There is a direct link between the CalFUSE price signal and the marginal cost of electricity, which ensures that unintended cost shift from specific program/technology participants (responding to the dynamic price) to non-participants is minimized. As the recent analysis of the impact of PNNL's DSO+T study (see above) demonstrated, the benefits from a transactive system with dynamic, cost-based prices include reduced annual electric system costs (12-19%) and **reduced annual bills for both participants (14-16%) and non-participants (10-14%)**.

Another relevant datapoint comes from E3's 2017-2018 evaluation of the SGIP program, which showed that energy storage dispatch that is optimized in response to hourly dynamic prices increases grid benefits for all customers (participants and non-participants) when compared to TOU rates[138] (see Figure 5-5).

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135 *See* CPUC 2020 Annual Report at 108, Building Decarbonization. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/reports/annual-reports/2020-annual-report.pdf.

136 Bornstein, Severin, et. al., "Designing Electricity Rates for An Equitable Energy Transition," Energy Institute at Haas working paper, UC Berkeley, 2021. (available at) https://haas.berkeley.edu/wp-content/uploads/WP314.pdf.

137 Linvill, Carl, et. al., "Smart Non-Residential Rate Design," Regulatory Assistance Project, 2017.

138 *See* "2018 SGIP Advanced Energy Storage Impact Evaluation" Prepared by Itron and E3. 2020.

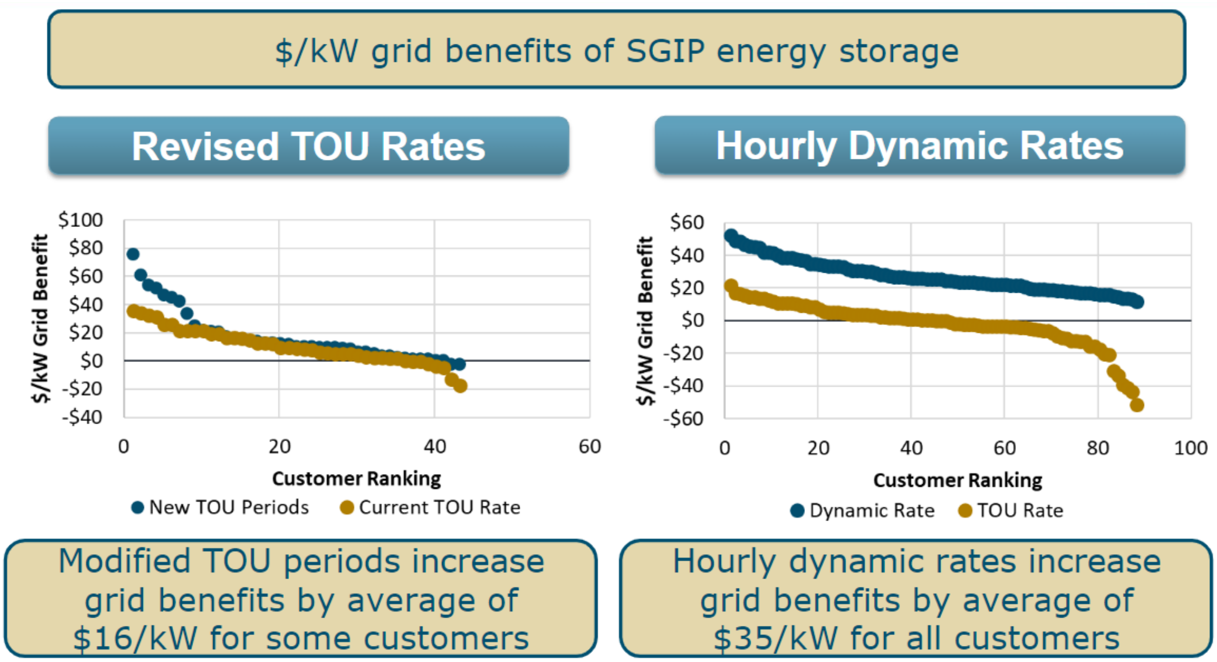

Figure 5-5: Findings from E3's evaluation of the 2017-2018 SGIP Program.

5.3.2 Other Customer Protection and Equity Benefits of CalFUSE Framework

In addition to the system-wide cost-containment benefits of the CalFUSE proposal, various elements of the proposal can be used to directly enhance customer protections and meet equity policy goals.

1. **Opt-in Transition**. The elements of the CalFUSE framework are intended to be offered initially on an opt-in basis. This allows flexibility for customers who prefer to acquire automated price-responsive energy management devices or prefer to wait and learn from the experience of early adopters, before transitioning to CalFUSE.

2. **Subscriptions Offer Equity and Customer Protections**. Subscriptions will allow for customers to purchase a customer-specific load shape and monthly energy quantity at a stable monthly price. The customer subscription tariff can incorporate income-based elements: subscription for low-income and vulnerable customers (e.g., CARE, FERA, Medical Baseline) can include climate-zone normalized load shape quantities at reduced prices. For customers, subscriptions provide bill stability while still providing economic incentives for opportunistic demand flexibility and energy arbitrage. Moreover, subscriptions may evolve over time, with annual adjustments to customer-specific load shapes that more accurately reflect usage pattern changes in response to class specific price functions.

3. **Class-specific Price Functions**. The CalFUSE framework accommodates different scarcity price functions for the capacity cost components of the composite CalFUSE price without 1) impacting the customer's ability to access the prices, 2) necessitating a separate rate-specific educational effort, or 3) adversely affecting the scalability of the CalFUSE based demand flexibility solutions. Thus, if it is desirable to do so to advance equity goals, a price function specific to low-income customer class could be designed with a built-in subsidy or to reduce the range of scarcity price volatility.

4. **Benefits Realized by Non-participants**. A unique aspect of price frameworks that incorporate scarcity function (as in CalFUSE), when compared to time-based rates (such as TOU or CPP), is that the system benefits of some customers responding to the dynamic prices accrue to all customers in the form of lower prices. This includes customers who are not able shift their demand due to structural reasons, such as, a lack of suitable automation technology. In contrast, customers who are not able to shift their consumption in response to TOU or CPP rates are at a disadvantage in not being able to reduce their bills. Hence, the CalFUSE based framework could be a far better pathway to advance equity interests.

5. **Marketing Education and Outreach (ME&O)**. Customer education about dynamic rates will be an essential part of the transition to dynamic rates. The education and outreach efforts initiated by the rollout of default TOU rates across all the major IOU territories has already laid the groundwork. Customers are now familiar with the notion of time-varying rates. Furthermore, there is evidence from tracking surveys and ex-post evaluation in the transition to default TOU rates that customers on time-differentiated rates evolve their behavior and usage patterns over time as they learn about the cost-benefit tradeoffs through experience. The transition to dynamic rates, on an opt-in basis, is the next step in the evolution of offering widespread cost-based rates that encourage economic decision making on the part of ratepayers to support more efficient grid utilization. Third parties will play a primary role in providing an interface for customers that opt-in to dynamic rates, and in ensuring that customer devices are managed/automated to respond to dynamic prices.

5.3.3 Concerns About Extreme Weather Events and Reliability Impacts on California Ratepayers

Stakeholders have raised concerns about the potential for dynamic prices to adversely affect California consumers during extreme weather events as was the case for Texas consumers in February 2021, when Texas experienced multiple days of large-scale outages due to a cascading set of failures driven by extreme cold weather conditions.[139] This section addresses these concerns and highlights how the design of CalFUSE proposal mitigates the many shortcomings that led to Texas customer who were enrolled in a RTP program through Griddy, an electricity retailer in the deregulated Texas market.

[139] PG&E comments to the May 25, 2021, advanced DER and demand flexibility management workshop. *See* Appendix 8.2.3.

