ELECTRIC LOAD FLEXIBILITY ANALYSIS FOR THE CLEAN ENERGY TRANSITION

Peter Alstone & Mary Ann Piette

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A clean energy transition on the electricity grid is underway with the addition of new renewable generation, improved capabilities for sensing and controls, and "distributed energy resources" (DER) that include efficiency, battery storage, flexible loads, and electrified heating and transportation. The complex interactions between these advances require new analytic techniques to support decisions by utilities, regulators, and enterprises developing and deploying new DER. In this paper we describe an approach for estimating the potential of flexible loads (often also referred to as "demand response" (DR)) to contribute to the planning and operation of the grid. The analysis was developed in the California context in support of a California Public Utilities Commission rulemaking to reform DR.[1] *This provided a unique opportunity to work directly with stakeholders and regulators in developing new frameworks for public interest scientific analysis. We describe our modeling approach for load flexibility across four key dimensions: reshaping with rates (shape), shedding at critical time (shed), shifting timing of loads to capture renewables (shift), and fast response (shimmy) to balance the grid. These concepts represent a new classification approach for responsive demand, driven by new needs on the grid and capabilities of controls and computing technology and designed to be both mathematically tractable and*

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[1] CAL. PUB. UTIL. COMM'N, RULEMAKING 13-09-011, ORDER INSTITUTING RULEMAKING TO ENHANCE THE ROLE OF DEMAND RESPONSE IN MEETING THE STATE'S RESOURCE PLANNING NEEDS AND OPERATIONAL REQUIREMENTS, (Sept. 19, 2013), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M077/K151/77151993.PDF.

simple to understand by stakeholders and regulators. The study identified significant potential for DR loads to support the grid and a need for integration of planning and deployment between DR and other DER. Along with conventional peak load management, an emerging opportunity is for load shift–changing the timing of demand to better match renewable energy generation. Shifting can avoid curtailment of renewable energy during times of surplus (an emerging and growing feature of the California grid) and directly support the transition to clean energy. We identify how load shifting can improve the performance of the grid and reduce the cost of compliance with renewable energy targets. Under a broad range of possible load shift frameworks, the overall outcomes show that shifting can reduce operational greenhouse gas emissions by approximately one-half for this shifted quantity of energy.

INTRODUCTION

In response to the imperative to address climate change, a clean energy transition for the electric grid is required and should be accelerated, even compared to the relatively fast deployment of renewables underway already.[2] Progress thus far has driven down the cost of solar and wind, making them competitive with conventional resources on levelized cost of energy (in $/kWh) terms even without accounting for the climate externalities associated with fossil fuel mining and combustion.[3] As solar and wind are deployed, they transform the planning and operations of the electric power system with significant implications for demand-side management (DSM) and the emerging technology category described as distributed energy resources (DER).

In this work, we describe our engagement in analysis to support policymaking associated with the potential of DERs to support low cost and reliable electricity service in a future grid with higher contributions from renewables. Our analysis was developed to support regulation and planning for California, a state with an electric power system undergoing rapid change to integrate renewable energy in large quantities. This article focuses on the development of a model to estimate the potential value of Demand Response (DR) and follow-up work to understand the role of Shifting energy (i.e., "flexibility" in demand) in reducing the greenhouse gas intensity of the grid. Throughout this paper, we describe both our technical approach to modeling and analytic results, along with the context of our work and the public policy frameworks we worked within.

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[2] INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, GLOBAL WARMING OF 1.5°C (2018), https://www.ipcc.ch/site/assets/uploads/sites/2/2019/06/SR15_Full_Report_High_Res.pdf.

[3] *Lazard's Levelized Cost of Energy Analysis*, Lazard (Nov. 2, 2017), https://www.lazard.com/perspective/levelized-cost-of-energy-2017/.

A. Regulatory Context

Specifically, we developed this work in the context of supporting Demand Response research at the California Public Utilities Commission (CPUC). This was initiated with the 2025 Demand Response Potential Study,[4] supporting CPUC rulemaking focused on "Enhancing the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements."[5] The study was designed to bridge the analysis of DER with grid investment and operations and to communicate the results of the study clearly to policymakers and stakeholders in the power system who need to synthesize across those domains.

Following the DR Potential Study, a decision was issued in the rulemaking that included the formation of the Load Shift Working Group (LSWG), to be convened by stakeholders for one year to provide ". . . a final report on its proposals, which will inform a future rulemaking to consider new models of demand response."[6] Through our engagement with that Working Group as technical experts, we supported the stakeholder discussions with analysis of the proposed pilots and possible frameworks for implementing load shifting, including an analysis of the possible greenhouse gas impacts of Shifting load.

B. Methodological Summary

An important technical contribution of this work was the modeling analysis we developed in support of the 2025 DR Potential Study. The important features of the model, which built on and expanded the conventional framework for assessing DR in a public policy context, are: 1) We took advantage or newly available smart meter data and based the model on a large sample of hourly- and site-level resolution demand, joined with synchronized weather and renewable energy production data; 2) We developed new methods classifying the capabilities of DR into four core functions that can be modeled and understood by stakeholders: Shape, Shift, Shed, and Shimmy (which we describe in more detail in the "Demand Response Analysis Framework" Section); and 3) We synthesize the results in terms of

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[4] Peter Alstone et al., *2025 California Demand Response Potential Study - Charting California's Demand Response Future: Final Report on Phase 2 Results*, Lawrence Berkeley Nat'l Lab, (2017), http://eta-publications.lbl.gov/sites/default/files/lbnl-2001113.pdf.

[5] CAL. PUB. UTIL. COMM'N, *supra* note 1.

[6] CAL. PUB. UTIL. COMM'N, DECISION 17-10-017, DECISION ADOPTING STEPS FOR IMPLEMENTING THE COMPETITIVE NEUTRALITY COST CAUSATION PRINCIPLE, at 2 (Oct. 26, 2017), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M198/K319/198319901.PDF.

economic supply and demand curves that represent the long-run average cost and value of resources, and enable comparison of the costs of flexible load with other renewables integration alternatives.

We begin the article by describing the emerging challenges for grid management and the technology drivers for DER as background and context. This is followed by a description of the modeling framework for DR potential we developed to describe and estimate the contributions of flexible load. We describe the outcomes for California from the study and also present an analysis of how avoiding curtailment of renewable energy through Shifting can improve the greenhouse gas performance of the grid. The GHG assessment covers a range of pathways to deploying load shift developed by stakeholders to address market and regulatory framework gaps.[7]

C. Outcomes

The results suggest a range of policy and R&D responses are appropriate for capturing more of the value that is available to the grid from DER in general and DR/flexible loads. Some of these factors are better integrated approaches between Energy Efficiency and DR, a consideration of how dynamic prices could be a pathway for flexible loads, and the pathways for public policy and technology that could help achieve the deep levels of solar and wind deployment that are required for meeting climate and energy goals.

Portions of the description of our modeling work and results presented in this article have been presented in various forums, including the 2025 California DR Potential Study[8] and a conference paper at the ACEEE Summer Study.[9] Another follow-on paper describes recent results on the effort to define the need and pathways for the Shift resource.[10] This work extends on those through a more in-depth institutional analysis of the results and additional analysis related to the greenhouse gas and cost performance of flexible load implementation pathways.

[7] CAL. PUB. UTIL. COMM'N, NEW REPORT: FINAL REPORT OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION'S WORKING GROUP ON LOAD SHIFT (Jul. 15, 2019), https://gridworks.org/2019/07/new-report-final-report-of-the-california-public-utilities-commissions-working-group-on-load-shift/.

[8] Alstone, *supra* note 4.

[9] Peter Alstone et al., *Integrating Demand Response and Distributing Resources in Planning for Large-Scale Renewable Energy Integration* (2018), https://aceee.org/files/proceedings/2018/#/paper/event-data/p359.

[10] Giulia Gallo et al., *Mobilizing the Anti-Duck Brigade: Tech. and Mkt. Pathways for Load-Shifting Demand Response in Cal.* (2018), https://aceee.org/files/proceedings/2018/#/paper/event-data/p179.

I. BACKGROUND AND CONTEXT

A. The Electricity Regulatory Challenge

Electric power is a fundamentally challenging system to operate (and regulate) partly because of the fundamental physics of the system. Figure 1 illustrates some of these dynamics of investment and operation on the grid. In order to maintain a stable grid, control actions and operations need to react to imbalance in fractions of a second. Without continuous and reliable controls and balancing at that timescale, the system can enter unstable states and lead to blackouts. These control actions are far faster than a person could respond, and furthermore, the intrinsic response of alternating-current power systems is nonlinear and complex. Only specialized machines and automated systems can maintain this balance. On the other end of the timescale, the equipment that is typically installed and used to generate and distribute power can have construction lead times of years and operational lifetimes of decades. The projects are complex and require specialized skills to effectively plan and build. Put simply, the grid is slow to build and fast to operate with complexity throughout the system.

Since utilities are typically operated as regulated monopolies or publicly controlled entities, there are regulatory bodies and public boards whose roles are to help guide the investment decisions and operational rules that enable safe and reliable power to be provided to customers. With a system that spans continents and has specialized knowledge across time domains, it is impossible for any single technical expert to fully describe and plan the system (much less a regulator who also balances political and social considerations that underpin decisions). In spite of these obstacles, the regulatory and management frameworks that have arisen over the last century in this context have mostly managed to avoid frequent blackouts and accidents, partly through careful and conservative frameworks for supporting decisions related to investment in the system. The lifetime of conventional generation assets, transmission projects, and distribution system upgrades tend to be on the order of years to decades, and the pace of technological advancement in these systems is relatively slow. Thus, the regulatory processes in public commissions and boards that have emerged to support the grid are typically similarly lengthy with multi-year planning processes and decadal goals.

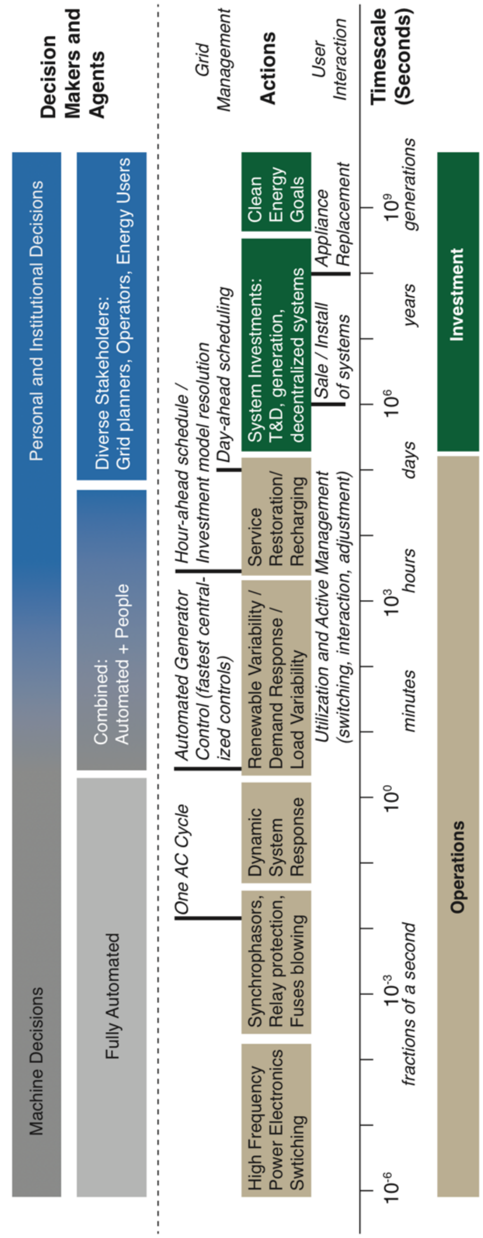

Figure 1: Conceptual timeline illustrating various decisions related to the operations and investment in the power system. Note that the time scale is logarithmic, ranging from fractions of a second to decades.[11]

[11] Alexandra von Meier, *Integration of Renewable Generation in California: Coordination Challenges in Time and Space* (2011), https://uc-ciee.org/downloads/EPQU_von_Meier_2011.pdf.

However, a fundamentally new set of technology needs is emerging on the power system that challenges this status quo regulatory paradigm. The imperative of climate change requires action to invest in new generation technology on a pace that would replace conventional generation in decades. The progress of renewable energy technology and DER advances is fast enough that there are significant reductions in cost and improvements in performance every few years, which means that regulatory decisions about investment could be different from one year to the next. Furthermore, since the cost of emerging technology is dependent on the scale of deployment, the choice to invest and deploy emerging technology can change the future costs within the planning horizon.12 The new clean energy technology systems being considered by regulators can also introduce changes to the grid operationally that are important to consider–variability in renewable power generation needs to be balanced in real-time, and flexible loads can carry some of the burden.

With clean energy emerging, planning the future power system requires incorporating these new dynamics into decisions while maintaining the same level of reliable and safe power. In addition to (and often in advance of) technology advances, updates are also needed for the energy analysis models and tools that support regulatory decisions. New models can not only synthesize what is possible into a framework that captures the important dynamics of the power system but also provide results with enough simplicity that regulators can understand them, weigh alternatives, and take action.

B. Renewables Deployment and the California Grid

Renewable energy has been deployed in California rapidly over the last decade along schedules defined by the legislature in terms of renewable portfolio standards (RPS), which specify minimum grid mix levels (usually with an incrementally increasing level over specified years). California has a current RPS goal of 33% by 2020 and 50% by 2030, which was established in Senate Bill 350.[13] The state added a new goal as well with Senate Bill No. 100 SB100, to be 100% "[c]lean" by 2045.[14] The clean energy definition in Senate Bill No. 100 expands on the conventional RPS by including large-scale hydroelectricity and nuclear power along with the typical solar, wind, geothermal, and small-scale hydro that count towards the RPS. In order to

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[12] Noah Kittner et al., *Energy Storage Deployment and Innovation for the Clean Energy Transition*, 2 Nature Energy 17125 (2017), https://www.nature.com/articles/nenergy2017125.pdf.

[13] S.B. 350, 2015 Leg., Reg. Sess. (Cal. 2015).

[14] S.B. 100, 2017 Leg., Reg. Sess. (Cal. 2017).

generate large fractions of energy with renewables and clean generators, the fleet of electricity generators serving loads in the state have changed.

Figure 2 illustrates how the fleet of generators has expanded in California since the 1950's. Natural gas burning power plants eclipsed hydroelectricity by the mid 1960's, and there was a boom in gas generation capacity in the early 2000's. The fleet of "clean" generators, as defined by SB100, have a base of hydroelectricity and nuclear power, and since 2010, there has been a boom in wind and solar in response to the statewide RPS goals. In terms of the total energy produced by the fleet, currently the state is on pace with the mandated RPS timeline and, with 34% renewables in 2018, is already passed the statutory goal of 33% by 2022 three years early.[15]

[15] CAL. ENERGY COMM'N, *TRACKING PROGRESS*, http://www.energy.ca.gov/renewables/tracking_progress (last visited Dec. 27, 2019).

