Title

2025 California Demand Response Potential Study - Charting California's Demand Response Future: Final Report on Phase 2 Results

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Publication Date
2017-03-01

Peer reviewed

BERKELEY LAB

LBNL-2001113

Lawrence Berkeley National Laboratory

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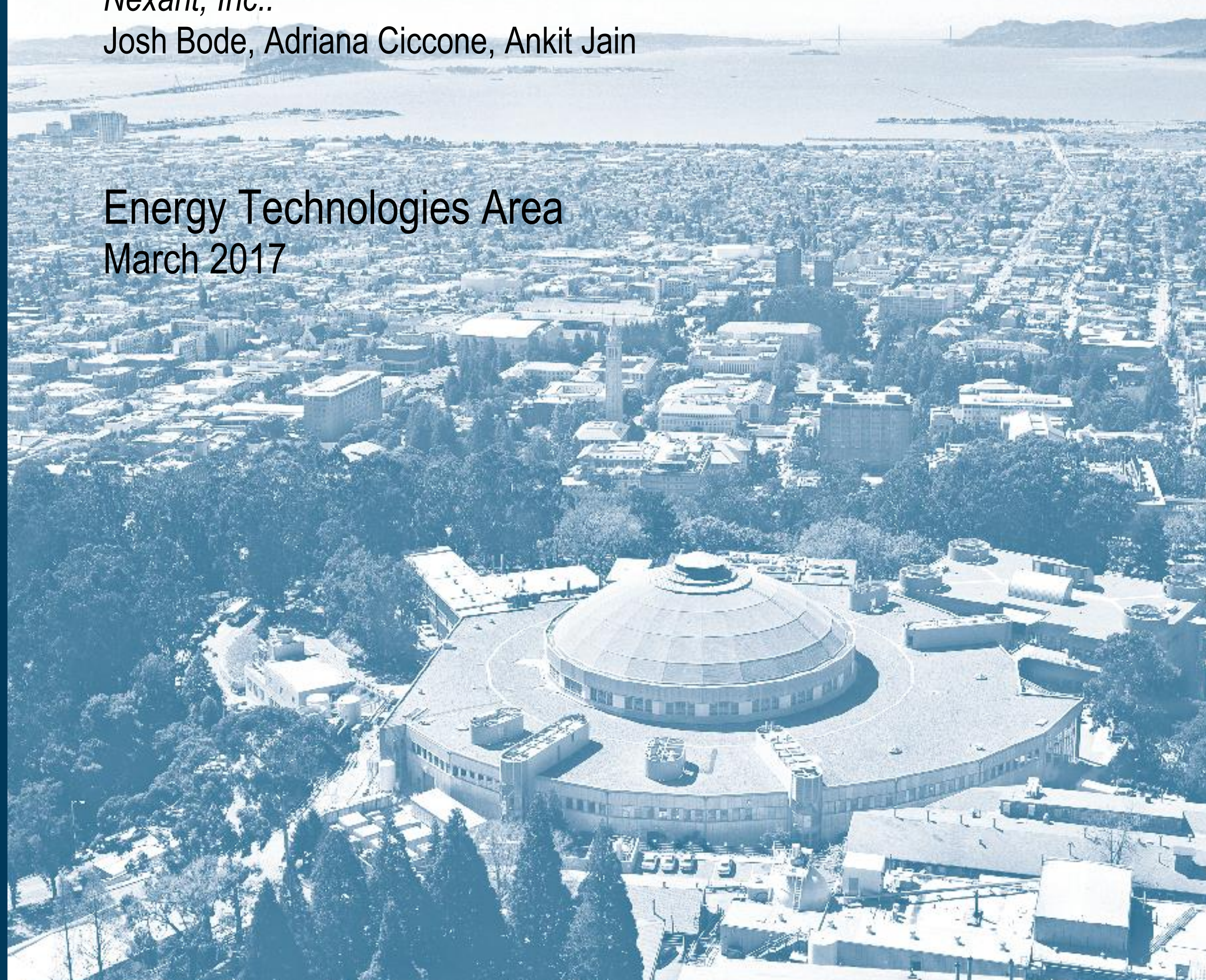

Energy Technologies Area
March 2017

Disclaimer

Acknowledgments

This work was supported by the Assistant Secretary for Energy Efficiency and Renewable Energy, Building Technologies Office of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The work described in this report was funded by the California Institute for Energy and Environment, which is funded by the California Public Utilities Commission (CPUC) under CPUC Contract No. 13IA5025 UC-CIEE Subaward No. POCP04-L01.

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November 10, 2016

The imminent risks of climate change demand rapid decarbonization of the power sector. California has energetically embraced this imperative, targeting emission reductions of 40% below 1990 levels by 2030.This study from the Lawrence Berkeley National Laboratory (LBNL) begins to reveal the role of demand response in reaching that goal.

Aspects of how this study was done and what it tells us deserve emphasis. The study begins with a ground breaking data set. Leveraging California's advanced metering infrastructure, electricity usage data from over 200,000 smart meters has been mined and organized into clusters representative of California's electricity customers. This vivid characterization reveals the contours and nuances of how electricity is consumed by members of a highly diverse population, a step which is critical to any effort attempting to change how that consumption occurs for the better.

Building on this foundation LBNL has embraced the challenge of our rapidly evolving technological landscape. The study models traditional tools of demand response, such as industrial pumps, HVAC and lighting, while also pushing ahead into electric vehicles, batteries, and data centers. The result is a broad suite of possible responsive technologies and systems, the operation of which may be altered at strategic times to the advantage of the customer and public.

Adding to its breakthroughs in characterizing customers and technologies, the study provides another big step forward in framing its results. LBNL replaces a traditional monolithic concept of demand response with a more nuanced alternative: shape, shift, shed, and shimmy – four flavors of demand response, each with a unique character complementing the needs of the grid.

Each of these innovations in how the study was done make it possible to better understand demand response's potential and future value. The most prominent conclusion of the study is that traditional demand response – that which reduces hot summer peak demand – may be of limited value in the future, a conclusion, which is equally true for generators of a similar operating profile. In its place, the study finds a need to shift customer usage patterns to complement abundant day-time solar generation. Similarly, the study finds that demand response is not of equal value in all places, but rather of greater value in targeted locations. These conclusions deserve careful consideration and, where reasonable, action.

This study's results give me confidence in the trajectory of California's demand response policies, while reminding us there is work to be done yet. The California Public Utilities Commission has already taken critical steps, including:

- investing in the integration of demand response into wholesale markets where it can be dispatched consistent with locational marginal prices;

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- enabling a new generation of demand response aggregators capable of delivering tailored options that work for customers with unique needs,
- committing to default time of use rates for all customers by 2019; and
- committing to greater differentiation of incentives based on relative locational value.

Each of these steps will do as the study suggests: increase the targeting of demand response to times and locations of greater value and thereby serving grid needs. However, it is not enough to be merely on the right trajectory; considerable follow through and attention to detail will be required. It is my hope that this rich study will support that ongoing effort and that our cause will be sustained.

I applaud the Lawrence Berkeley National Lab's research team for the first rate work, as well as the many contributors on which they relied. It's my pleasure to commend their work with compliments to all stakeholders with an interest in understanding and helping realize the full potential of demand response.

Michel P. Florio
Commissioner
California Public Utilities Commission

DISCLAIMER

ACKNOWLEDGEMENTS

This work was supported by the Assistant Secretary for Energy Efficiency and Renewable Energy, Building Technologies Office, of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The work described in this report was funded by the California Institute for Energy and Environment, which is funded by the California Public Utilities Commission (CPUC) under CPUC Contract No. 13IA5025 UC-CIEE Subaward No. POCP04-L01.

We would like to thank the individuals listed below who provided guidance, assistance, and critical review of the project. We appreciate their substantial contributions to this work, and note that inclusion on the lists of individuals and organizations below does not necessarily signify an endorsement of the study results on their behalf. Any errors and omissions in the study are our own.

Thank you to the following CPUC staff for their contributions to this study:

CPUC Energy Division, Demand Response Customer Generation, and Retail Rates
Simon Baker, Jean Lamming, Nathan Barcic, Bruce Kaneshiro, Robert Levin, Rachel McMahon, Joy Morgenstern, Maryam Mozafari

CPUC Office of Ratepayer Advocates (ORA)
Sudheer Gokhale

CPUC Office of the Commissioners
Matthew Tisdale

Thank you to the following individuals at Lawrence Berkeley National Laboratory (LBNL) and the University of California for technical assistance and project administration:

California Institute for Energy and Environment (CIEE), University of California
Carl Blumstein, Terry Surles, Ken Krich, Eric Lee

Energy Institute at Haas, Haas School of Business, University of California at Berkeley
Andrew G. Campbell

LBNL Building Technology and Urban Systems Division
Norman Bourassa, Jessica Granderson

LBNL Energy Analysis and Environmental Impacts Division
Charles Goldman, Pete Cappers, Joe Eto, Kristina LaCommare, David Lorenzetti, Andy Satchwell

LBNL Energy Storage and Distributed Resource Division
Douglas Black, Jonathan Coignard, Jason McDonald, Janie Page, Sam Saxena, Michael Stadler, Rongxin Yin

Thank you to the following additional individuals in external and partner organizations who provided input, review, and guidance to the project:

Brattle Group
Ahmad Faruqui, Ryan Hledik

CLECA
Barbara Barkovich

EDF

Jamie Fine

EnerNoc
Mona Tierney-Lloyd

Johnson Controls
Vish Ganti

Navigant Consulting
Debyani Ghosh, Greg Wikler

PG&E
Gil Wong, Neda Oreizy

SCE
Mark Martinez, Frank Harris

SLAC National Accelerator Laboratory
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Slice Energy
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David Posner, CPISF
Jill Powers, CAISO
Heather Sanders, SCE
Nora Sheriff, CLECA
Mike Ting, Itron
Leslie Willoughby, Sempra Utilities
Greg Wikler, Navigant
Gil Wong, PG&E

List of Abbreviations

AAEE	Additional achievable energy efficiency
AMI	Advanced metering infrastructure
AS	Ancillary services
BAA	Balancing authority area
BAU	Business-as-usual
BEV	Battery electric vehicle
BTM	Behind-the-meter
CAISO	California Independent System Operator
CBECS	Commercial Buildings Energy Consumption Survey
CEC	California Energy Commission
CEUS	Commercial End-Use Survey
CPP	Critical peak pricing
CPUC	California Public Utilities Commission
C&I	Commercial and Industrial
DER	Distributed Energy Resource
DLC	Direct load control
DOE	U.S. Department of Energy
DR	Demand response
DRAM	Demand response auction mechanism
DRP	Distributed resource planning
DRRC	Demand Response Research Center
DSM	Demand-side management
EE	Energy efficiency
EIA	Energy Information Administration
EUI	Energy use intensity
EV	Electric vehicle
GW	Gigawatt
HVAC	Heating, ventilation and air-conditioning
IDSM	Integrated demand-side management
IOU	Investor-owned utility
ISO	Independent system operator
IT	Information technology
JASC	Joint Agency Steering Committee
kW	Kilowatt
kWh	Kilowatt-hour
kW-yr	Kilowatt-year
LAP	Load aggregation point
LBNL	Lawrence Berkeley National Laboratory
LED	Light-emitting diode
LLNL	Lawrence Livermore National Laboratory
LMP	Locational marginal price
LSE	Load-serving entity
LTPP	Long-term procurement plan
MECS	Manufacturing Energy Consumption Survey

MW	Megawatt
NAICS	North American Industry Classification System
NEM	Net energy metering
NERC	North American Electric Reliability Corporation
NOAA	National Oceanographic and Atmospheric Administration
O&M	Operations and maintenance
OIR	Order instituting rulemaking
OpenADR	Open automated demand response
PAC	Program administrator cost
PDR	Proxy demand resource
PCM	Production cost modeler
PDR	Proxy demand resource
PG&E	Pacific Gas and Electric Company
PHEV	Plug-in hybrid vehicle
PV	Photovoltaic
R&D	Research and development
RA	Resource adequacy
RASS	Residential Appliance Saturation Survey
RDRR	reliability demand response resource
RECS	Residential Energy Consumption Survey
RPS	Renewable portfolio standard
SCADA	Supervisory control and data acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMART T-Stats	Smart communicating thermostat
SONGS	San Onofre Nuclear Generating Station
Sub-LAP	Sub-load aggregation point
TAG	Technical Advisory Group
T&D	Transmission and distribution
TOU	Time-of-use
TPP	Transmission planning process
TRC	Total resource cost

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1. Executive Summary

California's legislative and regulatory goals for renewable energy are changing the power grid's dynamics. Increased variable generation resource penetration connected to the bulk power system, as well as, distributed energy resources (DERs) connected to the distribution system affect the grid's reliable operation over many different time scales (e.g., days to hours to minutes to seconds). As the state continues this transition, it will require careful planning to ensure resources with the right characteristics are available to meet changing grid management needs.

Demand response (DR) has the potential to provide important resources for keeping the electricity grid stable and efficient, to defer upgrades to generation, transmission and distribution systems, and to deliver customer economic benefits. **This study estimates the potential size and cost of future DR resources for California's three investor-owned utilities** (IOUs): Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

Our goal is to provide data-driven insights as the California Public Utilities Commission (CPUC) evaluates how to enhance DR's role in meeting California's resource planning needs and operational requirements. We address two fundamental questions:

1. What cost-competitive DR service types will meet California's future grid needs as it moves towards clean energy and advanced infrastructure?
2. What is the size and cost of the expected resource base for the DR service types?

Demand response operates across a range of timescales from transient responses in seconds to long-run shifts in daily behavior, and the value created by DR depends on the timescale of the response. This dynamic necessitated a new framework for potential study analysis, and we developed a supply curve modeling framework to express the availability of system-level grid services from distributed resources, based on large samples of Smart Meter Load Shapes. To facilitate comparisons between the cost and value created from having a diverse set of flexible loads, we created a new DR services taxonomy and an analytic framework that groups these services into four core categories: **Shape**, **Shift**, **Shed** and **Shimmy**.

- **Shape** captures DR that reshapes customer load profiles through price response or on behavioral campaigns—"load-modifying DR"—with advance notice of months to days.

- **Shift** represents DR that encourages the movement of energy consumption from times of high demand to times of day when there is a surplus of renewable generation. Shift could smooth net load ramps associated with daily patterns of solar energy generation.
- **Shed** describes loads that can be curtailed to provide peak capacity and support the system in emergency or contingency events—at the statewide level, in local areas of high load, and on the distribution system, with a range in dispatch advance notice times.
- **Shimmy** involves using loads to dynamically adjust demand on the system to alleviate short-run ramps and disturbances at timescales ranging from seconds up to an hour.

1.1. Study Background

The CPUC Energy Division funded this study to support DR policymaking, concurrent with rulemaking R.013-09-011. Based on the current policymaking process needs, we estimated how DR could provide grid services in 2020 and 2025, across a range of scenarios for DR market and technology options. This report summarizes our results after the second of two project phases.

- In Phase 1, we studied peak shedding (conventional) DR that qualifies for system and local resource adequacy capacity credit and compared DR costs with avoided cost estimates for conventional generation, transmission, and distribution.
- In Phase 2, we broadened our study to cover more advanced technology to enable fast-response DR and help meet California's future capacity, energy, and ancillary services.

This study focuses on system-level services (i.e., services that meet transmission system level needs and could be organized by the California Independent System Operator (CAISO)) to help inform the DR "bifurcation" process. Bifurcation is an organizing concept for advancing DR policy. It refers to integrating some resources into the CAISO markets for direct dispatch to meet system needs ("supply" DR) with other resources that are controlled or dispatched outside the market ("load-modifying" DR).

1.2. Approach

The analytical framework developed for this study forecasts levelized cost supply and demand curves for the years 2020 and 2025, and for four defined DR services types: Shape, Shift, Shed, and Shimmy. The analysis employs a bottom-up, customer end-use load forecasting model with tight integration between weather, loads and renewable generation patterns (constituting net load). These are in turn, combined with a detailed DR cost database to express DR supply curves for each grid service, showing how much DR is expected to be available across a range of costs.

There are three primary methods we use to assess DR opportunities for an expected near-future grid:

- **LBNL-Load** examines IOU-provided load data and demographics (~11 million customers) and groups them into cohorts, or "clusters," based on the similarity of their demographic and load. LBNL-Load examines hourly load data (from ~220,000 customers) to define characteristic load profiles for the clusters, as total load and by end uses. LBNL-Load forecasts loads for the years 2020 and 2025 according to the 2015 Integrated Energy Policy Report.
- **DR-Path** generates a range of DR pathways based on the load forecasts from LBNL-Load. These pathways represent likely futures, given technology adoption, DR participation, and cost projections for existing and emerging technologies. The DR-Path tool can be used to develop annual supply curves to estimate the available DR in a given case.
- The **Renewable Energy Solutions** (RESOLVE) model is used to estimate a set of value benchmarks for each type of DR to the system based on the avoided cost of investment and operation when DR is available for use. RESOLVE is a power system investment and operations model that uses optimization to minimize costs while meeting planning and operational requirements, including renewable generation targets and resource adequacy constraints among others. The cases modeled in RESOLVE are run separately from LBNL-Load and DR-PATH, reflecting the different purpose and architecture of the model and enabling our integrated economic analysis. In RESOLVE a range of DR availability scenarios were run to estimate the value of DR for reducing the overall cost of the power system for two benchmark cases describing the level of expected renewable energy curtailment: low and high.

The DR-Path results/output are supply curves that express the available quantity of particular DR resources across a range of possible costs. We use two methods to express DR costs—both shown in Figure 1:

- **The Price Referent Approach:** This is the cost of procuring an alternative resource that could meet the same needs as the DR service (e.g., a natural gas combustion turbine that could carry peak load instead of peak Shed DR). If you assume that these resources will need to be procured one way or another, the price referent effectively sets a DR cost ceiling for procurement.
- **The System Levelized Value Approach:** This compares supply with some estimated "levelized value" to the grid across a range of possible DR services. The levelized value could be thought of as load demand curves. The intersection of a supply curve and levelized value demand curve could represent a procurement target or expected market outcome if the incentives were aligned completely, linking DR aggregators with value streams from the service.

Both approaches provide DR "cost-effectiveness" estimates—meaning the DR resource procurement where the costs are outweighed by benefits. We refer to the results as "cost-effective DR," but our results should not be taken as a literal application of the "cost-effectiveness protocols" used by the CPUC to assess utility programs. The DR cost estimates include the total gross cost of the resource. We adjust these to simulate revenue opportunities available to DR aggregators or customers: revenue from ISO markets, site-level co-benefits from investment in control technology, and payments from service to the distribution system operator.

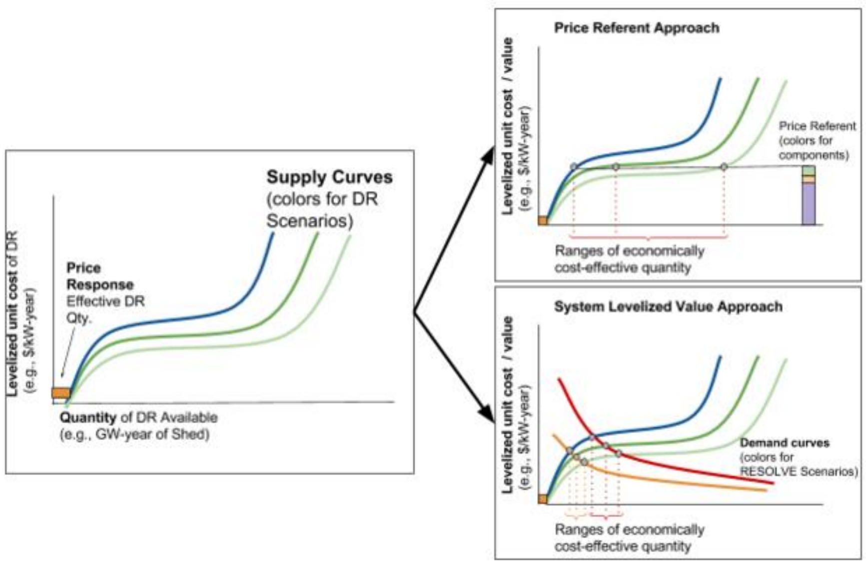

Figure 1: Illustrative diagram showing two approaches for DR economic valuation used in this study: Price Referent and System Levelized Value.

1.3. DR Services to the Grid

We find that there are many opportunities for flexible loads to provide value to the operation of a renewable powered electricity system.

The **Shape** resource provided by Time of Use (TOU) and Critical Peak Pricing (CPP) can be modeled as both Shed and Shift DR service types since price signals can reduce load during peak hours, as well as shift load to off-peak hours. In this study, we assessed three TOU/CPP rate scenarios in addition to a flat rate scenario as a counterfactual baseline. Our Shape analysis is based on a model developed by Nexant to estimate of how retail pricing structure is expected to change load, based on empirical data from pilots and past performance. We model three of many possible mixes of TOU/CPP rate adoption (Rate Mix #1, #2 and #3), which are described in more detail in the main report. In Figure 2 below, the x-axis indicates total GW of Shed DR provided by various TOU/CPP rate mixes. Shape-as-Shed DR resource is calculated by taking the price response load impacts from the top 250 hours. In summary: For the Residential sector, all of the Rate Mixes have a default conventional TOU rate and ability for customers to opt-out to a flat rate. We integrate the expected load impacts from each Rate Mix and translate them into magnitudes of effective Shed and Shift service. Shape-as-Shed service is estimated by treating reshaped loads as if they were dispatched to meet system needs, and finding the equivalent quantity of load Shed.

The results from the Shape-as-Shed analysis show a total effective Shed for each of the three options at approximately 1 GW. Rate Mix #1 and Rate Mix #3 have no CPP for residential customers (but are included for non-residential) and different mixes of TOU rates (#1 includes “super off-peak” rates). Rate Mix #2 has a TOU mix similar to Rate Mix #3 but also includes a residential opt-in CPP option. The Shape-as-Shift DR potential is approximately 1.8 gigawatt-hours (GWh) per day for 2025, indicating that significant load can be shifted throughout the day with price signals from retail rates. The average total daily load in 2025 is 600–700 GWh, so the Shape-Shift resource represents approximately 0.3 percent of load shifted.

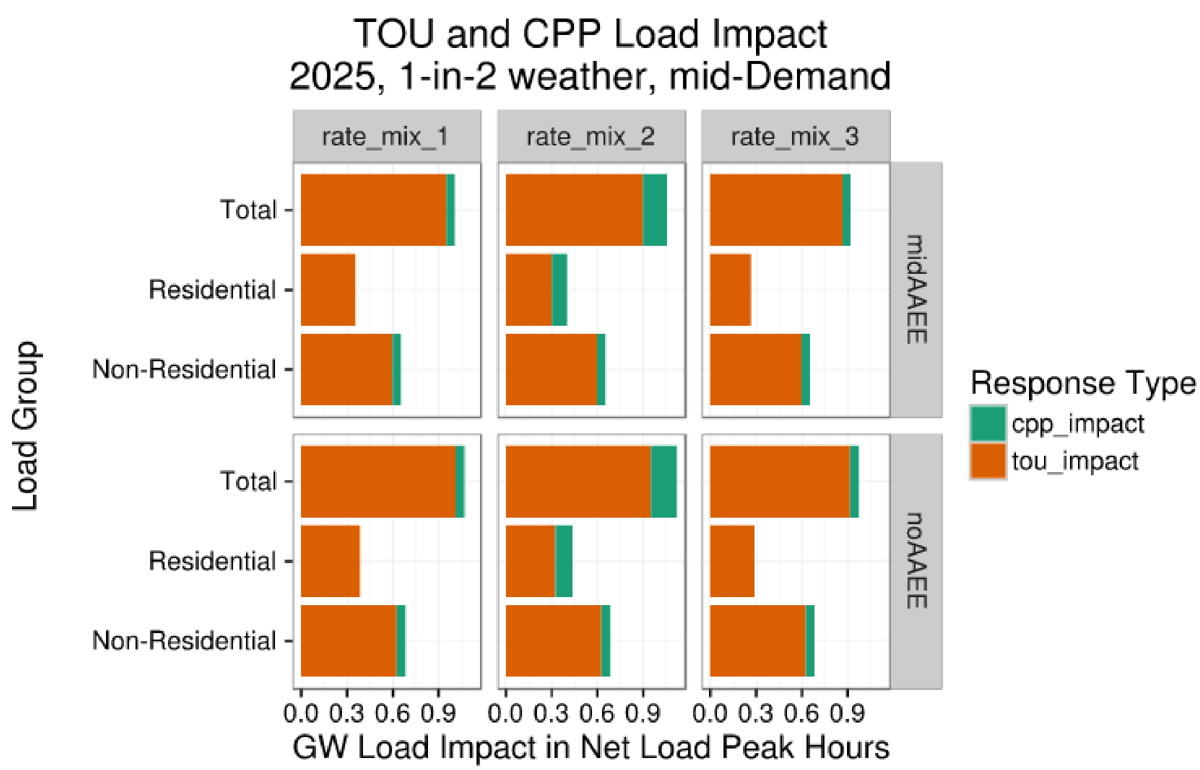

Figure 2: Shape-as-Shed resource for 2025 under 3 rate mixes under the 2 energy efficiency (EE) scenarios: no AAEE and mid-AAEE.

We modeled Shift-type DR resources that consume load and shed load during a 24-hour period, remain energy neutral, and are based on end-uses that can move energy consumption from one hour to a different hour. Shift-capable loads have significant potential to reduce overgeneration during hours of high renewable generation and avoid the need for some multi-hour ramping.

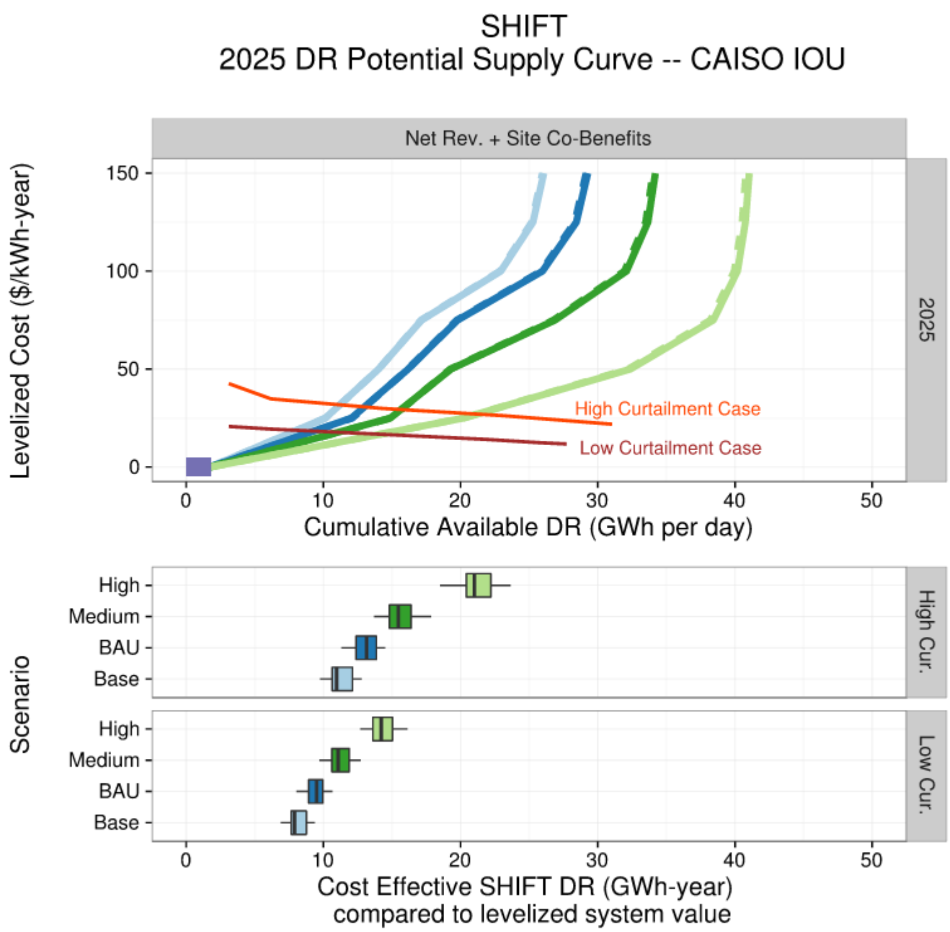

Figure 3: (top) Shift DR supply curve compared to demand curve, and (bottom) range of cost-effective quantity from Monte Carlo analysis.