A. BACKGROUND

Griddy provided service to its roughly 29,000 customers at wholesale energy prices. Griddy is said to have saved its customers nearly $17 million since its inception in spring 2017 to February 2021. However, during the Texas cold wave, the combination of wide-spread outages and high demand caused wholesale prices to spike to the price cap ($9,000/MWh) for more than 3 straight days. It should be noted that the prices were manually held at the price cap by the Texas PUC when there was a failure on part of the ERCOT market algorithms.[140] This extended price spike led to high bills (as high as $17,000) for some Griddy customers. As a result, Griddy, was forced to declare bankruptcy. Wholesale price plans, ***which were previously allowed without regulatory approval or oversight***, were outlawed by the Texas Legislature.

As was highlighted in reporting on the fate of Griddy:

> The company became a target for lawsuits, fodder for unflattering stories about Texas in the national media, and an easy scapegoat for public officials looking for someone to blame. Just weeks after the crisis, Griddy found itself sued by the state and forced into bankruptcy. […] Griddy's demise underscores long-standing flaws in the deregulated market—a lack of consumer protection, poor public understanding of the market, and virtually no provisions to safeguard reliability.[141]

B. ANALYSIS

There are some superficial similarities between the power outages that Texas experienced in February 2021 and the rolling outages initiated by CAISO in August of 2020. In both cases, extreme weather resulted in the lack of adequate generation to meet the net system demand. However, there are many significant structural differences between the states' regulatory and market environments, including:

a) The isolation of the Texas grid from its neighbors, and
b) The lack of a reliability market in Texas.[142]

Multiple analyses have assessed that *the fundamental lack of regulatory mechanisms in Texas exacerbated the impacts of the 2021 cold wave on all ratepayers.*

The market structure in California includes a reliability market in addition to a commodity market. The Resource Adequacy (RA) program "obliges electricity providers [LSEs] to pay power plant owners for electricity-generating capacity".[143] In addition to the structural differences, the market cap for wholesale prices in Texas is set to $9000/MWh compared to a $1000/MWh soft cap (and

[140] Note: Prices had only hit the $9,000 cap for a total of 3 hours over the previous 5 years.

[141] Loren Steffy, "Griddy Argues It Was, in Fact, a Champion of Consumers", Texas Monthly, June 9, 2021. (available at) https://www.texasmonthly.com/news-politics/griddy-argues-it-championed-consumers/

[142] Note: Texas is one of the only places in the country that is operated as an energy-only market.

[143] "What is Resource Adequacy? Three Requirements that Keep the Lights on in California", Union of Concerned Scientists. (available at) https://blog.ucsusa.org/mark-specht/resource-adequacy-in-california/.

$2000/MWh hard cap) in California.[144] The difference in the market and regulatory structures led to drastically different outcomes during the two extreme weather events in February 2021 (Texas) and August 2020 (California). In Texas, wholesale prices held at or near the $9000/MWh price cap for *approximately straight 87 hours.*[145,146] In comparison, California energy prices (on all markets) were not above $500/MWh for more than *5 hours on both August 14th and 15th combined* (Figure 5-6).[147]

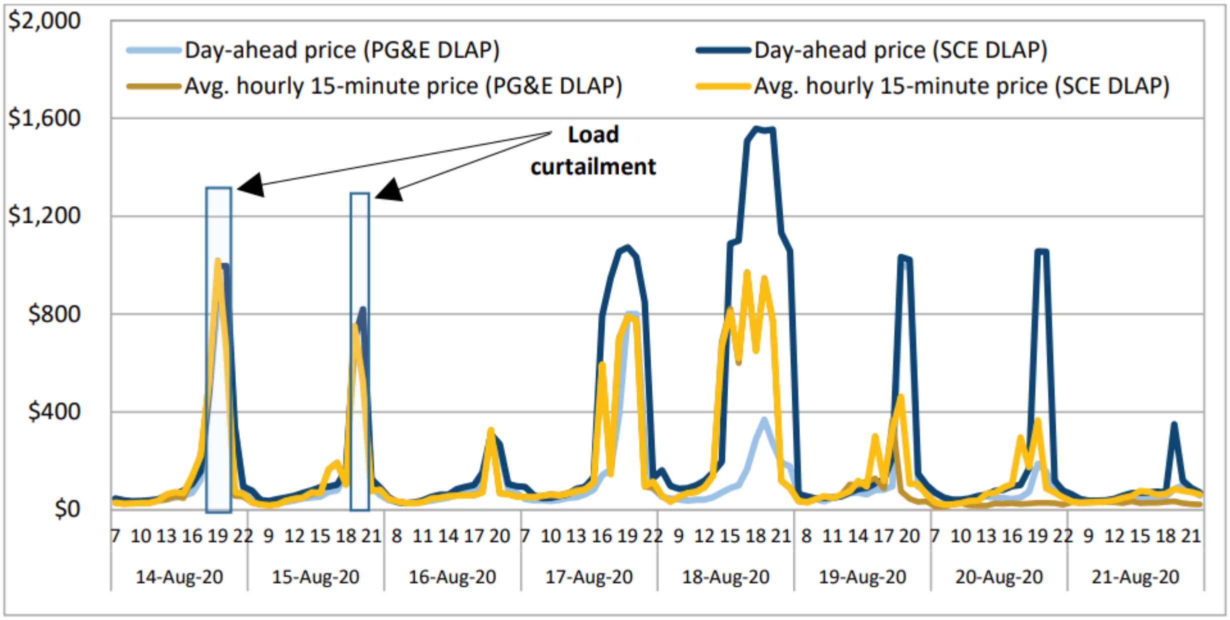

Figure 5-6: CAISO day-ahead and real time peak hour prices (August 14-21).

C. CONCLUSION

Staff proposes that the combination of (a) consumer protection elements of CalFUSE (subscription options and transactive elements), (b) the regulatory authority of the CPUC over retail rates, and (c) the structure of the California market can mitigate both the magnitude and likelihood of the type of extreme adverse outcomes that impacted Griddy's customers in Texas. The CalFUSE proposal provides California ratepayers the opportunity to respond to dynamic prices (through device automation and energy management services) and reduce their electricity bills and contain system costs, while also ensuring that there are adequate regulatory protections in place for both individual customers and the system at large.

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144 "CAISO Tariff Amendment to Enhance Market Parameters and Import Bidding Related to Order No. 831", February 22, 2021. (available at) http://www.caiso.com/Documents/Feb22-2021-TariffAmendment-PricingParameters-OrderNo831-ER21-1192.pdf.

145 "Average Texas electricity prices were higher in February 2021 due to a severe winter storm", Today in Energy, U.S. Energy Information Administration (EIA), May 7, 2021. (available at) https://www.eia.gov/todayinenergy/detail.php?id=47876.

146 Loren Steffy, "Griddy Argues It Was, in Fact, a Champion of Consumers", Texas Monthly, June 9, 2021. (available at) https://www.texasmonthly.com/news-politics/griddy-argues-it-championed-consumers/

147 Based on data available from the CAISO Daily Market Watch Reports for August 14th and 15th, 2020. (available at) http://www.caiso.com/.

Furthermore, as noted above, Staff anticipates that the maturing third party energy management services market will serve a critical role in facilitating the successful rollout of the CalFUSE framework, particularly for residential customers. Increased automation and interconnection of devices and third-party EMS options at scale should engender wider participation and the ability to "set it and forget it" to allow for optimized load management while meeting reliability needs during CAISO emergencies. This proposal and the recommended rulemaking should explore the dynamics of the EMS market and assurances of customer protection during such reliability events.

6 Learnings from Other Dynamic Pricing Programs

This chapter focuses on key elements of dynamic rate pilots and programs implemented in various jurisdictions across the country. It is instructive to consider what the learnings from these pilots and programs can tell us about the optimal design of a dynamic pricing program under the CalFUSE framework. The table below, provides a summary of each of the programs discussed in this chapter.

Table 6-1: Dynamic pricing programs discussed in this chapter.