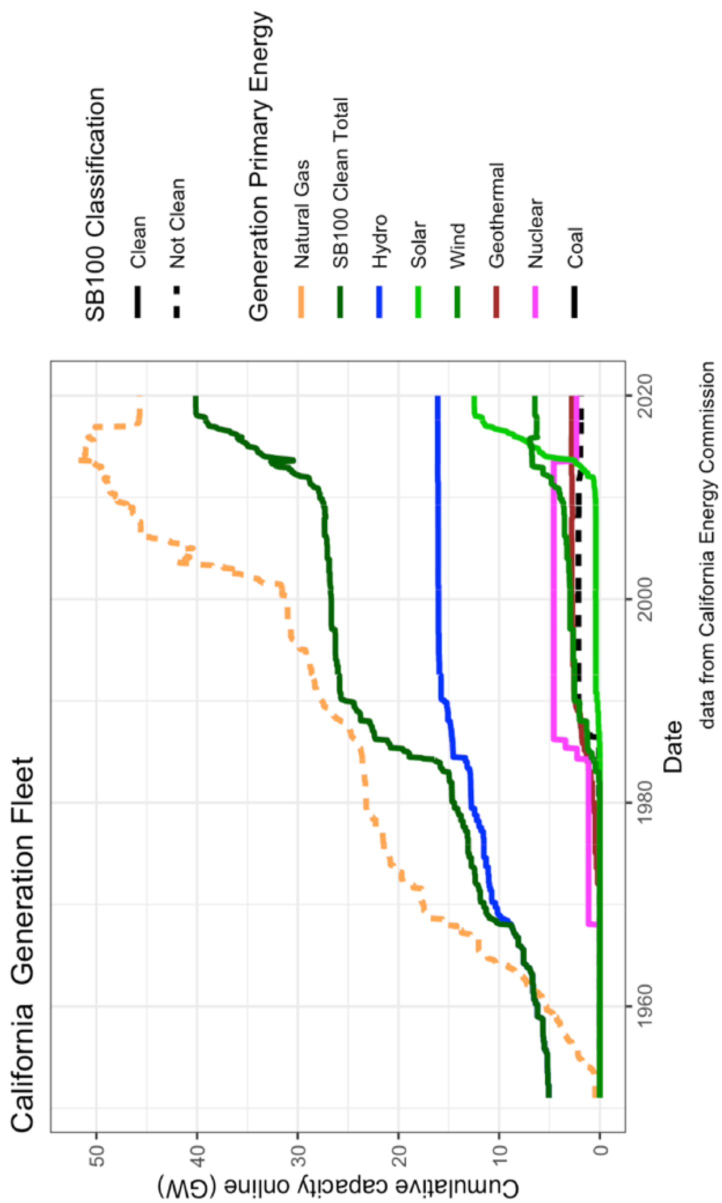

Figure 2: Cumulative total online California generation fleet from 1950 to 2017, by primary energy source. Additional capacity is from new plants, and loss in capacity is due to plant retirement.[16]

[16] California Natural Resources Agency, California Power Plant Generator, https://data.cnra.ca.gov/dataset/california-power-plant-generator (last visited Jan. 28, 2020).

While the California grid is interconnected and synchronized with the regional power system, the resources under control must be managed and balanced by the California Independent System Operator (CAISO) with little deviation from pre-planned transfers to adjacent states. As a "balancing authority," CAISO is responsible for managing generators to safely and reliably serve the load at the least cost, primarily serving the load of customers of the three investor-owned utilities in California (Pacific Gas & Electric, Southern California Edison, and San Diego Gas and Electric), which serve loads for approximately 75% of the electricity in the state. Other portions of the state are served and balanced by public utilities, water districts, and cooperatives (including Los Angeles Dept. of Water and Power, etc.). Through a series of markets for energy and other grid services, CAISO coordinates scheduling and balancing between generators and the load serving entities under control and coordinates operations with other adjacent balancing authorities.

The operational challenge posed by increasing renewable generation on the balancing authority is the intermittency of the resources combined with the rigid need to balance supply and demand at all times. Solar and wind power availability are subject to natural cycles and random variability are not able to be "dispatched" in the manner that conventional generators typically are operated to match demand. The conventional approach to grid operation is to dispatch flexible generators to match uncontrolled and inflexible demand. With more inflexible renewable generation online, the operational constraints of the conventional power system are strained.

C. The Duck Curve and Curtailment

The new challenges of operating the grid with renewables have been exemplified in California policy discourse by the "duck curve," initially described and predicted by the California System Operator.[17] Figure 3 (based on actual CAISO operational data from recent years) shows how these predicted duck curves are already "in the wild" and showing up in operational situations. The concept is that one can take demand and subtract renewable generation that is online to find a "net load" that needs to be served by other generators. This net load has a steep downward and upward ramping characteristic from solar coming online in the morning and fading with sunset in the evening. The overall effect is that renewables have significantly reduced and delayed the evening peak load and added new, steep net load ramps (particularly in the evening). Throughout the day, additional solar and wind power adds to the short-run variability on the grid as well.

[17] Cal. Indep. Sys. Operator, *What the Duck Curve Tells Us About Managing a Green Grid* (2016), https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

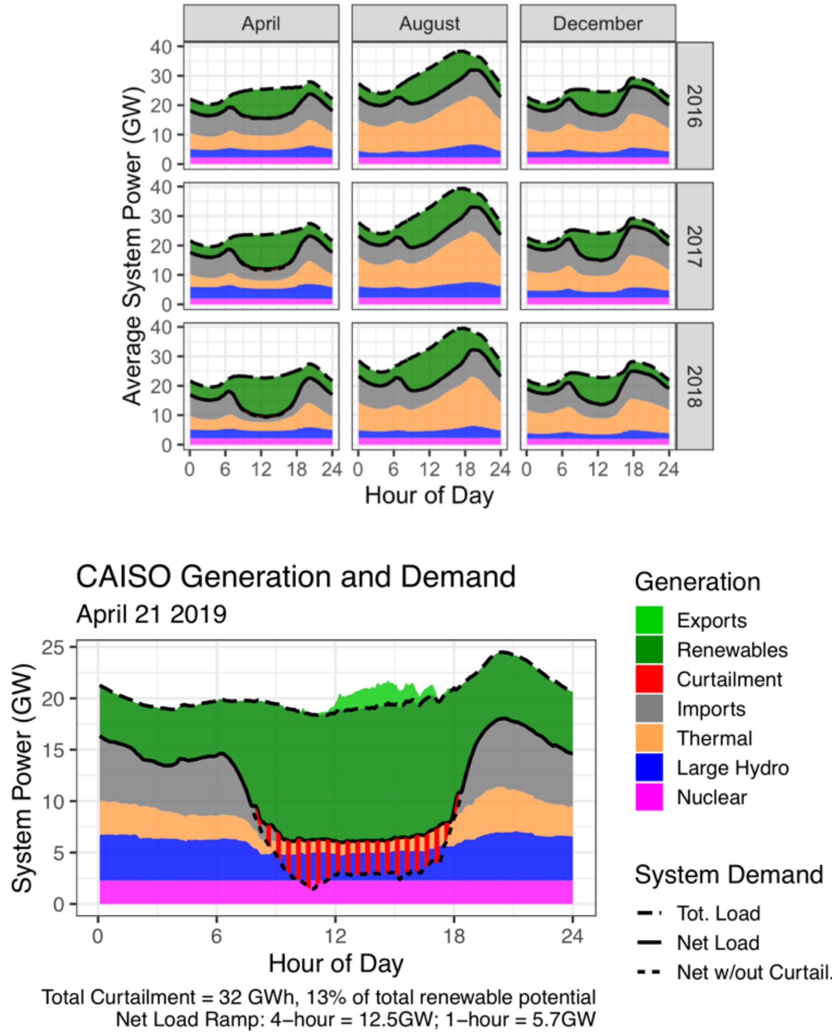

Figure 3: [A] California ISO operational profile from April 21, 2019, a representative day from recent operations with very high curtailment, and [B] Average operations for three months in 2016, 2017, and 2018 showing the daily profile for the average of all days in the month. Both plots show generation by source, and indicate demand based on different contributions from Renewables with and without curtailment.[18]

[18] CALIFORNIA ISO, http://www.caiso.com/informed/Pages/ManagingOversupply.aspx (last visited Jan. 26, 2020).

Maintaining stability and reliability on the power system requires careful operation of resources, which can lead to situations where there is more renewable supply available than the load remaining after must-run generation resources that are needed online. In the middle of the day when there is high solar output carrying load, it is important to keep enough dispatchable resources online and operational, so they are available for the steep afternoon ramp-up. This means some minimum level of flexible generators needs to be kept online, and that renewable generation that would reduce the net load below that level is not usable. The operational strategy for managing this "excess" renewable generation is curtailment, in which solar or wind generators with available resources are instructed to not operate (highlighted in red in Graph [A] in Figure 3).

Ultimately, curtailment of renewables leads to higher emissions in real-time than would have otherwise occurred. In the context of RPS-driven policy, this means that additional renewable energy capacity needs to be procured to replace the "lost" clean energy–presenting a possible source of value from flexible loads that could fill in the curtailment periods and lead to load shedding at other times. During curtailment, the marginal price in energy markets is zero or negative. Just based on marginal costs of production for renewable generators, there is zero cost for the solar or wind energy. The negative price bids to generate energy are artifacts of production tax credits or congestion on the power system. In addition to using flexible loads to shift demand, there are a range of other renewable integration approaches that can similarly make use of this energy. These include using battery energy storage shift apparent loads and transmission lines to make the generation available to neighboring areas (if there are no transmission constraints), among others.[19]

Renewable curtailment events totaled 380 GWh in 2017 in the California ISO region, which represents 0. 2% of renewable generation for the year. The total was 20% higher in 2018, with 460 GWh curtailed and upward trends continuing. Figure 4 illustrates the total curtailment by season over the last five years. In the Spring of 2019 alone, over 400 GWh was curtailed, nearly as much as in the whole of 2018.

[19] Jim Lazar, The Reg. Assistance Project, *Teaching the "Duck" to Fly* (2d. ed. 2016), https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-teachingtheduck2-2016-feb-2.pdf.

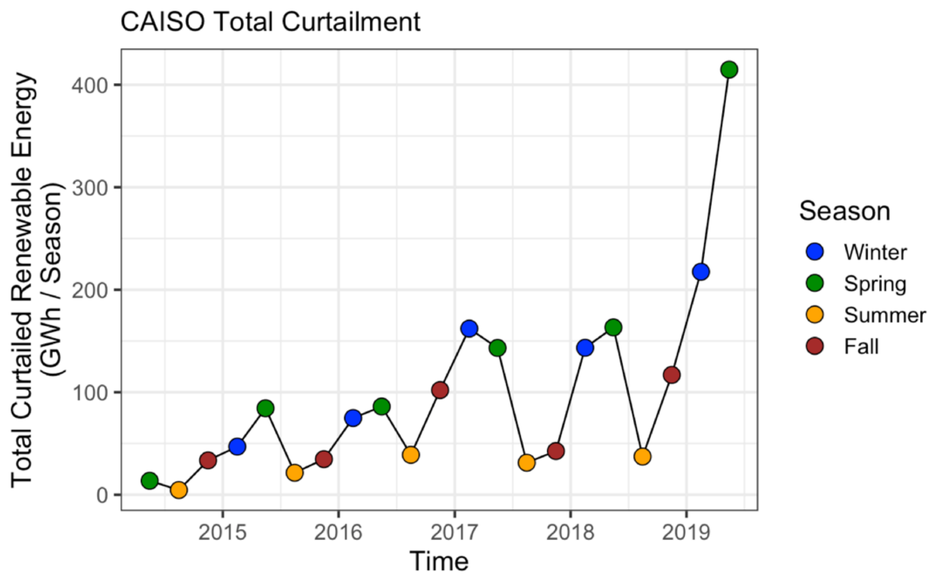

Figure 4: Total curtailed renewable energy in California.[20]

The relatively modest levels of curtailment in 2017 and 2018 are approximately equal to what is expected, given California's progress on RPS of 34%–a technical report that estimated curtailment in 2024 reported an estimate of 0.1% curtailment with a 33% RPS,[21] which is about half as much as was observed at that level. The same report estimated that at a 50% RPS (which should be by 2030 based on RPS targets) the curtailment could rise to 5% of the overall renewable generation, representing a significant challenge and opportunity to manage loads and capture the energy that would otherwise be curtailed. More recent estimates of curtailment from a set of production models supporting the Integrated Resource Planning process at the CPUC ranged from 2,000 to 11,000 GWh per year by 2030 (2-10% of the potential renewable generation). It is expected that the fraction curtailed, without other interventions, would continue to grow as renewables continue to be deployed past the 50% RPS point. If this curtailed energy is ultimately replaced by increased investment in new generation, the annual cost to replace curtailed energy is currently $20M/year and is expected to

[20] CALIFORNIA ISO, *supra* note 18.

[21] James H. Nelson & Laura M. Wisland, Union of Concerned Scientists, *Achieving 50 Percent Renewable Electricity in California: The Role of Non-Fossil Flexibility in a Cleaner Electricity Grid* (2015), https://www.ucsusa.org/sites/default/files/attach/2015/08/Achieving-50-Percent-Renewable-Electricity-In-California.pdf.

be $100M-500M/year by 2030.[22]

Figure 5 illustrates how the continued addition of renewable generation could affect the net loads (before curtailment) in California. To develop these illustrative plots, we used 2017 operational data for monthly average days and project renewable generation forward by increasing the scale of existing solar and wind in accordance with growth to meet future RPS requirements. We also grow demand based on forecasts from the California Energy Commission Integrated Energy Policy Report. The estimated net loads in 2018 and 2019 using this method were overall consistent with observed data in those years (for months with available data thus far). A key feature of the plots is the minimum mid-day net load (a core driver for curtailment); the average day in 2022 would be on par with the biggest curtailment day from 2019 with minimum net loads around 5 GW. It is reasonable to expect significant curtailment in other times of year as well, as summer and winter conditions in the middle of the day approach minimum net load levels that trigger curtailment.

[22] U.S. ENERGY INFO. ADMIN., LEVELIZED COST AND LEVELIZED AVOIDED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK 2019, at 8 (2019), https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf (based on a $40/MWh levelized cost of new build for solar in 2023).