Figure 3 shows the breakdown of the Shift DR potential in 2025 at the $50 price ceiling, disaggregated by utility service territory and end use. Colors (**top**) and bars (**bottom**) represent DR market scenarios. Dotted lines are 1-in-2 weather and solid are 1-in-10 weather. Low- (**RED**) and High-Curtailment case (**ORANGE**) horizontal lines are demand curves. Equilibrium price is the intersection of demand curves and supply curves. Industrial loads provide approximately 4 GWh-year in PG&E, and nearly 5 GWh-year in SCE, with agricultural pumping providing 1.7 GWh-year and 0.5 GWh-year in PG&E and SCE, respectively. Commercial HVAC is another large contributor, with more than 5 GWh-year between the three IOUs.

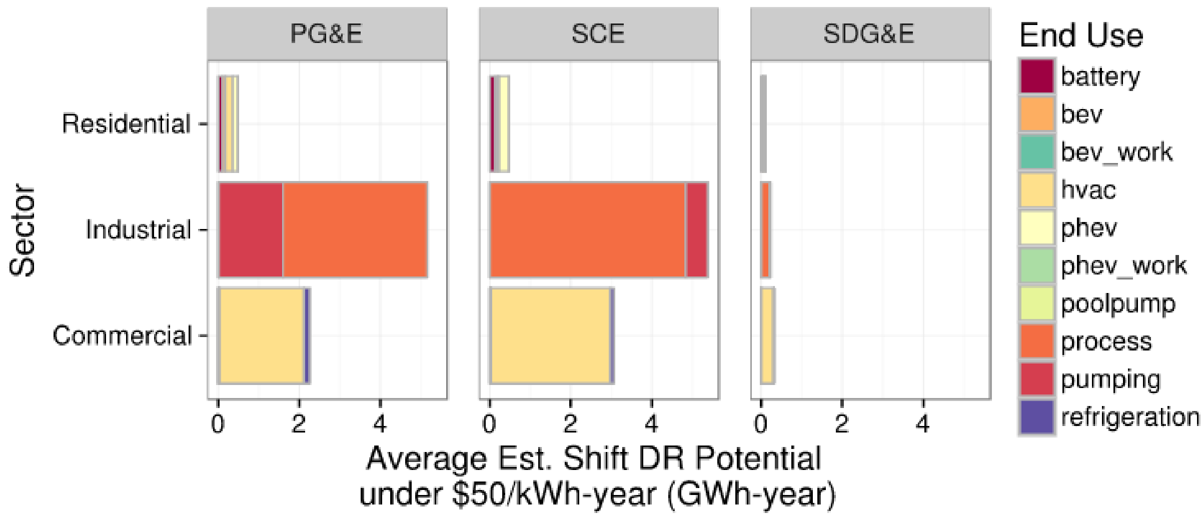

Figure 4: 2025 Shift DR potential by IOU service territory and end-use contributions under $50/kWh-year, mid-AAEE, 1-in-2 weather year, medium scenario.

ISO market integration challenges: Resources that shift load into high-curtailment hours can offer significant capital investment and operational cost savings by reducing renewable overgeneration, but there are significant market and regulatory challenges for capturing this value through centralized dispatchable markets. These include challenges establishing a baseline for frequently-dispatched resources like Shift, organizing and coordinating resources for discrete dispatch, ensuring CAISO market software reflects the capabilities and operating constraints of resources and identifying mechanisms to compensate resources for avoided flexible generation procurement that may not be reflected in energy market prices.

Shift and Price-based Dispatch: Energy market prices are an indicator of what Shift patterns are most valuable—increasing demand when there is s surplus in renewable power (at zero marginal cost) and reducing loads in the early morning and evening when prices are high, and it would be appropriate to also explore how *Shift*-type resources can be handled directly in the retail market through pricing programs paired with automatically responsive DR controls. The retail price framework for organizing shift could accomplish the same fundamental dynamics as wholesale market integration but with much more transparent and simple “dispatch” –simply connecting consumption of electricity by particular loads to the forecasted locational marginal price. Automated retail price response would avoid some transactions costs related to scheduling coordinators, eliminate issues related to estimating counterfactual baselines, and eliminate constraints introduced by ISO market dispatch integration. A retail-based Shift pathway would also come with its own challenges around incentivizing investment in control technology and customer adoption, compared to the wholesale market case where DR aggregators have strong incentives to understand how to best target technology investment at customer sites.

Regardless of whether **Shifts** are dispatched directly through wholesale markets or indirectly through predictable and/or automated price response, there is a significant potential to provide value to the grid if DR technology and systems are installed and available for response. The current stock of conventional DR technology is fast enough to respond to the necessary signals and may be candidates for parallel use or low-cost upgrades compared to new DR sites with updates to control routines and settings. Current work on integrating control technology in the energy code should adapt to ensure that Shift capabilities are achieved along with conventional Shed.

Conventional **Shed** DR is procured and dispatched to decrease system-wide load during peak day events, designed to offset the need for operating peaking power plants, reduce pressure to invest in conventional generation to carry the peak load and respond to contingency events. The dynamics of the system needs, however, are quickly changing with respect to peak capacity planning.

Under a "conventional system peak DR" price referent cost-effectiveness framework, our findings suggest that Shed DR resources could provide ~4.2 GW of RA credit capacity in 2025 under the 1-in-2 weather, mid-AAEE, Rate Mix #3 scenario utilizing the price referent of $200/kW-yr. Even more would be possible if site level co-benefits are captured, which is shown in Figure 5**.** Colors lines (**top**) and bars (**bottom**) are DR market scenarios. Dotted lines represent 1-in-2 weather, and solid are 1-in-10 weather. $200 price referent is generation (**PURPLE**), transmission (**ORANGE**), and distribution (**GREEN**). The Shape-shed DR results are additive and provide an additional 1 GW of reduction (labeled "TOU/CPP"), for a total of 5.2 GW.

A second economic assessment methodology, a system levelized value approach using RESOLVE to generate system *demand* curves, results in different conclusions about the economically cost-effective amount of **Shed** DR –essentially suggesting that there is close to zero value created related to avoiding investment in the generation fleet. The outcome is the result of rapid deployment of renewable generation before significant retirement in the thermal generation fleet. Combined with significant energy efficiency investments that modify the system load curve, the expectation is that there will typically be sufficient generation available during net load peak times to meet system-wide demand, and therefore no opportunity for accounting for value from avoided investment in new capacity, (i.e. the avoided cost of a CT generation plant).

There are still significant opportunities for Shed DR to provide value to the grid that are not explicitly modeled in RESOLVE. First is local capacity. While there is a surplus on the system level, the local availability of generation is still a binding planning constraint in some transmission-constrained areas. The Los Angeles Basin, San Diego, and Ventura County all currently experience local capacity constraints that must be met either with costly local generators (with attendant emissions in densely populated areas), fixed energy storage, or demand response and other IDSM approaches. A conventional price referent may be appropriate for estimating the local capacity resource value, or a more in-depth geographic analysis of DR potential and the cost of alternatives. About half of the statewide Shed resource (2–7 GW depending on the scenario) is located in these currently constrained areas. Second, fast **Shed** resources have the ability to meet the needs of the distribution system and avoid investment and maintenance. Finally, there may be a role for DR to respond to contingency events that are not avoided through normal resource adequacy planning processes, preventing or limiting the extent of blackout. These “Emergency DR” services have highly uncertain potential due to uncertainty in both the effectiveness of DR for mitigating cascading failure events and the value of avoided blackouts.

For 2025, we modeled significant renewable capacity contributing to the system's supply. The RESOLVE model indicates slightly more economic opportunities for the utilization of conventional DR, namely meeting ramping needs. As customer-sited solar becomes a larger contributor to mid-day electricity supply, other generators must be ramped down to prevent curtailment. However, the sun goes down as the evening demand peak sets in, creating a need to rapidly ramp-up non-solar generators back to meet evening load. In the absence of DR, this need is met in the RESOLVE cases by a combination of increased California gas dispatch, higher imports, and energy storage discharge. When Shed DR is available, it is frequently dispatched by RESOLVE during these steep evening ramps. However, the low value for Shed resources even in 2025 and 2030 suggests that RESOLVE does not find significant value for Shed resources in reducing renewable curtailment due to alleviating upward ramping constraints in the 2016 - 2030 timeframe. Rather, the value that Shed DR provides in dispatch is related to fuel savings from reduced gas dispatch. This value is relatively small, even during the peak periods.

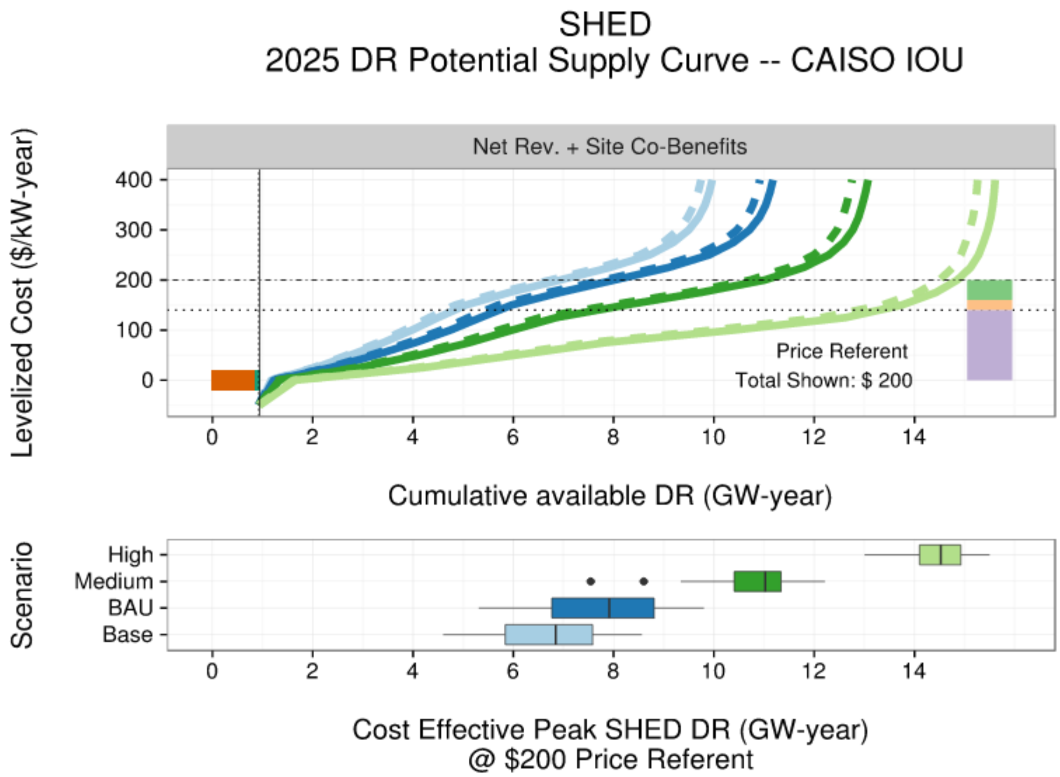

Figure 5: (top) Shed DR supply curve compared to conventional $200/kW-yr price referent, and (bottom) range of cost-effective DR based on Monte Carlo analysis of DR market and technology.

Shed DR technology is diverse and quickly evolving as more end-uses become enabled with control technologies. We provide the 2025 Shed DR results broken out by utility, sector, and end use. In PG&E approximately 1.5 GW of the 3 GW of Shed potential comes from the industrial sector, while ~800 MW comes from commercial and ~600 MW from residential sectors. SCE's potential is driven equally by commercial and industrial, with approximately 1.25 GW from each sector, and another 0.4 GW from the residential sector. In SDG&E, commercial sector lighting and HVAC are key end uses that provide the majority of the available Shed DR.

The **Shimmy** service type is fast DR that operates on a seconds-to-minutes ("regulation") and minutes-to-hours ("load following") timescale that has high value for managing short-term fluctuations in the net load.

We estimated that Shimmy resources have the potential to provide value to the CAISO system over the 2016–2030 timeframe. We found a total of $21 million in benefits for 600 MW of load following in 2025, and $22.5 million in benefits for 600 MW of regulation in 2025. Just as the savings offered by Shift resources decline as the system becomes saturated with available Shift resource, the savings per megawatt of Shimmy fall as we add more Shimmy resources. We also found that 600 MW is close to the market depth for regulation, whereas the market for load following is deeper. Results from the RESOLVE model suggest a core value of Shimmy resources to grid operation in the future could derive from freeing battery storage to prioritize soaking up cheap renewable power instead of managing short-run variability—essentially freeing the batteries to provide additional Shift resource.

Our results indicate that **Shimmy** load following resources are cost competitive for ~350 MW at about $50/kW-yr. **Shimmy** regulation DR is shown to be cost-competitive up to approximately $85/kW-year in the medium scenario, resulting in a DR potential of ~450 MW across all three IOUs. As more DR is added, it becomes less valuable, resulting in a cost-competitive DR potential of 300 MW up to approximately $75/kW-year in the high scenario.

Shimmy resources have the potential to provide significant but bounded value to the CAISO system over the 2016–2030 timeframe—significant in having a relatively high value per kilowatt per year but bounded by the fact that the size of need (and markets for ancillary services) are finite and based on the short-term variability on the electricity system. The value of advanced DR will increase over time, as the CAISO system integrates additional renewables and curtailment becomes more significant during the midday hours.

The CAISO has been working to establish rules and transaction requirements to enable DR to more readily participate in ancillary services (AS) markets, but this has been unrealized. However, the current market prices for AS, in particular, regulation up and regulation down, are depressed, and currently, may not reflect future pricing trends for products participating in these markets in 2020 or 2025.

1.4. Transitioning from conventional to advanced DR

For years, the greatest need to the electricity grid was managing peak demand; however, with the more use of renewable generation and mandates to meet even higher RPS of 50 percent, the challenges of the grid have shifted away from peak capacity shortfalls, thus drastically reducing the need for Shed-type resources for serving the CAISO balancing authority over the coming decade and beyond. This suggests that the focus on system Sheds should be redirected to focus on local and distribution system needs and that the control technology and business relationships in place could be the foundation of new portfolios that combine targeted and/or fast Shed with Shift. Achieving these transitions will likely require the following:

- Integration between policy at the CPUC and CAISO to ensure that market designs are matched with the most cost-effective pathways for DR services.
- Continued work on how integrated energy efficiency (EE), behind-the-meter storage and DR can lead to value across a range of categories—integrated demand-side management.
- Continued work to integrate value streams at the system scale, on the distribution system, and at the site level—distributed resource planning (DRP). We did not undertake

a detailed study on site-level electric bill impact or explicit distribution system service modeling dynamics but did include a set of first-order estimates for the scale of benefits in these areas that are likely achievable when DR technology provides multi-scale service. Given the co-benefits for site-level service, the result is an increase of about **4 GW of additional Shed DR** capacity compared to a model run without co-benefits.

2. Introduction

Demand response is an important resource for keeping the electricity grid stable and efficient; deferring upgrades to generation, transmission and distribution systems; and providing other customer economic benefits. The CPUC in looking to meet California's rapidly evolving resource planning and electricity grid operational needs is evaluating how to *significantly enhance DR's role*. Although California has extensive experience with certain forms of DR, new and different DR resources will be required for the grid's evolving needs - ones that are more flexible and able to respond faster than their historical counterparts.

The CPUC recently bifurcated the investor-owned utility DR program portfolio into two categories: (1) load-modifying resources, which reshape or reduce the net load curve; and (2) supply resources, which are integrated into the CAISO energy markets (CPUC Decision D.14-03-026). The definitions and operational requirements for each will have important implications for whether feasible DR options can participate and provide value across a range of grid services. The CPUC's decision provides a general framework for the future of DR in California.

Our study used advanced metering, customer demographics, technology and other data to estimate how DR can cost-effectively meet the needs of California's changing electric grid. This report details how DR can meet the system and local peak capacity needs that drive California's resource adequacy (RA) requirements and how advanced technology can enable fast-response DR and help meet California's need for future capacity and ancillary services.

The geographic scope of our study was the service areas of the three major California IOUs: Pacific Gas and Electric Company, Southern California Edison and San Diego Gas & Electric. We worked with staff from each organization to obtain customer electric load data to support this work. A broad stakeholder group contributed technical expertise to inform our study. This technical advisory group (TAG) includes representatives from the utilities, DR aggregators, regulatory agencies, advocacy organizations, and others who provided important input that informed our approach and methods. We have developed a framework for characterizing the cost, performance, and availability of manual and dispatchable DR technology.

In the future, California's power system will include larger fractions of energy provided by wind and solar energy, an increase in new loads such as electric vehicles (EVs), and the potential for greater availability of dedicated energy storage. There have also been dramatic increases in the capabilities of "Smart Grid" information technology systems, with high-resolution visibility and control and new analytic and operational capabilities. Our study's foundational goal was to identify "system needs" and new ways that DR's technical capabilities can meet those needs (***Figure 6***). We compared DR to alternative approaches such as traditional AS from generators, grid infrastructure expansion and grid-scaled dedicated energy storage technology. Additionally, we took into account realistic customer preferences and market dynamics.

Although California has extensive experience with certain forms of DR, new and different DR resources will be required for the grid's evolving needs - ones that are more flexible and able to respond faster than their historical counterparts.

For four DR services types in this analysis, LBNL created a structure that generates levelized cost supply curves and demand curves in 2020 and 2025. The supply curve framework was based on a bottom-up, customer end-use load forecasting model based on more than 200,000 interval and smart meter load shapes. We developed granular load flexibility potential estimates using end use forecasts. LBNL then combined these potential estimates with a detailed DR cost database to express DR supply curves for different grid services, which estimated how much DR is available across a range of levelized costs.

2.1. Regulatory and Technology Background

The CPUC Energy Division funded this study to support DR policymaking, concurrent with rulemaking R.13-09-011. Based on the current policymaking process needs, we estimated how DR could provide grid services in 2020 and 2025, across a range of scenarios for DR market and technology options. This report summarizes our results after the second of two project phases.

In Phase 1, we studied conventional DR (peak load shedding resources that qualify for system and local resource adequacy capacity credit) and compared the cost of DR with an estimate of the avoided cost for conventional generation, transmission, and distribution. This phase included Shed and Shape-as-Shed DR. We released Interim Phase 1 findings on April 1, 2016. The findings were updated on August 19, 2016 with improved assumptions. Concurrent with the update, the software and data inputs developed for Phase 1 were released publicly under an open source license.[1]

In Phase 2, we broadened our study to cover more advanced technology options that can enable fast-response DR and can help meet California's future capacity, energy, and ancillary service needs, including the full stack of DR types we outline above (Shape, Shift, Shed, Shimmy). While the underlying approach is the same as Phase 1 (comparing the cost of supplying DR resources to an estimate of the value for those resources), it also introduced substantial methodological advances. First, is the use of a system optimization modeling approach to estimate the service value rather than a static price referent. The LBNL team selected the RESOLVE model, executed in collaboration with E3, because of the modeling framework flexibility for adding DR capabilities that match with the LBNL-LOAD and DR-PATH estimates. An additional improvement in Phase 2, is using a "Monte Carlo" analysis to estimate the uncertainty in forecasts for DR potential.

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[1] Available at: http://drrc.lbl.gov/project/2015-california-study

This study focuses primarily on system-level services (i.e., services that meet needs at the transmission system level and could be organized by the California Independent System Operator, or CAISO) to help inform the process of "bifurcation" in demand response. Bifurcation is an organizing concept for advancing DR policy. It refers to integrating some resources into the CAISO markets for direct dispatch to meet system needs (known as "supply" DR) with other resources that are controlled or dispatched outside the market (known as "load-modifying" DR). While we focus on system-level dynamics, we also include estimates for the way DR technology could help needs at the local sub-transmission level and local capacity areas (LCAs). These layers of value help provide context to the system-level estimates and could be part of future portfolios of jointly planned resources that meet electricity system needs for both the distribution and transmission systems.

2.1.1. The Need for Flexible Loads on the Electricity Grid

California's electricity system is undergoing unprecedented change. Long a leader in environmental policy and renewable energy development, California's current goals call for meeting 50 percent of California's retail electricity sales with renewable energy by 2030 and reducing greenhouse gas (GHG) emissions to 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050. In addition, California policies are expected to result in significant adoption of behind-the-meter solar PV. The implications for managing a substantially cleaner electricity system are what drive our framework for understanding the role of DR in the future grid.

A 50 percent renewable electricity system in California will have high penetrations of variable solar and wind generation, collectively reaching as high as 35 to 40 percent of total delivered electricity by 2030. Variable generation is different from conventional generation because it can generate electricity only when the wind and solar resources are available. Moreover, the output of wind and solar farms are subject to both variability and uncertainty, meaning that the output fluctuates from moment to moment in a manner that is not entirely predictable.

This rapid scale-up of renewable generation combined with aggressive energy efficiency investments in California is leading to a fundamental shift in generation planning for the grid. The now-famous duck curve illustrates how the net load profile that needs to be carried by conventional and dispatchable generation has changed, with a significant reduction in the overall peak and a shift in the net peak from mid-day to the early and late evening hours.

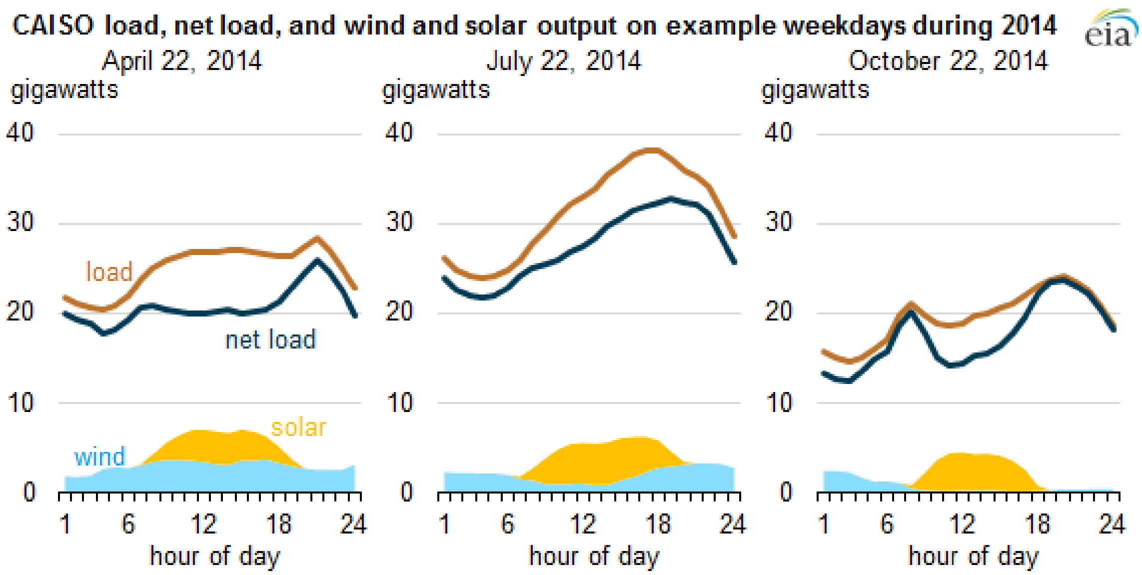


Figure 6: Changing system needs in California for ramping to meet net load have been described as a "duck" curve because of the graph's shape (here, most evident in the net load curve from October 2014). Source: Based on CAISO data and CAISO / EIA reports.

Peak loads continue to grow, but more slowly than they had historically. Based on our best estimates of plant retirement schedules, the conventional fleet that was has been developed as part of long-run reliability planning is now sufficient for meeting system-level peak demand into the near future, through 2025. Thus the value of DR that is targeted for reducing system-level peaks is diminished compared to the case where it captures both operational revenue from energy markets and offsetting generation capacity investments. While the apparent value of system-level Shed resources is low, the ability to Shed to support local reliability in transmission-constrained areas and constrained distribution circuits remains important and valuable, and as we describe below the need for system-wide Shed has been replaced with the need for Shifts, which could provide significant renewables integration value.

Figure 7 below illustrates grid conditions for on Summer Weekdays, which continues to be the annual peak load season. The rows show gross load statistics, the net load (gross minus intermittent renewables), and the contribution of intermittent renewable power generation (solar and wind). For each type of trend line, the left column shows the average of all summer weekdays, and the right column shows the maximum observed value for each hour of the day. These data show the "mid-AAEE" energy efficiency scenario and "Rate Mix #2". The growth in peak gross load will be slowed by energy efficiency, and the contributions of wind and solar both reduce the peak load and shift the annual peak hours into the evening (from ~2 PM to 7 PM). Figure 8 zooms in on the annual peak net loads and the overall effect we observe in the years we simulated is that the trend from 2015-2025 has relatively slow growth in the net load peak, from 42 to 46 GW over the period (based on the 1 in 10 weather scenario). The colors represent different rate mixes and the line type represents different weather scenarios. The data shown are for the 'mid-AAEE' energy efficiency scenario. The existing and expected future generation fleet has been planned over multi-year reliability study periods for a higher peak load.

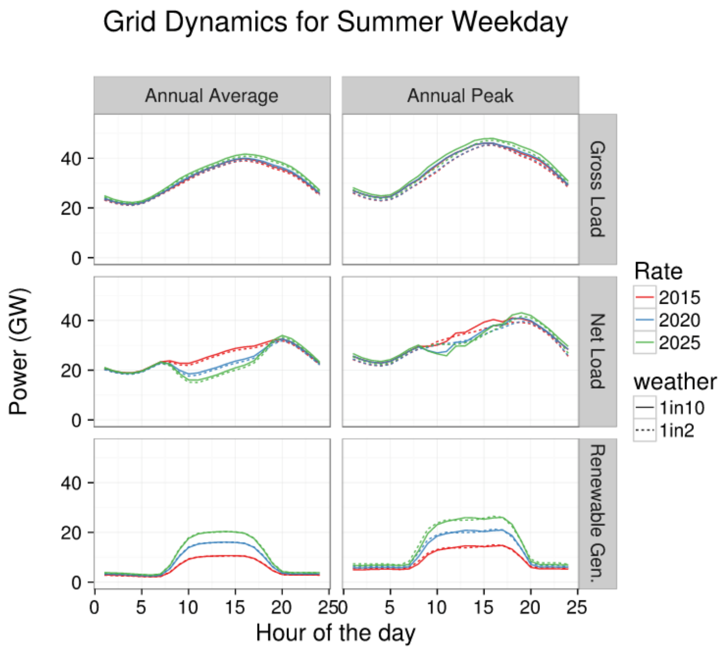


Figure 7: Grid conditions on for Summer Weekdays, with trends grouped by year (color of line) and weather scenario (line type).

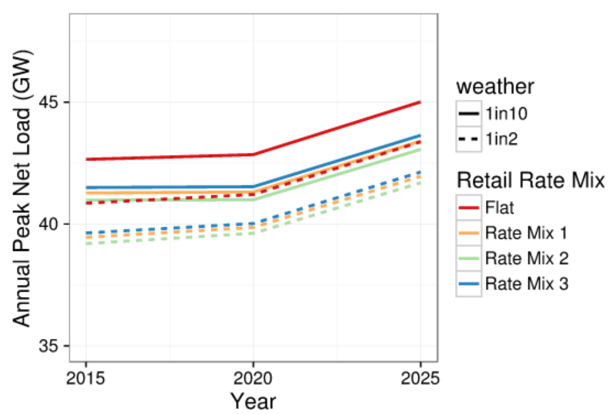


Figure 8: The annual peak net load across the three study years.

In the study, we identified the resource with the highest potential annual grid value, which was a Shift to capture excess renewable energy and reduce the cost of operations. Figure 9 below, exemplifies the need, showing the Shift resource dispatch profiles we estimated with RESOLVE mapped onto the annual load forecast for a 2025, 1-in-2 weather scenario. In Figure 9**,** estimated optimal dispatch profiles are shown in figure (A) from a load perspective, whether the load goes up or down, and in figure (B) from a generator perspective, as if the load was bidding into the energy market. The dispatch profiles are averages of the dispatch profiles for the RESOLVE day types that most closely match the 365 days in our LBNL-LOAD model year. This represents the times when it is valuable to shed and to take, given the flexibility to shift throughout the day. There is a significant and distinct expected need to "take" energy in the middle of the day and "shed" in the early evening. In the late night and early morning, a mix of shed and take is optimal, depending on the day. From the generator perspective, this looks like "Generator Up" for shed and "Generator Down" for "take" – and the graphical representation recreates the Duck Curve. This essentially confirms that the value that can be created from Shift DR derives directly from renewables integration energy capture.