Program	Customers	Timeline	Details
Georgia Power 2-part RTP	15,000 C&I customers	Since 1992	Hourly rate where customers are billed for "baseline" use at an otherwise applicable tariff and pay (or receive credits) for energy used above (or below) the baseline each hour at the RTP rate.
ComEd Residential RTP & Ameren Power Smart Pricing	Residential	Since 2010 (ComEd) and 2018 (Ameren)	Hourly RTP rates that incorporate wholesale energy market prices for residential customers.
TeMix RATES pilot	Residential	2019-2020	CEC-EPIC funded pilot that offered dynamic pricing through a subscriptive transactive tariff.
SCE RTP Rate (TOU 8)	Commercial and Industrial	Started in 1987 as a pilot and was converted to a standard rate	Hourly RTP rate where prices are set based on temperature forecasts day-ahead.
SDG&E PYD pilot	EV charging	Since 2016	Day-ahead hourly rate for EV charging at participating multi-unit dwellings and workplaces.

6.1 Georgia Power's Two-Part RTP Tariff

The positive impacts of dynamic rate programs on peak loads have been studied extensively. Studies have found that: (a) customers effectively respond to high peak prices and low off-peak prices by lowering their peak demand; and (b) customers further reduce their peak-hour consumption in response to stronger peak/off-peak price ratios.[148] A long-standing RTP program offered since 1992 by Georgia Power demonstrates the above points. The program, which has the largest number of participants of any RTP tariff reviewed in this chapter, has targeted Commercial and Industrial customers (approximately 15,000 customers)[149] and has demonstrated substantial load reductions during peak hours.[150]

Under Georgia Power's two-part tariffs, customers are billed for their "baseline" usage, which represents their normal operation under a conventional tariff, at their standard rate and pay (or receive credits) at the hourly price for the energy used above (or below) the baseline. The standard rate charged to customers for their "Customer Baseline Load" (CBL) usage ensures the revenue neutrality of RTP customers, thereby protecting non-RTP customers against structural cost-shifts. The hourly price, for usage that varies from a customer's CBL, is based on marginal costs, and Georgia Power offers both hour- and day-ahead programs to its enrolled customers.[151] In addition, customers can also purchase a variety of financial risk management products to reduce their risk exposure, resulting in a successful program where very few customers have left the tariff, even after periods of extreme price volatility.[152]

In one incident, when the hourly price reached $6.40/kWh, Georgia Power saw 850 MW of load reduction (out of 1500-2000 MW of incremental or above-baseline load) from its RTP customers. The company also noticed that customers have responded to low off-peak prices by expanding their facilities and business operations in Georgia. In other words, the rate has served to bring economic growth to the state and been a form of strategic electrification as well as load management. Georgia Power has also found that manufacturers with highly energy-intensive processes, such as chemical and pulp and paper companies are generally the most price responsive customers. It is also learned that commercial customers such as office buildings, universities, grocery stores, and a hospital respond well to real-time pricing.

148 Faruqui, Ahmad, et al., "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity", Electricity Journal, Vol. 30, Issue 10, 2017, at 64-72.

149 Faruqui, Ahmad, "Pricing Programs: Time-of-Use and Real Time," Encyclopedia of Energy Engineering and Technology, 2007, at 1181. (available at) https://www.raponline.org/wp-content/uploads/2016/05/kcc-dynamicpricingframingpaper-2008-03-25-26.pdf

150 *Id.* at 1182.

151 *See* "Best Practices in Tariff Design - A Global Survey." Presented by Ahmad Faruqui and Sylvia Tang at 28. (available at) https://www.brattle.com/wp-content/uploads/2021/06/21941_best_practices_in_tariff_design_-_a_global_survey.pdf.

152 Barbose, Galen, et. al., 2004. "A Survey of Utility Experience with Real Time Pricing". LBNL, 2004. (available at) https://doi.org/10.2172/836966.

6.2 ComEd hourly pricing program, and Ameren Power smart pricing program

A well-designed dynamic pricing program should provide net benefits to both its participants and non-participants. Participants can reduce their electricity bills by shifting load to lower priced hours. Non-participants benefit from reduced system-wide demand and lower costs for electricity during high priced hours. The system-wide effect is often referred to as demand response induced price effects (DRIPE).

ComEd, an Electric utility company in Illinois, has been offering its hourly pricing program to residential customers since 2010. Program participants have access to hourly prices and receive hourly alerts about the electricity prices. Their electricity cost varies hour by hour based on wholesale market prices.

A recent analysis of ComEd's Hourly Pricing Program[153] indicates that in 2019 the program, which costs $2.6M, had a gross benefit of $13.8M, resulting a net benefit of $11.2M. More than half of the benefits were system wide (DRIPE), which accrued to all PJM customers. The next largest category of benefits was bill savings, with participants saving an average of $132 on their annual electric bill.

Ameren, an electric utility company in Illinois, offers a "Power Smart Pricing" program[154] to its residential customers where the cost of electricity varies hour by hour based on actual market prices. Simulating the behavior of a rational Ameren EV customer, the Citizens Utility Board (CUB), an Illinois ratepayer advocate, found that participants could reduce annual EV charging costs by up to 50% compared to traditional rate offerings.[155, 156] In a separate simulation, CUB also found that managed EV charging could produce up to $2.6 billion in cumulative consumer savings in Illinois through 2030.[157]

The ComEd and Ameren programs are both good examples of how participants and non-participants can benefit from a well-designed dynamic rate program and highlights the potential to reduce ratepayers/system costs through RTP rates and managed charging.

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153 "ComEd's Hourly Pricing Program, 2019 Annual Report", Elevate Energy, April 2020.

154 Kolata, David, et. al., "Charge for Less: An Analysis for Electricity Pricing for Electric Vehicles in Ameren Territory," Citizens Utility Board, 2020. (available at) https://www.citizensutilityboard.org/wp-content/uploads/2020/02/ChargeForLess_Ameren_Final.pdf

155 *Id.* at pp. 2 of 6.

156 "ComEd's Hourly Pricing Program, 2019 Annual Report", Elevate Energy, April 2020, at 6.

157 "Charging Ahead: Deriving Value from Electric Vehicles for All Electricity Customers (Vol. 2 in the ABCs of EVs Series). Citizens Utility Board," 2019, at pp. 6 of 28. (available at) https://www.citizensutilityboard.org/wp-content/uploads/2019/03/Charging-Ahead-Deriving-Value-from-Electric-Vehicles-for-All-Electricity-Customers-v6-031419.pdf.

6.3 TeMix's Retail Automated Transactive Energy System (RATES) Pilot

In 2019, the Retail Automated Transactive Energy System (RATES), a CEC-EPIC funded pilot run by TeMix, Inc. in collaboration with SCE, implemented and tested several advanced elements that are part of the CalFUSE proposal[158].

The RATES pilot implemented a subscription transactive tariff that combined: (1) a subscription for a customer-specific quantity (kWh) of energy in each hour of the year, based on the customer's historical metered usage and billed at the customer's otherwise applicable tariff for each month; and (2) simple energy buy- and sell- tenders offered directly to customers and their price-responsive devices. With the subscription portion of the tariff, customers paid a predictable, non-dynamic price for their historical usage.[159] The subscription was designed to create a customer-specific, revenue-neutral baseline bill. If the customer used more or less energy in an hour than subscribed, the RATES pricing/billing platform automatically purchased (import) or sold (export) energy at the real-time price that varied with supply, demand, and other grid conditions. This bi-directional transactive design aimed to better reflect the marginal cost of supplying and delivering electricity and signal customers to change their consumption patterns.

In the RATES pilot, automated technology was utilized to enable price responsiveness over multiple time-horizons. TeMix sent hourly electricity tenders to the customers for the following 24 hours, with hourly updates to the price after the 24-hour notification.[160] TeMix also sent four 15-minute tenders just before each hour. Finally, a five-minute tender was sent just before each five-minute interval. Load dispatch was continuously optimized over each of the time-horizons with the aid of machine-learning algorithms. The optimization determined a schedule for individual devices (e.g., HVAC, EV charging, or a pool pump) according to simple user preferences, such as preferred hours per day, and energy price thresholds.[161]

The RATES pilot demonstrated how using technology and optimization, with a dynamic pricing and bi-directional transactions, customers could easily self-manage their energy usage and onsite generations and take advantage of energy prices bi-directionally.