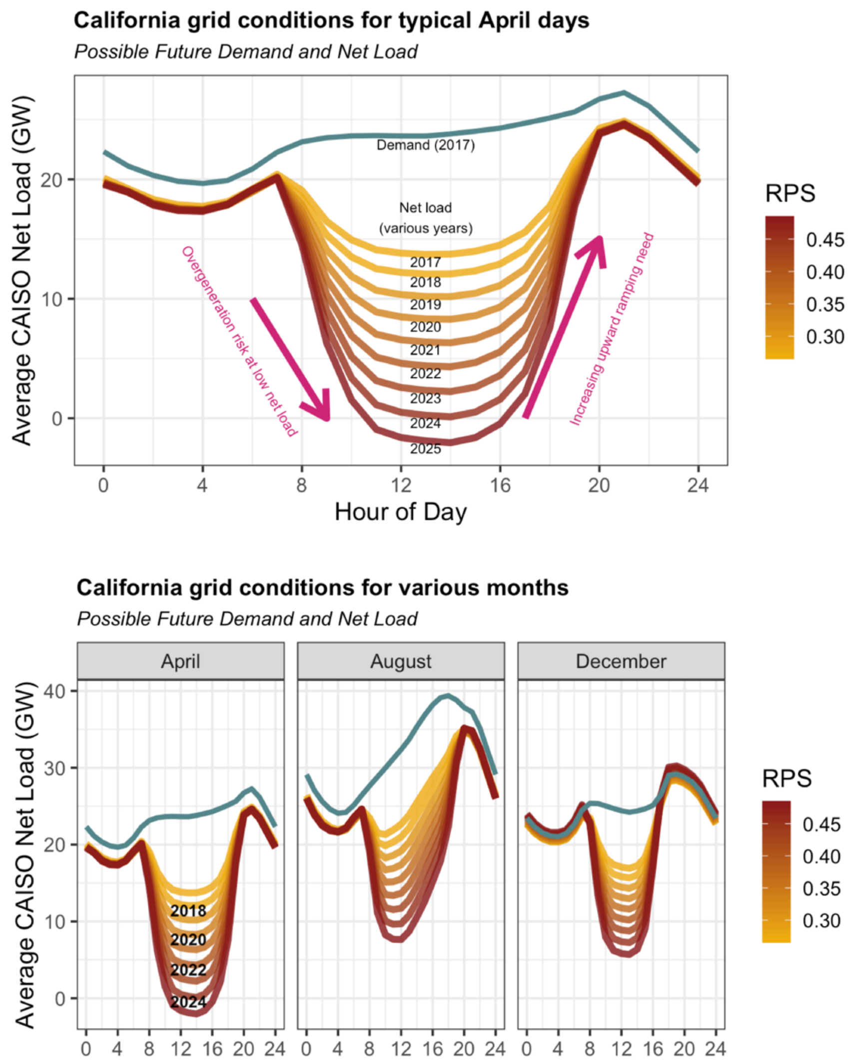

Figure 5: Possible future net load characteristics of California grid. The curves show the implied net load at various RPS levels and are labeled with the associated year the state is expected to reach that level.

D. Distributed Energy Resources

As new dynamics have emerged on the grid, there have been advances as well in the controllability and connectivity of loads that have opened a range of new possibilities for DER. Demand response, energy efficiency, distributed generation, and storage are all changing the opportunity space for investments at the edge of the grid that support power systems operation along with providing better site-level service.

A core driver for DER is advances in information and communication technology (ICT). Both computational cost and efficiency and levels of connectivity have rapidly expanded over the past decades.[23] Combined with the widespread deployment of smart meters, including between 50% and 100% coverage in California,[24] the spread of connectivity and computational applications for DER influences a range of technology. Connectivity and optimized control of systems is enabling new applications for DR, which relied previously on FM and cellular dispatch systems. Figure 6 shows how DR fundamentally is a coordination process between the grid and building or device-level control systems. The estimated investment required and performance capabilities of dispatch communication technology, local control, and telemetry were a core focus of our modeling work. ICT advances mean that the dispatch of DR can be targeted to the device level over the internet, the local control can be informed by adaptive and model-based control strategies, and telemetry and settlement is backed by high resolution meter data. Beyond DR, the ability to target energy efficiency investments based on load shape and to identify customer sites that are promising for DER also follow from the same ICT advances. Energy efficiency has transformed in recent years from a focus on bulk energy savings through equipment efficiency improvement to a holistic approach that also includes building commissioning and controls upgrades, time-dependent value of savings, and monitoring-based approaches. Commissioning has the potential for 10's of billions of dollars in energy savings nationwide.[25]

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[23] Jonathan Koomey et al., *Implications of Historical Trends in the Electrical Efficiency of Computing*, 33 IEEE ANNALS OF THE HIST. OF COMPUTING 46, 46, 52 (2011).

[24] Adam Cooper, Inst. for Elec. Innovation, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid*, at 3 (2016), https://www.edisonfoundation.net/iei/publications/Documents/Final%20Electric%20Company%20Smart%20Meter%20Deployments-%20Foundation%20for%20A%20Smart%20Energy%20Grid.pdf.

[25] Evan Mills, *Building Commissioning: A Golden Opportunity for Reducing Energy Costs and Greenhouse Gas Emissions in the United States*, 4 ENERGY EFFICIENCY 145, 162 (2011), https://link.springer.com/content/pdf/10.1007%2Fs12053-011-9116-8.pdf.

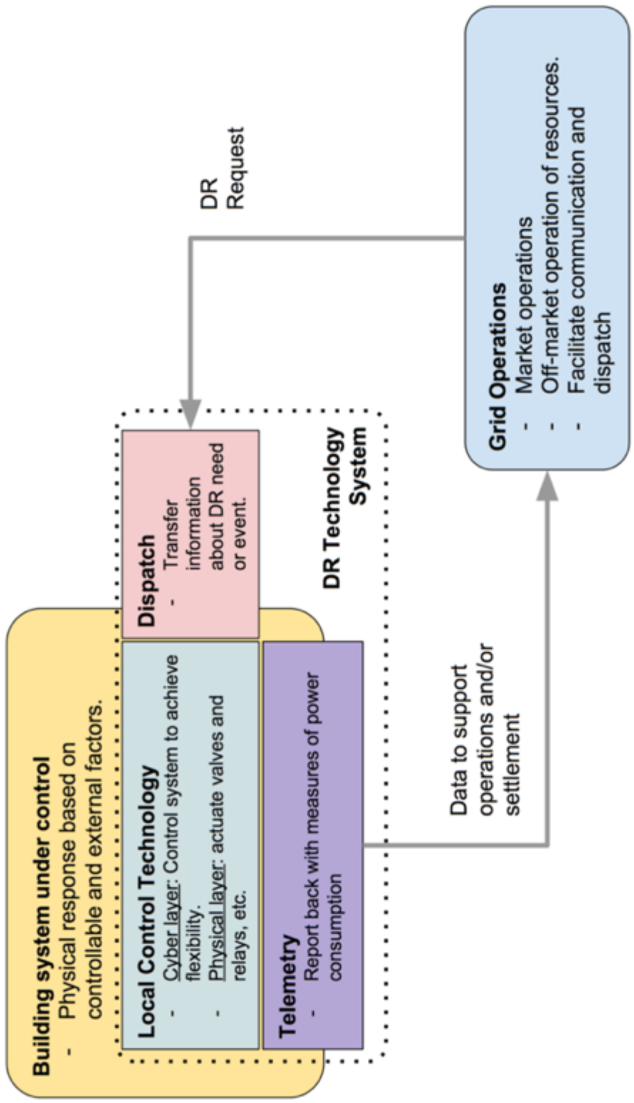

Figure 6: Interactions between building energy systems and grid operations. The dotted line area outlines the focus of our cost and performance modeling efforts.

There is also new technology in deployment and development that could reshape the DER landscape: electric vehicles, electrified heating, and distributed solar and storage. A mass deployment of electrified heating and transportation is both necessary to meet climate stabilization goals[26] and will require significant upgrades to electricity systems and introduce new management challenges that could be facilitated with demand responsive features. While distributed solar generation has been cost-competitive and scaling up for several years, distributed storage is only emerging. As the cost of storage drops, deployment both in "front" and "behind" customer meters could in principle add a significant new resource base for flexibility in the timing of demand on the grid along with providing fast-response ancillary services that stabilize operations.

E. Synthesizing the Capabilities of DER

It has long been a challenge to synthesize the opportunities in the electricity sector for informing public policy related to technology deployment in the face of tradeoffs between alternative options for providing service. The vast scale of the power system, and the need for specialized expertise to understand varied components from generation to T&D to loads and buildings, demands an analytic approach that synthesizes the key features in each area for informing development. A key innovation in energy analysis for distributed resources has been the concept of supply curves for conserved energy that were originally developed in the context of energy efficiency.[27] These "EE supply curves" clearly show a range of costs and benefits and enable comparison to competing alternatives;[28] they inspired our framework for DR.

Now, a wider range of DER approaches can support integration of renewable energy serving a large fraction of load; beyond energy efficiency (EE), there are emerging demand response (DR), distributed generation, and distributed battery energy storage resources to consider. Non-DER renewables integration options include expanding the use of large-scale transmission, centralized battery storage, and increasing the flexibility of conventional power plant generators. Taken together, this represents a fundamental change in the planning and operations of the grid with the addition of variable generation, more distributed assets, and new capabilities for communication and controls. Managing the transition requires more than new technology but also new methods of analysis to support public

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[26] James H. Williams et al., *The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity*, 335 SCIENCE 53, 53 (2012).

[27] Arthur Rosenfeld et al., *Conserved Energy Supply Curves for U.S. Buildings*, 11 CONTEMP. ECON. POL'Y 45, 46-49, 54-55, 58, 64 (1993).

[28] *Id.*

policy and regulatory choices between a range of complementary and competing technology pathways.

Our approach in developing a DR potential modeling framework expresses the same dynamics expressed in EE supply curves: an estimate of the stack of investment opportunities that are shown in the context of their effective cost of service. By organizing the results in terms of these supply curves for DR, it is possible to weigh the benefits of various scales in resource against the value to the grid. The framework is also useful for comparison to the renewables integration alternatives that are available, either one by one or in an integrated framework (e.g., through the Integrated Resource Planning process at the CPUC).

II. Demand Response Analysis Framework

We developed a DR analysis framework (called the "DR Futures Model") based on the context of renewables integration, emerging capabilities of DER, and the need for analytic tools to understand the value of flexible loads to the power system. Serving the goal of the 2025 DR Potential Study for the CPUC, the framework aims to synthesize the trends in grid management needs with emerging opportunities for DR and estimate the potential with results that are actionable for policy development and technology deployment.

A core challenge we identified was the fragmented framework for describing and modeling the capabilities of load control and grid operations. In response we developed a new framework for classifying DR approaches into four broad categories: *Shape, Shift, Shed, and Shimmy*. These provide a conceptual bridge between the emerging needs on the grid and discrete capabilities of DR technology systems that is tractable to include in both demand-side and grid modeling. Supply curves for DR service along these dimensions can inform grid planning and enable comparison to alternative investments. Table 1 lists the details of what service products fit conceptually in each category, and the names of markets, incentives, or revenue opportunities that are relevant in the California context. Other ISO/RTO regions and balancing areas have different market structures in place.

Table 1: Examples of specific DR services that fit in four DR categories. Items with `*` were not included in our CA Potential study explicitly.

Category	DR Service Product	California Market Name
Shed	Peak Capacity	System and Local RA Credit
	Economic DR	Economic DR / Proxy Demand Resource
	Contingency Reserve Capacity*	AS- spinning
	Contingency Reserve Capacity*	AS- non-spin reserves
	Emergency DR	Emergency DR / Reliability DR Resource
	DR for Distribution System	Distribution
Shift	Economic DR	Combination of Energy Market Participation
	Flexible Ramping Capacity*	Flexible RA -- energy market participation w/ ramping response availability
	Peak Capacity *	System and Local RA Credit
Shimmy	Load Following	Flexible Ramping Product / Real time market (similar)
	Regulating Reserve Capacity	AS- Regulation
Shape	Responsive Behavioral DR - Event-based	Critical Peak Pricing (CPP)
	Load shaping DR - Load shaping	Time of Use Pricing (TOU)
	Load shaping with EE*	EE Time Dependent Value

The categories of DR service in Figure 7 illustrate how DR spans timescales from years to seconds. Starting at the long end of the time scale, we define *Shape* as long-term response to electricity rates and other incentives to change the timing of load or reduce peak loads. Reshaping the load in the face of time-of-use rates is a fundamental element to matching loads with the typical patterns of generation on the grid and emerging surplus of renewable electricity in the mid-day period and reducing the need for peak capacity. *Shift* is a service-neutral change in the timing of hour-to-hour energy use, in response to daily changes in the patterns of availability of renewable generation. A core goal of shifting energy is to avoid renewables curtailment and alleviate ramping from diurnal patterns in solar generation. *Shed* describes DR that curtails energy service in response to critical peak conditions on the grid. Reliably reducing loads at peak times can avoid or delay the need capacity investments in generation or T&D and has been the core goal of conventional and existing DR programs. Finally, *Shimmy* is a category of DR that involves fast changes to loads for balancing the grid–in the study we modeled two timescales: 15-minute "load following" responses and 4-second "frequency regulation" responses. Frequency regulation is a current ancillary service provided by generators and fast DR, and load following service is not explicitly implemented in California but is elsewhere, and in principle, is similar to real-time energy market dispatch.

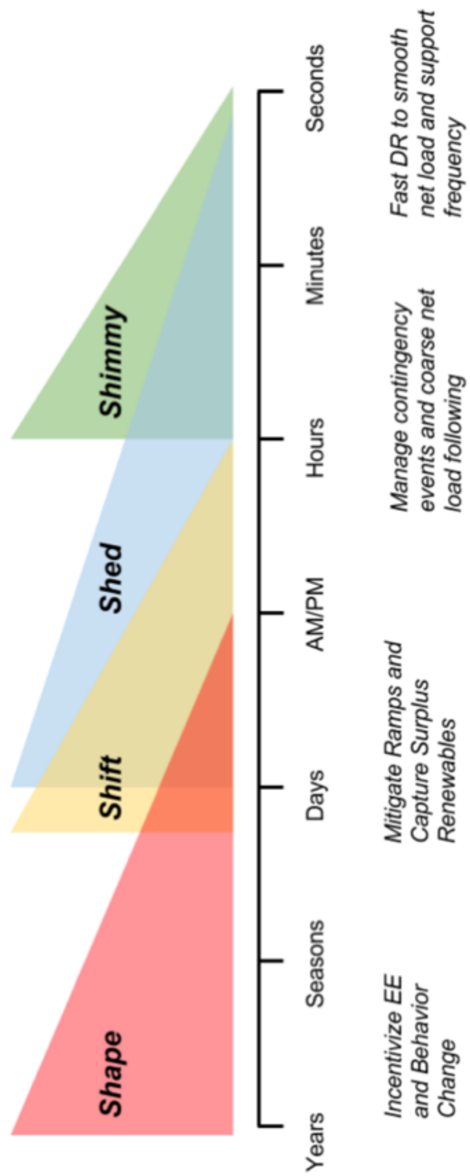

Figure 7: Dimensions of DR Service.

A. Modeling Approach

Our analytic framework for assessing DR resources was based on modeling the potential for loads to provide Shift, Shed, and Shimmy services in terms of the cost and performance across a range of technology. The approach in the model is to use estimated end-use load shapes in combination with a DR technology cost, performance, and customer adoption models to estimate the total achievable availability of DR resources across a range of price levels–resulting in supply curves for the resources.

In our framework, the Shift, Shed, and Shimmy resources are inherently dispatchable or responsive to dynamic signals and prices from the grid. Shape, on the other hand, is based on underlying behavioral and permanent responses to rates. The result of reshaping in terms of value to power system operations ultimately manifests partly as a beneficial Shift in energy use and also in reductions in peak loads, similar to Shed DR. Thus, in our analysis we express the effects of load shaping in terms of the equivalent Shift and Shed resources. Our estimate of the equivalent Shift and Shed from the Shape resource in the study was based on prospective TOU rates for 2019 deployment using demand elasticity estimates from existing TOU programs.