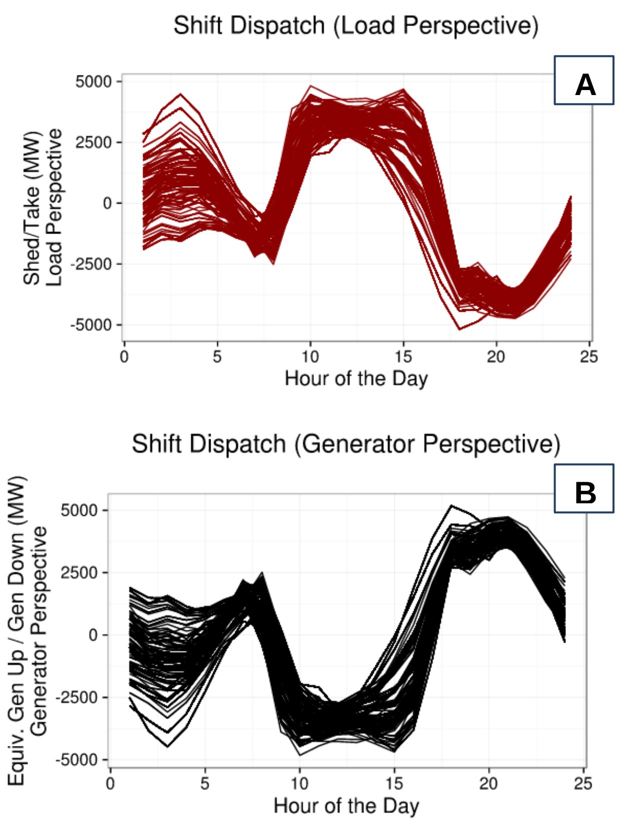


Figure 9: Estimated optimal dispatch profiles for Shift resources from two measurement perspectives.

2.1.2. How DR Fits into CPUC Goals and Other Proceedings

The transition to bifurcating DR is occurring in the context of other important and related policymaking efforts at the CPUC and California Energy Commission (CEC).

Loading order: In 2003, the principal energy agencies in California established a loading order, putting as high priorities energy efficiency (EE), DR, renewables, and distributed generation.

This order effectively prioritized decreasing electricity demand before developing more generation, and using renewable and distributed generation before fossil-fueled generation. In 2012, the CPUC reinforced the loading order with a ruling that standardized the planning assumptions across all three IOUs. The CPUC noted an ongoing preference for DR and EE by explicitly noting, “The loading order applies to all utility procurement, even if pre-set targets for certain preferred resources have been achieved.”

Planning processes: Three important planning processes could incorporate DR and assist in replacing, or delaying the need for investment in, alternatives to meet the requirements for a reliable and efficient grid: resource adequacy (RA) planning, the long-term procurement plan (LTPP), and the transmission planning process (TPP). These are summarized below:

- RA: In 2004, the CPUC adopted an RA policy framework establishing RA obligations for all load-serving entities (LSEs) within its jurisdiction. The intent is to demonstrate that each LSE has procured sufficient capacity resources, including reserves, to serve its aggregate system load and local reliability needs on a monthly basis. Each LSE must show RA that is sufficient to meet 115 percent of its total forecasted load.
- LTPP: LTPP by LSEs is a 10-year look-ahead at system, local, and flexible needs, comparing anticipated demand against existing generation and new resources, and excluding retirements.
- TPP: CAISO’s TPP is an annual planning process to direct investment in transmission system additions and upgrades in support of a range of system goals.

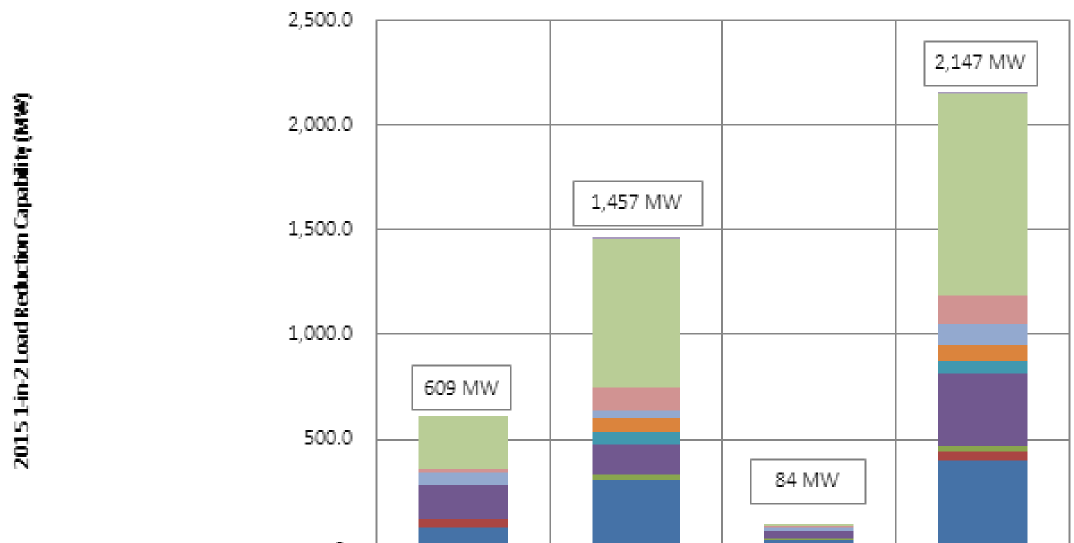
Valuing DR: The ability to count DR towards RA and the manner in which DR is incorporated in long-term planning are critically important for establishing value streams that incentivize investments in DR technology, programs, marketing, and incentives. A set of DR working groups was convened to guide the joint parties Joint Proposal (in CPUC Rulemaking R.13-09-011), with work on load-modifying DR, supply resources, and a DR auction mechanism (DRAM). These working groups’ reports and outcomes inform the current study’s inputs and assumptions.

On December 9, 2014, the CPUC issued Decision (D.) 14-12-024. Most important to our study, this CPUC decision approved and outlined a study to assess the DR potential in the service territories of California’s three largest utilities: PG&E, SDG&E, and SCE.

In its 2014 decision, the CPUC established a four-year timeline to assess the potential for DR, during which working groups are to create recommendations for categorization and valuation of DR programs. On November 19, 2015, the CPUC issued Decision 15-11-042, which clarified the commission intent to proceed with bifurcation and defined the pathways for valuation of supply and load-modifying resources (specifically that load-modifying resources only provide capacity value through being embedded in CEC load forecasts that are used to set procurement targets). The CPUC is set to enforce this strict bifurcation as of 2018. The decision also approved a set of updates to the cost-effectiveness protocols used to evaluate utility DR activity. Our study incorporates both DR resource categories (supply and load-modifying) in a harmonized framework to help inform the continued development of DR markets and programs.

2.1.3. Existing DR in California

Figure 10 shows the existing DR capability by IOU and customer sector in California for 2015. These data show that the IOUs currently provide about 2.1 GW of DR according to the administrative and market settlement frameworks for defining the size of the resource. In the Results section of this report, we comment on how these values compare with the DR in the LBNL model for 2014, which is an important benchmark comparison for our model.



	PG&E	SCE	SDG&E	Total
Non-Res - Real time pricing		2.5		2.5
Non-Res - Interruptible rates	252.1	707.8	1.0	961.0
Non-Res - Demand bidding	21.0	114.5	2.6	138.1
Non-Res - Critical peak pricing	51.5	29.8	20.9	102.2
Non-Res - Air conditioner load control	2.7	64.3	3.1	70.1
Non-Res - Agricultural pump control		59.4		59.4
Non-Res - Aggregator programs	165.7	147.2	34.7	347.6
Residential - Peak time rebates		27.0	5.3	32.3
Residential - Critical peak pricing	36.9			36.9
Residential - Air conditioner load control	78.9	304.5	17.0	400.3

Source: Utility Monthly reports on interruptible load and demand response programs. Filed with the CPUC (A.11-03-001).

Figure 10: Total DR resource based on filings for 2015.

2.1.4. New Approach for DR Potential Estimation

This research is the first study to comprehensively evaluate the technical potential, availability and cost-competitive potential of DR in California, and presents a new methodological approach for public policy support of the electric power system. We have organized and integrated new DR economic and market value concepts, and use newly available Advanced Metering Infrastructure (AMI) data as a basis for modeling DR potential. California has a strong history of conducting related research on the potential for energy efficiency. This research will extend this tradition into the DR realm, but with significant changes to the approach and methodology.

Our team developed a framework that creates supply curves of enabling technologies and end-uses for the DR products in order to determine the potential DR in California. Rather than following the EE framework that looks at the annual technical, market, and economic value streams, this new approach allowed us to examine DR availability on an hourly basis, using hourly load profile customer data, and end-use load profiles to determine the amount of DR available for each hour of the year. Because the value of DR is based on the hourly availability, this methodology gave us the ability to determine how much supply is available for each hour and weight its value based on overlap with times of system need for specific DR products. For our study, we did away with the references to technical, market and economic potential, and rather, introduced the following:

- **End-use Load Forecasts and Technical Baselines:** Segmentation, disaggregation and forecasts of end uses over a range of customer clusters that represent the population and building stock. These establish the expected baseline gross load disaggregated by end use across a diverse building stock.
- **Supply Curves of DR Potential:** Development supply curves that synthesize the DR costs, availability, shed-ability and quantity coincident with system net load needs.
- **Economic Valuation of Cost-competitive DR:** Determination of the value that DR could provide compared to alternative sources of reliability and capacity. The competitive quantity of DR is based on analysis of the supply curve in the context of the alternative technology price.

The model we used to implement the study is organized in two main modules. The first, LBNL-LOAD, is an end-use load, baseline-forecasting engine. Taking raw data from utility databases in combination with supporting datasets, we create forecasts of large representative sets of end-use load shapes over the course of a year, with hourly resolution (8760 hours per year). These fundamental baseline load shapes are the key input to DR-PATH, our techno-economic model for demand response.

The key features of LBNL-LOAD are:

- **Clustering** the customers in the state into representative demographic and energy usage groups speeds the computation and is appropriate for large-scale geographic potential modeling. Our approximately 3,500 clusters represent the customers in the services territories of PG&E, SCE and SDGE.
- **End-use baseline load shapes** are disaggregated based on weather sensitivity and first-order engineering models.
- **Linked renewable generation and weather** modeling lets us use weather-adjusted baselines that are linked with a coincident renewable generation potential forecast to estimate DR Potential. This means our estimates are in the context of a plausible net load profile that can be the basis for valuing the timing of demand-side resources.
- **Harmonization** with existing policy frameworks is important to make the model useful for planning, and we link the forecasts for growth in demand and investment in energy efficiency to CEC long-term forecasts.

The key features of DR-PATH are:

- **Cost and performance data** for a range of DR technology options are used to define the inputs to a techno-economic model, which uses the baselines from LBNL-LOAD to estimate availability and technology cost resources at sites where they are installed.
- **Propensity score models** define the likelihood of customer adoption, which we use to estimate the effects of customer engagement, marketing, and incentives on DR resources potential.
- **Supply curves** for DR resources are based on a well-defined taxonomy of resource types, and enable transparent comparisons of the cost and performance of DR to its value or other investment options for supporting the grid.
- **Monte Carlo** analysis lets us simulate many possible future pathways for the system and reveal the inherent uncertainty in forecast estimates. The architecture of the model enables computational parallelization (which speeds up the code).

Comparing DR to EE

One of the challenges of estimating DR's potential in a framework that is useful for planning and policy development is the manner that DR differs from energy efficiency, with regard to measure lifetimes and "durability." Specifically, in efficiency potential studies, each efficiency measure has an assumed lifetime during which it provides a relatively predictable stream of energy benefits from fixed equipment under regular operation. DR products, however, involve a set of strategies and actions taken by customers, or automatically by devices, in response to a system event or signal. These dispatch events may occur frequently or rarely depending on how particular sites participate in day-ahead and real-time electricity and ancillary services markets managed by the CAISO. This temporal variance in DR provision of grid services makes it vastly different from energy efficiency analyses. There are also differences in the durability of resources from year to year. Energy efficiency load reductions last for the full useful lifetime of equipment, while customer commitments to load curtailment are often renewed on a periodic basis (e.g., annually). Therefore, with respect to “measure lifetimes,” DR technology attrition includes control equipment failure along with enrollment-related factors like the opt-out rate and effects of move-outs. In the model we developed, we employ an estimated lifetime for automation technology to characterize the investment horizon for controls in developing DR levelized costs that includes our best estimate of these combined effects.

This study’s approach deviates from energy-efficiency potential studies in several ways. As discussed above, DR measure lifetimes often differ from energy-efficiency (EE) measures, where an end use can be installed in a site and the savings begin accruing as soon as the end use becomes operational. Many EE programs have incentives that are paid through upstream, midstream, or downstream payments. For DR technologies, few of these characteristics apply. Rather, customers are recruited and offered the program via customer account managers, aggregator outreach, direct mail, phone calls, and in some cases, door-to-door. The DR programs typically have constraints on how often the program will be dispatched, and the customer load availability (i.e., whether the end use in operation) is uncertain. If the DR program requires automation for signal and dispatch, then installation and provisioning of the technology adds another complexity layer that is not involved with EE end uses.

A growing number of integrated demand-side management measures provide both EE and DR capabilities; these include smart communicating thermostats or advanced lighting controls or building automation systems associated with space conditioning that enable DR communication.

In EE programs, a utility can commit to a buydown of specific end uses by their make and model, which are clearly defined by ENERGY STAR standards. Policy at both the state and federal level provides guidance on building codes, lighting and appliance standards that facilitate adoption of EE technologies. The framework for DR programs and standards is not as well defined. DR enabling technologies, dispatch requirements, qualifying loads and program rules lack the standardization that EE maintains.

Additionally, because of bifurcation, DR is increasingly seen as a distributed energy resource (DER) that needs to have the flexibility for dispatch across a number of hours throughout the year. However, DR benefit streams are unequal during all hours, and the resource isn’t always available at all times since the program administrators typically constrain the number of events that will be called to increase program participation. End uses such as HVAC units that are enrolled in the programs are not typically running year round or at all hours. These factors complicate how to assess DR value and available quantity throughout the year. We note this is an area where the state-of-the-art for EE programs is advancing as well; the same advanced meter data that supports our study can also improve EE benefits’ estimates.

2.1.5. Extending the analytic framework

Our analytic framework links measured site-level loads, weather, renewable generation, and a model for estimating the implications of distributed energy investment. The organizing principle is to simulate many internally consistent cases for yearlong operation, avoiding the pitfalls of approaches that decouple the dynamics of loads, generation and behavior. Our integrated demand-side modeling framework, with appropriate modifications and setup, could be applied as well for a range of other policy and operational goals:

Informing Public Policy

Adding sub-modules to the DR-PATH and valuation elements of our work could enable testing integrated portfolios of distributed energy technology investment options, linking **energy efficiency** and **distributed generation** with demand response and fixed storage.

Establish distributed energy **technology development targets** by estimating the likely implications of technology systems with particular combinations of cost and performance. Possible future technology systems that are structurally likely to be cost-effective but do not exist in the market would be ripe for R&D, while technology options that lack feasible pathways to cost-effectiveness would not be prudent targets.

Simulate the **effect of policy decisions** with carefully constructed scenarios. An example is testing the effect of widespread code-defined control technology rollout, or testing the effect of a dynamic electricity rate paired with responsive technology.

Accelerating Smart Deployment

A key finding of our study was that there is a high value from **targeting investments in control technology and customer acquisition**--some customers have load shapes and characteristics that make the sites more likely to be cost-effective as individual opportunities. The value of DR, particularly Shed resources, is also not evenly distributed across the grid but concentrated. There are high value DR opportunities in local generation constraint pockets and in areas served by constrained distribution circuits. Using customers' AMI data and demographics to focus investment in areas potential could be applied (and ground-truthed) by using them to actively target customers with favorable demographics and loads.

With visibility into customer-level DR performance, both **controlled and natural experiments** are possible to understand how to most effectively target high value / low cost DR. This A-B test approach could help accelerate understanding of how to involve large numbers of people with DR through widespread, aggregated loads.

Catalyzing DR with AMI

California has made significant investments in Advanced Metering Infrastructure (AMI) that has led to a qualitative shift in the visibility of decentralized energy systems. With 15-minute to hourly measurements of electricity and natural gas consumption at nearly every premises in the state, there are millions of data points being measured in the background of utility operations every day. Our analysis framework is based on a large sample of the available data (1 continuous year, 2014, for about 200,000 sites out of the total ~15 million), and shows the value of **access to large samples of AMI data** for informing public policy on distributed energy systems. It is straightforward to aggregate and/or anonymize customer data that could be used to update model inputs and assumptions.

Many non-utility actors --- aggregators, advocacy organizations, and the public sector --- are working to unlock the potential of DR, and for them to be successful in DR technology R&D and market scoping it is a priority to have some mechanism for visibility into data about the demand at the edge of the grid. We have worked with the CPUC to release an anonymized version of the underlying datasets we used in Phase 1 of this study, and they represent some of the most granular and high-resolution data that are available publicly describing California households, businesses, and industrial facilities. Ongoing and frequent packaging and release of fully anonymized site-level data could help ensure public policy is informed by an up-to-date picture of demand. With discrete, uniformly formatted, and predictable releases of data, it could be possible for stakeholders not just in DR policy but distributed resources in general to use and develop a shared set of models and tools for advocating and engaging with the public process. The data would also be a significant catalyst for technology R&D and electricity markets research. Additional work on data access for individual customers to potential third-party aggregators is likely required as well, for customer acquisition, but anonymized data could be helpful for overall market scoping and general geographic or demographic targeting.

2.2. Study Limits, Uncertainties and Simplifying Assumptions

This study provides estimates of the technical and economic DR potential in California, and is the first of its kind to implement the newly developed LBNL methodology. As is the case with any model, our framework cannot capture all the possible potential energy scenario permutations for California, and while the results are instructive, they are neither exhaustive nor a final word. The technology costs, end-use performance and adoption rates described in this report are developed to represent our best understanding of the ability of various end-uses to provide different types of DR services. More work is needed to verify, evaluate and understand these new DR capabilities in customer loads, especially the frequently dispatched and rapidly responding loads that are needed beyond the traditional DR for hot summer peak hours. This is a new field with limited data on the long-term performance of these technologies and systems. Based on the results, however, our study suggests the following potential opportunity areas for action to improve the understanding and functionality of DR in California:

- **Uncertain future value for Shed:** The Phase 2 results include findings on Shed DR under both the Price Referent valuation framework and the "System Levelized Value Approach", which is based on values from the RESOLVE model. We note elsewhere and highlight here that the ultimate choice of a "correct" valuation framework for Shed resources is complex and depends on the specifics of how resources are used. Because the RESOLVE model does not explicitly include constraints related to system emergencies, distribution system services, or local capacity needs, these are not reflected in the Levelized Value supply curves. However, the RESOLVE model is designed to accurately reflect trends in the installed generation fleet and includes constraints imposed by systemwide resource adequacy. As new approaches emerge to better model the value of contingency, distribution and local resources in a harmonized framework with system planning, we expect the results could increase for Shed DR based on an integrated Levelized Value.

- **Forecast uncertainty:** The study relies on a range of forecasts, from statewide macroeconomic trends to electric vehicle deployment. Every forecast has inherent uncertainty. As DR advances in the context of broader trends, the potential that relies on them will change as well.
- **Gathering empirical data on capabilities for building infrastructure to dynamically shift energy use.** The Shift service type resource is by far the largest opportunity we identified for DR to provide system-level value for the future grid. Significant potential value to the system (up to ~$600 million/year) from dispatchable daily energy Shifts that are enabled with advanced control technology, with economically effective DR up to ~5 percent of daily energy shifted in 2025 (for the high-curtailment, mid-additional achievable energy efficiency [AAEE] scenario), and in subsequent years, an expectation of continued growth in the valuable Shift resource quantity as more renewables come online. The model we used for estimating the quantity of technology-enabled Shift that is possible is based on engineering judgment and is not yet well-supported with field experience, which should be used to verify the resource availability and inform how to transition DR technology and markets to this emerging opportunity area.
- **Linking EE and DR "co-benefit" analysis on the integration of energy efficiency and demand response**. Customers want to be able to manage their electricity costs and have energy service options. Further understanding of how to integrate the delivery of EE and DR together will likely help lower the cost of DR. This is especially important for controls measures. Our approach to jointly consider EE and DR was through simplified "co-benefits" that did not explicitly model the dynamics of DR and EE as a portfolio of technology investment, and this first order analysis suggests large potential gains from portfolios that bridge service behind the meter with the broader grid.
- **Electric storage system sizing, control, automation and performance evaluation.**

Electricity storage is a quickly evolving sector, and there is a need to better understand how the market for these systems will change in the next few years as prices continue to drop. Advanced controls for both electric storage and automated building systems are in their infancy with respect to integrating operational optimization. These systems' coevolution could significantly change the DR potential depending on the technology's trajectory, and currently, careful analysis of control systems integration and operations is needed to ensure that the systems are used in an optimal configuration.

- **Rate selection.** This study developed and implemented a methodology to evaluate how various existing and emerging Time Varying Pricing (TVP) electricity rates could provide demand reduction within the framework of DR valuation. Since these rates act as load-modifying resources that change consumers' consumption patterns, (i.e., modify the load consumption shape), they influence the amount of DR available for supply side-facing DR programs. We simulate a set of cases from 2015 TOU Pilot Advice letters, but the actual rates are likely to be different. If future rates are significantly different from those we include in the study, the underlying load shape would change.
- **Load shifting with prices.** One of the key study findings shows that there is great value from shifting electric loads to periods when there is significant potential for over generation from solar resources. Future TVP rate designs might help manage this load shifting, and this study had only limited review of this strategy. Also, the study excludes speculative analyses of how price-responsive, transactive energy devices[2] could amplify the response to time-varied prices, instead relying on existing empirical research that largely reflected behavioral modifications, structural investments in energy efficiency, and shifting the typical time of energy service.
- **Multi-market DR resources.** The supply DR resources' cost and value analysis in this study are all single DR product or market value streams. No effort was made to explore how a DR resource could provide value in multiple markets and result in a resource portfolio. This is a study shortcoming, and there are clearly issues with multiple program participation, potential complications in program baseline rules, and ultimately, the availability of DR services. A better understanding of these issues can only help improve DR cost-effectiveness measurements.
- **Distribution system value of DR**. We conducted a perfunctory and high-level, limited analysis to evaluate DR's value at the local distribution system, which suggested a

[2] Transactive energy refers to the use of a combination of economic and control techniques to improve grid reliability and efficiency. For more information, see http://www.gridwiseac.org/pdfs/te_framework_report_pnnl-22946.pdf

significant opportunity for DR, on the order of 2–5 gigawatts (GW) of responsive resource that is cost-effective. It is likely that there will be greater value for DR at the local distribution system level for constrained areas, and additionally, the value estimates from the CPUC Distributed Resource Planning (DRP) process should inform future analysis.

- **Comparison with real-world DR markets.** The Demand Response Auction Mechanism (DRAM) pilots currently**.** The Demand Response Auction Mechanism (DRAM) pilots currently underway are collecting bids from DR aggregators for Shed DR, and get a range of bids for service. These bids would be analogous to supply curves we developed for net expected revenue if the DRAM participants were bidding at their true expected shortfall (similar to marginal cost bidding, but with a longer timeframe for cost accounting). Opportunities to find additional information through market processes like DRAM can provide a valuable ground-truth for techno-economic models like the one we developed. The benchmarking we used to calibrate the model has included careful consultation with experts and Shed estimate comparisons to current-day utility programs.

3. Methodology

This section provides an overview of the study's approach, focusing on how we categorized DR resources and the mechanisms that provide value for these resources. Detailed descriptions of the methods and assumptions are documented in Appendices C–I.

3.1. DR Futures

The study's "bottom-up" modeling framework for DR capabilities and availability leverages large customer-level electricity use and demographic datasets provided by each of California's investor-owned utilities (IOUs). The first step for estimating DR resource availability is to group customers in similar cohorts, or "clusters." Each cluster represents an aggregation of real customer consumption and demographic information. Each cluster's consumption time series is disaggregating into its constituent end uses, and these end-use baseline load shapes are forecasted to the study years.

Second, the tool forecasts likely DR pathways, given existing and emerging technologies' cost projections and adoption information for the selected forecast years. The resulting pathways represent the likely set of possible futures, given technology adoption and DR product participation.

Finally, the tool presents the distilled results of the analysis through DR cost-versus-grid service product supply curves. These supply curves provide a visual representation and tool for interpreting the available DR resource in the forecasted scenarios and weather years.

In the DR Futures model, we developed two core analytical capabilities:

1. **LBNL-Load:** This is an end-use, load-forecasting approach that capitalizes on IOU-provided demographic data for the full set of more than 11 million utility customers and hourly load data for 220,000 customers across the three IOUs. Using these data, we developed approximately 3,500 representative customer clusters characterized by a typical demographic profile, location and hourly end-use load estimates. Table 1 below provides details on the number of customers and clusters by sector for each of the IOU service territories. See Appendix C for documentation, intermediate results and discussion of this model.
2. **DR-PATH:** This is a DR capability analysis model that estimates the potential hourly DR contributions to support system reliability across a diverse set of future pathways. The possible pathways consider the predicted end-use load (from LBNL-Load), technology capabilities, market design parameters, and expected participation rates-derived from the demographic variables. It includes an economic analysis framework that estimates the effective capacity available at a range of levelized cost ceilings to establish supply

availability curves. See Appendix G for documentation, intermediate results and discussion of this model.

Table 1: Customer clusters for each IOU service territory by customer sector

Utility	Customer Sector	Cluster Quantity	Average Customer Number Per Cluster
PG&E	Commercial	789	780
PG&E	Industrial	929	240
PG&E	Other	24	18,000
PG&E	Residential	320	18,000
SCE	Commercial	527	1,200
SCE	Industrial	540	240
SCE	Other	44	5,900
SCE	Residential	153	34,000
SDG&E	Commercial	86	1,800
SDG&E	Industrial	145	180
SDG&E	Residential	20	72,000

LBNL-Load and DR-PATH are used as an integrated package to simulate self-consistent energy futures cases with coincident and time-synchronized weather, loads, prices, renewable generation, and distributed technology scenarios. The cases help define the implications of qualitatively different future scenarios, and could be thought of as a sensitivity analysis. We also use a Monte Carlo approach to estimate many possible supply curves for each case.

The study's model includes end uses and dispatchable enabling technologies for this report listed below in Table 2.

Table 2: Summary of enabling technology options included in Phase 2 results.

Sector	End Use	Enabling Technology Summary
All	Battery-electric and plug-in hybrid 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	Depending on site size, energy management system Auto-DR, DLC, and/or Smart T-Stats
	Lighting	A range of luminaire-level, zonal and standard control options
	Refrigerated warehouses	Auto-DR
Industrial	Processes and large facilities	Automated and manual load shedding and process interruption
	Agricultural pumping	Manual, DLC, and Auto-DR
	Data centers	Manual DR
	Wastewater treatment and pumping	Automated and manual DR

For Phase II, additional DR enabling technologies with faster communication and load data acquisition capabilities were added to the analysis. These added "Fast DR" technologies qualify or are expected to qualify for ancillary services and other market products which require faster response to a dispatch signal, with the fastest requirement of 4 seconds for regulation up or regulation down market participation.

As part of the process of determining which end-uses are currently or likely future Fast DR participants, LBNL surveyed a number of DR industry stakeholders (including aggregators, scheduling coordinators, ESCOs, and contractors).

The end-uses eligible for Fast DR included in this analysis are:

- Agricultural Pumping (including variable frequency pumps (VFPs)
- Commercial HVAC (with EMS and/or VFDs)
- Commercial Battery
- Commercial BEV and PHEV (fleet and public)
- Commercial Lighting (luminaire and zonal)
- Commercial Refrigerated Warehouses

- Industrial Battery
- Residential Battery
- Residential BEV and PHEV
- Wastewater Process and Pumping

We assume that for end-uses that can deliver Fast DR services, the same local control technology would be used as their "slow DR" equivalents, and that the main differences between Fast and Slow DR technologies are in the telemetry and dispatch configurations, with the exception of advanced technologies such as variable frequency drives and pumps. Therefore, the hardware and installation costs for Fast DR control technology are the same, and any additional costs are for the telemetry and communication system upgrades, which could be for metering, a resource interface, a gateway or another component.