[158] *See* Retail Automated Transactive Energy System (RATES), funded by CEC EPIC Grant GFO-15-311. (available at) http://temix.net/images/GFO-15-311_Retail_Automated_Transactive_Energy_System.pdf

[159] Note: The subscription option creates a two-part tariff using a methodology that is similar to Georgia Power's Customer Baseline Load as described above in Chapter 4.

[160] Cazalet, Ed, et. al., "Final Project Report: Complete and Low-Cost Retail Automated Transactive Energy System (RATES)", California Energy Commission, June 2020, at 10. (available at) https://www.energy.ca.gov/sites/default/files/2021-05/CEC-500-2020-038.pdf

[161] *Id.* at.E-5, E-6.

6.4 SCE RTP Rate

Real time pricing rates and their contributions to load shifts (DR) are not new among California IOUs. SCE TOU-8 is a real time pricing rate, offered by SCE to all non-residential customers receiving bundled service, where customers receive hourly prices based on temperature forecasts. This rate started as a pilot in 1987 to test price communications to customer and their responses to real time pricing. The rate offers seven different hourly pricing schedules, based on the time of day, season, and temperature. Customers who participate for a minimum of 36 consecutive months are qualified to apply incentives for automated DR control devices.[162], [163]

SCE's RTP customers have shown significant load response compared to residential TOU customers.[164] For example, on September 4, 2019, which was a system peak day for SCE, the 102 customers on the TOU-8 rate schedule, delivered load reductions of approximately 31%, with an aggregate impact of 14.31 MW.[165]

6.5 SDG&E Power Your Drive (PYD) Pilot Program

SDG&E's Power Your Drive (PYD) pilot program uses a dynamic price signal to incentivize EV charging during low price periods. The program, which started in January 2016, offers a day-ahead hourly rate for EV charging at participated multi-unit dwellings and workplaces.[166] The PYD pilot program aims to influence charging behavior through offering hourly dynamic rates that are calculated for each circuit based on projected demand and communicated to enrolled EV drivers on a day-ahead basis.[167] To control charging costs, participants can set a maximum price they are willing to pay to charge their EVs.

Customers were able to achieve bill savings as well as utilize significantly more energy from renewable resources while charging their vehicles. Charging pattern data show that more customers (86%) charge during off-peak hours, compared to customers on TOU rates (80%) and tiered rates (75%). As Figure 6-1 shows, both drivers at multi-unit dwellings (MUDs) and at workplace sites delayed charging in response to high prices during peak hours.

162 *See* SCE RTP Program Fact Sheet. (available at) https://www.sce.com/sites/default/files/inline-files/RTP%20Fact%20Sheet%200918_WCAG_2.pdf

163 *See* SCE Demand Response Programs Fact Sheet. (available at) https://www.sce.com/sites/default/files/inline-files/DR%20Programs%20Fact%20Sheet%200521_WCAG.pdf

164 *See* PG&E 2020 General Rate Chase Phase II, A.19-11-019, "Commercial & Industrial Real Time Pricing Pilot and Research for Other Customer Classes – Supplemental Testimony," at 1-21.

165 *Id.* at 1-16.

166 *See* SDG&E PYD Pilot Eighth Semi-Annual Report, April 1, 2020, at 1.

167 *See* Power Your Drive Pricing Plan. (available at) https://www.sdge.com/pyd-map.

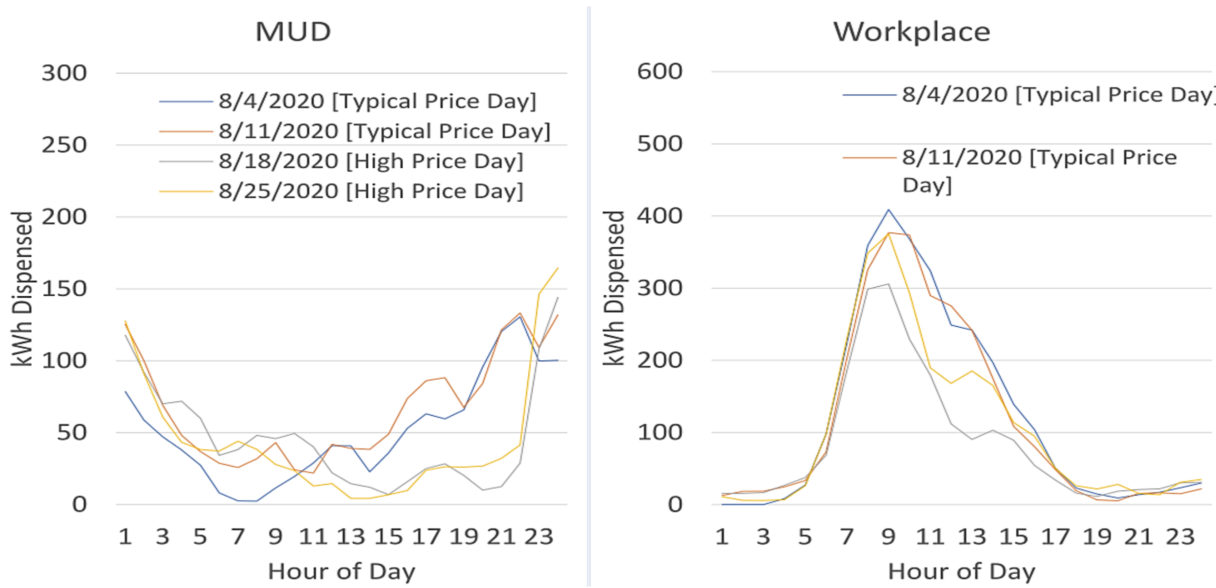

Figure 6-1: Example load shift on high-priced days at MUD and workplace sites for the SDG&E Power Your Drive Program.[168]

6.6 Conclusions

As the summaries above show, many of the fundamental elements of the CalFUSE proposal have been tested before and proven to be feasible and effective in achieving many of their aims. Multiple studies demonstrate that customers can be responsive to price signals and willing to curtail load during high price periods. Studies of these programs show that load reduction estimates are robust and can be observed across a range of climate conditions and rate designs, though the magnitude of the load impacts vary based on those factors. Studies also show that hourly pricing programs can be beneficial to both participants and non-participant customers, generating a system-wide benefit.

[168] *See* SDG&E Power Your Drive Research Report, April 2021, Figure 15 – Example Load Shift on High-Priced Days at MUD and Workplace Sites.

7 Conclusions and Next Steps

This white paper has presented Energy Division Staff's proposal for enhancing demand flexibility to meet the challenges facing California's electricity system. Staff highlighted apparent shortcomings of the current suite of demand response programs and retail rate structures in Chapter 3. The misalignment of incentives in the status quo of demand management policies is preventing California from fully realizing the potential of its resources, including renewable generation, DERs, and EVs, and ultimately impeding the successful achievement of the State's climate goals.

To address the urgent need for unlocking demand flexibility across the State, in Chapter 4 of this white paper, Staff proposed a flexible, unified signal for energy demand in California (CalFUSE) policy roadmap with six key elements:

1. Develop standardized, universal access to the current, customer-specific electricity price across the state.
2. Introduce dynamic electricity prices where the energy price component is based on the CAISO locational marginal price.
3. Transition from demand charges towards dynamic capacity charges, where volumetric scarcity prices based on system utilization are used to recover capacity infrastructure costs.
4. Ensure the prices are bi-directional, where customers import and export electricity at a symmetric, dynamic composite price that is linked to avoidable marginal costs.
5. Provide a subscription option, where customers pay for their historic hourly energy usage at a pre-determined price; this protects against both bill and revenue volatility, while still encouraging opportunistic, system-beneficial load shift.
6. Enable a transactive framework, where customers have the option to purchase (import and export) energy quantities at pre-determined prices that are based on future load forecasts; this allows customers to optimize their demand ahead of time and improve electric service provider visibility for planning and operations.