Our end-use load shapes were developed using ~220,000 annual hourly sitewide load shapes from customers across California as a basis for capturing the timing and spatial variation of DR availability. We developed a model called "LBNL-LOAD"[29] to develop a set of representative end-use load shape forecasts with estimated disaggregation in key end-use categories and forecasted consumption linked with scenarios in the CEC Integrated Energy Policy Report for 2020 and 2025. The data are aggregated into ~3,500 clusters that each represent typical loads for a customer class, in a geographic region, with similar demographic characteristics. These clusters were developed based on basic demographic information from all ~11 million customers of the major investor-owned utilities (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) and designed to be representative of the diversity in statewide demand.[30]

The technology model we built includes estimates for the cost and capabilities of over 100 possible DR measures that each apply to a specific sector and end-use (with the scope described in Table 2). It is notable that there are several important emerging technology options that were not included in this study. These include: thermal storage systems for HVAC and refrigeration, advanced EV charging, and electrified hot water and space heating that could be controllable. Each of the technology areas listed previously

[29] Alstone, *supra* note 4, at 3-1.

[30] *Id.* at 1-3.

are the subject of ongoing work by our team with the CPUC, with updated results on the Shift potential from these expected in late 2019.

Table 2: End uses and enabling technology included in these results.

Sector	End Use	Enabling Technology Summary
All	Battery-electric and plug-in vehicles	Level 1 and Level 2 charging interruption
	Behind-the-meter batteries	Automated DR (Auto-DR)
Residential	Air conditioning	Direct load control (DLC) and Smart communicating thermostats (Smart T-Stats)
	Pool pumps	DLC
Commercial	HVAC	Auto-DR, DLC, and/or Smart T-Stats
	Lighting	Luminaire, zonal and standard control options
	Refrigerated warehouses	Auto-DR
Industrial	Processes and facilities	Automated and manual process scheduling
	Agricultural pumping	Manual, DLC, and Auto-DR
	Data centers	Manual DR
	Wastewater treatment and pumping	Automated and manual DR

Details on the model assumptions are available in (LBNL 2017a).[31]

The model includes information about the response time, magnitude of load flexibility, and required investment and operations costs for different combinations of dispatch, local control, and telemetry options. Our customer adoption model was developed by a team from Nexant consulting and results in estimates of the fraction of customers in various sectors who will adopt DR technology in the face of different incentive or benefit levels and marketing approaches; it was calibrated based on historical participation in DR programs. We synthesize the techno-economic potential using the "DR-PATH" model, which combines the technology inventory and customer adoption propensity models with the clustered load shapes to estimate the available resource at a range of cost levels, for each of the core DR services, developing supply curves that represent the long-run average cost of providing various quantities of each service.32 Because the clusters are

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[31] *Id.* at 3-3.
[32] *Id.* at 1-3, 2-10.

geographically specific, it is possible as well to estimate the DR resource potential for local planning areas where different needs and constraints on the transmission and distribution system, and the presence of local renewable generation could result in different values of the service.

B. Interpreting Modeling Results

Figure 8 shows two methodological options for how the supply curves we develop are compared with estimates of the value of the resource to the power system to estimate a cost effective resource quantity: a price referent approach (the standard for capacity payments to DR Shed resources) and an approach based on a demand curve for the DR service that has diminishing returns to additional DR capacity.

1) The **price referent** approach compares the supply curves with the cost of an alternative resource (e.g., for Shed DR, the alternative cost of peak capacity if there is a need for capacity expansion to meet peak loads). The economically cost-effective quantity of DR to procure (or support with policy) is the amount that is lower cost than the alternative. This approach is useful but has a drawback in its embedded assumption that there is a limitless need for the DR resource as long as it is below the price referent and that the value to the system is the same for the first GW of service and the fifth, etc.

2) In an alternative "**system levelized value** approach" we use a grid planning and operations model (RESOLVE, developed and implemented by E3)[33] to estimate the additional value to the grid of various quantities of DR resource. The result is a set of estimates for the long-run average ("levelized") reductions in the cost of building and operating the power system across a range of capacity levels for DR that is analogous to a demand curve. Assuming the model structure is accurate and given the input assumptions, these demand curves can be compared to supply curves to estimate an economically cost-effective quantity and price of DR at the intersection. Additional methodological details and assumptions for our study are in the reports and supporting documentation we developed for the CPUC.[34] In the sections below, we describe the results and interpret the opportunities that are suggested for integration of DR, energy efficiency (EE), and distributed energy in general as renewables ramp up.

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[33] Energy & Envtl. Econ., *RESOLVE: Renewable Energy Solutions Model*, https://www.ethree.com/tools/resolve-renewable-energy-solutions-model/ (last visited Oct. 11, 2019).

[34] Alstone, *supra* note 4, at 2-1.

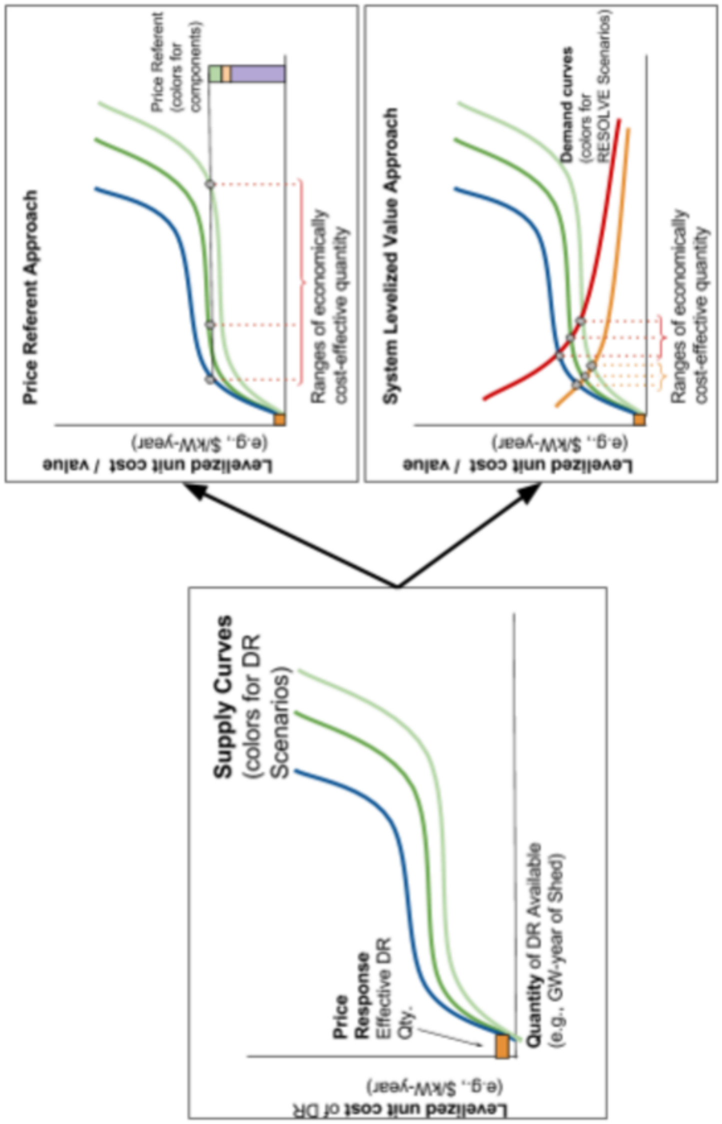

Figure 8: Methods for assessing supply curves for DR in the context of different valuation approaches.

C. Demand Response Roles in the Future Grid and California Results

The focus of our effort in developing and applying the modeling framework was estimating the DR potential in the service territories of the three IOUs regulated by the CPUC. In this section, we summarize the results of that effort and synthesize the policy and deployment related actions that are suggested by the findings. The assumptions we made about the cost and performance of the technology were developed and vetted in a public process through the DR rulemaking by a stakeholder group and a technical advisory committee. Additional resource types we did not model (see Table 3 for a summary of the scope) would in principle only increase the resource compared to what we describe.

1. Shape. – Our estimates of load reshaping through TOU and CPP prices were based on a range of residential prices that were proposed for the 2019 TOU rate design cycle and have an evening peak period with lower prices in the middle of the day. The commercial and industrial TOU rates were based on existing estimates of response. 35 We estimate these prospective near-term rates will result in reductions in the peak load equivalent to approximately 1 GW (~2% of the overall peak) and result in ~2 GWh of shifted load per day through changes in behavior and schedule (~0.5% of volumetric energy demand), assuming the response is similar to past TOU rates. These Shed and Shift outcomes that can be achieved with a Shape pathway–at essentially zero cost since the rates are constructed to be revenue neutral–represent an important and foundational element of DR futures.

An important point of context for this estimate is that the responses included in the model are based on historic responses, mostly from schedule-based and behavioral changes. As more automated price responsive systems come online, the expectation is that the scale of impact from load shaping will increase.

2. Shift. – We found that there is a significant emerging opportunity to support the grid with DR through frequent Shifts to capture renewable generation that would otherwise be curtailed. Unsurprisingly, in retrospect, the ideal Shift dispatch profile resembles the opposite of the duck curve–shifting load from the evening peak time to mid-day when renewables may be curtailed and night-time and morning shifts depending on the conditions of the wind power resource. These shifts create value for the system by avoiding curtailment and thus reducing the cost of RPS compliance since fewer additional solar and wind projects are required to compensate for

[35] Daniel G. Hansen et al., Christensen Assoc. Energy Consulting, *Statewide Time-of-Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report* 42-43 (Nov. 15, 2015), https://efiling.energy.ca.gov/GetDocument.aspx?tn=207031&DocumentContentId=21313.

curtailment. There are also reductions in the ramps between low and high demand times, reducing ramping pressure on the generation fleet and relaxing the constraints on dispatch, which can also result in lower system operating costs and further reduced curtailment.

There were two scenarios included to estimate the value of Shift (and the other categories we modeled) to the grid using the RESOLVE model: the "High Curtailment Case" represents a future with policy and technology deployment assumptions that result in the high end of plausible curtailment levels, and the "Low Curtailment Case" represents one where other non-DR renewables integration reforms have reduced curtailment. These were designed to be bookend cases; the future activities and deployment of integration strategies is uncertain. Figure 9 shows both demand curves in the context of Shift supply curves for a range of scenarios. The light blue represents a 2015 technology baseline and the darker blue represents a possible 2025 scenario with business-as-usual progress. The green supply curves represent a "medium" and "high" case for advances in the cost and performance of DR technology.[36]

Overall, our model estimates 10–20 GWh of cost-effective Shift resource (equivalent to 2%–5% of the daily load Shifted through load control) in the CAISO operational footprint. Among the technology options included in the model, the most cost effective were commercial HVAC, industrial processes, and water pumping. Based on the estimated savings from avoided investment and operations costs, we expect the value of this prospective Shift resource to the power system is $200–$500 million annually. It is notable that this estimate is in line with future estimates of "lost value" from curtailed renewables.

While our approach estimates the scale of the flexible load resource, it does not define the pathway of an organizational framework or dispatch method that could be used to signal and control loads. There are a range of options available, from out-of-market programs to dynamic pricing to tight integration and dispatch through coordinated energy markets. A number of these alternative pathways were explored and proposed as possibilities by the Load Shift Working Group, as described in the final LSWG report.[37]

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[36] Alstone, *supra* note 4, at 7-1-7-18 (providing details on the assumption for the scenarios defined).

[37] CAL. PUB. UTIL. COMM'N, *supra* note 7.

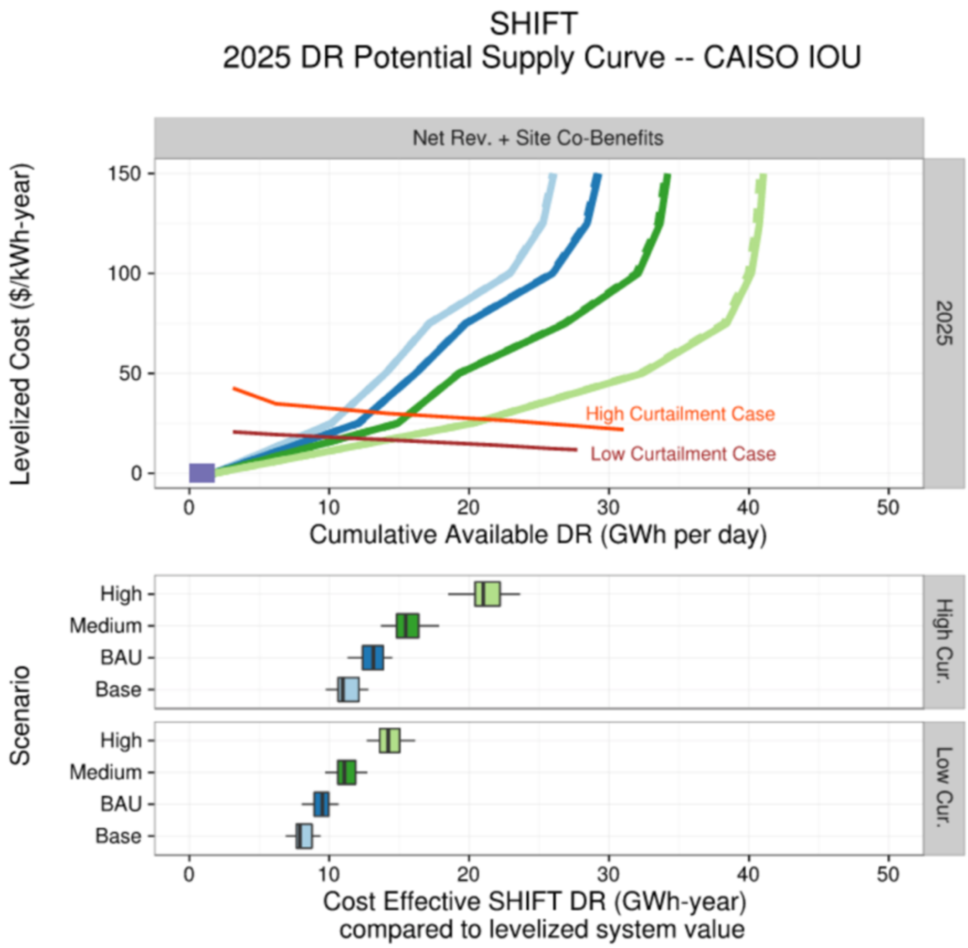

Figure 9: 2025 Shift supply and demand curves for four supply scenarios and two demand scenarios (upper panel), and box plots showing the range of outcomes for the scenarios, with uncertainty based on a Monte Carlo analysis that varied the cost and performance estimates for DR technology (lower panel).

3. Shed. – Most DR programs that have been developed in the last twenty years have focused on peak load Shed - reducing or curtailing loads during the critical peak hours of the year to avoid the need for additional generation capacity construction. We found that while there is a significant role for these resources in the future, capturing their value will require a change in approach compared to the conventional programs and technology. The DR program's, circa 2017 in our study, area totaled ~2 GW of Shed capacity and are structured primarily to meet *system-wide* peak capacity needs and local needs in transmission-constrained areas. Because of the significant additions of renewables to the CA grid, the overall system net load peak is below what was planned for. Based on background research by E3 that supported our study in 2015, the 2025 forecast showed excess thermal capacity in the state and low probability that new plants will be needed until well after 2025. If there is no opportunity for DR to avoid capacity expansion (because no binding constraints exist), it suggests a low system-wide value for Shed.