3.2. RESOLVE Model

A key Phase 2 study feature is the use of the RESOLVE model to identify least-cost strategies for power system investment and operations. It optimizes in the context of constraints on meeting future renewable energy targets, operational requirements and capacity constraints on the grid. The planning period included in this study is 2016–2030.

RESOLVE was originally developed and is implemented by E3. During this project, the model was augmented to include a variety of DR services defined by LBNL and E3 – Shape, Shift, Shed and Shimmy. A key advantage of working with RESOLVE for this project was the ability to rapidly develop software modules for integrating the bottom-up DR future potential results executed by LBNL.

The work builds on RESOLVE cases for the CAISO area originally developed as part of the CAISO's studies of a regional market directed by Senate Bill 350 – the Clean Energy and Pollution Reduction Act of 2015.[3] Some assumptions from these cases, such as carbon price forecasts and gas price forecasts, were developed for SB 350 work, and remain in the model. E3 adapted the cases for this project by incorporating additional functionality to model flexible loads and through updating assumptions around future system conditions. The assumptions are explained in detail in Appendix H.

We describe key features of RESOLVE below that make it well suited for this study: explicitly modeling the value from supporting renewables deployment consistent with California statutory requirements and including two cases for renewable integration technology deployment.

[3] For more on SB-350, see https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

3.2.1. Renewable Curtailment and Overbuild

An important consideration when looking at how DR can help California meet its RPS targets, a binding constraint in RESOLVE, is that of renewable curtailment and "overbuild." When large amounts of renewable generation is built, their power generation can occasionally exceed the combination of electricity demand and power export capability, requiring the renewable production to be curtailed to maintain reliable grid operations. The effect of this is that available renewable energy is forsaken to maintain grid stability, and therefore additional renewables need to be constructed with different generation profiles in order to ensure compliance with a 50 percent RPS target. When this happens, the renewable portfolio is referred to as "overbuilt"—more renewable energy production capacity is present than would otherwise be needed in the absence of curtailment. In particular, building additional renewables with similar generation profiles (e.g., solar PV) leads to increasing marginal curtailment, as each megawatt-hour added has more of its generation added to an hour where curtailment already occurs, leading to further curtailment.

Renewable integration solutions (e.g., energy storage, more flexible gas generation or transmission to deliver more renewable generation) are then valued for their ability to reduce curtailment (in addition to more common value streams such as reducing fuel costs and deferring new capacity needs). Because each of these solutions requires potentially significant up-front capital investment, E3's RESOLVE model found that some curtailment is optimal in future time periods when the cost of adding solutions is higher than the cost of simply overbuilding the renewable portfolio. This is particularly true in 2025 and 2030, as forecast renewable penetration increases. However, marginal curtailment eventually reaches a high enough level that other solutions (e.g., storage) become cost-effective. These dynamics give rise to one of the most important value sources for resources like DR, which can alter the load profile to reduce curtailment of renewables.

3.2.2. Modeling Electric System Futures

Previous work by E3 identified that the curtailment level and the choice of load forecast are significant determinants of the value of new resources like DR that can contribute provide power system services. To capture the impacts of curtailment on DR value, we selected two bounding "curtailment futures": a High-Curtailment future and a Low-Curtailment future. To ensure consistency with current CPUC assumptions, these futures were based on two scenarios from the 2016–2017 CAISO Transmission Planning Process.[4] The combinations of these assumptions provide four scenarios that bound our estimates for DR value. Table 3 lists the

[4] For more information on CAISO's 2016–2017 TPP, see CPUC Rulemaking 13-12-010, available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11673.

assumptions underlying each.

Table 3: "Curtailment Futures" modeled in RESOLVE.

	High-Curtailment Future (LTTP Scenario: "High BTM PV")	Low-Curtailment Future (LTTP Scenario: "Out-of-State Wind")
RPS	50% by 2030 (Out-of-state resources permitted)	50% by 2030 (Out-of-state resources permitted)
Export Limit	2,000 MW	2,000 MW
Incremental Wind (Beyond 33% RPS)	None	3,000 MW by 2025
Behind-the-Meter (BTM) PV	26.9 GW of BTM PV in 2030	19.1 GW of BTM PV in 2030
Utility-Scale Solar PV	13.0 of utility-scale PV in 2030	12.4 GW of utility-scale PV in 2030

The CPUC's RPS Calculator Model[5] is used to create renewable portfolios for each of these curtailment futures, consistent with the LTPP specifications. Renewable overbuild is modeled endogenously within RESOLVE; for more detail see Appendix H.

Figure 11 shows the resulting renewable generation portfolios in 2030, when meeting the 50 percent RPS target assumption. The major difference between the two portfolios is the additional 8.4 GW of solar PV (both behind-the-meter and utility-scale) included in the High-Curtailment future. Solar PV systems have very similar, diurnal generating profiles due to daily timing of solar insolation across California. Therefore, the LTTP's High BTM Scenario, with its high PV penetration, acts as our High-Curtailment future.

A number of geographic and temporal simplifications are made in order to achieve a reasonable model runtime while maintaining focus on key cost considerations:

- Investment decisions and operational dispatch are made in multi-year time increments: 2016, 2020, 2025, 2030

[5] For more information, see http://www.cpuc.ca.gov/RPS_Calculator/.

- 37 representative days are modeled in RESOLVE in each year. These 37 days with appropriate weights to be equivalent to full year are chosen to best represent a typical full year's load, renewables, hydro, net load conditions, as well as the annual monthly distribution of days.
- Investment decisions are made for the Balancing Authority Area operated by the California Independent System Operator ("CAISO"). Since Given the CAISO is interconnected with other balancing areas, RESOLVE incorporates a geographically coarse representation of neighboring regions in the West (the Northwest, Southwest, and Los Angeles Department of Water and Power (LADWP)) in order to characterize and constrain flows into and out of the CAISO.

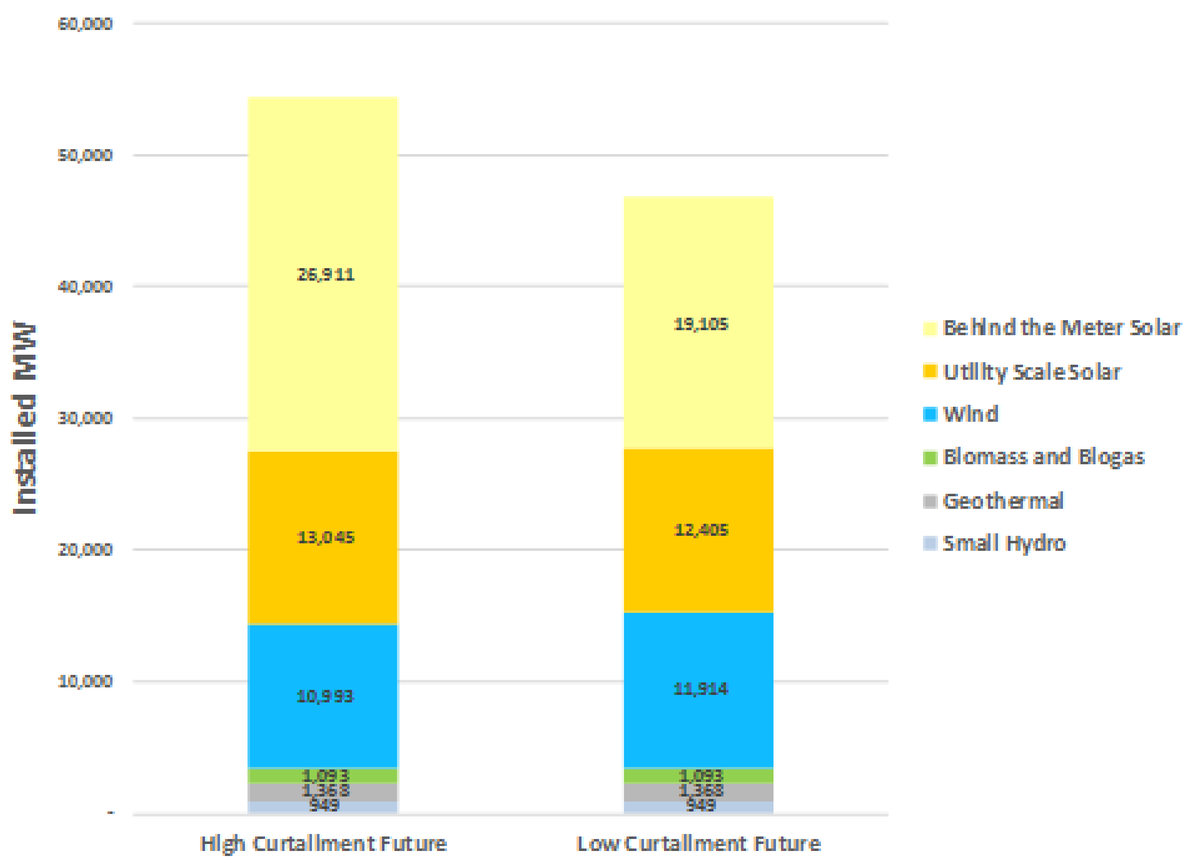


Figure 11: 2030 Renewable generation portfolios for High- and Low-Curtailment futures.

To quantify DR's value to the CAISO system, E3 began with a base case that contained no DR, and allowed RESOLVE to minimize system costs over the 2016–2030 investment period. Then DR was added to the system in increasing increments, and costs were minimized over the same period. Any decrease in system costs was attributed to the added DR resource. Figure 12 shows curtailment, by year, under the base case (i.e., with no DR).

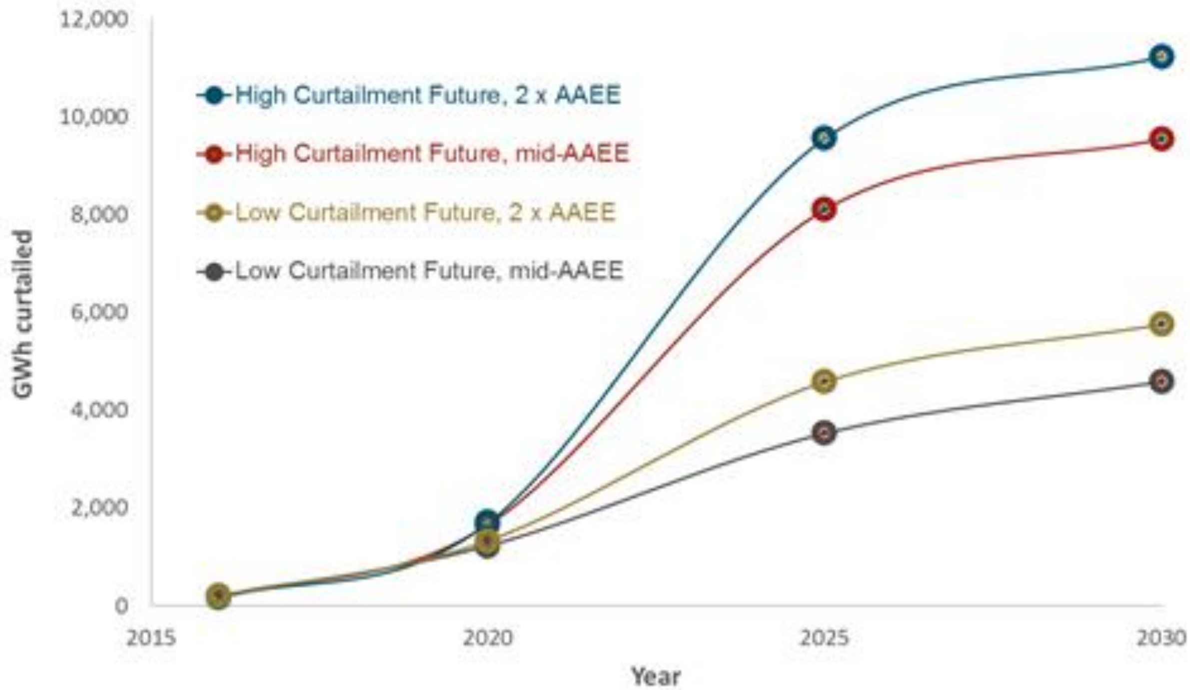


Figure 12: Base case curtailment, by year.

The High-Curtailment future has approximately 4,000–6,000 GWh (depending on load forecast assumption) more curtailment in 2025 and 2030 than the Low-Curtailment futures, due to their higher solar PV penetration. Doubling energy efficiency also increases curtailment by approximately 1,500–2,000 GWh. This is because lower loads in hours of high solar overgeneration increases curtailment, and this effect more than offsets any reduction in renewable energy procurement needed to meet the lower RPS requirement caused by lower load.

3.3. Demand Response Scenarios for Technology and Market Pathways

To forecast DR in California we defined three potential DR market and technology trajectory scenarios: (1) Business-as-Usual (BAU), (2) Medium, and (3) High. These three scenarios can be compared to the base scenario, which describes the DR market and technology characteristics at the time of this study, circa 2014–2015. The BAU scenario represents steady incremental improvement in technology performance and market adoption. The Medium and High scenarios explore what is possible with moderate and more aggressive technology and market transformations. Table 4 summarizes the assumptions that define the trajectory of cost, performance, and propensity to adopt DR for the three years modeled and reported: 2014, 2020 and 2025. Note that 2014 was chosen as the base year because it was the last full calendar year for which smart meter hourly data were available prior to commencing this study.

Table 4: Summary of scenario defining model parameters.

Parameter	Parameter Description	Scenario	2014 Value	2020 Value	2025 Value
Cost	Full DR enabling technology cost relative to the base cost (lower is better)	BAU	1.00	1.00	1.00
		Medium	1.00	0.95	0.90
		High	1.00	0.85	0.70
Performance	DR service quantity (kW or end-use load fraction) available relative to base performance (higher is better)	BAU	1.00	1.05	1.10
		Medium	1.00	1.10	1.20
		High	1.00	1.20	1.40
Propensity	Likelihood to enroll and participate in DR relative to base propensity (higher is better)	BAU	1.00	1.05	1.10
		Medium	1.00	1.15	1.30
		High	1.00	1.25	1.50

3.3.1. Propensity Scores and DR Adoption Rate

The choices and preferences of electricity users and customers determine success or failure of DR programs—without initial and ongoing enrollment there will simply not be loads available to provide service to the grid.

In DR-PATH we model the likelihood of customers to adopt DR using statistical methods that combine the best available information on current-day DR program adoption rates and controlled studies to understand how demographic factors, incentives, and marketing combine to result in some fraction of customer adoption. **We refer to the expected fraction of customers as a "propensity score,"** in line with standard practice in economic analysis. Nexant Consulting, Inc. was the technical lead on developing the propensity score model, and the results of that model are used in combination with current-day enrollment. Details on the methods for propensity score estimation are available in Appendix F, including a

> ***The study is designed for the next generation of DR applications****, which not only includes meeting peaking capacity, but also new and recent applications such as resources to meet longer and larger sustained ramps (ramping capacity), fast response to address renewable volatility and multiple up and down ramps throughout the day, and shifting of loads to avoid over-generation in the middle of the day. For most of these applications, there are no mature existing programs against which to benchmark.*

description of factors that are estimated to influence propensity to adopt DR (which could be useful for broader work on DR as well).

The figures below are a synthesis of our estimates for the fraction of customers that will contribute to DR resource availability in 2025, using the Shed resource as an illustrative example. As the price of DR service goes up, additional incentive payments are available and our propensity score model yields higher expected participation rates. Note that the implied rate of participation for many end-uses is limited by adoption (e.g., EV and HVAC) but for others like batteries there is a possible pathway for every site. Overall, the participation rates are in the range of 5-10% (and much lower for commercial customers) for the region of the model where one would expect prices to settle (between 0-200 $/kW-year).

The following set of figures display the implied DR participation rates in 2025 by Sector. The line colors in each sub-plot correspond to end-use categories and the line types correspond to utility service areas. These results are a synthesis of a propensity score model and its implementation in DR-PATH across a range of technology and market pathways.

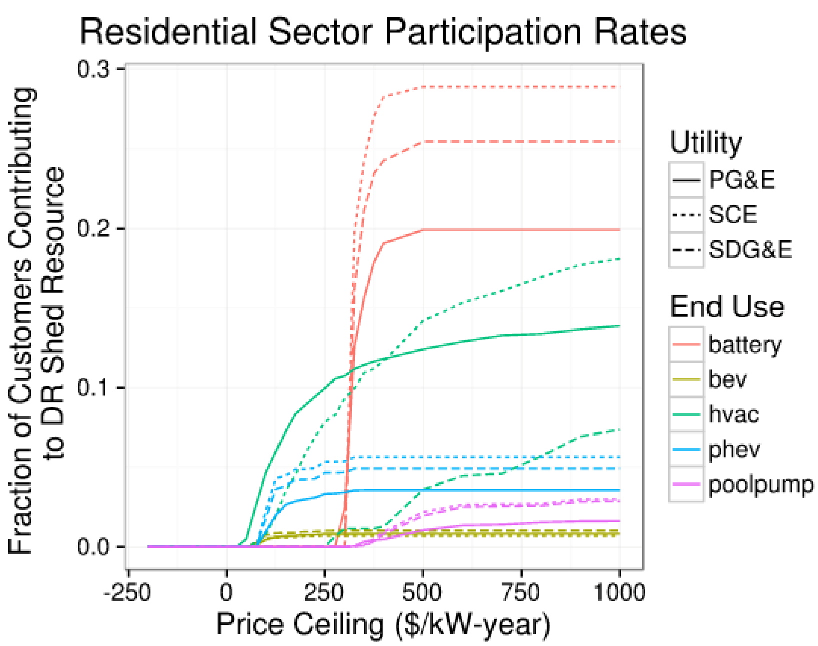


Figure 13: 2025 Residential Sector DR Shed Participation Rates per IOU and End Use at Varying Price Ceilings ($/kW-year).

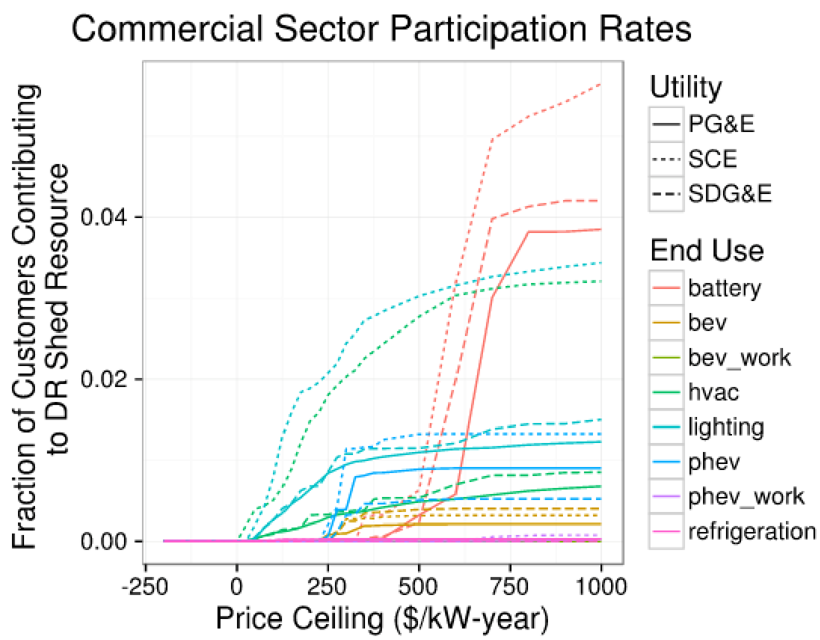


Figure 14: 2025 Commercial Sector DR Shed Participation Rates per IOU and End Use at Varying Price Ceilings ($/kW-year).

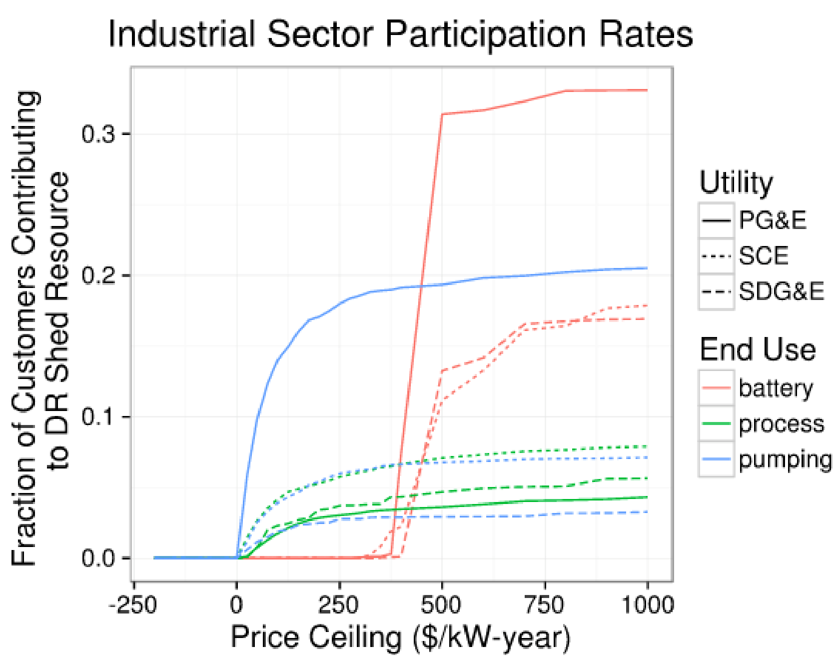


Figure 15: 2025 Industrial Sector DR Shed Participation Rates per IOU and End Use at Varying Price Ceilings ($/kW-year).

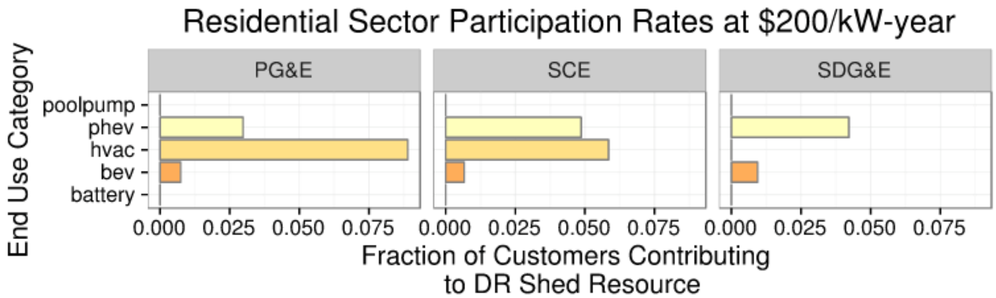


Figure 16: Residential Sector Participation Rates per IOU and End Use Category at $200/kW-year.

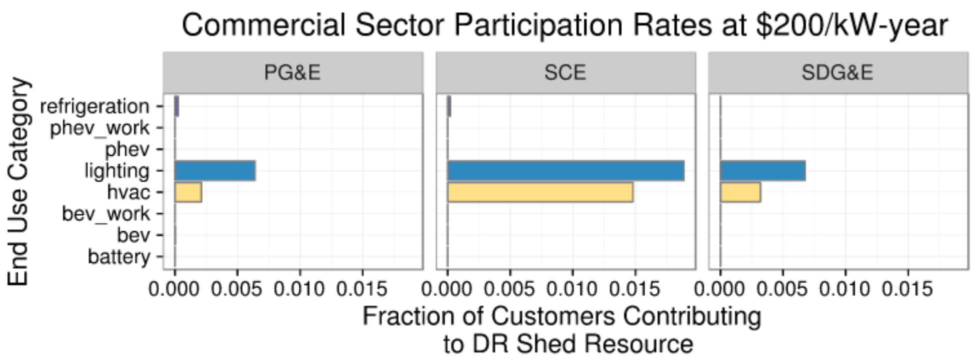


Figure 17: Commercial Sector Participation Rates per IOU and End Use Category at $200/kW-year.

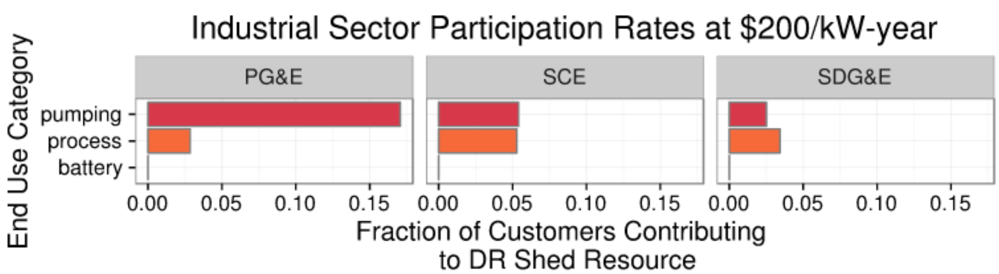


Figure 18: Industrial Sector Participation Rates per IOU and End Use Category at $200/kW-year.

3.4. Demand Response Service Types

Based on future grid needs, we defined four key "service types" (Table 5 ***below***) for which we estimated DR potential: Shape, Shed, Shift and Shimmy.

- **Shape** captures DR that reshapes the underlying load profile through relatively long-run price response or on behavioral campaigns—"load-modifying DR"—with advance notice of months to days. It provides value in our study as an alternative and low-cost path for achieving a level of energy "Shift" and peak load "Shed" (those service types described below). Our estimates of potential for Shape are either "Shape-as-Shift" or "Shape-as-Shed" equivalent values. The Shape technology pathways we modeled were time-of-use (TOU) and critical peak pricing (CPP) rates.

- **Shift** represents DR that encourages the movement of energy consumption from times of high demand to times of day when there is surplus of renewable generation. Shift could smooth net load ramps associated with daily patterns of solar energy generation. Examples of Shift technology pathways we include are behind-the-meter storage, rescheduling flexible batch processes[6] like EV charging fleets or pre-cooling with HVAC units.
- **Shed** describes loads that can occasionally be curtailed to provide peak capacity and support the system in emergency or contingency events—at the statewide level, in local areas of high load, and on the distribution system, with a range in dispatch advance notice times. Examples of Shed technology pathways we include are interruptible processes, advanced lighting controls, air-conditioner cycling, and behind-the-meter storage.
- **Shimmy** involves using loads to dynamically adjust demand on the system to alleviate short-run ramps and disturbances at timescales ranging from seconds up to an hour. Examples of Shimmy technology pathways we include are advanced lighting, fast-response motor control, and EV charging.

These service types or resources stack span a range of possible California electrical grid needs mapped conceptually onto a timeline in Figure 19, ranging from years (addressed by Shape) to seconds (met by Shimmy and some Shed resources). These overlapping pathways for load flexibility across timescales are fundamental to cost-effectively supporting large-scale renewables on the grid. Next, we elaborated on these pathways for DR to provide value to the grid. These service types form the core of grid support products that are needed today and in the future in California. Previous studies for energy efficiency or distributed generation often treat the resources as “static” decentralized energy investments with deterministic outcomes, but DR investment outcomes are more probabilistic and depend on continued customer engagement for a durable resource. Furthermore, the value created by DR depends on the specific timescale of the response.

[6] A batch process is a processing mode: the execution of a series of programs on a set or "**batch**" of inputs, rather than a single input.