To implement the policy roadmap proposed in this white paper, Staff recommends the following next steps:

1. The CPUC should open a Rulemaking that starts with a discussion of amendments to CPUC Ratemaking Principles to align with updated demand flexibility guidelines and provides a venue to chart the adoption of a Statewide demand flexibility strategy as outlined in this white paper.

2. The CPUC should coordinate with CEC's LMS initiative and statewide price portal. The CPUC should consider implementation of a statewide price portal, including the potential authorization of funds needed to create/supplement the proposed CEC MIDAS database.

3. Staff has identified several key implementation questions for the CalFUSE roadmap in Chapter 4 and recommends that the CPUC create a Staff-led working group to engage stakeholders in addressing the questions identified in this white paper and to discuss other important considerations related to a Statewide demand flexibility strategy. Some of the key considerations include, but are not limited to:

   a) What should be the regulatory process for adoption of dynamic fixed cost recovery (e.g., through scarcity price functions)?

   b) Should certain utility fixed costs be recovered exclusively through monthly subscriptions or monthly, fixed charges?

   c) How to resolve details regarding the infrastructure necessary to support a Statewide demand flexibility roadmap (e.g., price portal, transactive system, oversight of new systems, ratepayer funding, etc.)?

   d) What process should the Commission undertake to update dynamic price functions to maintain revenue balance?

   e) What process should the Commission undertake to ensure that the benefits of a Statewide demand flexibility strategy? are accessible to both bundled and unbundled customers.

   f) Whether, and if so how, a possible transition of a subset of customers, including those currently on boutique rates, to a rate that is aligned with demand flexibility guidelines, should occur?

   g) How to evaluate the Staff demand flexibility proposal and provide guidance on process to improve/modify various elements of the Staff CalFUSE roadmap based on experience and evaluation of past and existing Pilots.?

   h) How to encourage third parties, Automation Service Providers (ASPs), Electric Vehicle Supple Equipment (EVSE) providers, and other device manufacturers, to be directly involved in the development of the Statewide demand flexibility strategy and rates that are adopted as port of the strategy so that the automated responsiveness to dynamic rates can scale and achieve the full potential identified by Staff in this white paper and make the experience user-friendly for less-sophisticated residential and small commercial customers, while ensuring proper consumer protection?

8 Appendix

8.1 DER Action Plan 2.0: Load Flexibility and Rates Vision Elements

On April 21, 2022, the CPUC adopted Version 2.0 of its DER Action Plan, which, like the prior DER Action Plan, will serve as a roadmap for CPUC decision-makers, CPUC staff, and stakeholders as they facilitate forward-thinking DER policy.[169]

Track One of the four tracks of the action plan is called the Load Flexibility and Rates Track, which is focused on improving demand-side resource management through more effective, integrated DR and retail rate structures that promote widespread, scalable, and flexible load strategies enabled by electrification and DER deployment opportunities. The vision and corresponding actions address grid issues associated with the growth of renewables, electrification, and DER adoption in support of California's clean energy goals, minimize cost of electricity service, and provide fair compensation for grid services provided by customer owned DERs.

The CalFUSE proposal is aligned with the vision elements of the Load Flexibility and Rates Track shown below:

Vision Element 1A: Dynamic and RTP rate options that address load flexibility objectives are available for each customer class and customers are educated to make informed choices.

Vision Element 1B: Available rates reflect time-variant and location-based marginal costs and are transparent, equitable, and aligned with load management standards.

Vision Element 1C: Dynamic and RTP rates are designed to maximize participation and benefits for customers in disadvantaged communities, and to minimize pricing volatility and bill impacts through robust consumer protection elements.

Vision Element 1D: Available rates reflect cost causation and provide opportunities for fair compensation for the comprehensive benefits provided by DERs.

Vision Element 1E: Rates are designed to allocate costs in alignment with cost causation principles for all customers enrolled in each rate tariff.

Vision Element 1F: A menu of time-varying rate options is made available to load management technologies through a "universal access"[170] pricing platform and customized rates marketing, education, and outreach for all customer segments.

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[169] Final Draft of CPUC DER Action Plan 2.0. (available at) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M467/K470/467470758.PDF.

[170] Note: Universal access refers to statewide access to pricing information available via online portal, search engines, apps, in-home devices (i.e., NEST or other programmable thermostats), or other relevant technologies).

Vision Element 1G: Potential strategies, including non-ratepayer-funding proposals, are considered to address affordability concerns associated with high electric rates that may impede adoption of transportation and building electrification DER technologies, especially among low-income and ESJ communities, and tribal nations and tribal utilities.

Vision Element 1H: Electric vehicle owners, fleet operators, and charging station managers respond to price and/or load management signals that reflect the real-time and dynamic costs and benefits of charging at different times to optimize grid operations and reduce charging costs.

8.2 Stakeholder Comments to May 25, 2021, Advanced DER and Demand Flexibility Management Workshop

Following a public preview of ED Staff's proposal for a unified, universally-accessible, dynamic economic retail electricity price signal (then referred to as "UNIDE") at a workshop held on May 25, 2021, ED invited stakeholders to submit informal written comments to the public service list associated with R.12-06-013. ED received comments from 18 parties which have been summarized by Staff below.[171]

8.2.1 SDG&E

SDG&E expressed support for UNIDE's goal of more granular price signals for customers as long as the benefits outweigh the costs and there isn't an unintended cost shift from participants to non-participants. SDG&E stated its support for dynamic pricing and recognized the importance of providing load shift incentives to customers.

SDG&E stated some concerns regarding the ability and interest of customers to participate in dynamic rates. SDG&E agreed that automation has a role to play in responsiveness to granular price signals but is concerned about the equity element of access to automated price-responsive technologies.

SDG&E also highlighted the importance of including third parties, especially CCAs, in discussions about dynamic rates. SDG&E mentioned that a majority of its current load will be served by CCAs, and SDG&E is unsure if CCAs will choose to invest the necessary resources to offer RTP rates.

SDG&E recommended that the CPUC assess the costs to develop, implement, and evaluate a UNIDE-type rate offering, citing that the CPUC required multiple pilots prior to defaulting residential customers to TOU rates.

SDG&E also had some specific comments on the implementation details of the UNIDE roadmap:

1. SDG&E agreed that CAISO market integration is not required to create more flexible resources with DERs.
2. SDG&E suggested that a price portal could be built and managed by a state agency, via a third party.
3. SDG&E expressed the concern that while wholesale prices are effective at balancing supply and demand, they may cause unintended consequences during extreme scarcity events. SDG&E cited the example of the negative experience of Texas residential customers on wholesale prices. SDG&E acknowledged that there are market differences between Texas and California and suggested thoughtful deliberation on this issue.

[171] Stakeholder comments (in full) available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops/advanced-der-and-demand-flexibility-management-workshop.

8.2.2 SMUD

SMUD stated that it hopes to scale its flexible demand programs as a lower cost alternative to utility-scale battery storage. SMUD is committed to exploring advanced rate and incentive structures and cites its early adoption of TOU rates as evidence of this commitment.

In comments to the CEC LMS Rulemaking, which were also submitted to ED staff in response to the UNIDE workshop, SMUD stated that pilot programs are necessary to understand the impact of customer response to new rate designs. SMUD also stated that implementation schedules for new rate structures will need to anticipate that utility billing system updates may be resource- and time-intensive processes. SMUD expressed concerns about developing hourly prices for all customer classes and stated that utilities should have full discretion to determine which customer classes would benefit from a dynamic pricing tariff. SMUD also stated that the interplay between dynamic pricing and load forecasts needs to be considered to ensure that system reliability is not compromised. This is especially true of load management programs that are counted towards resource adequacy requirements. SMUD also urged CEC to investigate the impact that RTP rates may have on the deployment of transportation and building electrification technologies, they stress that rates should encourage adoption of these technologies to meet state climate goals.