The trajectory of California's thermal fleet has been somewhat different than the assumptions from 2015, and recently, a tightening of expected capacity availability has led to new forecasts in the CPUC Integrated Resource Planning process showing constraints in the next five years between 2019-2024.[38] The cause of this faster-than-expected constraint is partly from the retirement of aging thermal generation units, including generators that use "once-through cooling" where cooling water is not recycled. New state environmental and water resources management regulations would require upgrades to these plants to continue operating. This new operating reality indicates that there is indeed value for Shed DR at the system scale in the near term.

Figure 10 shows the mix of technology we modeled and how combinations of technology lead to a supply curve for the Shed resource. The value of Shed depends on the location and local needs; at a conventional value ranging from $50-$100 /kW-year, the scale of the available resource is 2-5 GW with an annual value between $100-$700 million. There are also significant areas where Shed can add value at the local level for sites located in areas with constrained transmission systems. About half of the Shed resource we identified is located in the currently constrained regions in California (in Ventura County, the LA Basin, and San Diego). We described the local resource scale in a separate technical addendum to our DR potential study.[39]

Overall, our analysis indicates a steady and growing need for the Shed resource, with an expanded new focus on local needs. In addition to alleviating transmission and generation capacity constraints, there is a wide range of possible additional value based on a plausible range of assumptions for future market and technology trajectories.[40] For example, there may be significant Shed needs to serve distribution system needs (up to 5-10 GW depending on uncertain future frameworks for valuing and operating distribution-level Shed DR) and value for supporting reliability of islanded microgrids or sections of the power system in system emergencies and

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[38] CAL. PUB. UTIL. COMM'N, RULEMAKING 16-02-007, ORDER INSTITUTING RULEMAKING TO DEVELOP AN ELECTRICITY INTEGRATED RESOURCE PLANNING FRAMEWORK AND TO COORDINATE AND REFINE LONG-TERM PROCUREMENT PLANNING REQUIREMENTS, at 6 (Jun. 20, 2019), http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=302942332.

[39] Alstone, *supra* note 4.

[40] *See id.*

contingency events.

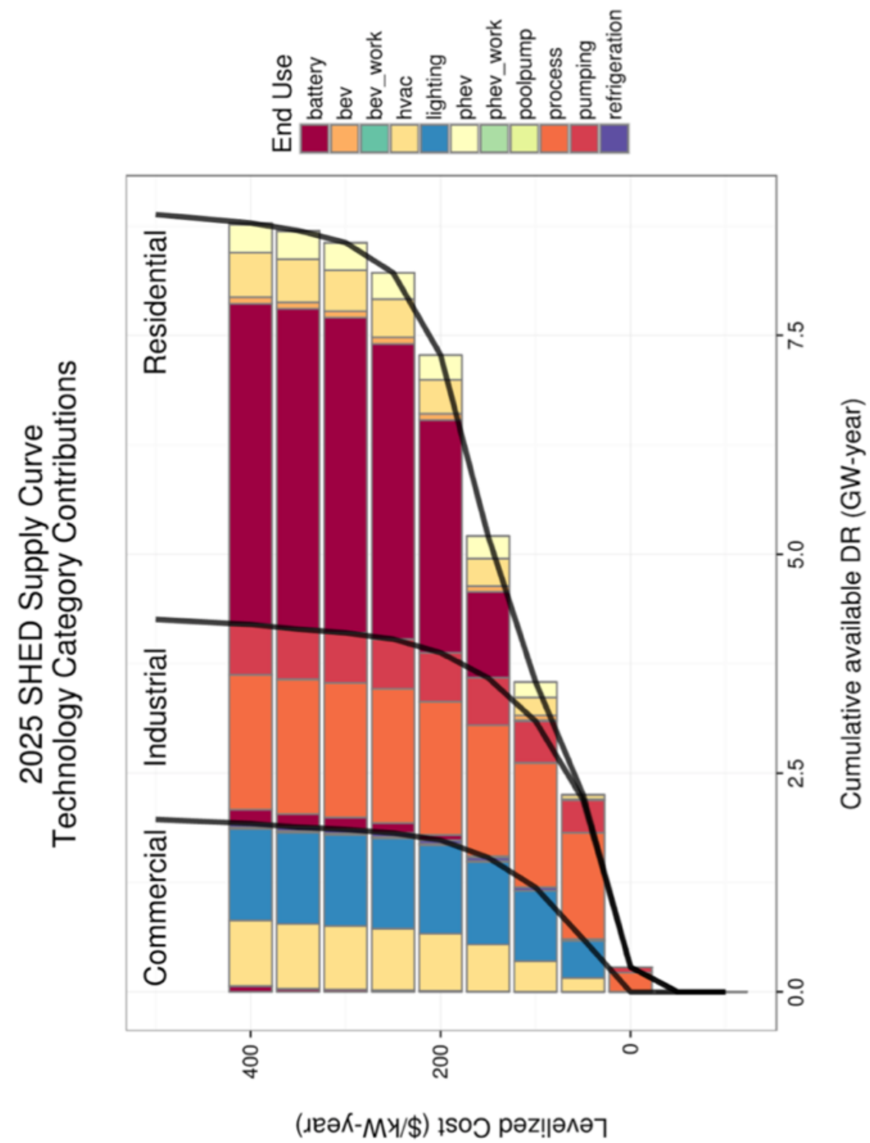

Figure 10: Technology contributions to the 2025 Shed supply curve.

4. Shimmy. – The two pathways for Shimmy we modeled have different timescales–15-minute load following and 4-second frequency regulation–but for both, we estimate approximately 300 MW of potential for load to stabilize the grid with bidirectional, fast response. The estimated value of these grid services is $25 million per year, and the markets for Shimmy are "thin" compared to Shift and Shed (i.e., there are steep downward slopes in the demand curve, with significantly diminishing returns to additional resources after the needs for Shimmy are met). The specific pathway to creating system-wide value for Shimmy was interestingly related to freeing batteries from the need to provide Shimmy and enabling them to increase Shift and avoid curtailment. This dynamic where the value of Shimmy is related to opportunity costs in other services is similar to the conventional description of price formation for frequency response, where the price for the ancillary service is directly related to the opportunity cost of lost revenue in the energy market (and thus is tied to energy market prices). Our result reinforces the concept that fast-response Shimmy is a secondary service where the value will be related to opportunity costs in serving load with energy, or (new to the operational paradigm) shifting energy.

III. LOAD SHIFTING AND GREENHOUSE GAS REDUCTION

A key result of our study was the identification of a broad need and large available resource for Shift DR. This emerging opportunity is directly responsive to the emerging priorities and constraints placed on the grid by climate change. There has always been a priority for grid planners to find the least cost pathway to deliver reliable and safe electric power; using DR to Shed load at peak times contributes to this work by reducing the need for additional transmission and generation to carry loads at peak times. As we discussed earlier, incorporating the harms and costs from globally significant emissions like CO2 and local air pollution means that more zero-emissions resources are needed, changing the dynamics of net load on the grid. Shifting the timing of loads should enable more efficient use of variable solar and wind generation conceptually, and the specifics of how much flexibility and load shifting "helps" with reducing GHG is important for charting a pathway forward to implementation.

The analysis we describe below helps addresses these questions related to Shift and GHG and was completed in the process of supporting the CPUC Load Shift Working Group, which was convened to address this and other regulatory priorities related to Shift. The working group met 11 times through 2018 with contributions from 85 stakeholders representing 63 organizations (notably including all three major IOU's in California, CAISO, a number of DR industry representatives, and public interest intervenors). The final report from that group describes a summary of the outcomes.[41] The report describes a range of pathways that were discussed and refined in the group to incentivize and dispatch load shifting. These form the basis for our analysis below, which assesses the potential load impacts and resulting changes in grid performance for each.

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[41] CAL. PUB. UTIL. COMM'N, *supra* note 7, at 1-20.

A. Conceptual Framework for GHG and Shift

When loads are shifted to better match renewable generation, what would we expect?

- **Reduced cost** to serve load from arbitrage in prices and increased load in low price periods.
- **Reduced peak** loads since "take" tends to happen mid-day and "shed" in peak times.
- **Reduced curtailment** from more demand during curtailment hours.
- **Reduced emissions** from more demand during zero or low emissions times and avoided demand at high emissions time.

To drive our analysis we use two approaches to represent how load shifting can support low-GHG grid operation: a compliance framework where load shifting is a cost-reducing measure to meet binding RPS targets by utilizing otherwise-lost clean energy or as an arbitrage framework based on timing demand to reduce the marginal emissions of the grid.

In the **compliance framework** for value, loads are able to **utilize available zero-carbon power** by increasing demand during a curtailment event and avoiding the need to turn down renewables. The output of the renewable generators then "counts" towards achieving the RPS standards set by California. If this generation were curtailed, the lost opportunity to generate needs to be replaced by new build of additional renewables. The most straightforward method for replacement is through new-build wind or solar in the future. Based on the expected cost for building new utility-scale solar PV in 2023, the implied societal opportunity cost is $40/MWh.[42] If load shifting is less expensive, it can be an economically optimal choice as part of a portfolio of investments in the context of the binding RPS cap. We do not do additional analysis with this framework but describe it here to clarify that this is one way to conceptually describe the role of load shifting. In this framework, the assertion is that RPS caps are binding and will drive the overall level of emissions on the grid. Various investments are made to meet this cap, and load shifting can be part of those investments to reduce the overall cost.

The **arbitrage framework** for estimating the value of Shift presents another way to frame the opportunity. When loads are reduced at peak times and increased in times of curtailment, the effects on the grid are that the

[42] U.S. ENERGY INFO. ADMIN., LEVELIZED COST AND LEVELIZED AVOIDED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK 2019, at 1-25 (2019), https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

marginal generator serving peak loads (which tend to be fossil fuel units) are turned down. The marginal emissions during curtailment times are zero if there are no constraints on the otherwise-curtailed solar or wind generators on serving load. The typical marginal emissions from a natural gas power plant is around 0.3 tn. CO2 per MWh. If every shifted megawatt-hour resulted in the reduction of emission by 0.3 tn., the implied value based on the social cost of carbon43 ranges from $10-$200 per shifted MWh. The analysis described below assesses the potential gains from load shifting using an arbitrage framework.

B. Analysis Methods for Estimating GHG Impacts

In the analysis presented below, we assess both the scale of avoided curtailment (the first framework) and the implied emissions savings related to marginal GHG (the second framework) for a range of pathways to achieve Shift. The basis for the analysis is retrospective, using characteristics of the grid during the 2017 operations year and assessing the implied outcomes with various load shifting concepts. Based on the actual profiles for demand, solar and wind generation, market prices, and estimated marginal emissions, we estimate what value shifting loads would have provided to the grid. Value here is defined in terms of reduced curtailment, reduced cost to serve load, and reduced emissions due to arbitrage.

Since there are no active, large-scale Shift programs in California, the approach we take is to impose speculative load shifts on the demand profile using a set of scenarios that represent a range of possible dispatch profiles; these are designed to cover the range of concepts from the LSWG and support understanding of the sensitivity of grid value.

The datasets from 2017 that we combined as a basis for this analysis are illustrated in Figure 11. The sources of load and price data for the analysis were the CAISO "Managing Oversupply" web page[44] and CAISO OASIS (an online portal to access CAISO prices[45]). In order to estimate the impacts of changes in load on operational emissions, we use estimated marginal

[43] This is a highly uncertain parameter. *See, e.g.*, U.S. ENVTL. PROT. AGENCY, *The Social Cost of Carbon*, https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html (last visited Oct. 2, 2019); *see also* Katharine Ricke et al., *Country-Level Social Cost of Carbon,* 8 NATURE CLIMATE CHANGE 895, 895-901 (2018); *see also* Robert S. Pindyck, *The Social Cost of Carbon Revisited,* 94 J. ENVTL. ECON. MGMT. 140, 140-60 (2019).

[44] Cal. Indep. Sys. Operator, *Managing Oversupply*, http://www.caiso.com/informed/Pages/ManagingOversupply.aspx (last visited Oct. 2, 2019).

[45] Cal. Indep. Sys. Operator, *Open Access Same-Time Information System*, http://oasis.caiso.com/mrioasis/logon.do (last visited Oct. 2, 2019).

emissions. These estimates were provided to us by WattTime[46] and were originally developed and used in support of a California energy storage incentive program ("Self-generation Incentive Program," or "SGIP") impact evaluation.[47] These hourly estimates are based primarily on the marginal prices in the real time energy market. These prices reveal information about the efficiency and emissions of the marginal generator because the bids are typically based on the marginal operating costs of power plants, and it is possible to infer the cost of fuel based on known information about the power sector. In these emissions estimates, periods with typical prices between $30-$50 /MWh can translate to emissions based on the cost of natural gas (enabling a conversion from dollars to energy quantity) and estimates of the emissions intensity of natural gas burned in power plants.

When the prices are very low or negative, this indicates renewable generators are likely on the margin since there is no additional cost to operate them once built. Prices can be negative due to congestion and the opportunity value of production-based incentives and tax credits that would be gained by producers when they operate. In practice, negative pricing typically indicates that somewhere on the system a renewable generator is being curtailed. Increased load at these times, if it results in a reduction in curtailment and is served with renewables, would not result in additional emissions. Conversely, when loads are reduced during times with higher emissions, this would reduce the load on the marginal generator, reducing fuel consumption and emissions. This is the basic framework that underlies our analysis to estimate the overall emissions impacts from changes in load associated with Shifting and flexible demand–reducing the load in some hours and increasing in others.

[46] WattTime, *Working with Regulators*, https://www.watttime.org/solutions/regulators/ (last visited Oct. 2, 2019).

[47] Itron, *2016-2017 Self-Generation Incentive Program Impact Evaluation* (Sept. 28, 2018), https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/2016-2017_Self-Generation_Incentive_Program_Impact_Evaluation.pdf.