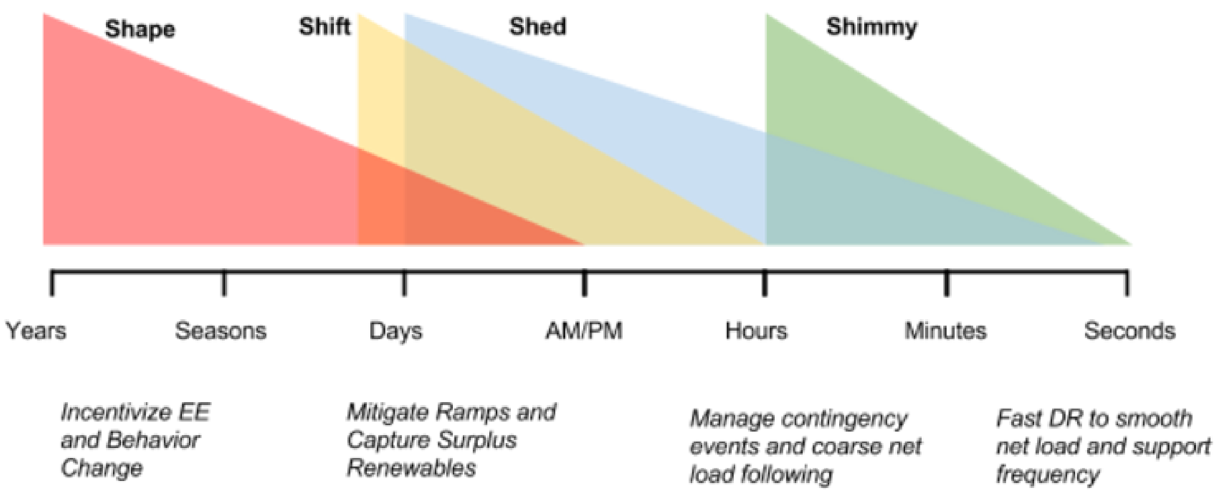


Figure 19: DR service types presented over timescale for grid service dispatch frequency and/or response.

Shaping the load with "slow changing" TOU rates and critical peak pricing is a long-term approach that results in structural changes to the stock of loads (e.g., energy

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DR Participation in CAISO markets

Controllable DR resources, including behind the meter battery storage, can provide flexible services to existing wholesale markets that can potentially defer the need for additional conventional generation resources, with sufficient penetration. Controllable DR resources can support the integration of renewable energy sources, and support policy targets for renewable standards and a low carbon future. CAISO and the CPUC continue to develop rules that encourage broader participation of non-generator resources in the wholesale markets, including load following ancillary services.

A cooperative effort for developing market, policy, and technology systems for Shifting could result in novel models for compensating/incentivizing DR enablement and response. For example, flexible capacity credits could be awarded based on an expectation of future response as buy-down for appropriately specified control technology.

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efficiency investments).[7] These equipment changes, combined with behavior change, can provide some effective Shift and Shed resources without integrating them into an explicitly dispatched market. Shift resources are flexible loads that are dispatched to capture surplus renewable electricity, and other strategies that effectively shift load from periods of high price and scarcity to load marginal cost; usually this means shifting from the morning and evening hours into the middle of the day, when solar electricity is abundant.

In this study, we modeled Shift as a dispatchable resource with enabling technology to respond to a signal. In principle this could be a centrally organized "market" for shifting energy or simply a dynamic price and/or instructions based on a price forecast. Shed resources include and go beyond conventional DR, which is often dispatched many hours or a day ahead to manage forecasted peaks at the system level. It also includes fast-shedding resources that can meet local capacity needs or distribution system needs, and respond in the event of contingency and emergency conditions. Finally, we define fast DR that can follow sub-hourly to seconds-level signals as Shimmy resources. The need for Shimmy is bounded based on the variability in the net load, but has high value for maintaining stability. In addition to the existing variability from a diverse set of loads, the growing fleet of solar and wind power generators introduces new kinds and scales of Shimmy-scale variation.

These DR Service Products all provide value to the grid, and are framed and valued differently in various balancing authority areas. In California, there are ranges of existing and emerging products for DR participation in CAISO markets, resources adequacy procurement, and at the retail or load-modifying level. We map these California DR markets to the Shape-Shift-Shed-Shimmy framework in Table 5 and Table 6 below. The choice to reframe market products into the more generic services framework was a conscious one, designed to ensure the results of the study are broadly applicable for future market structures that may not match current-day approaches. The mathematical formulations of the service types closely match CAISO and other requirements when possible (e.g., with conventional Shed). Another benefit we uncovered in the course of the study, is the usefulness of a shorthand lexicon for DR in having technical exchanges of ideas about future policy and market operations. The short names trade detail in their specificity for broader and more accessible concepts in grid management, and facilitate discussions between building scientists, policy analysts and power systems experts without necessarily requiring specific and esoteric knowledge of California market processes.

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[7] Lazar, J. 2016. *Electricity Regulation in the US: A Guide.* Second Edition. Montpelier, VT: The Regulatory Assistance Project. http://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.

Table 5: Demand response service types modeled in this study.

Service Type	Description	Grid Service Products/Related Terms	Analysis Unit	**Shape** (TOU/CPP) Included in service type analysis?
Shift	Demand timing shift (day-to-day)	Flexible ramping DR (avoid/reduce ramps), Energy market price smoothing	kWh-year	Yes
Shed	Peak load curtailment (occasional)	CAISO Proxy Demand Resources/Reliability DR Resources; Conventional DR, Local Capacity DR, Distribution System DR, RA Capacity, Operating Reserves	kW-year	Yes
Shimmy	Fast demand response	Regulation, load following, ancillary services	kW-year	No

Table 6: Demand Response service types mapped to California's conventional wholesale and retail market products.
Note: "#" Indicates service products that are included in results from both DR-PATH and RESOLVE.

	DR Service Product	California Market	Description / Notes
Shed	Peak Capacity	System and Local RA Credit	Resource Adequacy planning capacity. Requires participation as Economic DR resource and 4-hour continuous response capability requirement.
	Economic DR	Economic DR / Proxy Demand Resource	Resources in the energy market. (Proxy Demand Resource). RDRR can also bid economically in energy markets.
	Contingency Reserve Capacity	AS- spinning	Dispatched within 10 minutes in response to system contingency events. Spinning reserves must also be frequency responsive. CAISO currently has no established method for allowing DR to provide this.
	Contingency Reserve Capacity	AS- non-spin reserves	Able to respond within ten minutes and run for at least 30 minutes. The sum of Spinning and Non-spinning Reserves should equal the largest single system contingency.
	Emergency DR	Emergency DR / Reliability DR Resource	Resource can only be called when the system is in dire condition with limited dispatch. Not always in CAISO markets, however resources in these programs must register as Reliability Demand Response Resources (RDRR) in CAISO to access the wholesale energy market.
	DR for Distribution System	Distribution	Manage targeted issues. California is not currently deploying this type of DR but is the subject of study in the DRP. The capacity value is related to investment deferral in the distribution system.
Shift	Economic DR	Combination of Energy Market Participation	One mechanism for dispatchable shift could be participation in the energy market, both as a "load down" resource like PDR, and as a "consuming" resource in other hours. Current proposals in the CAISO ESDR could lead to bidirectional energy market structures like this.
	Flexible Ramping Capacity	Flexible RA -- energy market participation w/ ramping response availability	DR that counts towards flexible RA. Requires participation in the market with economic bids and 3-hour continuous response capability.
Shimmy	Load Following	Flexible Ramping Product (similar)	"Load Following" is modeled in RESOLVE as a symmetric flexibility product on a 5-minute dispatch. The CAISO Flexible Ramping Product is capacity that is awarded in the real-time market, for either increasing or decreasing load but without symmetric dispatch. The resources ramp in five minutes.
	Regulating Reserve Capacity	AS- Regulation	Capacity that follows (in both the positive and negative direction) a 4-second ISO power signal. It requires 1-hour of continuous response. Capacity is limited by the resource's 5-minute ramp.
Shape	Load modifying DR - Event-based	CPP	Utility-dispatched DR. This can be used to reduce an LSE's capacity for System RA requirement by impacting its forecasted peak load. This can be dispatched through power, reliability, or price signaling.
	Load Modifying DR - Load shaping	TOU	This is either Permanent Load Shifting or TOU style DR. This impacts the whole load shape, not just the peak. This resource is active every day and not dispatchable.

3.4.1. Shape Resource Description

Shape resources represent the effect of "load-modifying" resources like TOU and CPP rates, and behavioral demand response programs that do not have direct automation tie-ins to load control equipment. They are not modeled specifically as a service type, but the load-modifying DR effects are values under the same framework as Shed and Shift for comparison to ISO-dispatched resources.[8] These long run (TOU) and day-ahead (CPP) behavioral responses are thus comparable to Shed and Shift, but accomplished through rates or behavioral event signals. For price responsive DR, demand was compared between a flat rate scenario and three different rate mix scenarios (see Appendix E) in order to calculate hourly Shape resource impacts. These building blocks for DR help clarify and reveal the pathways for providing value on California's electricity system with an increasingly renewable generation fleet.

This study includes an assessment of modified load shapes from the effects of TOU and CPP under three rate availability and enrollment mixes, but excludes the possible effects of additional enabling technology investment or responses from prices more closely connected with the real-time, locational marginal electricity prices. Behavioral DR based on signals other than retail price (i.e., normative messaging) were not explicitly modeled, but emerging evidence suggests these resources can provide load modifications similar to peak pricing events, albeit muted in load impact percentages. With more significant investments in automatically price-responsive technology and exposure to real-time dynamic prices, it could be possible to achieve a significant portion of the dispatchable "Shift" resource we identified using price signals as opposed to conventional dispatch.

3.4.2. Shift Service Type Description

Shift represents DR that encourages increased energy consumption during times of day when there is surplus of renewable generation and smooths net load ramps associated with daily solar energy generation patterns. Energy consumption is then reduced during evening hours when renewable generation ramps down and net load increases, thereby "shifting" energy consumption. Shift resources are estimated in terms of kilowatt-hours per day of shifted load—equivalent on first-order terms to excess battery capacity that is available for daily arbitrage.

The Shift service type is DR that moves load to desired times during the day. This involves one or more periods of Shed (load reduction) paired with one or more periods of take (increasing load) during a single calendar day. For this study, we constrain the shift to be energy-neutral, meaning that the total energy (kilowatt-hour) shed is equal to the energy taken. The dispatch schedule of this resource is determined by grid needs (see Appendix H) and typically follows a

[8] See the Shape results for a description of this valuation methodology.

pattern that aims to even out system load throughout the day. Therefore, Shift DR is often scheduled to take load during times of low net load (generally during the early afternoon solar peak) and shed load during peak net load hours (generally during the evening, when solar generation is low and demand is high). This resource supports many needs of the grid, including (1) reducing peak load, which improves reliability and reduces need for peaking generation units; (2) increasing midday energy consumption, which reduces solar energy curtailment; and (3) decreasing afternoon ramping needs, which is accomplished by the combination of (1) and (2).

The following end-use services provide the resources for Shift service types:

- **Thermal Shift:** refrigerated warehouses; air conditioning, heating and ventilation; water heating (boilers)
- **Batch Process Shift:** data center batch processes, waste water treatment and pumping, agricultural pumping
- **Electricity Storage:** batteries, electric vehicles, pumped hydroelectric storage (not modeled here)

Figure 20 shows Shift strategies' impacts. Shift resources generally provide value by moving loads into midday hours to eliminate overgeneration from solar PV.

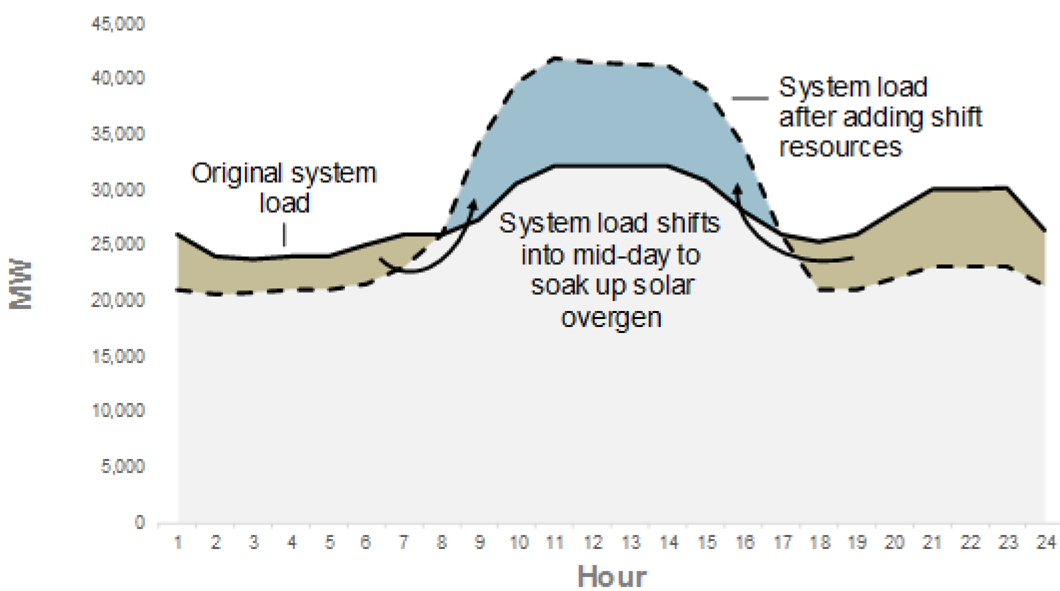

Figure 20: Illustrative Shift resource.

3.4.3. Shed Service Type Description

Shed describes loads that can occasionally be curtailed to avoid system upgrades and generation facilities related to peak capacity—at the statewide level, in local load pockets, and on the distribution system with a range in dispatch advance notice times. Shed is measured and estimated in terms of equivalence to a peak power generator that is available during the top 250 hours of the year, a heuristic we verified based on a parallel analysis of the estimated load-carrying capacity of demand response. Figure 21 presents the 2025 system load summary for gross, renewable, and net loads. The black dots indicate the top 250 hours used in our analysis of the Shed service type.

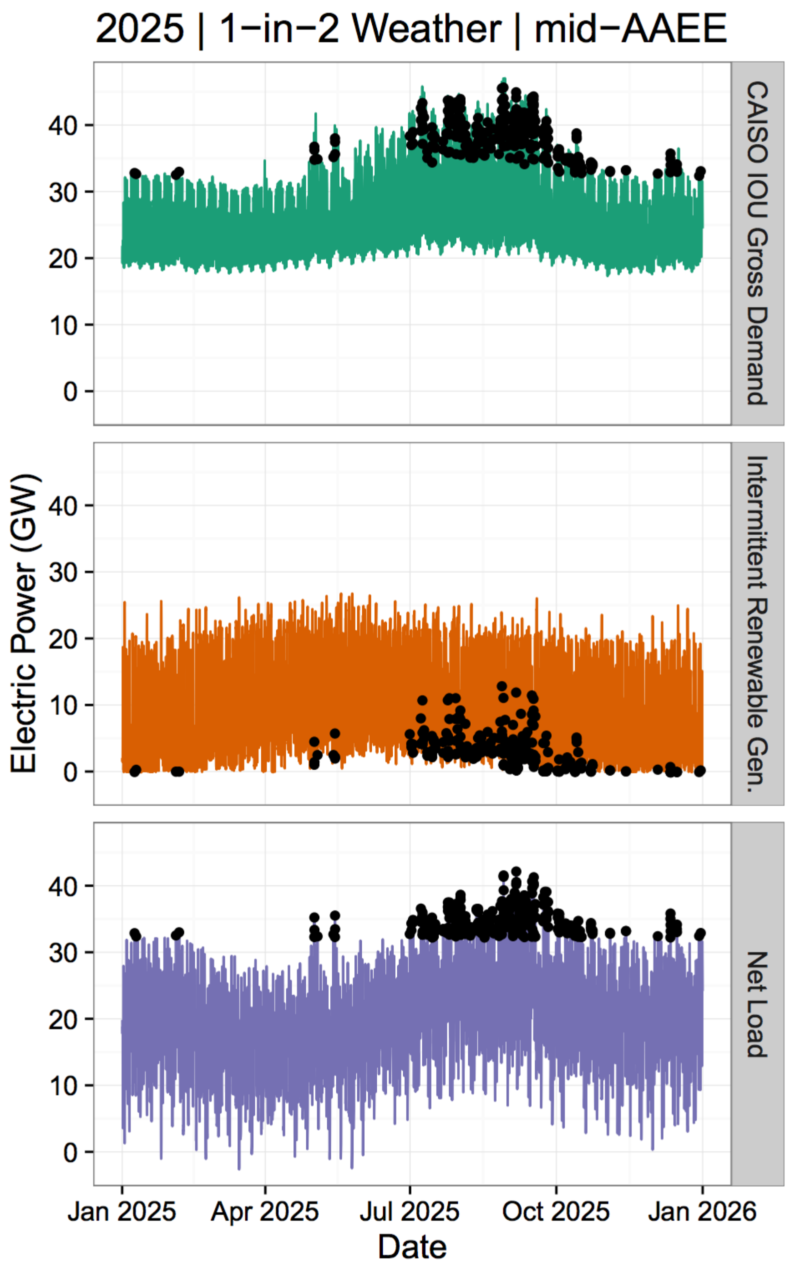

Figure 21: System load summary for 2025, in the 1-in-2 weather year. The black points indicate the top 250 hours of the year.

The Shed service type represents DR that is called to reduce customer load demand during peak net load hours. This is the service that was reported on in the current study's Phase, and represents traditional "hot summer day" DR. Shed service supports the grid by reducing the peak capacity required by the grid, and therefore improves reliability and reduces the need for expensive peaking generation units. Service interruption is the most common type of conventional DR, falling under the Shed service type category.

Figure 22 shows a representative illustration of Shed resources, also known as "conventional demand response." Dispatching Shed resources can potentially avoid the costs of building and running marginal gas peaker plants.

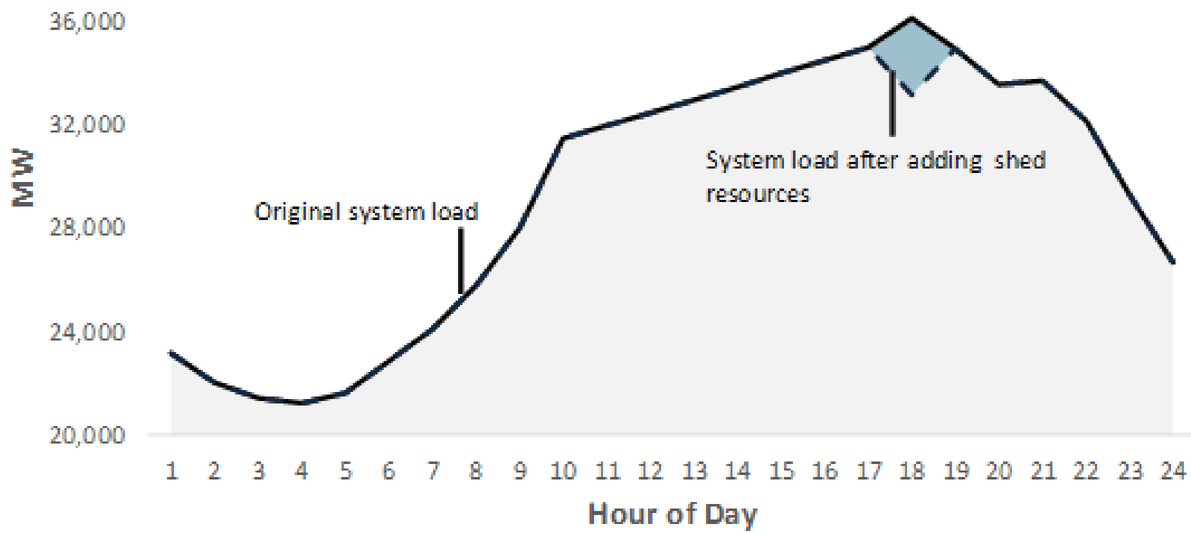

Figure 22: Illustrative Shed resource.

3.4.4. Shimmy Service Type Description

Shimmy involves using loads to dynamically adjust demand on the system to alleviate ramps and disturbances at timescales ranging from seconds up to an hour. Estimates for Shimmy are based on the annual weighted average availability of appropriately fast resources, with emphasis on hours when the price in the ancillary services regulating reserves markets is highest.

The Shimmy service type represents "Fast" DR and includes what is often referred to as ancillary services (AS), which support the continuous flow of energy through the grid to meet demand. In other words, this service corrects the real-time, continual gap between predicted (and therefore dispatched) demand and actual demand. This gap can be from either too much or too little predicted demand, and therefore Shimmy resources must be able to both take and shed load on a short timescale. We estimate DR potential for two types of Shimmy service: (1) load following, where the resource follows a five-minute dispatch signal, and (2) regulation, where the resource follows a four-second dispatch signal. Shimmy DR supports the grid by reducing the need for generation units to provide this service.

The Shimmy function of DR is shown in Figure 23. This reduces the need for other resources (e.g., storage, thermal generators) to provide these functions, leaving them more available to provide other value, such as freeing up batteries to charge during periods of overgeneration to reduce curtailment.

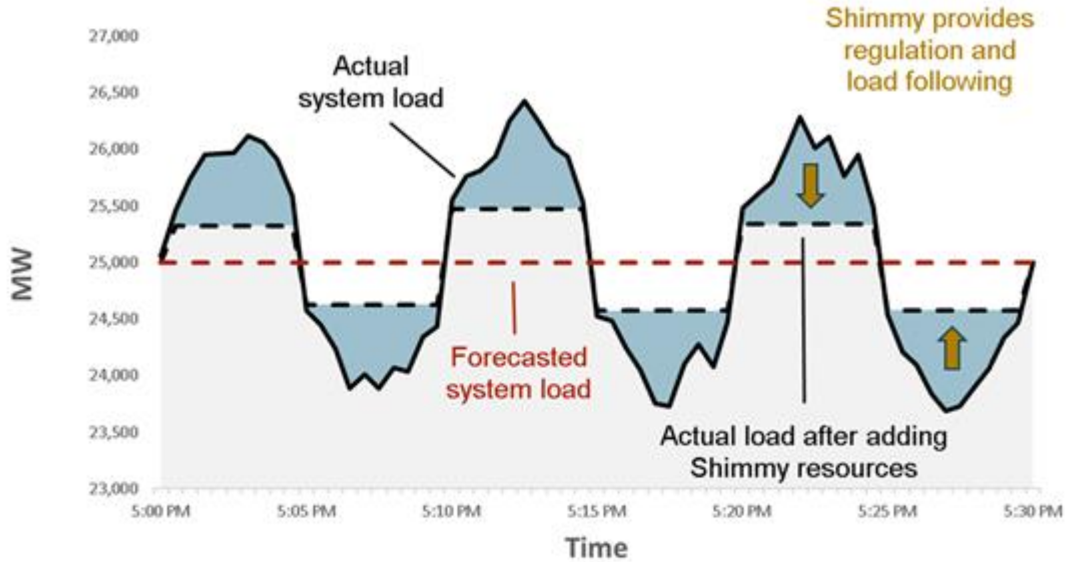

Figure 23: Illustrative Shimmy resource.

4. Economic Evaluation of DR Potential

4.1. DR Supply Curves

Results of this study are primarily represented in the form of DR supply curves (see Figure 24 for an example). These curves show the cumulative DR quantity available (x-axis) for a range of levelized DR cost values (y-axis). Different colors indicate different DR scenarios, with dotted lines indicating a 1-in-2 weather year, and solid lines indicating a 1-in-10 weather year. The DR quantity shown is the total across all utilities, customer clusters, end uses and available technologies. The units are either power (Shed, Shimmy) or energy (Shift) over the entire year, aggregated from hourly values as described in Appendix G. Levelized cost (y-axis) refers to annualized cost per unit of DR capacity, including technology costs, financing, marketing and administration. Shed and Shift services can be provided by the Shape resource (TOU and CPP), but this resource is not included in the supply curve calculations. Therefore, we represent the Shed or Shift DR provided by Shape as a bar at zero cost that effectively shifts the supply curve to the right.

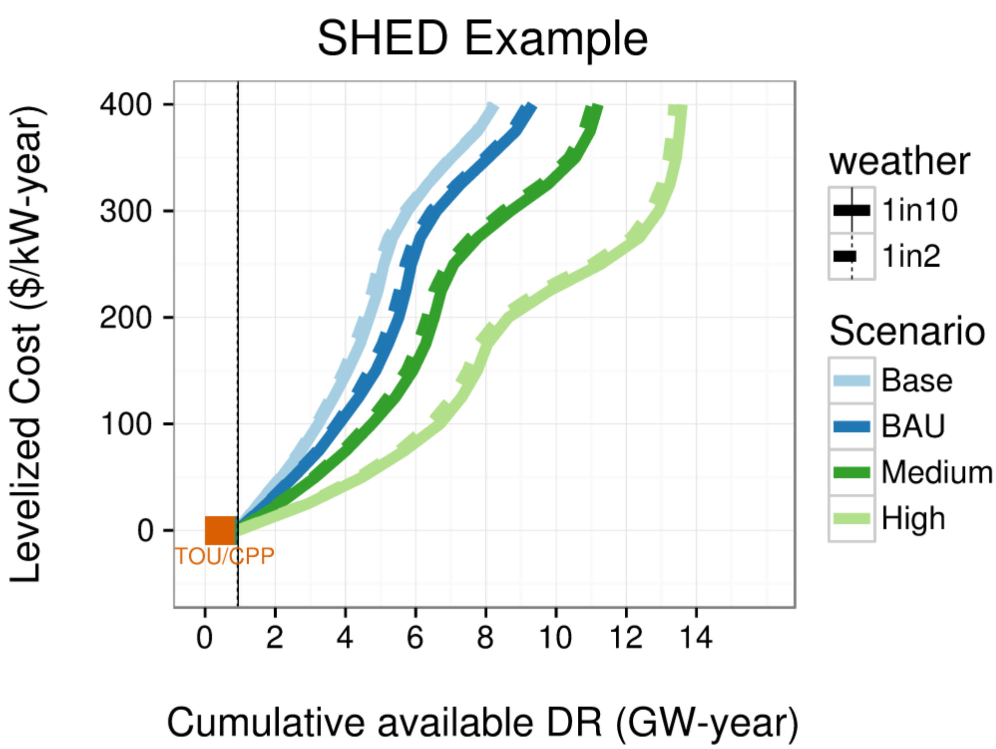

Figure 24: Example supply curve for Shed-type DR.

The cumulative available GW-yr of DR (x- axis) includes three potential DR market and technology trajectory scenarios: (1) Business-as-Usual (BAU), (2) Medium, and (3) High. Line colors indicate the DR scenario; a solid line and dashed line is typical (1-in-2) and extreme (1-in-10) weather cases, respectively, under the Rate Mix #3.[9]

The DR supply curves we estimate are an expression of what types and quantity of DR will be available across a range of costs. The supply curves only include one "category" of DR (Shed, Shift, Shimmy), and have different scales and shapes, depending on the geographic scope of the analysis, market, and technology scenarios, and cost accounting frameworks. To evaluate whether and how much DR is economically viable, we compared the supply curves with estimates of the value of the specific service to the grid, using two different valuation methods: (1) price referent, and (2) levelized value, both described below.

4.2. Monte Carlo Simulation for Technology Uncertainty

We used Monte Carlo simulation to estimate how uncertainty in modeling assumptions affects the levelized cost of DR enablement, and we identified two key sources of uncertainty in estimating the cost of DR enabling technologies:

1. Uncertainty in expected cost/performance of emerging DR-enabling technologies, that is, the costs and performance of the DR technology available for sale in the U.S. market
2. Uncertainty in site-specific performance and enablement costs, that is, the costs to enable a site with the DR technology, and the actual performance at the premise

We simulate variability in modeling assumptions due to both sources of uncertainty by using stochastic sampling to populate the enabling cost, performance, and lifetime of each enabling technology for each cluster. We randomly sample values for each data field from distributions specified in the enabling technologies database described in Appendix G. Appendix G also provides a detailed description of the Monte Carlo simulation procedure.

We generate many realizations of stochastically populated inputs related to technology cost, performance and lifetime. In addition to these stochastic realizations, we generate one deterministic realization that contains inputs obtained directly from the literature without any stochastic variation.

Due to stochastic differences in modeling assumptions, the levelized cost of DR-enablement for a particular cluster differs in each of the realizations. These differences give us a range of supply

[9] Recall that the DR Potential estimates in this study are developed under the assumption that default TOU pricing will be in effect for all IOU customers. This assumption about TOU ultimately reduces the amount of load that is available for DR services, similar to advanced EE initiatives (SB 350). As we developed the supply curves of DR potential, we include load shapes that have been modified by Rate Mix #3, that is, our analysis applies the TOU load impacts to modify the base case load shapes which make an overall reduction to the load available for DR in each hour.

curves. The results below include supply curves for all of the stochastic and deterministic realizations, and box plots that show the range and distribution of results across realizations.