8.2.3 PG&E

PG&E expressed appreciation for ED staff's holistic approach to demand side flexibility in order to support California's climate goals. PG&E expressed a commitment to continue exploring time-varying rates. PG&E recommended a series of future workshops to align stakeholders around the topics of scoping, planning, operations, and data access and cyber security.

PG&E provided an extensive list of issues for the series of workshops including, but not limited to:

1. How UNIDE address problems not already addressed in existing and ongoing proceedings.
2. Develop a shared set of specific objectives and ratemaking principles of UNIDE.
3. Scope the existing research and assess new research required to enable the success of UNIDE within different customer groups.
4. Address dual participation rules in the context of UNIDE.
5. Assess how UNIDE will impact the reliability and planning processes which involve both CAISO and CEC, including how load impacts from UNIDE will be incorporated by the CEC.
6. Issues related to bi-directional pricing of DERs exports under UNIDE.
7. Concerns related to cyber security and data privacy, especially related to the price portal.

PG&E suggested that the results of their recommended workshops should result in a report that includes scoping for a possible rulemaking.

8.2.4 Cal Advocates

Cal Advocates expressed support for a proposed rulemaking and stated it would be a central place for more cohesive discussion of issues pertaining to demand-side management.

Cal Advocates also had specific comments on the each of the 6-steps of the UNIDE proposal and additional areas of consideration that are summarized below:

1. Cal Advocates recommended the use of the CEC MIDAS portal since it will likely reduce the implementation costs for utilities.
2. Cal Advocates cited PG&E's recent analysis in its GRC Phase 2 RTP Track that shows that generation prices are much easier to accurately forecast when the capacity prices are determined based on the day-ahead rather than the day-of markets. Cal Advocates suggests that the day-ahead market would offer the best risk/reward ratio for customers. Cal Advocates also raised whether the implementation of Step 2 and Step 3 would be synchronized.
3. Cal Advocates commented that conveying capacity costs in an hourly RTP rate is inherently more complex due to the fact that capacity procurement costs are often procured a year or more in advance through multiple procurement solicitations. Cal Advocates recommended that methodological differences between SCE's EPIC Pilot and PG&E pilot RTP rates should be compared. Cal Advocates also expressed concern as to whether the approach implemented by SDG&E in its PYD program would generate sufficient customer interest. In addition, Cal Advocates also questioned the 6-year approach currently used for calculating long-run generation marginal costs. The 6-year approach may not be suitable for an RTP, which is inherently short-run. Cal Advocates suggest that a revenue neutral adder like the one proposed in PG&E's RTP pilot be considered to ensure that RTP recovers the same revenue requirement as other rate designs. [172]
4. Cal Advocates raised the concern that a bi-directional price for exports could lead to a cost burden from participants to non-participants and recommended that the NEM proceeding record be studied for problems with how to value customer exports. Additionally, Cal Advocates raised the concern of potential double payment and double counting of capacity value if the RTP price signal already includes an embedded capacity component, then any capacity contract would provide double payment.
5. Cal advocates asked for additional clarity on the details of the subscription option in the written proposal.
6. Cal advocates recommended that ED staff consider the findings of the evaluation of dynamic pricing options currently proposed by PG&E to assess if all rate classes would be a good fit for UNIDE. Cal Advocates recommended that the proposed rulemaking allocate several opportunities for workshops to gauge customer interest and appropriateness.

[172] Note: In both the CEV and C&I pilots, PG&E proposes to include a flat revenue neutral adder "to retain parity relative to base rate schedules." PG&E GRC Phase 2 Supplemental Testimony, filed March 29, 2021, at pg. 1-52. For more information see section C in Cal Advocates Prepared Testimony in Response to Pacific Gas & Electric Supplemental Testimony on Commercial & Industrial Real Time Pricing Pilot and Research for Other Customer Classes filed May 28, 2021.

7. Cal Advocates recommended coordination with utilities to accurately assess the costs associated with the implementation of UNIDE. Cal Advocates also recommended coordination with CCA/Direct Access providers since those providers would have to create their own rate for customers.
8. Cal Advocates commented that UNIDE may lead to changes in participation of existing event-based DR programs since customers may choose to participate in the real-time option due to overall lower bills and the increased transparency (from a lack of baseline calculations). Cal Advocates echoed PG&E's comments from PG&E's RTP track of its GRCI Phase 2, where PG&E stated that dynamic rates could undercut the success of getting customers to accept the default TOU rate. Cal Advocates recommended that residential customers should not be introduced to dynamic rates until the completion of the default TOU transition and note that TOU rates may provide sufficient load responsiveness. Cal Advocates also expressed concerns about the financial risks of dynamic rates to residential customers who may be less capable of shifting load in response to price signals.
9. Cal Advocates recommended that ED staff also consider some kind of time-varying transmission rate in the proposal. Cal Advocates stated that utilities recover transmission costs predominantly through large NCDCs that are a significant portion of many non-residential customers' bills. Cal Advocates recommended that ED intervene in the FERC-jurisdictional transmission owners rate cases and recommend a transmission rate that is more consistent with the rest of the utilities' retail rate design. Cal Advocates stated that a time-varying transmission rate could potentially have a much larger bill impact on customers who have variable loads, than the time-varying generation or distribution components of UNIDE.

8.2.5 San Diego Airport Parking (SDAP)

SDAP expressed its support for the UNIDE proposal (particularly steps 1-3), because it would aid fleet operators to charge vehicles in a manner that is beneficial to the grid. SDAP provided a variety of comments regarding different aspects of the Staff proposal including:

1. Elements 1-3 of the UNIDE proposal are essential for renewable integration and should be fast-tracked. The design of Steps 1-3 should reflect inputs from customer representatives, consultants, academics, and other stakeholders
2. Elements 2-3 should be default for nonresidential customers (opt-out rates should be TOU, including CPP) and dynamic prices should include time-sensitive delivery costs/rates.
3. Demand charges should be eliminated in favor of time-dependent, volumetric pricing (as opposed to capacity pricing), and fixed cost recovery burden should be shifted onto load driving high system utilization and capacity upgrades. Demand and subscription charges impose high costs on high-power EV charging. Current EV subscription rates (SDG&E EV-HP and PG&E CEV) do not improve operational flexibility and do not facilitate customer response to grid conditions.
4. Elements 4-6 are less essential and should be postponed until elements 1-3 are successfully implemented (should all be opt-in). Bi-directional distribution rates could be of value where

exports to grid cause costs, however the further upstream in the distribution grid, the more likely exports provide benefits. The CPUC should not assume distribution costs of imports and exports are symmetric (requires further study).

5. Subscription for load shapes could be great improvement; however, it is not essential. Subscriptive and transactive features may be two of many tools to get time-dependent rates that encourage beneficial load shifting, but other options can also be considered.
6. The CPUC should consider advocating for time-differentiated retail transmission rates at FERC (get rid of transmission demand charges). FERC has allowed this when IOUs have requested in the past (SDG&E 2008).
7. UNIDE complements (D.) 20-12-023's finding of facts with renewable integration, reducing demand charges for EVs, and contributing towards Gov. Newsom's 100% EV goal by 2045. UNIDE should prioritize shifting load to hours of lowest carbon intensity (not just lowest cost hours). All large commercial businesses should be required to implement BTM storage for a percentage of their load at peak time (perhaps 50%). Billing Tariffs & Sheets need to be easy to read (see SDG&E's Public GIR billing for a good example)

8.2.6 SCE

SCE stated that the Bonbright Principles should always be used when designing retail rates. Several of the principles support dynamic pricing rates (based on marginal cost, encourages conservation during peak demand). However, other principles like stability and understandability are compromised by hourly or even daily price changes. SCE also provided the following comments:

1. Customer eligibility will be vital to consider. E.g., customer on medical baseline rate relying on life-sustaining medical equipment would not be an ideal candidate for price fluctuating rate. Additionally, emergency DR programs have been quite successful and should remain a part of the plan of the future (mixed solution future).
2. Customer education will be critical for UNIDE's success. UNIDE is energy industry driven and not consumer driven, so it will be important to ensure clear understanding of risks and rewards. Rate design and participations options should be consistent and simple to maximize participation.