[A]: Net Load

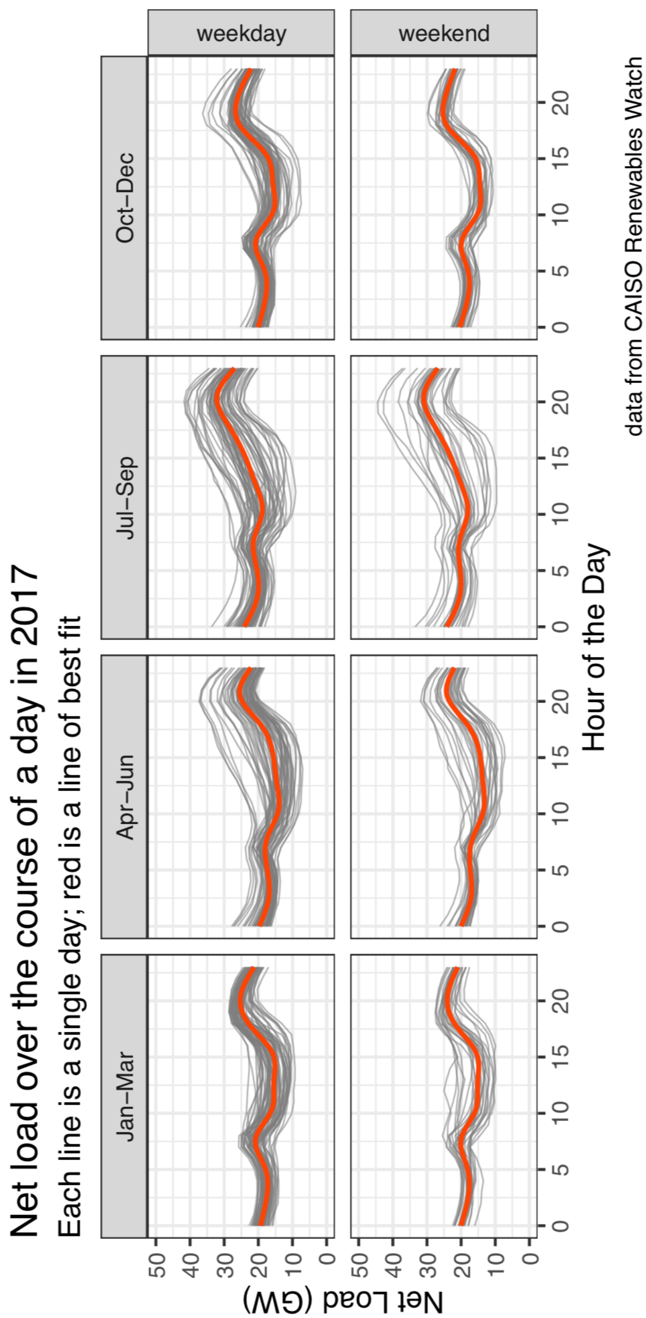

Figure 11[A]: Operations data, estimates from 2017.

[B]: Energy Market Prices

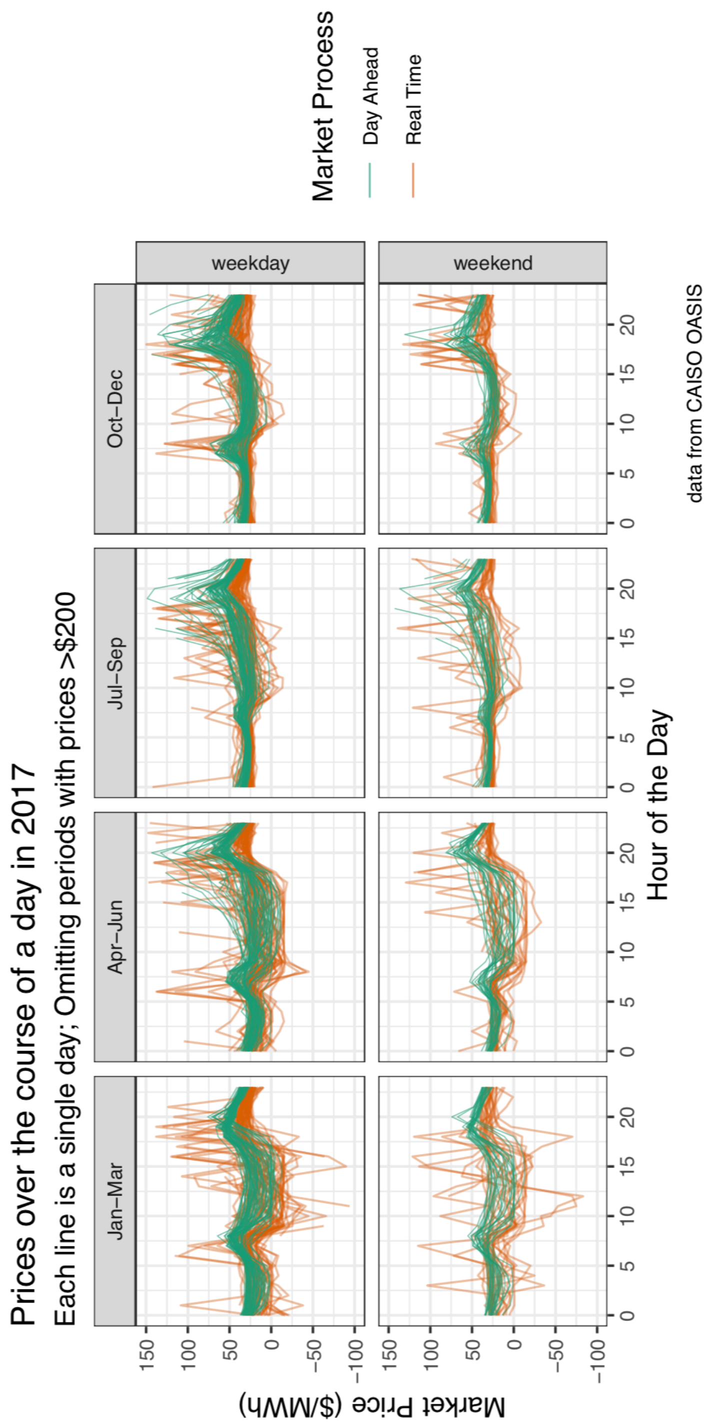

Figure 11[B]: Operations data, estimates from 2017.

[C]: Estimated Marginal Emissions

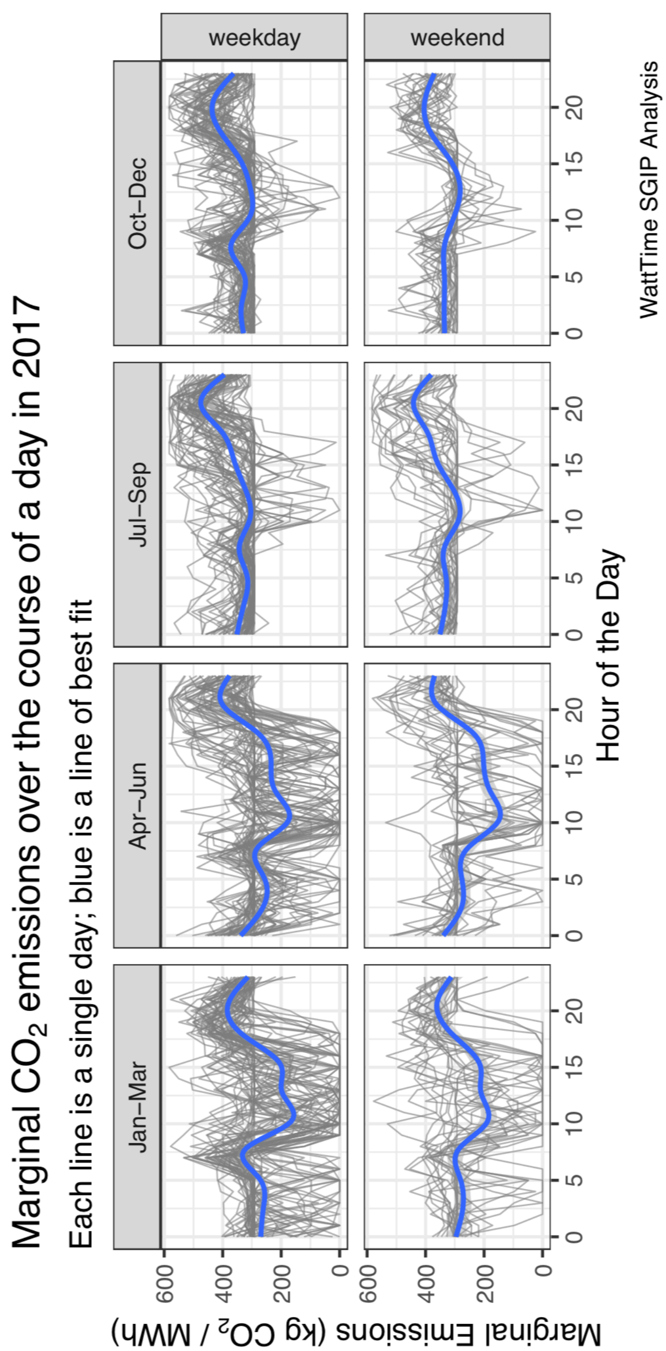

Figure 11[C]: Marginal CO_2 estimates from 2017.

The approach we took was to establish the expected load impacts (reduction and increase) due to shifting a range of concepts that were under discussion as part of the Load Shift Working Group in 2018, which were distilled to six concepts for distinct deployment pathways with different combinations of market frameworks and dispatch methods. These are summarized in Table 3. The concepts are broadly defined in two categories:[48]

1) Load modifying: Flexible loads modify the timing of demand to optimize based on prices, emissions, or other priorities. The concepts described by the LSWG included a range of priority targets and various approaches to communicate these and support customer response.
2) Market integrated: Dispatchable loads are controlled through integration with the energy market, coordinating bids and dispatch through the CAISO. This proposed concept is more narrowly defined, based on the "Proxy Demand Resource – Load modifying resource" market integration model that was launched in 2018 by CAISO for behind-the-meter storage, simulating flexible loads that could respond to the same signals and result in the same net load effects as battery storage.

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[48] CAL. PUB. UTIL. COMM'N, *supra* note 7, at 1-20.

Table 3: Summary of the six concepts for Shift presented in the LSWG final report.[49]

Name *Type*	Description
Load Shift Resource 2.0 (LSR2.0) *Market Integrated*	An expanded scope version of the CAISO "Proxy Demand Resource – load shift resource" (PDR-LSR) that includes flexible loads along with behind-the-meter storage. Loads are dispatched by the system operator to increase during times with negative pricing on the CAISO market.
Critical Consumption Period (CCP) *Load Modifying*	A retail load increase framework where incremental load increases are requested by load-serving entities (utilities) during times of curtailment, and customers choose to respond or not. The concept is designed for large customers who can significantly increase load when instructed.
Market Informed Demand Automation Service (MIDAS) *Load Modifying*	Establish a price or emissions signal that is published through an application programming interface (API), enabling connected devices and systems to respond.
Pay for Load Shape (P4LS) *Load Modifying*	Target load shapes are defined, and end-use control is oriented towards achieving those targets. The target could be based on expected prices, emissions, or curtailment at either the system or local scale and can be updated daily, weekly, monthly, etc.
Market Integrated Distribution Service (MINTDS) *Load Modifying*	This framework is similar to the LSR 2.0 concept but would include a distribution system layer as a primary focus. Loads are dispatched to minimize the impacts on the distribution system first, and any remaining Shift capabilities are dispatched through LSR 2.0.
Distribution Load Shape *Load Modifying*	This framework is similar to the P4LS, with a focus on defining load shapes that are primarily responsive to distribution system constraints and also to system-level needs.

[49] *Id.* at 7-16.

For both categories, the specifics of how load impacts were defined and applied is described in more detail below. For any particular pathway, the load impact time series includes both load increase ("take") and decrease ("shed") periods. These load impact time series are then multiplied by the hourly price and emissions data in each hour and summed to develop an estimate of the operational changes for each:

- The change in overall emissions based on emissions arbitrage / net effect of load changes on the operation of the marginal units.
- The change in costs to procure energy on the real time market, a price arbitrage analysis.

We also estimate two additional features from the load impacts that are helpful for describing the value to the power system:

- The quantity of curtailment avoided (based on the sum total increased load during times with negative prices and capped at the reported total curtailed energy in each hour). This is useful for communicating the fraction of curtailment that might be avoided by particular strategies.
- The change in annual peak net load (based simply on the difference in the maximums). This is an additional potential pathway to value for flexible loads since reduced annual peak demand leads to a reduced cost for peak capacity. Grid operators in California (and many other regions) make payments to generators for these services that represent a significant annual cost.

Because of the context of this study and simplifying assumptions, it is important to keep the following in mind when interpreting these results and considering their applicability for other places and time periods:

- The **California ISO footprint is a special case** with positive correlation between prices, net load, and emissions. Note in Figure 11 how the typical daily shape of loads, prices, and emissions estimates are similar. This makes it "easy" to choose a target to prioritize compared to places with negatively correlated features. For example, at times when coal generators are the marginal unit, there are typically lower prices but higher emissions compared to gas, which may be the marginal unit at other times of day. This dynamic exists in regions with significant remaining coal fleets, like the midwestern United States.50 Since California does not have significant coal

[50] Duncan S. Callaway et al., *Location, Location, Location: The Variable Value of Renewable Energy and Demand-Side Efficiency Resources,* 5 J. ASS'N ENVTL. RESOURCE ECONOMISTS 39, 39-75 (2018), https://www.journals.uchicago.edu/doi/pdfplus/10.1086/694179.

generation, the tradeoffs are typically between gas and zero-carbon generators.

- **As more renewables are added, the opportunity for avoiding curtailment grows.** We described these trends previously. One can take our 2017 results as a conservative case since the value of and opportunity to Shift continues to grow.
- **This analysis is designed to be a first-order view** into the range of emissions and grid impacts that are plausible from load shifting. The goal is not to estimate the magnitude precisely for each resulting metric but to understand the likely "direction" of change related to shift and the order of magnitude of the opportunity. Other approaches using more detailed analytic techniques would be appropriate for estimating the magnitude more precisely currently and for future scenarios.51 Three sources of error we are aware of related to our approach are: 1) We did not account for elasticity in prices or marginal emissions in this analysis. By omitting this, we expect that these first-order estimates are biased towards higher apparent gains from price and emissions arbitrage. 2) We did not account for spillover gains or losses to other participants in the market from improved price stability and changes in the operation of the energy and ancillary services markets. 3) We did not complete a statistical analysis of the annual peak capacity, instead we simply reported the maximum. These tradeoffs are made in exchange for simplicity and understandability of our results by stakeholders and policymakers and reflect the priorities of the forum we developed them for.

C. GHG Impacts from Load Shift

We modeled **Load Modifying DR** load impacts using an approach that roughly simulates the behavior of flexible loads operating in response to signals like prices and estimated emissions. The general algorithm we defined is described below:

1) Identify a "target" signal that the loads are responding to; this signal provides information about when to consume more or less energy and is an hourly time series. The options we include are day-ahead energy market prices, real-time prices, estimated marginal CO2 emissions, and the systemwide netload.

[51] These could include using techniques described by researchers who estimate marginal emissions with dispatch models and statistical learning methods. *See e.g.*, Kyle Siler-Evans et al., *Marginal Emissions Factors for the U.S. Electricity System,* 46 ENVTL. SCI. TECH. 4742, 4742-48 (2012); *see also* Callaway et al., *supra* note 16, at 39-75.

2) Find the average value of the target for each hour of the day including all of the days over a specified "averaging period." The averaging periods we included were daily, weekly, monthly, and over three-month periods. For the daily period, there is no averaging. Just the raw target signal is passed through. For the weekly period, the average of the target signal is calculated for each hour of the day (8 AM, 9 AM, etc.) based on the whole week. A similar approach is used for longer averaging periods.
3) Take the "inverse" of the averaged target load shape (multiply each value by negative one). This is the same as "flipping over" the time series. Finally, rescale this inverted time series so that on each day, the sum total of the time series is one. This way, the rescaled time series represents the fraction of the flexible demand that should be consumed in each hour of the day if a load is responding to the target signal.
4) Adjust the system demand so that it is reduced by approximately 1% in each hour (the portion that is "flexible") and reallocate the sum total of this flexible demand using the rescaled target load shapes from the previous step.
5) Compare the baseline (unadjusted) system load to the adjusted system load to estimate the impacts from shifting.