A simple example with two elements of the Monte Carlo simulation illustrated in Figure 25 below, using Residential "Smart" Thermostats as an example. There are two stages shown: Stage 1 establishes the average cost of technology for a given model run. The estimate is a random draw from a triangular distribution with a low, medium and high value. These Stage 1 estimates are the basis for the Stage 2, mid-point in which each site has a specific randomly selected value. The Monte Carlo estimates thus include variability related to broad market trends (Stage 1), and variability related to intrinsic site-to-site differences in the enabling technology cost (Stage 2). While the illustration only shows an enabling cost for technology and one performance metric, the implementation included a range of factors subject to variation: measure lifetime, operating costs, marketing cost, financing cost, administrative costs, and independent performance factors for each DR service type.

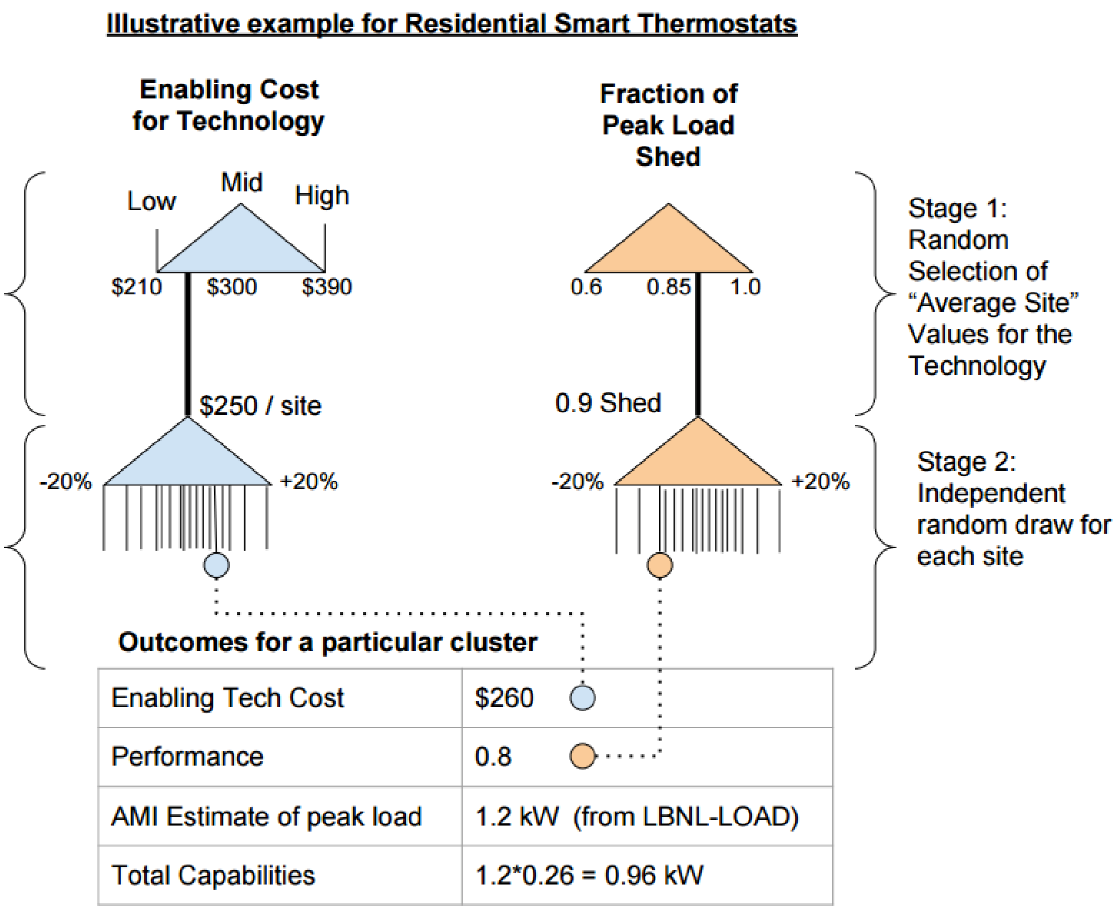

Figure 25: Illustration of Monte Carlo analysis approach for a simplified example.

4.3. Cost Perspective

When defining the cost of DR technology systems (i.e., the supply curves), we define the cost perspective as that of a DR aggregator who must pay for any incremental need for technology at a site, along with paying for incentives, program administration, marketing and any financing costs. The aggregator can receive revenue from wholesale market participation. The costs are presented in "levelized" terms—the expected average annual long-run cost, amortizing the initial cost of technology over its lifetime using a 7 percent weighted average cost of capital. In cases where technology is preexisting at a site (e.g., if a customer installs a smart communicating thermostat or there is preexisting control hardware from a previous DR program), we reduce the initial costs accordingly, based on the expected fraction of sites with that preexisting stock.

4.4. DR Sources of Revenue

Demand response services are able to receive revenue by participating in CAISO wholesale markets, as shown in Table 7. In this study, Shed services participate in the energy market and receive RA capacity payments, while Shimmy services participate in the AS market. Participation in other markets (including markets that do not yet exist) is possible but not quantified in this study. Such markets could include Reverse DR, where payments are given for taking additional energy from the grid, and Flexible Ramping capacity payments. Hourly prices for the energy and ancillary services markets quantified in this study are obtained from a PLEXOS simulation run by CAISO based on the 2014 LTPP scenario (CPUC 2013). We also consider high and low DR scenarios that capture price profiles where DR is more or less valuable to the grid. These scenarios are generated by increasing the price signal amplitude and multiplying the existing signal by a constant value (1.1 for the high-value scenario, and 0.9 for the low-value scenario). In all three scenarios, we maintain the upper and lower price caps specified in CAISO's modeling assumptions.

Table 7: CAISO markets considered for three DR service types.
NOTE: Checkmarks (✓represent market revenue calculated in this study, while asterisks (*) represent future potential sources of market revenue.

Service Type	Ancillary Services Market	Energy Market	Capacity and RA Payments	Flexible (Ramping) Capacity Payments	Reverse DR (future)
Shed		✓	✓		
Shift	*	*	*	*	*
Shimmy	✓				

Results for this study are aggregated to annual values, and therefore assumptions must be made for the dispatch frequency and timing of DR resources. Methods used to calculate annual revenue are directly tied to those used to aggregate hourly DR availability into annual values (Appendix I). Therefore, Shed DR energy market revenue is calculated as the total revenue earned in the top 250 net load hours of the year, where each hour of revenue is the amount of DR available times the market price. We do not include any market payments for Shift resources, but note that if significant market integration challenges are overcome there could be opportunities in a range of markets. Shimmy services are assumed to be needed during all hours of the year, and the expected annual revenue is the sum of hourly availability times hourly market price, with an assumption that shimmy resources are dispatched for an average of four hours per day.

4.5. Cost Frameworks

Our results include four cost frameworks that include various adjustments to the cost of DR resources at the system level. These "cost frames" enable understanding of how the portfolio of value that is provided by DR technologies can change the estimates of how much is cost-effective. In the cost frame listing below we include the shorthand description for each that is used in

1. **Gross total cost: ("Total")** The full cost of DR technology, soft installation costs, administration, marketing, incentives, and maintenance is included in the cost of services.
2. **Net cost with ISO market revenue stream**s ("Net Revenue")**:** Under this adjustment, the DR supply curves were adjusted to be lower, based on expected market revenue

streams, such as energy market revenues, that effectively decrease the levelized annual cost of DR technologies that can provide the DR service type.

3. **Net cost with revenue streams and site co-benefits ("Net Revenue + Site Co-benefits"):** Same as 2 above with the addition of co-benefits based on site-level value included to "buydown" the upfront capital costs of DR technologies. For certain end uses, the same technologies or device upgrades—such as smart thermostats, building energy management systems (EMS) or lighting controls—that enable DR also produce other cost benefits because they also allow a building to operate more efficiently (Goldman et al. 2010). Co-benefits were modeled as a percentage of enabling technology costs by which the upfront cost attributed to DR would be reduced. We applied co-benefits only to the following end uses: lighting (luminaire-level, zone level) controls, refrigerated warehouses, residential air conditioning (smart thermostat), commercial HVAC (EMS), EV chargers and batteries. In the co-benefits analysis, we made an assumption that the value DR investments provide to sites can be monetized by the aggregator, or that DR is adopted as part of a portfolio of measures where the portfolio approach leads to spillover cost reductions for DR.
4. **Net cost with revenue streams, co-benefits, and distribution system services ("Net Revenue + Site + Distribution Sys."):** Same as 3 above with the addition of revenue from serving the needs of the distribution system in ways that reduce the cost of operating or maintaining the system. We included an example set of possible distribution system benefits in the model, based on typical ranges of values and not based on an explicit model of distribution system needs. Our approach assigned a randomly selected distribution system value based on an expected range of values, where most sites have very low value (no constraint on the distribution system that needs serving) while a few have moderate to high value (where there are constraints on the distribution system that can be mediated with DR service).

4.6. Co-Benefits of DR Technologies

For certain end uses, the same technologies or device upgrades that enable DR (e.g., smart thermostats, building EMS, or lighting controls) produce other cost benefits by allowing a building to operate more efficiently (Goldman et al. 2010). These economic benefits are referred to in this study as "co-benefits," and were modeled as a percentage of enabling technology costs by which the upfront cost attributed to DR would be reduced. In practice, co-benefits could be realized through customer bill savings that come from DR-device-induced efficiency or energy efficiency (EE) incentives paid by a third party that help buydown the upfront cost of DR. Co-benefits were included in our study for the following end uses: lighting (luminaire-level, zone level) controls, refrigerated warehouses, residential air conditioning (smart thermostat), commercial HVAC (EMS), EV chargers, and batteries.

A previous study (Starr et al. 2014) showed co-benefits of implementing EE and DR measures together in a refrigeration system in the range of 25 to 40 percent, primarily from jointly completing the design, installation, commissioning, and incentives at the same time. However, in our study, to be more conservative, we assumed 33 percent co-benefits (the average of 25 percent and 40 percent; see Table 8) for the end uses that are considered (residential air conditioning smart thermostats, commercial HVAC with EMS, and refrigerated warehouses). Based on storage value streams collected from the Rocky Mountain Institute, we assumed a co-benefit of 50 percent for batteries, which in addition to savings from TOU price arbitrage and improved reliability locally (i.e., keeping critical loads working with backup power) can also provide co-benefits when linked with rooftop solar PV. We assumed co-benefits of 75 percent for lighting (luminaire and zonal), which has controls typically installed to receive energy savings benefits. Lastly, we assumed that the co-benefits of PHEV and battery electric vehicle (BEV) charging were 75 percent.

For added fast DR technologies such as variable frequency drive pumps or motors for agriculture, wastewater pumping, and wastewater process, we assumed a co-benefit of 75 percent from energy savings.

Table 8: Summary of DR technology co-benefits. Co-benefits reduce the cost of the technology by a defined fraction of the initial cost.

End-Use and DR-Enabling Tech	Initial DR Technology Cost Reduction from Co-Benefit	Potential sources of Co-benefits
Commercial and Residential HVAC (EMS and Smart Thermostat)	30%	Energy efficiency and kW reduction
Refrigerated Warehouses	30%	Energy efficiency and kW reduction
Batteries	50%	Consumption optimization, kW reduction, backup energy supply
Agricultural Pumps	75%	Energy efficiency, kW reduction and controllability
Wastewater Process and Pumping technologies	75%	Energy efficiency, kW reduction and controllability
Commercial and Residential BEV and PHEV Level 1 and 2 charging (Fleet and Public)	75%	Fast Charging and controllability
Lighting (Luminaire-level and Zonal)	75%	Energy efficiency and kW reduction

4.7. DR's Value to the Distribution system

For constrained feeders, value may be captured by DR technology **if the DR can be reliably dispatched and controlled to support distribution system operations.** In the version of the model used for this report we *randomly assigned* these "distribution system co-benefits" throughout IOU service territories as an illustrative case in the model results. Pilot studies have shown that distribution system DR value is highly concentrated and depends on feeder-level diversity. Our assumptions were a synthesis of possible cases that mirror early understanding of potential, and are described in Table 9 below wherein, distribution system benefits were randomly assigned within the DR Futures model throughout the IOU service territories to model, at first order, the potential cost savings from avoiding distribution system infrastructure upgrades required from load growth.

Table 9: Distribution system DR benefits assumption summary.

Distribution system DR illustrative example assumptions	
Performance Estimate	Equivalent to "conventional DR" shed in magnitude (limited by installed equipment capacity as well). Does not change propensity to adopt.
Mean Value	$25/kW-year systemwide
Site-Specific Value Assignment ***(Modeled as Truncated Log-Normal)***	• 50% of sites < $1.50 /kW-y • 75th percentile is $20/kW-y • Only top 5% of sites $160–$300

4.8. Economic Synthesis of Results

The supply curves are generated under the various cost frameworks discussed above and provide a visual representation and tool for interpreting the available DR resource where it intersects a given demand curve in our forecasted scenarios and weather years.

The third tool utilized for this study was the Renewable Energy Solutions (RESOLVE) model, developed by Energy and Environmental Economics (E3). RESOLVE is a power system operations and dispatch model that minimizes operational and investment costs over a defined time period by selecting an optimal portfolio of generation, storage, and demand-side resources.

The results provided by the DR-Path model are fundamentally represented in terms of supply curves that express the available quantity of particular DR resources across a range of possible costs for that DR resource. These results, like all of the results we show, are "levelized" costs, meaning they are the total cost of providing the DR service (e.g., upfront investment in equipment and enabling technology with ongoing annual operating expenses) amortized over the useful life of the DR technology. The decision of "how much DR" is useful requires a comparison of these costs to the value of service, providing estimates of economically cost-effective DR. We used two different methods to make these comparisons, both shown in Figure 26. We refer to these valuation methods as (1) the price referent approach, and (2) the system levelized value approach.

The Price Referent Approach: One method for comparing the available supply to a value is to define a "price referent," which is the cost of procuring an alternative resource that could meet the same needs as the DR service (e.g., a natural gas combustion turbine that could carry peak load instead of peak Shed DR). If you assume that these resources will need to be procured one way or another, the price referent effectively sets a DR cost ceiling, below which any available DR is economically more cost-effective than an alternative resource. We only implemented the price referent approach for analyzing Peak Shed DR, which is comparable to the conventional economic assessment of Peak Capacity DR. When programmatic peak capacity programs are assessed for cost-effectiveness, they are done at a portfolio level of resources (e.g., residential DLC program over an entire IOU territory) and compared to an administratively defined (4 pm to 9 pm) number of hours in the summer. In our approach, the supply curves for each site level end-use enabling technology described the availability and controllability for each resource in the top 250 net load hours, defined the costs, assigned benefit streams, and compared that supply curve to the price referent.

The System Levelized Value Approach: Another method for comparing supply with the value to the grid is to use explicitly defined "levelized value curves" for service (which are analogous to demand curves). In this study we used the RESOLVE model to estimate the effective value of DR by introducing a range of zero-cost quantities of DR into the model. RESOLVE estimates of the total cost of operating and investing in the grid, and we used the difference in the total cost before and after DR is available to estimate the value provided to the system for a given quantity of DR. RESOLVE expresses a range of pathways to value: avoiding investment in conventional generation, reducing costs of renewable portfolio requirements, and operational savings. We used the average total "levelized value" to identify where the cost of supplying DR was lower than the value created. The system levelized value approach utilizes the intersection of a supply curve and levelized value demand curve as an estimate of the equilibrium, where the cost of additional DR supply equals the value created. Demand response with a unit cost below this equilibrium price is considered economically cost-effective. We used the levelized value method for assessing potential for each of the supply-DR options: Shed, Shift and Shimmy.

In both cases—the price referent approach and levelized value approach—the resulting DR potential takes on a range of cost-effective quantities. These depend on the differences between possible supply curves (e.g., from one DR scenario to another) and on the particular price referent or levelized value curve that was the basis for comparison. Note that in Figure 26, we show how when there are cases with relatively "flat" supply curves there can be a wide range of quantity estimates if the price referent is used, or if the levelized value curve is flat in the region of intersection. Our economic analysis provides a range of benchmark cases for which DR type is and is not cost-effective, given different system conditions and for different system services. The price referent informs cost-effective benchmarks for load curtailment at the coincidence of distribution, transmission, and generation avoided costs. The RESOLVE model and levelized value curves identify DR that is cost-effective for overgeneration and ramping, given system conditions for a high RE future.

In this study, we explored the sensitivity of the estimates for DR potential in a variety of ways using DR scenarios (business-as-usual, medium, and high) that provide qualitative categories for market trends, with RESOLVE scenarios that show the differences in the value of DR based on whether there is relatively low- or high-curtailment of renewable electricity expected, and with a "Monte Carlo" approach to estimating many possible supply curves for each scenario.

The illustrative examples in Figure 26 are meant to clarify how the elements of DR supply and demand curves are constructed. The supply curves are colored based on DR scenario, and are adjusted if there is load-modifying DR (e.g., TOU price) that provides an equivalent service. The demand curves take the form of either price referent or system levelized value curves.

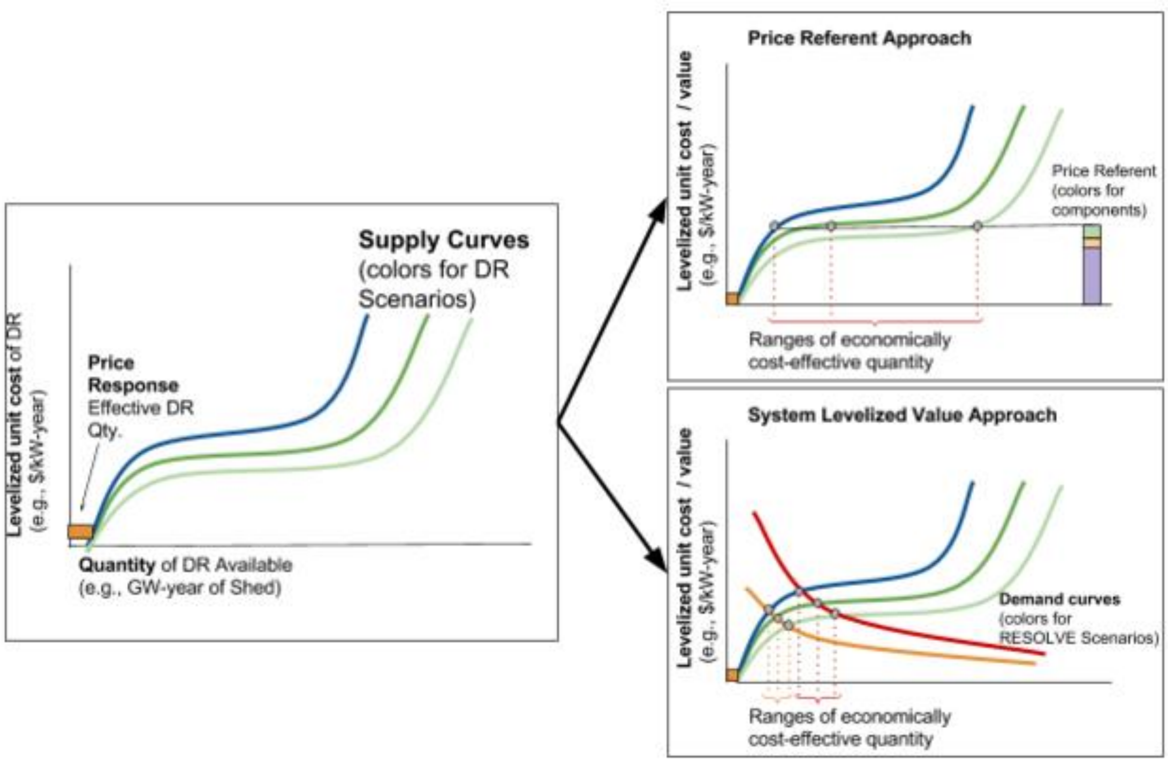

Figure 26: Illustrative diagram showing two approaches for DR economic valuation used in this study: Price Referent and System Levelized Value.

5. Results and Discussion

5.1. Demand Response Futures

This study's findings suggest that there are many opportunities for flexible loads to provide value to the operation of a renewably powered electricity system and improve the performance of investments in generation capacity and infrastructure. The needs of the system and capabilities of flexible loads span a range of timescales and geographic focus areas—from fast DR providing regulation to hours- or day-ahead response. In this section, we go into greater detail to discuss **Shape**, **Shift**, **Shed** and **Shimmy** DR services.

The Phase 2 study analysis includes results from E3's RESOLVE model, which estimated the value of DR to the CAISO system while addressing California's complex energy future with increasing RPS requirements and energy efficiency targets. The RESOLVE model introduced DR into a co-optimization model as a resource with no costs, and determined the value by examining the operational and fixed cost savings that result from each incremental megawatt of the DR service types that reduce the need to curtail renewable resources.

From the RESOLVE model results, we constructed demand curves based on the value of the DR, but these do not incorporate any costs associated DR procurement. Rather, the LBNL DR Futures model estimated those costs in developing the supply curves. Each model provided a value for DR; the RESOLVE model estimated the value to the CAISO system, while the DR Futures model estimated the costs of providing the DR services.

In the following sections, we present E3's analysis results from the RESOLVE model. For each service type category (Shed, Shift and Shimmy), results were produced by integrating the RESOLVE demand curves with the DR Futures' supply curves. It should be noted that E3 modeled each of the above advanced DR technologies at zero implementation cost. Thus, the economic results discussed in this report reflect merely the economic *benefits*.

5.2. *Shape* – Price Response

The Shape resource simulates DR potential through load modification in response to price signals such as TOU or CPP, or via behavioral signals, such as normative comparisons or public appeal. Exposing end users to time-varied prices can induce load shifts and sheds that meet the same needs as directly dispatchable technology—a long run reshaping of the daily load. This and other price-based "load-modifying" DR can provide significant value. In this study, we introduced three TOU/CPP rate scenarios in addition to a flat rate scenario, each of which provided the inputs for the Shape DR resource. Nexant developed estimates of residential load impacts,[10] which LBNL then used to model the systemwide load impacts from three mixes of retail rates, as summarized in Table 10. For a detailed description of the rates and assumptions utilized in each of the rate mixes, see Appendix E.

The Shape resource was analyzed with three different rate mixes (described in Table 9 below) within the context of two service types. We estimated the shape resource potential in terms of how it could provide Shed or Shift services through load impacts. The amount of Shed DR provided was quantified by determining the resource's ability to reduce load during the top 250 hours; this was the method used for all Shed resources. This allowed us to attribute market revenues and distribution system benefits consistently, prescribing value to Shape resources over the top load hours of the year. We also examined the impact of the Shape resource as a Shift service type, where we quantified the amount of energy shifted daily during desired dispatch hours as a result of customer response to price signals or behavior based programs[11].

It is important to note the way TOU and CPP are organized and presented in the supply curve results framework. Because TOU and CPP are load-modifying demand response (LMDR), we excluded them from "participating" in the supply side resources for RA. Rather, TOU/CPP scenarios provided LMDR as a base load shift and supply-side DR resources were procured and utilized in addition to that base load shift. Therefore, TOU and CPP impacts effectively shifted the supply curves to the right, as portrayed by horizontal bars along the x-axis that start at 0 GW and extend to the estimated Shape DR impact.

The Shape resource includes behavioral responses to price signals or behavioral signals, (e.g., Flex Your Power and behavioral demand response programs). In our evaluation, we included TOU and CPP rate price signals and considered behavioral programs to produce similar, but muted, load modifications as CPP signals. Below we provide an overview of the assumptions and considerations for the shape resource analysis.

5.2.1. Residential TOU Rate Mixes for Shape Service

Figure 27 illustrates the hourly TOU pricing structure for PG&E's option 2[12] and SCE's Option

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[10] See Appendix E for more information on the methodology for developing price response load impacts, rates, and elasticities.

[11] Note that Shape as Shift is modeled as a load modifying resource where Shape is modeled with the same parameters as the Shift service types, but as price response and not dispatchable. In contrast, the Shift service type resources are modeled as dispatchable supply side DR services.

[12] PG&E Advice Letter 4764-E Residential TOU pilot rates https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4764-E.pdf.

3,[13] from the Residential TOU pilot Advice Letters filed in December 2015. PG&E's Option 2 features a peak period from 6–9 pm during all seasons, with an additional off-peak from 4–6 pm and 9–10 pm in the summer. SCE's Option 3 features similar, but longer, peak (4–9 pm) and partial peak (11 am–4 pm and 9–11 pm in the summer) periods, with an additional "super off-peak" period from 11 am–4 pm in the spring. For the commercial sector, we include default TOU and CPP rates under all three rate mix options.[14] These rate structures, along with a standard flat rate and a CPP option, were combined to generate the three rate mixes used in this study (Table 10).

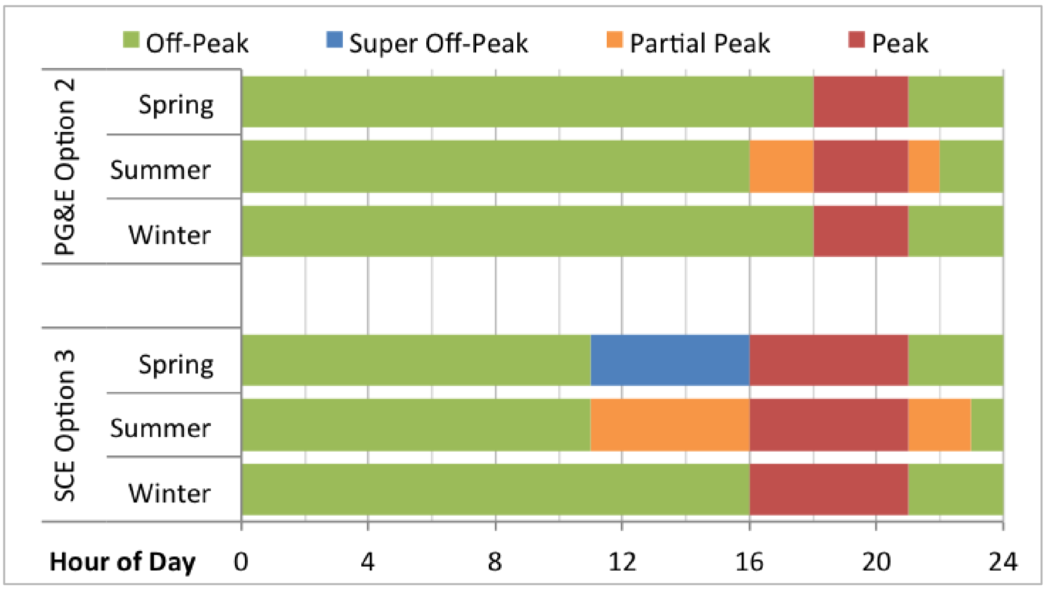

Figure 27: Time-of-use hourly structure for PG&E Option 2 and SCE rate Option 3 peak, off-peak, super off-peak, and partial peak periods.

[13] SCE Advice Letter 3335-E and 3335-E-A Residential TOU pilot rates https://www.sce.com/NR/sc3/tm2/pdf/3335-E-A.pdf.

[14] See Appendix E-6 "Price Responsiveness Model" for more information on the commercial sector TOU and CPP rates and assumptions used in this analysis.

Table 10: Shape resource retail rate mixes.

Rate Mix	Residential			Non-Residential
	Default	Opt-in	Default Opt-out	
Rate Mix 1	PG&E Opt 2	SCE Opt 3	PG&E Flat	TOU and CPP impacts derived from CA Statewide TOU Load Impact report, Christenson 2015.
Rate Mix 2	PG&E Opt 2	CPP	PG&E Flat	
Rate Mix 3	PG&E Opt 2	—	PG&E Flat	

Rate Mix #1 is structured as follows for all residential customers in the IOU service territories:

- PG&E Option #2 as the default rate with 75 percent enrollment
- SCE Option #3 as an opt-in rate with 15 percent enrollment
- Standard rate for customers that opt out of the default tariff with 10 percent enrollment

Rate Mix #2 is structured as follows:

- PG&E Option #2 as the default rate with enrollment at 90 percent of customers.
- Critical Peak Pricing (CPP) as an opt-in rate with a 15 percent customer enrollment rate
    - Customers that opt in to the CPP rate are also enrolled in the PG&E Option #2 TOU rate (dual participation)
- PG&E Standard flat rate for 10 percent of customers that opt out of the default tariff

Rate Mix #3 is structured as follows:

- PG&E Option #2 as the default rate with 90 percent enrollment
- Standard rate for customers that opt out of the default tariff with 10 percent enrollment

Figure 28 presents the amount of Shed service that can be provided by Shape resources ("Shape-as-Shed"). The x-axis indicates the total Shed DR GW provided by the various TOU/CPP rate mixes. The Shape-as-Shed DR resource is calculated by taking the price response load impacts from the top 250 hours of the year. We estimated that under Rate Mix #1, approximately 0.9

GW of load reduction is achievable from the residential and non-residential customer sectors during the top 250 net load hours of the year in the mid-AAEE scenario.[15] Under Rate Mix #2, which includes a residential CPP option, approximately 1 GW of peak load reduction is achievable. Under Rate Mix #3 (used in the Phase 1 analysis), we estimated a potential of 0.8 GW peak load reduction (out of approximately 40 GW net load peak). For each of the Rate Mix options, non-residential CPP rates are included, thus, load impacts from CPP are included in the results.