8.2.7 California Efficiency + Demand Management Council (CEDMC)

CEDMC expressed support for a renewed focus on load modifying resource (LMR) DR but reiterated that energy efficiency (EE) is the most important DER and should be incented by any retail rate changes. CEDMC said that LMR DR is nimbler and provides more value to the market than supply-side DR. However, supply-side DR currently represents largest proportion of DR and should not be neglected by exclusively focusing on RTP. The CPUC should continue to provide opportunities for all EE, LMR DR, supply-side DR, and exporting BTM resources. To get more supply-side DR, there is a need to simplify qualifying capacity valuation and CAISO market operations. CEDMC also provided the additional following comments:

1. Bi-directional pricing is an excellent way to fully take advantage of capabilities of exporting BTM DER (however, will require changes to electric Rule 21).
2. If a rulemaking is opened, it should be broader than "improving demand-side resource management through more effective DR and retail rates (RR) structures." CEDMC suggests instead defining the goal as "[d]eveloping an environment for demand-side resource management through the coordinated deployment of BTM DERs and dynamic retail rate structures to achieve grid decarbonization."[173]
3. UNIDE is incredibly complex, but the CPUC should try and enact as much of it as possible as quickly as possible. Striving for simplicity will be necessary. Structuring variable rates by location, and time of day (and sometimes linked to wholesale market conditions) will be very complex and require immense preparation. Key metric of success should be whether load is shifted to hours with lower carbon intensity.
4. The subscription option is interesting to CEDMC because it appears to envision creating another option in which a customer could commit to a specific load curve that would presumably be flatter and more evenly distributed than its current load curve. However, any such framework would need to include compensation for the avoided capacity and lower cost energy associated with a flatter load curve.
5. The CPUC should include a methodology for calculating the locational, marginal value of capacity which includes T&D investments to incent DER deployment in highest-need areas. CEDMC also supports eliminating demand charges while ensuring that cost allocations remain equitable.
6. Third party providers should have access and play major role in new framework.
7. There is a need to consider how UNIDE affects value of new LMR DR programs' RA allocations (D.) 14-03-026).
8. There is a need to consider CAISO's role in UNIDE (likely will require greater degree of communication between LSEs and CAISO to know potential load reductions in each sub-LAP).

8.2.8 California Independent System Operator Corporation (CAISO)

CAISO expressed strong support for greater demand flexibility and "grid informed" rate options. According to CAISO, ED staff presented a compelling vision for integration of wholesale market prices into a price signal that can address the increasing challenges of load management.

CAISO supports rate optionality: a base TOU default rate with more dynamic options available to those with the means to leverage them. However, it does not believe that all load need respond to

[173] *See* California Efficiency + Demand Management Council Informal Comments on May 25, 2021, Distributed Energy Resources and Flexible Load Management Workshop at pg. 2. (available at) https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops/advanced-der-and-demand-flexibility-management-workshop.

real-time price signals or that all customers should take service under a single RTP rate design. Rate optionality is key to best serving customers.

8.2.9 California Large Energy Consumers Association (CLECA)

CLECA expressed concerns that the UNIDE RTP model may provide inaccurate price signals and lead to revenue under-collection.

CLECA noted that volumetric rates fail to reflect how capacity and distribution costs are incurred, effectively treating a low load factor customer and high load factor customer similarly despite the greater system costs imposed by the low load, high demand customer. CLECA contended that coincident demand charges are an appropriate solution because they both reflect the capacity costs and send an appropriate price signal. Subscription charges may be a workable alternative for smaller customers, provided that subscription levels and charges increase as a customer's demand increases. Alternatively, the CPUC may wish to consider a penalty rate for customers that exceed their subscription demand level.

CLECA expressed concerns that the UNIDE proposal contains components that can lead to revenue under-collection and weak signals. First, the UNIDE framework bases capacity costs on scarcity prices in the CAISO market. These prices show up in few hours of the year, and during the remainder of the year wholesale energy costs would not include capacity costs. Second, if the DAM does not contain significant price variation from hour to hour, the need for additional system capacity will not be reflected in the cost. Third, CLECA notes that the model uses forecasts for capacity and distribution rates, adding additional risk that the generation revenue requirement will be under-collected should forecasts be inaccurate. It therefore strongly urged the CPUC to reconsider alternatives that better capture capacity costs.

8.2.10 TeMix Inc.

TeMix expressed strong support for UNIDE. Current DR programs are complex, inefficient, expensive, confusing, difficult to scale, etc. and, according to TeMix, UNIDE addresses these deficiencies.

TeMix does see the need for more pilots, and strongly supports incremental deployment of UNIDE. Parties need confidence optional advanced tariffs will be around long enough to recover investment costs (pilots cannot do this). All customers should have access (smart device owners will likely be first to join). The subscription portion of UNIDE (Step 5) could be adjusted for policies to support low-income customers without affecting dynamic pricing. Each step should be universally available from start of implementation (particularly real-time, bi-directional, and subscription pricing options); otherwise, unlikely to see full benefits of UNIDE.

Additionally, TeMix contended that implementation should not over-rely on real-time prices. According to TeMix, it would be a mistake to implement steps 2-3 without steps 4-6 and expose customers to potentially crippling bill volatility and suppliers to potential bankruptcy (e.g., Texas 2021 and California 2001 market failures).

8.2.11 Recurve

Recurve is supportive of demand-side solutions based on simple, unified frameworks. As such, Recurve applauds "UNIDE's "unified, clear, price signal." In the immediate short term, Recurve recommended that the CPUC can take steps to ensure consistent valuation and evaluation by establishing a unified DER value stack. This would alleviate barriers to funding and enable greater DER participation in providing demand flexibility.

Recurve noted that with AMI and meter-based analytics, the foundation is in place for aggregators to deliver value in the form of demand side products. A common valuation approach would allow these innovators to operate outside of historical technology and policy silos. Recurve singled out the CPUC-adopted Total System Benefits metric as an example of the type of approach policymakers should be pursuing.

Recurve pointed to the Advanced DER & Demand Flexibility Management workshop as a model for enabling holistic demand flexibility using rate design *in combination with* other approaches. It identified five core actions it would like to see the CPUC focus on:

1. Liberalizing data access rules
2. Fostering holistic programs through full integration (e.g., budgets, M&V, rules, goals)
3. Not penalizing external investment for demand flexibility resources when performing cost tests
4. Updating resource adequacy accounting rules to recognize different value streams
5. Streamlining aggregator access

8.2.12 California Energy Storage Association (CESA)

CESA expressed general support for a new rulemaking to explore the UNIDE proposal and offered various comments, including:

1. ED Staff should consider infrastructure investments needed to support the UNIDE pathway, including: how internet-connected and unconnected users can access load flexibility signals, and how utility billing system may support flexible end-uses.
2. The Staff proposal should detail how the UNIDE price would value load reductions and exports similarly. The simplest approach would be to institute a NEM framework for exported energy, whether from solar, a battery or an electric vehicle (EV). However, under current law and policy, NEM is only available to rooftop solar, and storage paired with solar, subject to certain restrictions
3. ED Staff should consider how DER market-integrated and market-informed pathways can be incorporated into the UNIDE concept. DER market-integrated/informed policy issues and barriers should also be in the scope of the new rulemaking.