The net effect of this algorithm is that approximately 1% of the system demand is defined as "flexible" and is dispatched *as if it were optimized* according to a price, emissions, or net load signal that is updated with varied frequency. Figure 12 shows a set of these target load shapes for the three-month averaging period. Note that because of correlation between loads, prices, and emissions, the targets are broadly similar.

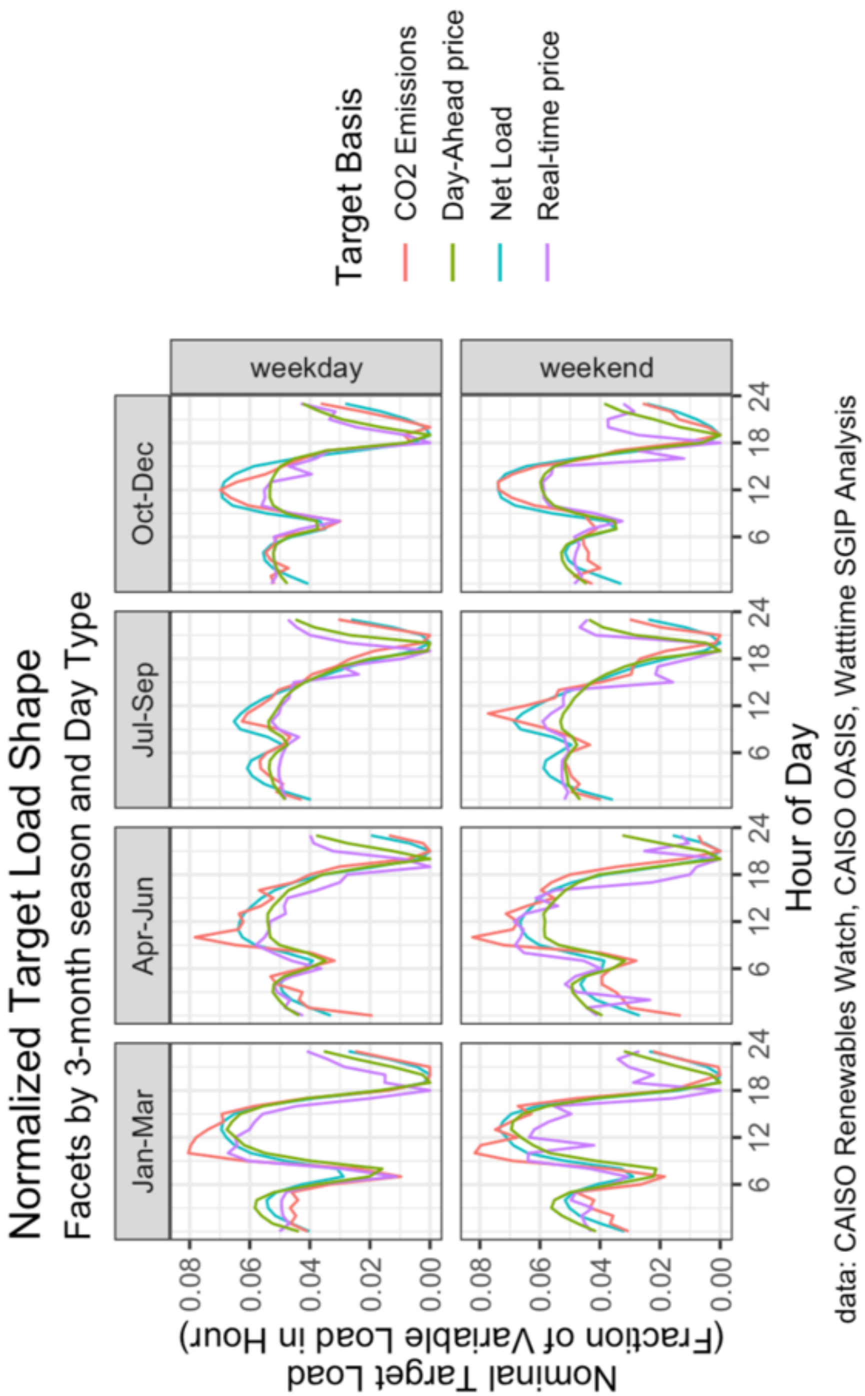

Figure 12: An illustration of the target load shape for flexible loads based on the algorithm we use in this analysis. The targets are differentiated by color, and these represent 3-month averaging periods.

The outcome for this analysis of load modifying DR impacts is summarized in Figure 13. Overall, most of the options that were considered were broadly similar. This makes sense among the target types given the correlation in California between loads, prices, and emissions. Significant reductions in CO2 were apparent for all options, both operationally and through reduced curtailment. With 1% of load shifted in 2017, around 120–150 GWh of curtailment would be avoided (approximately 50% of overall curtailment). The typical CO2 savings per shifted megawatt-hour were 0.12–0.15 t/MWh, which is about half of the typical emissions from a natural gas power plant. This implies that these "shifted quantities" of energy tended to reduce the emissions of that energy service by about half.

Because the concept of load modifying DR involves daily activity, there are spillover gains in terms of the peak load reduction on the power system. Based on the way we constructed assumptions in the analysis (including the illustrative assertion that 1% of load is flexible), we expect 1.5–2 GW lower annual peak loads, which is approximately 3%–4% of the overall CAISO peak. This represents a significant level of performance and is on the same order of magnitude as current-day existing DR programs. We emphasize that this outcome (and others related to magnitude) is not a predictive estimate and is illustrative based on the assumptions.

The implied savings in the energy market based on this analysis is relatively modest, about $80-100 million annually in 2017. It is important to keep in mind, however, that the opportunity for savings could grow with the growth in curtailment hours in the future.

There was only modest benefit apparent from frequent vs. infrequent updates of the target signal. The three-month average signal achieves a significant fraction of the overall value available from more frequently updated signals. Two outliers that contravene this trend are the daily updated responses to real-time price and CO2. In these cases, the targeted daily updates provided enough information to improve the performance of energy market savings (for real-time price) by a factor of 2x–3x and improve the performance with respect to emissions (for the CO2 target) by a factor of +30%.

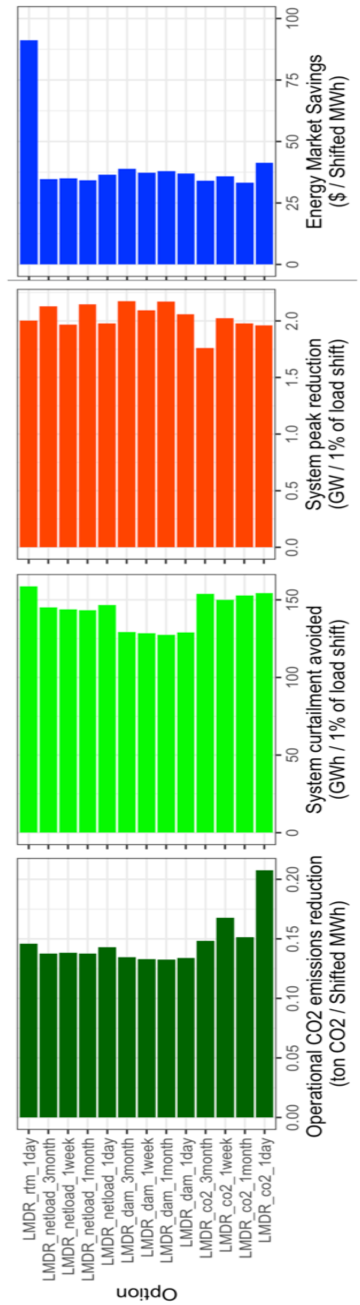

Figure 13: Results of load shifting for various load modifying DR options. Each option is coded as "LMDR" for load modifying DR, followed by the target signal type ("rtm" for real-time prices, "dam" for day-ahead prices, "netload" for the systemwide net load, and "co2" for estimated marginal CO2 emissions) and a label indicating the averaging period used. The four plots show the estimated grid impacts for various metrics.

1. Market Integrated DR. – The approach we took for modeling **Market Integrated** DR was different from the Load Modifying approach described above. For this category, we attempted to mimic the kinds of load impacts one might expect for flexible loads that are dispatched by a central grid operator. The basis for this is the CAISO "Proxy Demand Response – Load Shift Resource" that was developed and deployed in 2018. For this energy market mechanism, a behind-the-meter storage asset is able to place bids to consume energy (which looks like turning down a generator to the energy market). These bids will always be negative (i.e., the battery will be paid to charge when energy market prices are negative). The concept of our modeling extends this framework to loads that could "take" more (increase demand) in these times when there are negative prices.

The way we modeled these kinds of flexible loads participating in the energy market was as follows:

1) We start by defining the total capacity of flexible loads in terms of power: how many gigawatts of load are available to "take" during times of need. We modeled three of these "bid quantities:" 500 mW, 1 GW, and 2 GW.
2) During hours when there is curtailment, the total "take" quantity is defined as the maximum of the available flexible load and the total curtailment quantity. In this way, we limit the total load increase to be less than or equal to the total curtailment.
3) The total load that was increased during the curtailment hours is added up. We assume that some fraction of this energy that was served during curtailment times can lead to reduced demand in other hours (a load "shed"). This shed is allocated throughout all of the non-curtailment hours in proportion to the systemwide net load. We modeled three different fractions of shed: 0%, 50%, and 100% of energy neutrality. What it means to have 0% shed is that, even if there are times when loads are increased to capture curtailment, there is no decrease in load at all during other times of day. A 100% energy neutral shed means that for every kilowatt-hour that is increased, there is a decreased kilowatt-hour at another time of day.

The results of this illustrative modeling exercise are shown in Figure 14 below. This plot shows the case of 100% energy neutral behavior of loads. It is notable that, because most of the curtailment events are in the first six months of the year, those months are the times with the vast majority of the events.

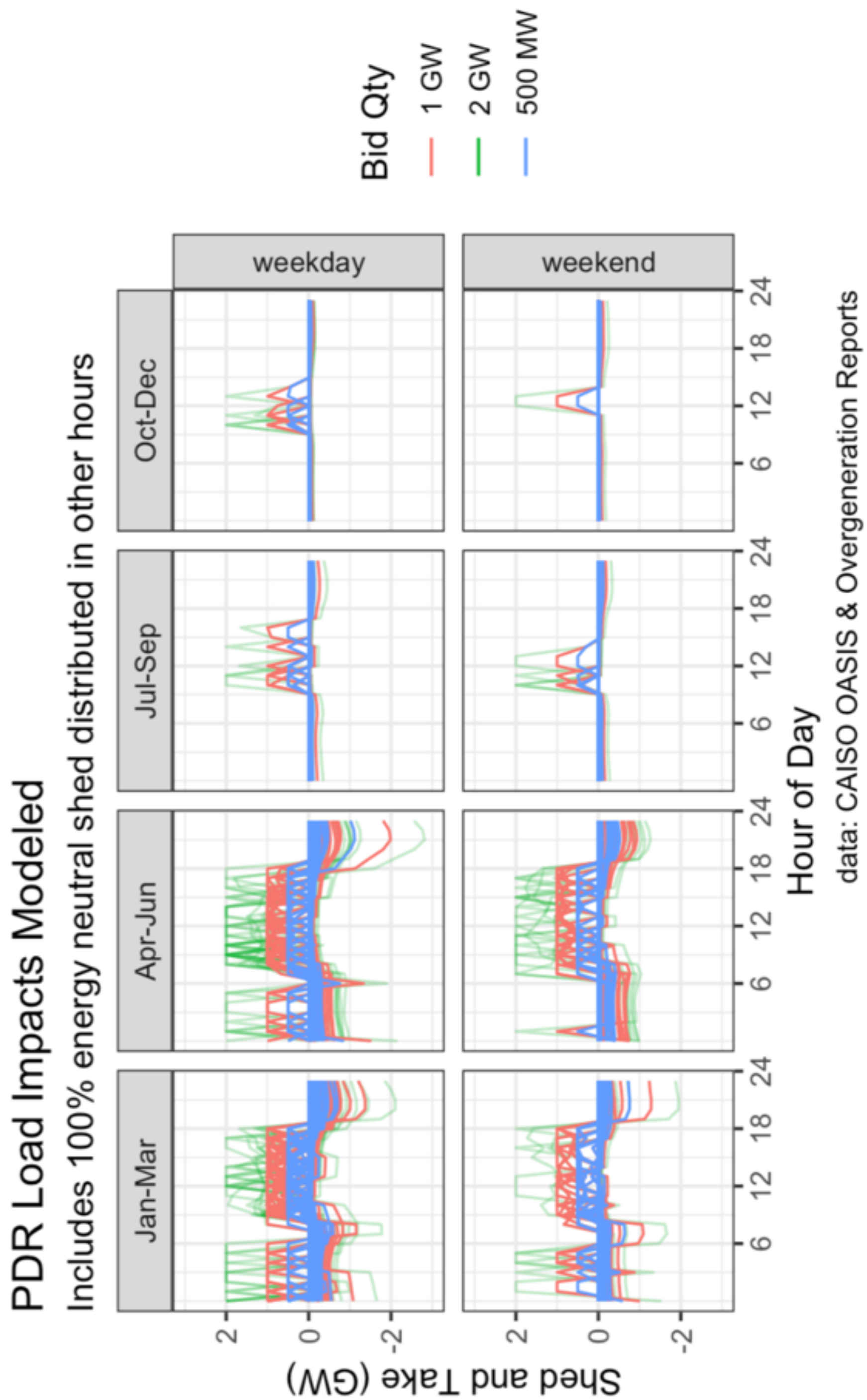

Figure 14: Illustrations of the load impacts from market integrated DR. Each line on the plot is an individual day of activity, for various bid quantities.

The outcomes of the load impacts for these scenarios are shown in Figure 15 and summarized here:

- The level of curtailment using market integrated PDR was significantly reduced. Even with a 500 MW flexible load, nearly half of the 2017 curtailment would be reduced. There were diminishing returns to more load bid into the market given 2017 dynamics. About 50%–70% of the curtailment in 2017 could have been avoided with 500 MW–2 GW of dispatchable PDR.
- The operational CO2 reductions depend on also having some fraction of load shed in non-take periods since it is possible to have some non-zero marginal emissions in a period with negative pricing. This meant that in the cases where there was no "shed" on the other side of the load increase, the overall CO2 emissions were increased. In real operational contexts, one would expect this to be a rare and unlikely outcome since many flexible loads achieve their flexibility by changing the scheduling of processes or demand.
- The energy market cost savings are modest, only $5–$20 million annually in 2017. On the basis of the gains per shifted megawatt-hour, the highest unit gains went to lower bid quantities, on the order of $40/MWh. These are modest arbitrage opportunities.
- It is not shown in the plots, but the total quantity of load shifted in market integrated PDR is about one-tenth that of the LMDR options modeled. This is because PDR is a more "targeted instrument" to reduce curtailment only in hours when it is happening versus load modifying DR that is more durable and persistent.
- Based on the assumptions of our modeling, there were no reductions in the peak load on the system from this form of market integrated DR since there happened to not be any curtailment of renewable energy on the annual peak load day in 2017.