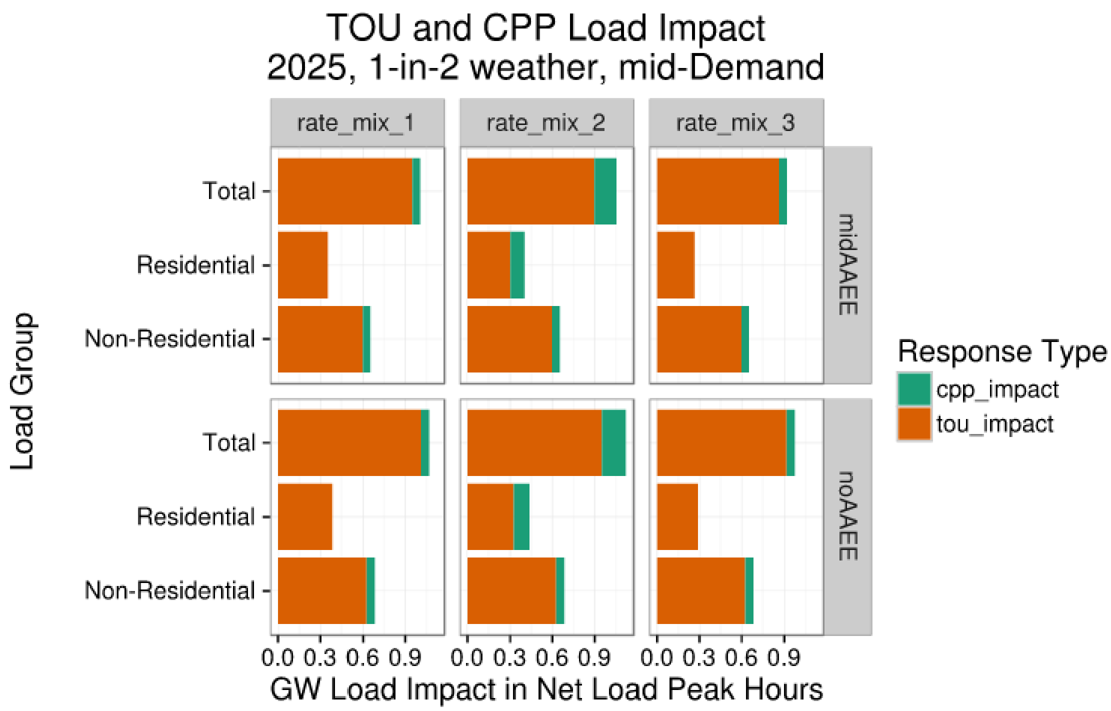

Figure 28: The Shape-as-Shed resource for 2025 under the three Rate Mixes under the two EE scenarios: no AAEE and mid-AAEE.

The Shape-as-Shift DR potential is approximately 1.8 GWh per day for 2025, indicating that significant load can be shifted throughout the day with price signals from retail rates. Figure 29 presents the results from the Shape-as-Shift analysis, where we found that each of the Rate Mixes performs equally well as a Shift service, with Rate Mix #2 (Optional CPP rate) providing slightly higher daily DR Shift results in 2025. The x-axis indicates the total GWh per day of effective shift DR provided by the various TOU/CPP rate mixes. The Shape-as-Shift DR

[15] For CPP valuation, we assumed that 15 events occur on the days with the highest daily peaks, each lasting 4 hours, would be dispatched during the summer months, for a total of 60 hours.

resource was calculated by taking the price response load impacts from a randomly assigned (Monte Carlo) dispatch of hours in the year.

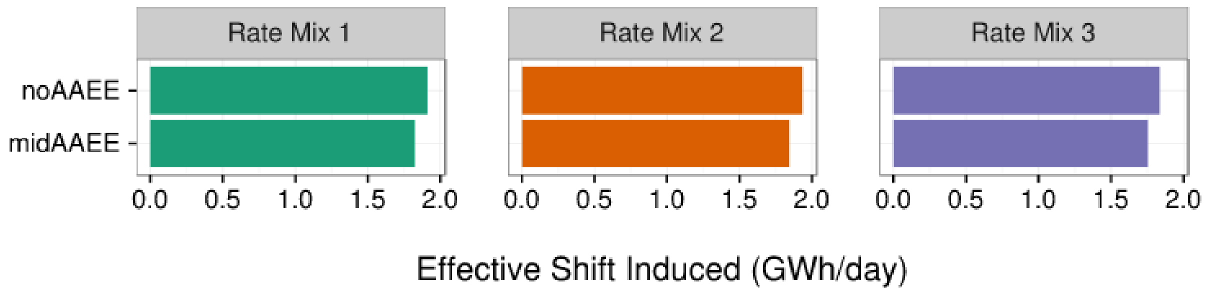

Figure 29: The Shape-as-Shift resource for 2025 under the three Rate Mixes under the two EE scenarios: no AAEE and mid-AAEE.

We estimated that the effects of TOU and CPP pricing provide the equivalent of approximately 1 GW in Shed resource and 1.8 GWh/day in Shift resource.[16] The average total daily load in 2025 is 600–700 GWh, so the Shape-Shift resource represents approximately 0.3 percent of load shifted. This is based on estimates of how "static" TOU retail pricing structure are expected to change load, and how those modifications provide service equivalent to Shed and Shift service described above. This study included modified load shapes from the effects of TOU and CPP under three mixes of rate availability and enrollment, but did not include the possible effects of additional enabling technology investment or responses from prices more closely connected with the real-time locational marginal price of electricity. With more significant investments in automatic price-responsive technology and exposure to real-time dynamic prices it could be possible to achieve a significant portion of the dispatchable Shift resource we identified using price signals as opposed to conventional dispatch. A distributed price-responsive portfolio of loads that can shift may be more cost-effective than using centralized dispatch and payments through specific supply-side markets for the Shift resource.

5.2.2. TOU and CPP Pricing Impacts

The load impacts for TOU and CPP pricing were calculated in a standalone model that predicts load impact based on a range of demographic factors for each of the rate options in the study. The combined impacts from a mix of rates (see Figure 30, Figure 31, Figure 32 and Figure 33) below show the load impacts that are the basis for estimates of the equivalent Shed and Shift DR. Note that the residential TOU rate impacts are energy neutral over the course of the year,

[16] It should be noted that CPP is available for dispatch up to 15 times per year and must be called a day in advance of a peak capacity event. Inasmuch, there is a risk of forecast error for predicting the load impacts from CPP events.

with slight load increases in the non-summer months and load reductions that are concentrated on the net load peak hours in the summer. The non-residential load impacts we included as an illustrative estimate includes a structural conservation behavior element, as was described in Christensen & Associates' report on Statewide Time-of- Use Scenario Modeling for the 2015 California Energy Commission Integrated Energy Policy Report.[17]

With different timing and price ratios, we expect that TOU prices, CPP, and other price-based strategies could be a low-cost opportunity to advanced adoption of DR technologies. As customers are exposed to price signals from dynamic pricing, we could see uptake in technologies that add convenience and control for managing their energy use. As more devices come online that are price responsive we expect deeper and more dynamic load Shifts and Sheds could be possible than we estimate in this study, since the load impacts included in our study are primarily from past studies with nominal low-cost enabling technologies.

Electric vehicles, behind the meter storage, and other new load categories could also significantly alter the dynamics of price sensitivity. Combining electricity storage, advanced controls, and retail prices that incentivize arbitrage could lead to a dynamic where significant fractions of the Shed and Shift we describe in the DR potential supply curves is achievable through retail prices alone.

There could also be other pathways to dynamic price exposure. Recent policy proposals for the CAISO markets for Proxy Demand Resources (The "ESDER 2" Second Revised Straw Proposal from September 19, 2016) indicate the possibility of bidirectional load exposure to prices. The passage below from the executive summary of that document describes how a "supply market price signal" could occur (emphasis ours):

> *"(Describing the expected dynamics of wholesale vs. retail market exposure for customers) …The end-use consumer would pay retail prices for load consumed. The ISO would settle wholesale energy at the wholesale market-clearing price, positive or negative.* ***The bid to consume load will simply be a price the bidder is willing to pay or be paid for energy and will be settled in the wholesale market through a Scheduling Coordinator independently from the retail settlement.*** *The bidder could, for example, structure a negative bid, which means the bidder expects to be paid for consumption of energy if negative bids are in the money and clear the market in certain intervals."*

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[17] Hansen, Daniel, et. al, Statewide Time-of- Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report, Christensen & Associates. December, 2015 http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207031_20151215T151300_Statewide_TimeofUse_Scenario_Modeling_for_2015_California_Energ.pdf

While supply market integration could be a pathway to price exposure, the transaction costs could be significant with additional categories of cost that would not be included in a dynamic price for consumption (e.g., scheduling coordinator fees, the loss of response from randomly withheld participants to establish a control group baseline). It is plausible that coordinated market participation through PDR could help concentrate incentives to push control technology in the market (aggregators who could profit from market participation would recruit customers and help finance and install load control). However, this supply market pathway for incentivizing control technologies could be undermined if sufficient control technology were preexisting, were installed for reasons other than DR, and/or the technologies were sufficiently valued for aesthetic, comfort, and bill reduction.

Figure 30 includes a detailed load impact estimate in the residential sector and a first-order estimate for the currently embedded (and assumed to be persistent) load impacts for non-residential sites. The plot displays a flat baseline and three Rate Mixes (described elsewhere).

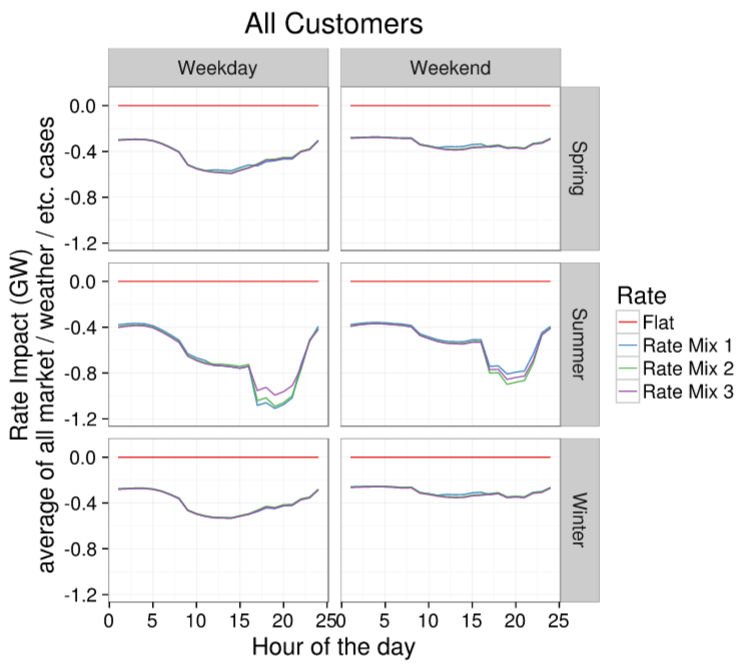

Figure 30: Average combined TOU and CPP load impacts for all customers in the CA IOU Service territories

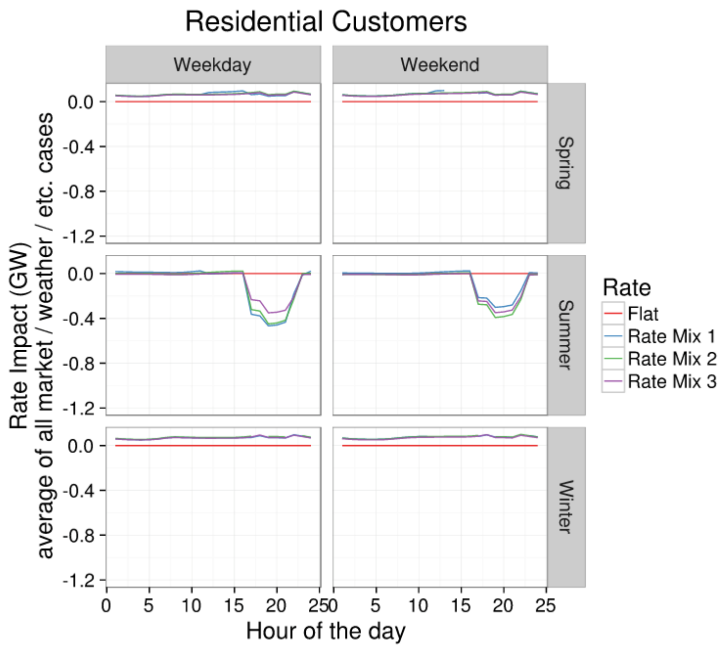

Figure 31: Average combined TOU and CPP load impacts for Residential Customers

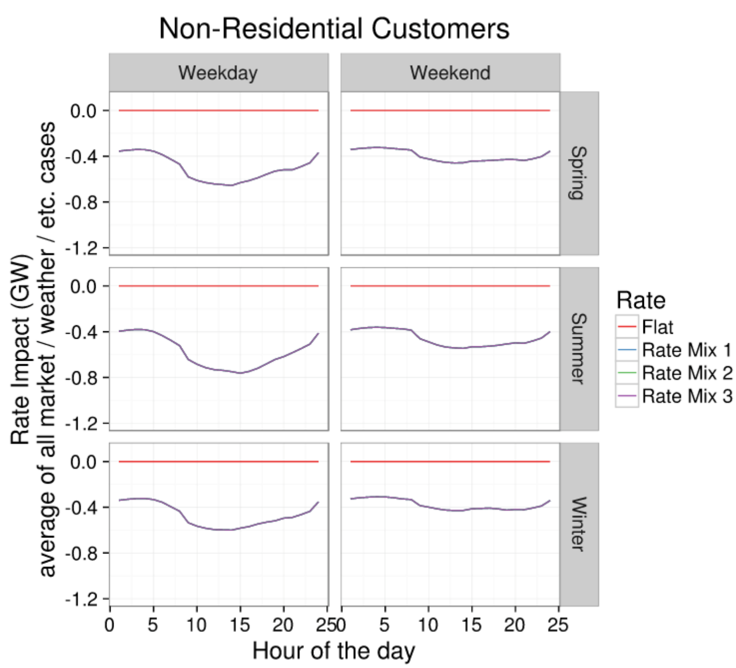

Figure 32: Average combined TOU and CPP load impacts for Non-Residential Customers

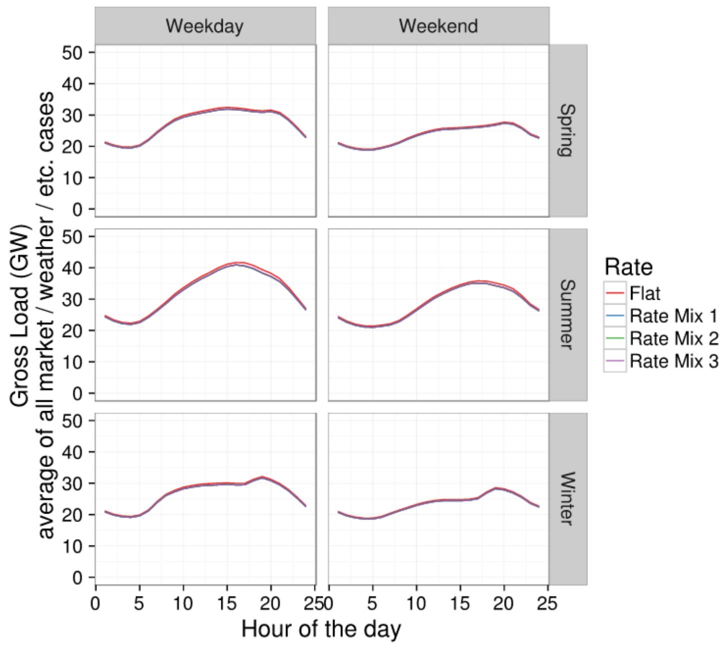

Figure 33: Average total gross load in CA IOU service areas for a flat baseline and three Rate Mixes (described elsewhere)

5.2.3. Behavioral Demand Response

Demand response from behavior changes can be dispatched or influenced through a variety of signals. In this study we model behavioral shifts and peak sheds mediated by retail price but there are other approaches that can lead to similar depth of response as well, through normative messages and third-party incentive programs. These "**behavioral demand response**" (BDR) approaches have emerged recently and leverage a range of new direct and social media channels for communicating with customers. The fast changing approaches to BDR and integration with controllable devices leads to significant uncertainty in the depth of response that is possible, and to the durability of response.

The evidence for BDR is emerging as programs are piloted, refined, and deployed. There are many anecdotal or small-sample studies and industry presentations available, and a few large-scale, controlled econometric studies that we highlight here. One study pairing communicating thermostats with BDR conducted in 2012 with ~1400 participants (700 each treatment and control) found no statistically significant effect for normative behavior appeals sent through a smart-phone application prompting users to remotely agree to energy reductions from HVAC.[18]

[18] http://www.etcc-ca.com/sites/default/files/reports/et11pge3074_opower_honeywell_final_report.pdf

A more recent large-scale assessment (10,000+ participants) did identify a response from similar normative appeals in an operational context. In that study, the average peak load reduction was 1.8-2.4 % depending on whether customers were already receiving energy reports on a consistent, regular basis (more savings for customers not already receiving a report)[19].

These findings suggest that the depth of resource for BDR is similar to retail price impacts, and that the ***details matter*** for BDR. There are differences in response between customer groups and messaging approaches and large scale samples are required to assess and verify the load impacts. The relationship between retail price and behavioral signals has not been identified, without clear evidence on whether there is potential for BDR to go beyond price or be a replacement for price-based shed. The ability of BDR to provide Shift DR has not been studied in detail, and could be a focus for future initiatives and enterprise activity as well. Any future studies or operational program impact verification should be based on careful treatment and control groups, aggregations of customers, and account for interactive effects with price to avoid double-counting.

5.3. *Shift* – Changing the Timing of Loads

We modeled Shift-type DR resources that consumed load and shed load during a 24-hour period, remained energy neutral, and were based on end uses that could plausibly move energy consumption from one hour to a different hour of the day. Loads that are available to be shifted daily can reduce system ramping needs and avoid renewable power overgeneration and curtailment. These resources included thermal loads, such as air conditioning and refrigerated warehouses, batteries, commercial and industrial batch processes, and electric vehicle charging. Shift resources, for the purpose of this analysis, are dispatchable resources, and each end use can respond to a dispatch signal that shifts the loads from one time period to another, in either a 4-hour, 8-hour, or 24-hour window. In each of these cases, it was assumed that the load within that window was split between a load take and a load shed. For example, a batch process that was shifted would be dispatched over an 8-hour window, with 4 hours of load consumption and 4 hours of load shed. In this example, a batch process that is typically scheduled to run at 5 pm would be moved to noon to consume load, and at 4 pm would be turned off to shed load for the following 4 hours, which effectively shifts the load from the later part of the day to the mid-afternoon. This resource would be available on a daily dispatch schedule. With adaptive and responsive loads that can shift energy consumption throughout the day, DR-enabled loads can support the grid by enabling better use of available renewable power and avoiding renewable

[19] Behavioral Demand Response Study - Load Impact Evaluation Report (2016) Nexant for PG&E; CALMAC ID: PGE0367.01

curtailment during hours when generation exceeds demand.

Shift service type DR captures potential loads that can be moved throughout the day. It assumes that the energy consumption is neutral over 24 hours; in other words, loads shed the same amount of energy that they take over a given window of time. Our energy neutral constraint on the Shift resource means that no "new" load is created in response, but only reshuffling. Some users may also have good reason to increase load if they have the option of low-price electricity in the middle of the day, a price elasticity dynamic that is analogous to efficiency rebound (e.g., an energy intensive industrial customer with slack in their process schedule, or a business operating a fleet of electric vehicles). This would be a "pure take" resource, and is often discussed in terms of "reverse DR", which was not considered within the scope of this study. Another simplifying assumption is that we do not model thermal losses or efficiencies resulting from shifting load.

Shift resources move load from early morning and evening hours to the midday hours of high solar output, thus reducing curtailment caused by solar overgeneration and lessening the need for imports during shoulder hours. Figure 34 shows the impact of allowing up to 20 percent of load to shift within the hour and the day on a high-curtailment day in 2025; it is an illustrative example showing a particularly high-curtailment day and how a "20 percent" Shift enables more renewable electricity to be put to use (note: 20 percent refers to a joint constraint on the maximum fraction of the daily electricity that can be shifted, and the maximum instantaneous load shed). Shift-capable loads have significant potential to reduce overgeneration during hours of high renewable generation.

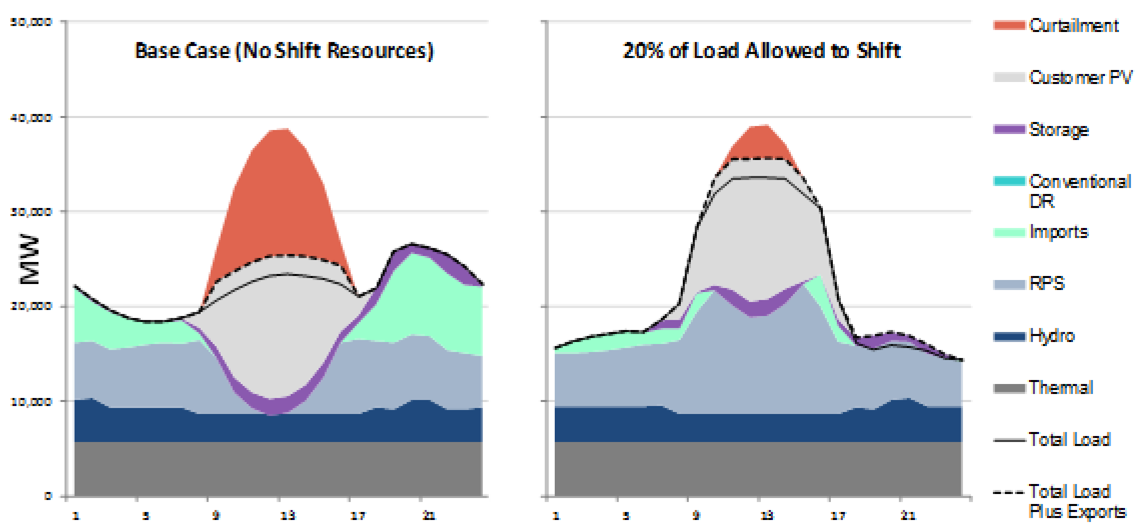

Figure 34: Dispatch impact of allowing 20% of system load to shift within each hour and within each day. Highest RESOLVE curtailment day, 2025.

For all modeled levels of Shift resource, we constrained the magnitude of Shift capable load to be a fraction of end-use load. Shift Take and Daily Shift constraints were defined as a fraction of daily load, while Shift Shed was defined as a fraction of the highest load hour in each day. Due to these differences in defining the constraints, we set the Shift Shed fraction to be twice the Shift Take and Daily Shift fractions. The three parameters are shown on the x-axis of the Results charts (e.g., Figure 35 and Figure 36). A 10 percent Shift case, for example, means hourly load can be increased to 10 percent above the maximum hour's load, and 10 percent of the load within the day can be shifted between hours. This is illustrated in Figure 35.

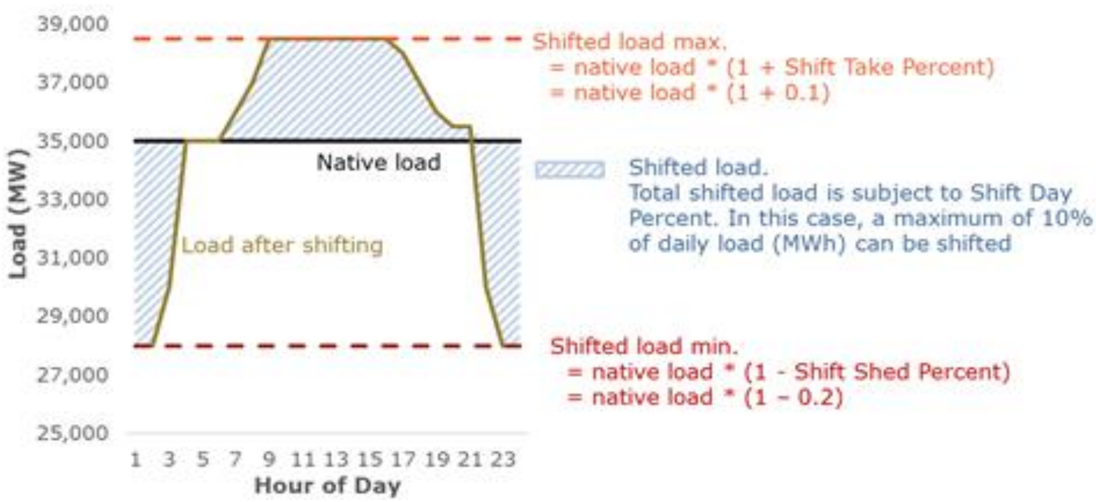

Figure 35: Illustration of 10% Shift case (the native load is shown as flat across the day to lower complexity for this illustration only).

The ability of Shift resources to "soak up" curtailment is highest for the first megawatt-hour shifted, and reduces as more Shift resources are added and the need for curtailment falls, as shown in Figure 36. The Low-Curtailment and High-Curtailment scenario results for mid-AAEE and double the AAEE forecasts are shown. The x-axis represents the percentage of daily and hourly load that is shifted, while the y-axis presents the annual GWh of renewable curtailment.

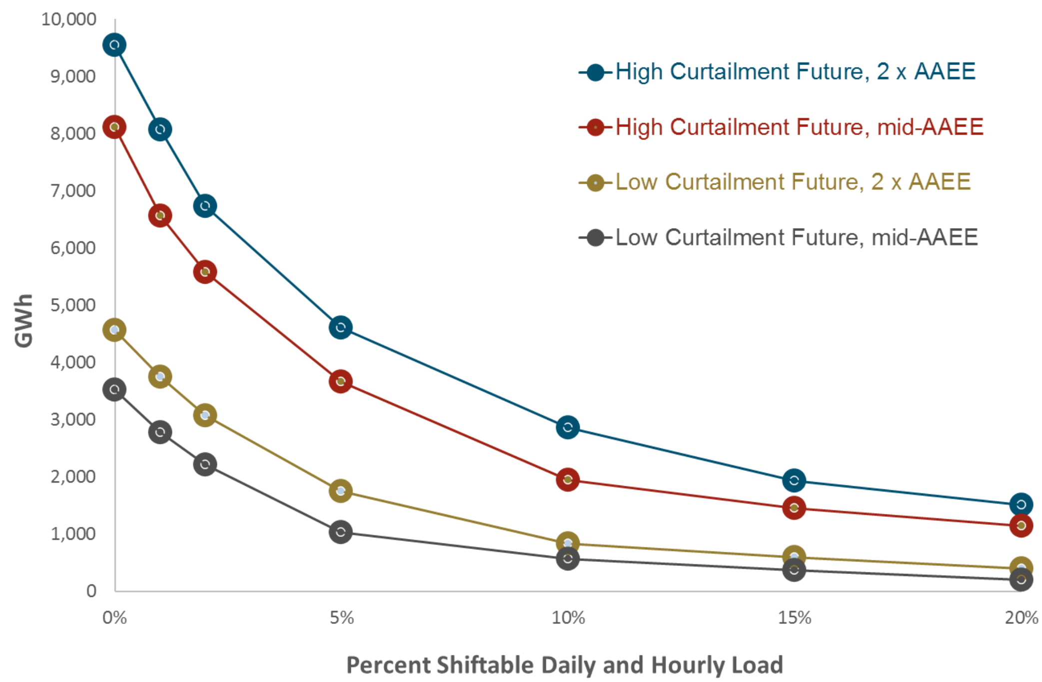

Figure 36: Annual curtailment by percent of "shiftable" load, 2025.