8.2.13 Google and OhmConnect

Google and OhmConnect expressed support for the UNIDE proposal. In particular, they view the first four steps of the six-step roadmap as being critical elements of the Energy Division vision. They offered the various recommendations, including:

1. The CPUC should ensure that the proposal continues to recognize the important role of third parties in the UNIDE framework and encourages participation by residential customers with enabling devices. There has been a proliferation of connected devices on the grid, and these should be enabled as grid assets and monetized as such.

2. The CPUC should open a new proceeding immediately to build a centralized and cohesive record around these issues. As presented by Karen Herter during the LMS proposed amendments Workshop, the CEC has been engaged in a proceeding to modify the Title 20 Load Management Standards in a way that would encourage customer load shift in response to a real-time price signal.

8.2.14 350 Bay Area

350 Bay Area expressed support for the Staff proposal but would like to see avoided transmission capacity value reflected in pricing signals so as to further incentivize DER deployment. 350 Bay Area supports the opt-in RTP option, matching capacity charges with coincident demand, and bi-directional pricing. It also offered the following additional comments:

1. Individual components of proposal have been suggested by parties over the past decade; regulatory agencies have the obligation to leverage the goals and capabilities that have been developed to provide savings to ratepayers while increasing reliability and resilience
2. Ease of customer participation must be made a priority: ease of use, easy enrollment, and low cost set up will have big impact on participation and results. Applaud proposal's focus on simplicity.
3. Implementation is no small task, but it is not that complicated and less complex than many commercial data activities. If you make the value available, loads will respond.
4. Reliance on real time locational value where practical is more accurate than the more generalized historic value embedded in DER avoided cost calculator (ACC).
5. Use of a fixed capacity constraint in proposed methodology ignores the DER value in reducing transmission related costs, which were identified in the En Banc white paper as being a driver of rate growth. The avoided transmission value should be included in the pricing signal.
6. While transmission cost recovery is FERC jurisdictional, cost causation and transmission planning are driven by CPUC, CEC, and CAISO processes.
7. DER deployment has been shown to reduce transmission needs, so incentivizing efficient deployment and dispatch of DERs through a rate signal is in ratepayers' interest.
8. Recent comments at CARB's Scoping Plan workshop reflect need for greater CPUC oversight of transmission investments.

8.2.15 SoCalGas

SoCalGas stated that it recognizes the importance of aligning prices with costs but worries that proposal might be confusing for unsophisticated customers; SoCalGas instead highlighted the roles that flexible Distributed Generation, Combined Heat and Power, hydrogen, and Renewable Natural Gas could play in achieving proposal's goals. It also offered the following comments:

1. Aligning energy prices with costs and emissions will be important for decarbonization, but dynamic rates may also be overly confusing to unsophisticated customers who do not have the "time, desire, knowledge, or access to proper technologies to navigate flexible energy prices."
2. Flexible DER technologies, such as distributed generation (DG) and combined heat and power (CHP), will be important for increased renewable integration and price stability.
3. 2019 CEC report expressed concern that CHP is a 24/7 must-run resource, but generation can be curtailed or cycled to take advantage of low grid prices when renewables are over-generating.
4. CHP can offer voltage support, enhanced reliability, T&D deferral, and reserve capacity just like a battery. Unlike batteries, CHP is not capacity or capital constrained and can run longer on a daily basis.
5. Flexible DG offers additional benefits such as fuel flexibility and long-term resiliency.
6. Power-to-Gas technology has the potential to address mid-day overgeneration as well as evening ramping needs by storing excess renewable generation to produce hydrogen through electrolysis.
7. Hydrogen can also be used to produce renewable natural gas (RNG), which can be used in the existing natural gas pipeline system for traditional gas fueled DERs.
8. Power-to-Gas/Gas-to-Power combination can play a similar role as battery storage, but with more storage.
9. Price of gas produced by Power-to-Gas is highly dependent on cost of electricity, so renewable overgeneration presents an opportunity for low-cost renewable gases.

8.2.16 Joint DER Parties

Joint DER Parties stated their support for the UNIDE proposal in theory but are concerned that this proposal will distract from the urgent need to remove barriers to DER participation in RA framework. They also offered the following comments:

1. CEC's proposed amendments to LMS require each of the five largest distribution utilities to propose an optional dynamic pricing tariff for each customer class by March 31, 2023.
2. Support the CPUC opening a rulemaking to develop and implement the UNIDE proposal.
3. Dynamic pricing and alternatives to non-coincident demand charges would better align prices with grid conditions/needs, GHG emissions, and cost causation.
4. Bi-directional RTP tariff with time- and location-based recovery of capacity costs should increase value of DERs.

5. Moving to a dynamic rate with temporal and spatial variability would make it much more difficult to forecast long-term costs and revenues of DERs, which could make financing for capital-intensive projects more difficult.
6. While CPUC works on UNIDE proposal, it must also continue developing ways for DERs to participate in the RA framework. Even if UNIDE is practical and implementation is smooth, it will take years before full rollout and customer adoption.
7. Current wholesale market participation of DERs is below where it should be because they are undervalued.
8. The CPUC needs to continue improving RA counting rules for BTM resources:
    a) FERC Order 2222 requires accommodation of DERs in wholesale markets, but that requires CPUC to work with CAISO to realize full capacity value of BTM resources.
    b) Depending on treatment of export compensation, some BTM resources may be better suited for wholesale market participation rather than UNIDE (example: schools with BTM batteries)
9. Barriers to operationalizing exporting DERs as supply resources could be resolved within a year if there was coordination between CPUC, CEC, CAISO, IOUs, and DER providers. If taken up in the pending RA PD, removal of barriers would lead to DERs selling RA to LSEs as early as 2023. UNIDE would then be a supplement, not replacement to the market integrated framework.
10. The CEC LMS deadline of March 2023 for dynamic tariff proposals may require OIR to be scoped such that it addresses all six steps of UNIDE all at once. The potential OIR should include the following scope:
    a) Day-ahead versus real-time energy market pricing.
    b) Hourly versus sub-hourly pricing intervals.
    c) Methodology for utilization-based collection of embedded capacity costs
    d) Locational granularity of pricing components.
    e) Methodology for monthly subscription charge, or other considerations for minimizing customer bill volatility within an RTP framework.
    f) Method for crediting exported energy at retail price and interaction with reforms to net energy metering being contemplated in (R.) 20-08-020.
    g) Guidance and recommendations for improving CCA access to IOU interval metering data to enable CCA RTP rate offerings.
    h) Guidance for schedule and budgeting of near-term offerings to study customer acceptance and response.
    i) Guidance for proposed investments in pricing engine, billing system upgrades, DERMS systems, day-ahead distribution system forecasting tools, line sensors, enhanced communications, and other enabling grid modernization investments.
    j) Operational coordination, communications, and visibility requirements between IOUs, LSEs, DER providers, and the CAISO.
    k) Metering requirements.
    l) Updates to the Rule 21 interconnection tariff.
    m) Program measurement and verification.

n) Accounting for UNIDE response in Resource Adequacy, CEC IEPR, and long-term planning.
o) Incorporation of learnings from RTP offerings that result from live proceedings.

8.2.17 UCAN

UCAN stated that it supports opening an OIR to explore the UNIDE proposal because the proposal should result in reduced T&D investment, and thus more affordable electricity rates. It also offered the following comments:

1. The proposal was compelling and well researched. The CPUC should open an OIR to explore the proposals.
2. The Staff proposal could help lower system costs, which would address UCAN's concerns about the affordability of California's clean energy goals.
3. Access to data is key to developing advanced rate designs, and therefore, Data access should be scoped into Rulemaking.
4. UCAN is concerned about affordability of increasing electricity rates, partly driven by investments in T&D and transportation electrification program spending.
5. Deployment of DERs can help offset need for T&D spending, and advanced rates can help with value proposition of DERs.
6. More demand flexibility should help reduce system and generation capacity costs.