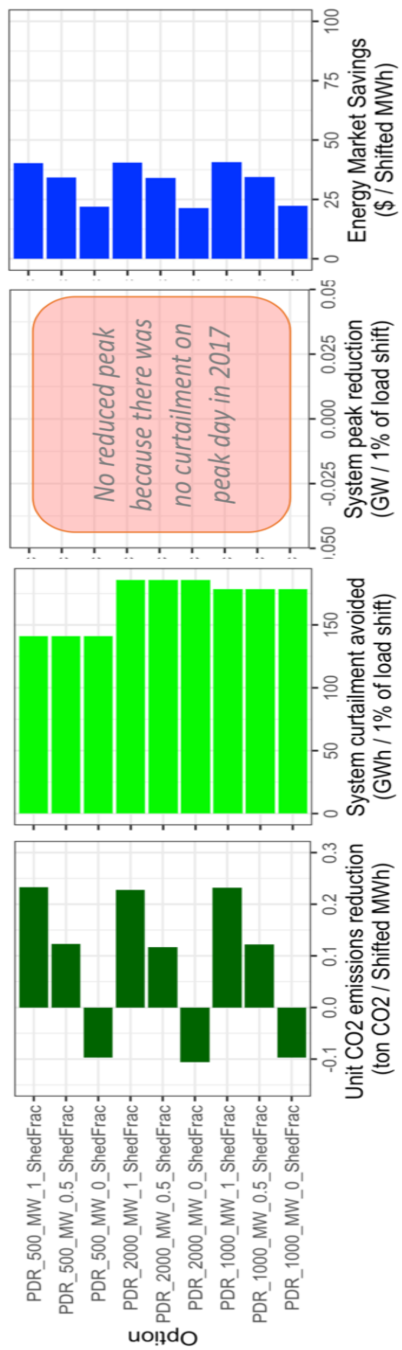

Figure 15: Results from load impacts of modeled DR for market integrated options. The various scenarios include 500, 1000, and 2000 MW bid quantities and 0%, 50%, and 100% "Shed Fractions" that define the level of energy neutrality. The bars for these scenarios are labeled accordingly on the left.

IV. PATHWAYS FOR FUTURE DR SUPPORTING RENEWABLES ON THE GRID

Over the next decade, the pace of change in the needs of the power system and opportunities for cost-effective deployment of resources in response will only accelerate as non-linear and threshold effects begin binding on the system with increasing renewables towards 100% deployment that is consistent with climate stabilization. There is a vital need for public policy to get ahead of the system changes for the value we identified in our study to be captured–up to $1 billion annually across the categories of DR. It is important to recognize that electricity regulation and policy emerged in the context of relatively slow, decade-scale changes in the capabilities and characteristics of the technology that compose the power system. The multi-year processes in place for planning rates and investment in the system were in sync with the conventional dynamics, but the emergence of renewables and DER is based on technology, like solar PV, battery storage, and ICT, that can experience orders of magnitude in advancement over the course of decadal planning cycles. Below we describe the implications from our study and others like it and propose a set of features of policy and technology deployment that are consistent with capturing cost-effective DER deployment in the face of renewables integration challenges and responsive to a rapidly changing future power system.

A. Matching the Capabilities of Flexible Loads with Grid Needs

One of the core findings of this work was that the new needs for flexibility on the grid are more diverse than traditional load shedding DR. The core value of peak load reduction DR is related to a reduced need for firm capacity of generators to carry the annual or seasonal peak loads. The consequence if these resources do not show up is a blackout, so there is a justifiable focus on ensuring the load shed resources are firm and predictable. In contrast, the need for shifting load is tied to more "soft" constraints related to making the best economic use of renewable generators. If a flexible load does not show up to capture curtailed renewable energy on a particular day, there is no blackout or other binding operational problem. The benefits of avoiding curtailment are cumulative, not acute. The other types of DR services we included in the study were load shaping with rates (which achieves many of the same goals as shed and shift) and fast-response shimmy services. These shimmy services are similar to load shed in having firm requirements tied to the security and stability of the power system.

Taken together, these diverse needs for firm (shed and shimmy) and soft (shift) services to the grid suggest that there may be an opportunity to "right-size" the information technology and controls to match the required certainty of service. For firm DR, the traditional approach of revenuegrade metering and real-time telemetry is likely to continue being appropriate for ensuring the value of load flexibility is accurately understood. For shift, a less costly approach may be able to achieve all or many of the system benefits without the need for costly IT systems. The load modifying options we modeled could mostly be thought of in this "soft path" category. Emphasizing the ability to take a coarser approach to control, our findings related to the sensitivity of the update period for load modifying DR showed that following the average price over a month or three months was about the same as responding to the day-ahead price.

B. Electrification of New Loads

Our study focused on existing loads, but there could be significant new opportunities to deploy shift-able (and shed-able/shimmy-able) loads as new appliances and machines are deployed to replace fossil fuel combustion. Electric water heating, space heating, and vehicles are all forecast to play large parts in the future decarbonization of the grid in California and elsewhere; this new build of loads that all have some inherent flexibility represents an opportunity to ensure that they are built and shipped from the factory with the appropriate communication and control systems to match well with the future power system. It will be much less costly to build in these controls rather than undergo complex retrofits later. This suggests a policy and need to understand these opportunities and consider regulation of these appliances and systems to meet standard protocols.

C. Where and When Matters for Energy Demand

The location and timing of loads matter greatly in a grid powered by significant renewable resources, which was supported by the findings in our study. We found that Shed resources are valuable in specific locations where local constraints are binding and that Shifts should occur based on day-to-day variability of the net load that depends on the weather (and associations with the available solar and wind generation). While this suggests a complex approach, there are two factors that help to simplify the execution. First is the predictability of the solar resource. The timing of sunrise and sunset seasonal weather are reliably predictable, and the average required response could be achieved with forward-looking TOU rates that have price ratios and periods that are designed to match the average load with the system conditions as well as possible. The second factor that could simplify response is the rapid pace of advancement in ICT, automation, and control technology. With ubiquitous connectivity, device-level control, and advanced optimization of load scheduling, it will not be necessary for most customers to engage with day-to-day variations in the conditions on the grid; instead, the authority can be delegated to control systems that act on their behalf to optimize the operation of controllable loads and systems.

D. A New Compact with Customers

California's success in deploying renewable electricity systems has flipped the challenges in grid management, and there is a need to raise public awareness of the new dynamics. For decades, the public message about the timing of demand (and the focus of TOU rates) was rightfully focused on reducing loads in summer afternoons, when high air conditioning demand drove annual peak conditions. Customers were encouraged to use more electricity at night and in the early morning and responded appropriately. There were policy and technology initiatives as well; for example, there was support for ice storage systems that make ice at night and draw on the reservoir of "cold" in the daytime for cooling. With the deployment of solar generation over the last five years, the needs have flipped. There is now a growing need to consume *more* electricity in mid-day periods on sunny days, and the net load peak that matters for managing capacity has migrated into the early evening hours. Reforms to TOU periods to align with these new needs have lagged the condition on the power system, and the multi-year process for updating TOU rates is likely to continue to lag behind conditions once new rates are deployed.

If dynamic Shift, Shed, and Shimmy are to be fully realized with day-to-day dispatch, there will need to be a fundamentally new compact between electricity suppliers and users who participate in DR programs. The conventional understanding and message that prices are relatively constant and the use of loads is disconnected from the conditions on the grid, with only occasional need for action (load shedding), will be replaced with a relationship of coordination for these customers. The delegation of authority to schedule and control loads from customers to automated systems will be critical for reducing the transaction costs of response that would otherwise prevent participation from many customers, but this requires a degree of trust in the systems that are put in place. Cybersecurity, institutional responsibility for DR aggregators, and the perception of risk and benefits to customers will all be important factors as the DR market changes.

E. The Battery Cost Wild Card

Behind the meter storage can, in principle, make any load demand responsive across the dimensions of Shed, Shift, and Shimmy with appropriate control. In our study, the forecasted cost of batteries dedicated to DR was sufficiently high that they were just at the boundary of economic cost-effectiveness. However, as distributed batteries are deployed to serve multiple value streams, including managing site-level bills (essentially serving as a "Shape" resource), increasing the reliability and resilience for critical loads, and serving the needs of the distribution system, there may be opportunities to reduce the effective cost of providing DR through multi-use applications. Furthermore, our assumptions about the costs and scale of batteries are highly uncertain, and, if batteries get cheaper faster than our forecast, they could outcompete and significantly grow the DR resource we identify, particularly for Shift, but also for Shed and Shimmy. Given the historical trend of "conservative" forecasts that underestimate the improvements in clean energy technology[52] and emerging evidence that battery costs and performance are improving more quickly than conventional forecasts on a trajectory towards $100/kWh.[53] At these low price points, assuming an average 5 year battery lifetime, the levelized cost of Shift from batteries could be $20/kWh-year, providing Shift (and other DR services) at a lower cost than most of the projections we made for load control. Since batteries scale across sites and can be installed in large capacity at substations, the levelized cost of storage will serve as a kind of price reference ceiling for DER in the future (similar to the concept of a capacity price referent tied to the construction of a new combined cycle natural gas plant). Load control and new generation capacity alike will need to beat the cost of storage to compete.

F. Integrating EE and DR

In our study, we treated potential "co-benefits" from implementing EE and DR together as a reduction in the expected cost of implementing a DR project since the benefits from EE can help to defray a portion of the initial investment in equipment and controls setup that dominate the cost of many DR resources. Based on our findings, the savings result in a growth in DR potential of 5%–200%, depending on the scenario and DR category. The low end of the range is Shift DR, where there is a large resource that is already cost-effective for DR-only implementation and the additional savings from EE do not significantly increase the resource. The high end is for Shimmy applications, where there are particular benefits to a portfolio approach. Our project confirms there is a compelling case for integrating EE and DR to achieve cost savings in implementation, but in practice, there are significant challenges related to administrative and implementation

[52] Alexander Q. Gilbert & Benjamin K. Sovacool, *Looking the Wrong Way: Bias, Renewable Electricity, and Energy Modeling in the United States*, 94 ENERGY, 533, 535 (2016).

[53] Kittner et al., *supra* note 12.

requirements to jointly executed projects.[54] What could integrated EE and DR look like?

One way that EE and DR fit together is considering EE as a core tool for shaping hourly loads. In a sense, any EE investment that operates at peak times is equivalent to a persistent DR Shed. This is also known as time-sensitive valuation.[55] EE that is focused on loads that operate in the morning or evening can reduce the ramps that are one of the key values for Shift. Two key technology areas where new demand responsive loads could be enabled are electrified transportation and heating systems; in these cases, better EE of the equipment will reduce the pressure on distribution system upgrades and increase the need for generation–in synergy with the goals of DR.

Beyond load shaping, there could be significant benefits to DR and EE in integrating deployment where there are opportunities to leverage fixed costs of a project (like engineering, controls hardware, monitoring and evaluation, metering, etc.) to serve both needs. This effectively reduces the cost of DR, as was the framing in our study, but could similarly be framed as EE costs being reduced through capturing benefits and revenue from DR market and program participation. In the California context, the most recent EE potential study estimated that behavioral, retro-commissioning, and operational EE has a market potential of 600–1000 GWh/year by 2030, or 20%–30% of the EE resource.[56] The associated controls upgrades required for these approaches to EE could be used for DR as well in many cases.

CONCLUSION

This paper has described new analytic techniques to support decisions by utilities, regulators, and enterprises developing and deploying new DER. Our emphasis is on the role of flexible loads at high levels of renewables integration. Some of the key insights and results are summarized below.

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[54] Jon Starr et al., *Effective Integration of Demand Response and Energy Efficiency in Commercial Buildings* 1 (2014), https://pdfs.semanticscholar.org/c608/3c9e9738c155e9e53cf7001cff7b6805e5c7.pdf; Charles Goldman et al., *Coordination of Energy Efficiency and Demand Response: A Resource of the National Action Plan for Energy Efficiency* 3-2 (2010), https://www.epa.gov/sites/production/files/2015-08/documents/ee_and_dr.pdf.

[55] Peter Alstone et al., *2025 California Demand Response Potential Study - Charting California's Demand Response Future: Final Report on Phase 2 Results*, LAWRENCE BERKELEY NAT'L LAB. (2017), http://eta-publications.lbl.gov/sites/default/files/lbnl-2001113.pdf.

[56] Navigant Consulting, Inc., *Energy Efficiency Potential and Goals Study for 2018 and Beyond* (Jan. 19, 2018), ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/DAWG/2018_PotentialGoalsStudy_Errata_011918.pdf.

- Based on the modeling assumptions developed through our work in 2015-2017 for the *2025 California Demand Response Potential Study*[57], there is a range of potential flexible loads that could meet various grid needs, including most notably an ongoing need for Shed and an emerging need for Shift. To manage peak loads, we identified a potential to Shed 2-5 GW out of a ~50 GW annual peak load for the CAISO operational area, or 4-10% of the peak. With the emergence of significant solar energy deployment in California there is an opportunity to shift timing and use generation potential that would otherwise be curtailed due to system operational constraints; we estimated Shift potential of 10-20 GWh/day, or 2-5% of the total energy demand.
- Understanding and modeling the interaction between DER and grid operations and investment is a significant challenge, as is communicating the results of the analysis. The simplified framework for DR we developed helped facilitate and accelerate conversations in contexts ranging from stakeholder meetings to modeling team discussions, and shows potential to serve a role in facilitating integration between DR and other DER.
- Integrating EE and DR is important for reducing the costs of deployment for both and understanding the interactions between the two types of demand-side management systems.
- Policy interventions should be crafted with the pathway to create clear value for DR resources and ensure consideration of the certainty required from resources. Shed has value based on long-run avoided capacity through infrequent dispatch, Shift resources derive value from repeated and frequent dispatch that results in operational savings and avoided curtailment of low-cost renewables, and Shimmy from providing grid balancing service that frees other resources to serve higher value needs. This suggests that it is appropriate to ensure that Shed and Shimmy resources are highly reliable given their role in system reliability, but the day-to-day precision of dispatch could be less important for Shift.
- The cost and performance of electric battery storage is a critical factor for determining the cost-effectiveness of load control and serves as a price referent.
- A core challenge is to create business model pathways for DR aggregators serving multiple applications (including broader EE, distributed storage, and PV) to reduce the fatigue and transaction costs to customers for unlocking the potential from integrated DER deployment. The relationship between customers, aggregators, load-

[57] Alstone, *supra* note 4.

serving entities (LSEs), and the system operator needs careful design to align incentives and value streams for DER.

- A core value from Shifts of load is from avoiding curtailment of renewable energy and reducing the overall emissions of the power system. Our analysis of emerging patterns of curtailment in California, combined with estimates of the marginal emissions, indicates that relatively slow-changing (weekly or monthly) signals to flexible loads can result in significant reductions in the carbon intensity of electricity generated to serve those loads (on the order of a 50% reduction in the carbon intensity compared to serving inflexible loads). More frequent updates can reduce emissions further, but at a cost in complexity and higher transaction costs. A portfolio of approaches could be considered that matches loads with "slower" flexibility (like scheduling some industrial or agricultural processes) to more persistent schedules and loads with "faster" flexibility (like water heaters) to dynamic signals. As policymakers develop frameworks to integrate flexible loads, these tradeoffs and portfolio opportunities should be considered.