Shift resources are estimated to provide up to $678 million ($2015) in savings to the CAISO system in 2025, with the greatest marginal savings coming from the first increment of shifted load. It should be noted that while there is high potential market savings from Shift resources, this doesn't equate with implied cost-competitive market size. In other words, the estimated market savings reflects value to the grid, but not necessarily what is most cost effective. In section 5.3.1, we evaluate the cost competitiveness of the Shift service type by inferring the market size based on the intersection of the supply and demand curves. As shown in Figure 37, each incremental megawatt-hour of Shift resource avoids curtailment at a diminishing rate. The Low-Curtailment and High-Curtailment scenario results for mid-AAEE and double the AAEE forecasts are shown. The x-axis represents the percentage of daily and hourly load that is shifted, while the y-axis presents the savings to the system in millions of dollars (2015). Because each incremental megawatt-hour of shift avoids less curtailment, each incremental megawatt-hour of shift generates less savings in two ways. First, each incremental shifted megawatt-hour replaces less gas generation with zero marginal cost renewable generation from curtailment reduction, yielding less fuel and O&M savings. Second, avoiding curtailment leads to a reduction in RPS and storage build, because a higher fraction of delivered renewables means less overbuild and storage are needed to meet the RPS. This means that as each incremental megawatt-hour shifted avoids less curtailment, it also avoids less RPS-related capacity build.

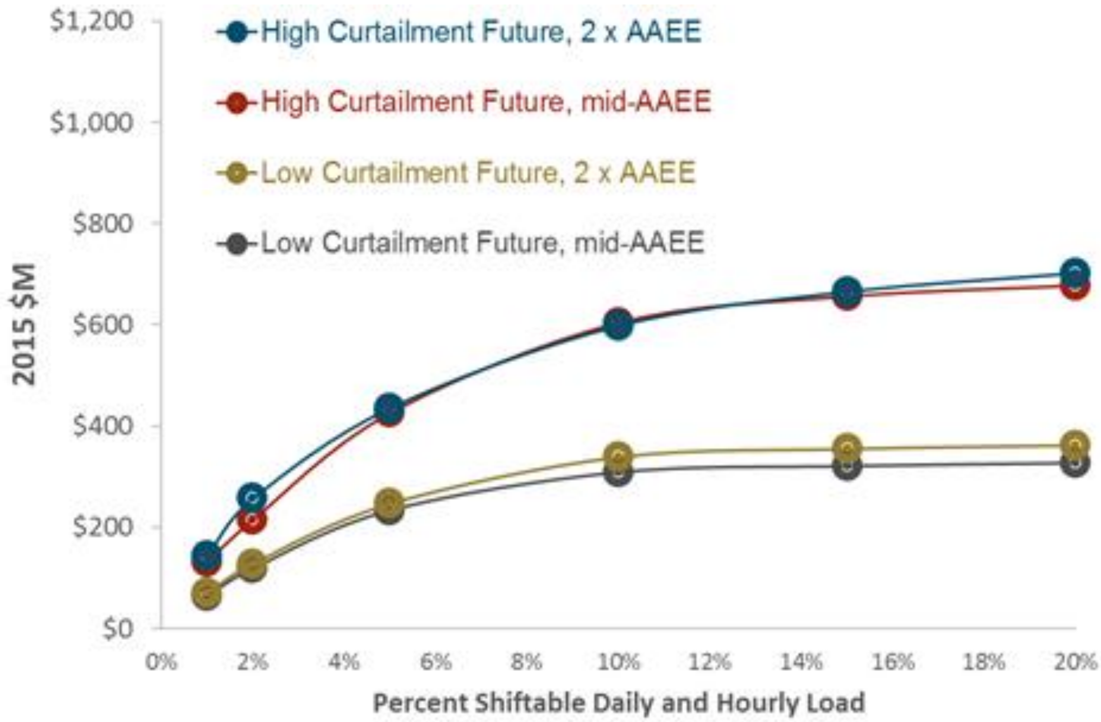

Figure 37: Total CAISO System savings from Shift resources, 2025.

RESOLVE estimated the number of megawatt-hours shifted in each year that minimizes costs to the CAISO over the 2016–2030 horizon. These megawatt-hour values can be used to create a "demand curve" that shows, at each incremental percent of shiftable load, the savings available to the CAISO per megawatt-hour of Shift resource made available. As shown by the blue curve in Figure 38, The Low-Curtailment and High-Curtailment scenario results for mid-AAEE and double the AAEE forecasts are shown. The x-axis represents the percentage of daily and hourly load that is shifted, while the y-axis presents the marginal $/MWh savings. Shift resources save the CAISO system $67 per MWh shifted in 2025 when only one percent of load is shiftable (under the High-Curtailment future, double the AAEE scenario). When 20 percent of load is shiftable, the final megawatt-hour of shift saves only $15/MWh. These values drop to $31 and $5, respectively, for the Low-Curtailment future, mid-AAEE scenario.

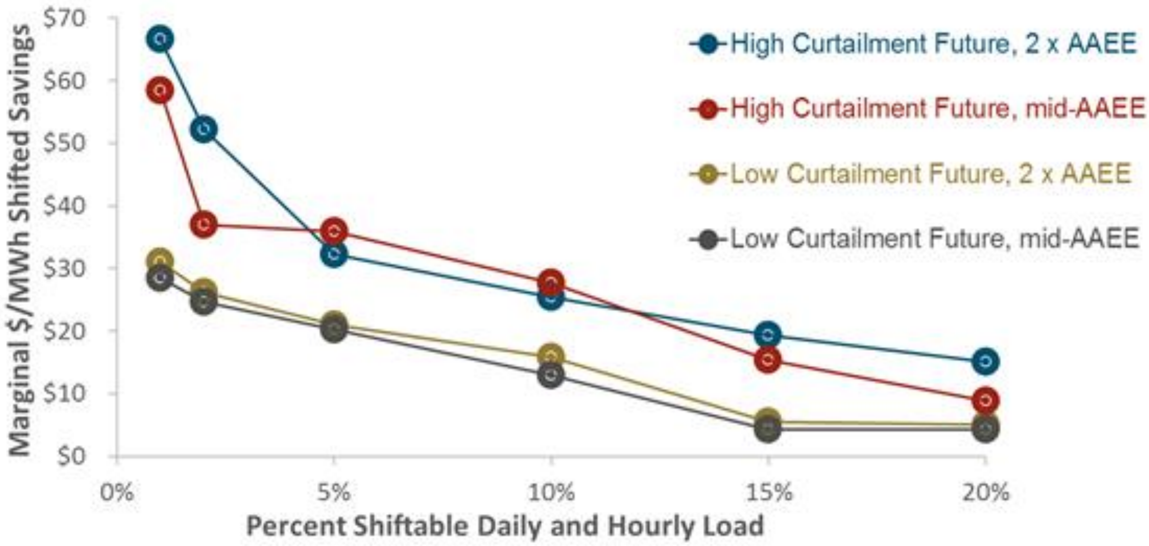

Figure 38: Marginal savings to the CAISO system per MWh shifted.

As shown in Figure 39, the savings from Shift resources increase at all penetration levels as we move closer to 2030. Recall that savings from DR assessed over the entire 2016–2030 period were allocated to individual years using the relative percentage of base case curtailment in each year. RESOLVE estimated increasing curtailment as we moved closer to 2030 and the assumed 50 percent RPS.

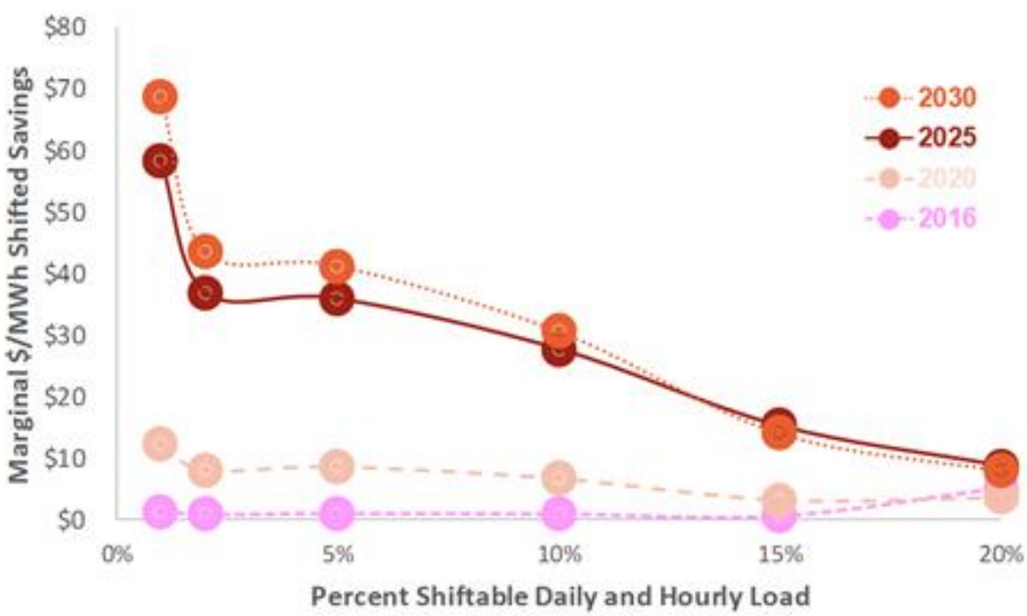

Figure 39: Marginal savings per MWh shifted, by year. High-Curtailment future, mid-AAEE scenario.

5.3.1. Valuing Shift Service Type DR with Supply Curves and Levelized Demand Curves

Shift resources have a high value to the grid, and our Shift technology cost and performance analysis indicates a significant opportunity to provide service, with a large resource at costs that are lower than the benefits. In each of the graphics provided below, we introduce the supply curves for the Shift resource and compare them to the levelized value of service; we note that the levelized costs and available cumulative DR units are reported in terms of kilowatt-hours and gigawatt-hours, respectively. The units reflect that Shift is an energy resource, as opposed to Shed and Shimmy resources, which are measured in kilowatts-year of effective capacity. Subsequent figures show average daily resource availability on the x-axis and the leveled costs per kilowatt-hour reported on an annual basis on the y-axis.

Figure 40 summarizes the main Shift findings. In 2020, only approximately 2.5 GWh per day is cost-effective—approximately 0.5 percent of the load. The RESOLVE modeling suggested the levelized value curve is relatively low in that year, close to $20/kWh shifted in 2020. However, by 2025, the value of Shift DR resources was shown to increase as more renewables are built to satisfy the 40 percent RPS requirements. The potential was shown to increase further with continuing cost reductions for Shift. Our analysis suggests that an estimated 10–20 GWh of daily Shift DR are cost competitive in 2025 if the automation technology is paid for both with site-level services ("co-benefits") and through revenue or other incentive pathways reflecting the value of Shift to the system. This results in an equilibrium price of $20–$40/kWh-year from system benefits. The colors in the lines (**top**) and bars (**bottom**) represent qualitative DR market scenarios. The dotted lines correspond to 1-in-2 weather years and the solid lines are 1-in-10 weather years. The Low-Curtailment case (**RED**) and High-Curtailment case (**ORANGE**) horizontal lines represent the levelized demand curves. The equilibrium price is at the intersection of the levelized demand curves and the supply curves. All of the estimates for supply Shed DR are shifted based on the contributions of TOU/CPP rates, which is indicated in **BLUE**. Case: Year 2025, Rate Mix #3, mid-AAEE trajectory. Figure 41 shows how the cost-effective potential (and implied market size) changes between 2020 and 2025, for the low- and high-curtailment cases. Significant growth is observed in all cases between 2020 and 2025, with an implied cost competitive Shift DR market size of $100–$400M/year by 2025.

While modest quantities of cost-effective resources are expected in 2020 with a full-cost accounting framework, Figure 42 shows how including co-benefits for both site-level and distribution system benefits could change the equation by 2025. The DR potential increases significantly when sources of revenue and co-benefits are included in the supply curves, (i.e., reduce the costs of the DR technologies).

In Figure 42, beginning with the upper left quadrant, going clockwise: Supply curves with unadjusted total costs, net total costs with ISO revenue, net revenues with site-level co-benefits (i.e., the same as Figure 40: (top) Shift DR potential supply curve results compared to a levelized demand curve, and (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.), and net revenue with site and distribution system benefits incorporated into Shed supply curves. Each quadrant depicts the supply curve estimates developed for the Base, BAU, Medium, and High scenarios.

Once we account for these benefits (assuming that some Shift DR is also optimally located in the distribution system so that it avoids building new infrastructure to handle load growth, and that some resources provide site-level benefits), the increase in Shift DR that is cost competitive is significant, resulting in more than 25 GWh per day in 2025, under the high curtailment and high potential scenarios.

With the full stack of integrated benefits, there is significant potential to develop technology by 2020 and continue to 2025, when system-level needs become more binding. This suggests a possible ramp-up role for “distributed resource planning” to use site and city-scale services to help scale up regional flexibility in advance of system-level need.

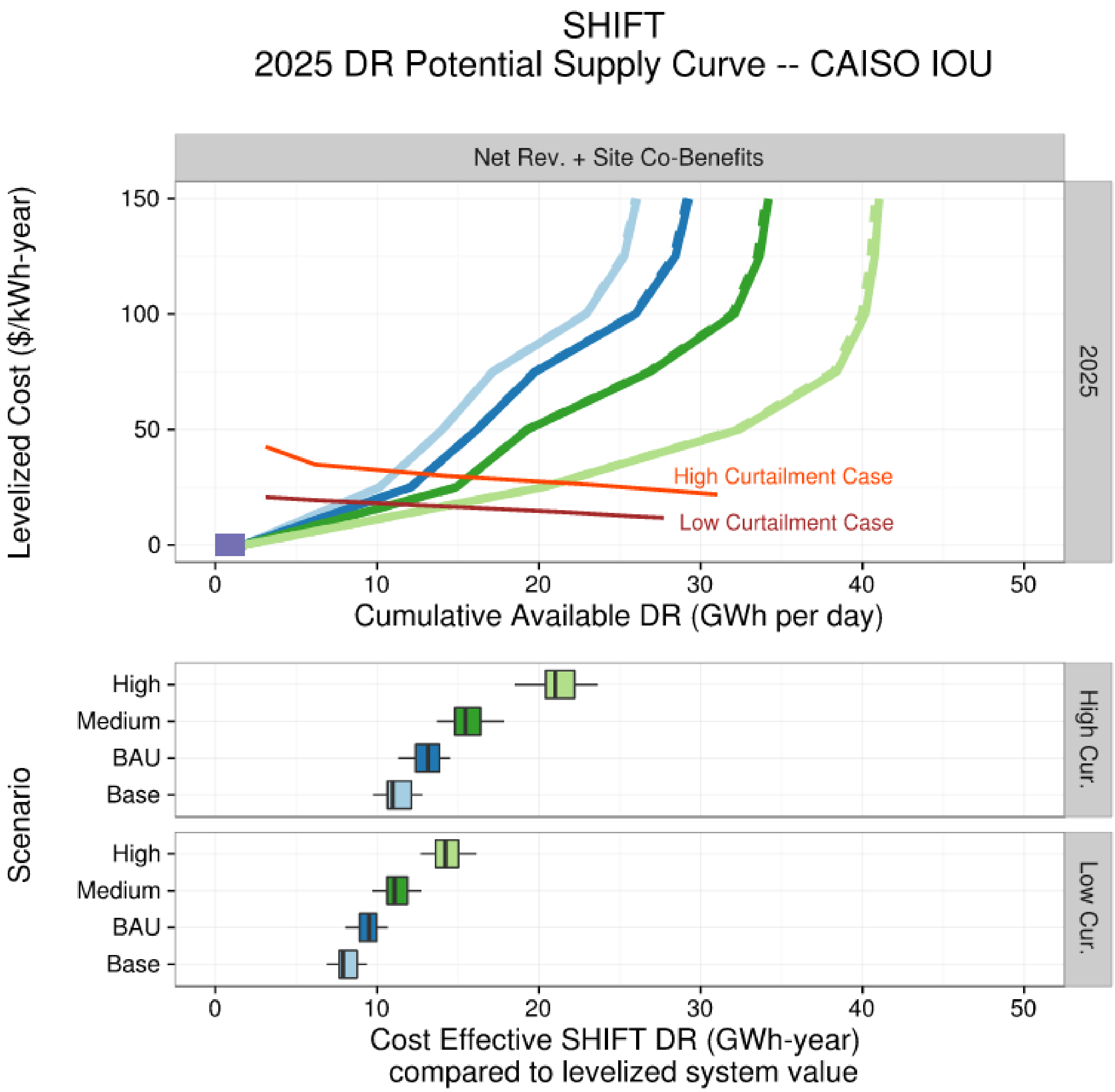

Figure 40: (top) Shift DR potential supply curve results compared to a levelized demand curve, and (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.

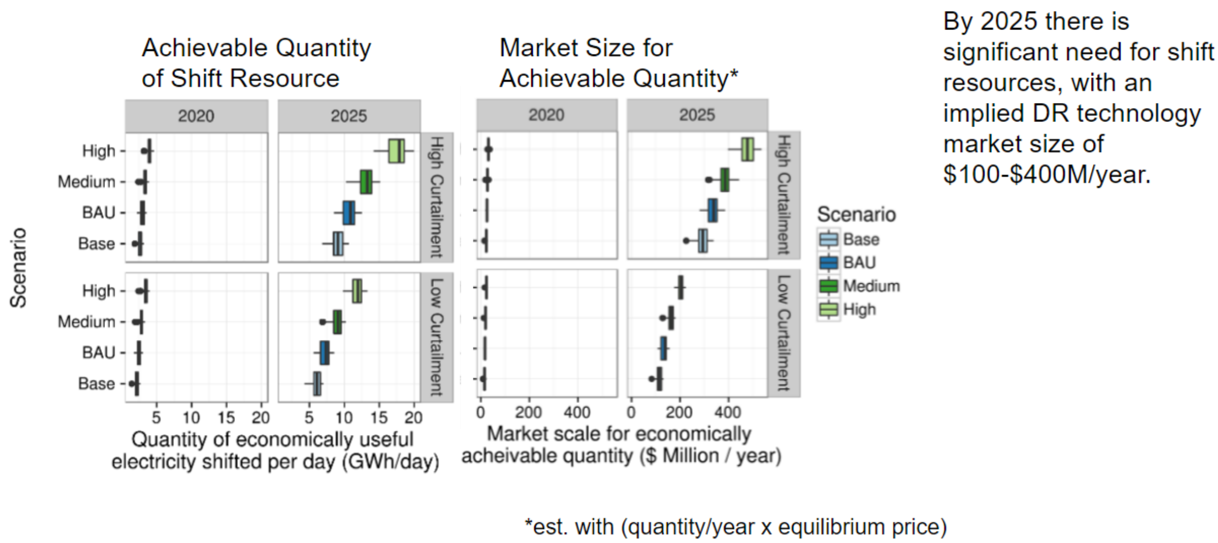

Figure 41: Box and whisker charts of Shift DR resource quantity (left) and approximate market size (right) for both 2020 and 2025.

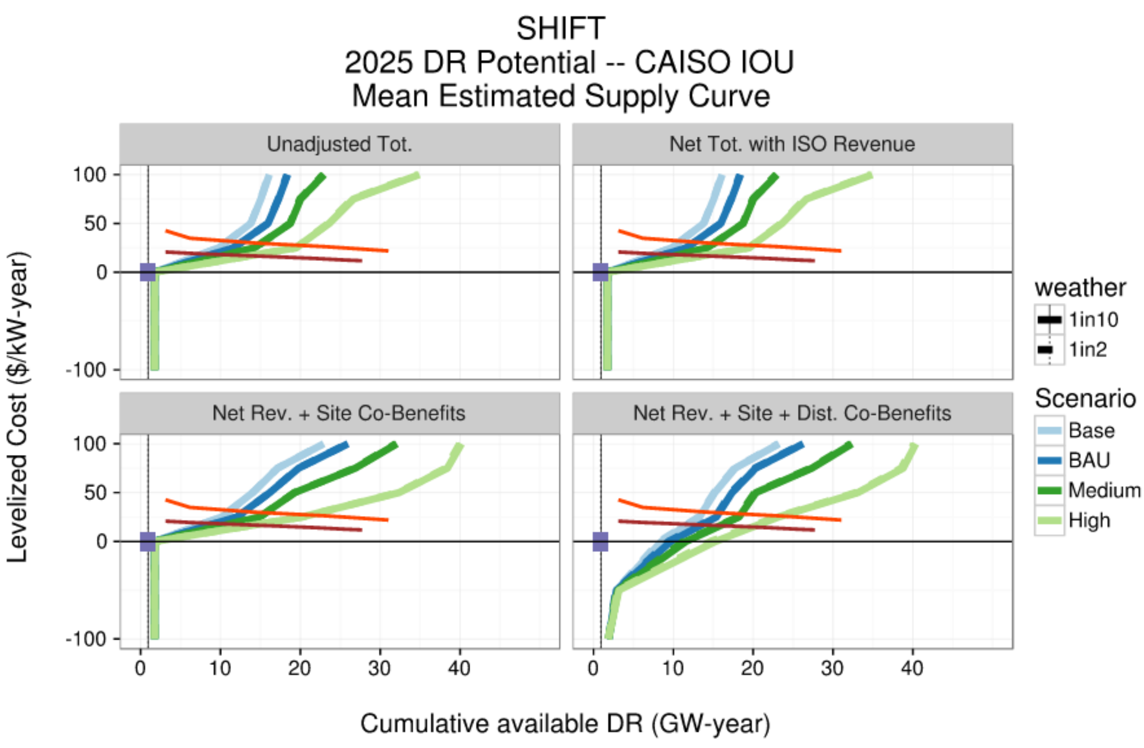

Figure 42: 2025 Shift-type DR potential supply curves with various estimates of revenue streams contributing to the economic efficiency of DR technology costs.

In Table 11 and Table 12 below, we provide the cost competitive prices and quantity of Shift DR from the DR Futures supply curves and the RESOLVE levelized demand curves, and represent the price at the intersection of each curve. The price and quantity reflects the levelized cost and value to the grid; in other words, the price for each DR unit (MW or MWh) is economical when compared to the costs of other generation resources. The costs and quantities for each service type are segmented by percentiles that capture the variance around the demand and supply curves' intersection.

Table 11: Levelized Price and Quantity of Cost Competitive Shift DR by Percentile (Low Curtailment Scenario – Medium DR Scenario)

Shift DR (Low Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue Co-Benefits + Distribution System Payments
25th Percentile Price per kWh ($)	$18	$18	$18	$16
25th Percentile Quantity (MWh)	8,489	8,489	8,874	13,322
50th Percentile Price per kWh ($)	$18	$18	$18	$16
50th Percentile Quantity (MWh)	9,018	9,018	9,324	13,760
Mean Price per kWh ($)	$18	$18	$18	$16
Mean Quantity (MWh)	9,053	9,053	9,426	13,935
75th Percentile Price per kWh ($)	$18	$18	$18	$17
75th Percentile Quantity (MWh)	9,632	9,632	10,128	14,618

Table 12: Levelized Price and Quantity of Cost Competitive Shift DR by Percentile (High Curtailment Scenario – Medium DR Scenario)

Shift DR (High Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue Co-Benefits + Distribution System Payments
25th Percentile Price per kWh ($)	$29	$29	$28	$26
25th Percentile Quantity (MWh)	12,513	12,513	13,061	15,625
50th Percentile Price per kWh ($)	$29	$29	$29	$27
50th Percentile Quantity (MWh)	13,320	13,320	13,708	16,390
Mean Price per kWh ($)	$29	$29	$29	$27
Mean Quantity (MWh)	13,336	13,336	13,898	16,486
75th Percentile Price per kWh ($)	$30	$30	$30	$28
75th Percentile Quantity (MWh)	14,174	14,174	14,639	17,370

Table 13 below summarizes the expected Shift DR potential by utility, by year. It shows the breakdown of expected potential by utility service area, and the implications of the portfolio benefits of multiple value streams (through cost accounting framework modifications).

Table 13: Shift potential (MWh-year) by year, by utility, for a range of cost accounting frameworks. The results are the 50th percentile for the case defined by the Medium DR market scenario, mid-AAEE energy efficiency trajectory, 1-in-2 weather, the "High Curtailment" RESOLVE case, and Rate Mix #3.

	2020			2025		
Cost Framework	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Unadjusted Tot.	1400	1800	94	5800	7100	430
Net Tot. with ISO Revenue	1400	1800	94	5800	7100	430
Net Rev. + Site Co-Benefits	1400	1900	97	6000	7500	450
Net Rev. + Site + Dist. Co-Benefits	4300	5000	240	7400	8500	570

5.3.2. Shift Technology

Shift resources come from a variety of technology options, with large shares from HVAC and process scheduling. Figure 43 provides a breakdown of the Shift DR potential in 2025 at a price level of $50 / kWh – approximately the upper end of the value we identified to the grid – disaggregated by IOU service territory and end use. Industrial process loads provide approximately 4 GWh-year to PG&E, and nearly 5 GWh-year to SCE, with agricultural pumping providing 1.7 GWh-year and 0.5 GWh-year to PG&E and SCE, respectively. Commercial HVAC is another large contributor, with more than 5 GWh-year between the three IOUs. It is notable that very little resource comes from behind-the-meter batteries in the case without co-benefits, suggesting that load control is more cost competitive than electrochemical storage for the first several gigawatt-hours shifted per day.

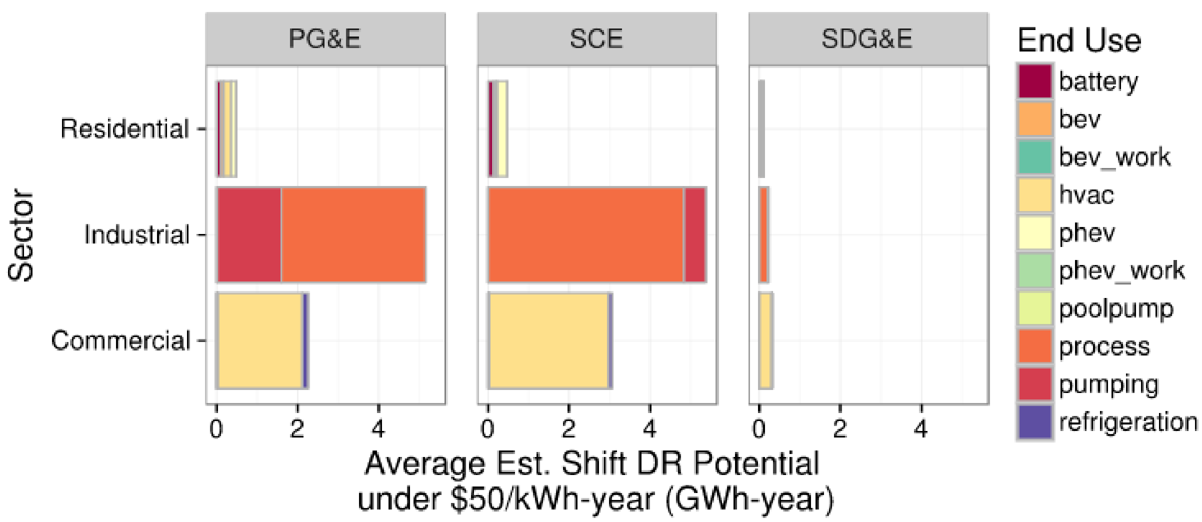

Figure 43: 2025 Shift DR potential by IOU service territory and end-use contributions under $50/kWh-year, mid-AAEE, 1-in-2 weather year, Medium scenario.

While behind-the-meter storage does not feature prominently in our estimates at $50/kWh-year, Figure 44 below shows that at costs of $100/kWh and up the contributions of behind-the-meter storage could be substantial. The contributions of each sector are grouped, with boundaries between the sectors shown using black lines. The levelized cost estimates are net of expected market revenue and site-level co-benefits from automation. Another way to read this is that if there are much steeper declines in the cost of storage (and/or additional value streams accessible to storage) then energy storage technology could be a significant contributor to the Shift resource. The results also suggest that electric vehicle charging could be an important resource with more aggressive cost and/or business model advances.

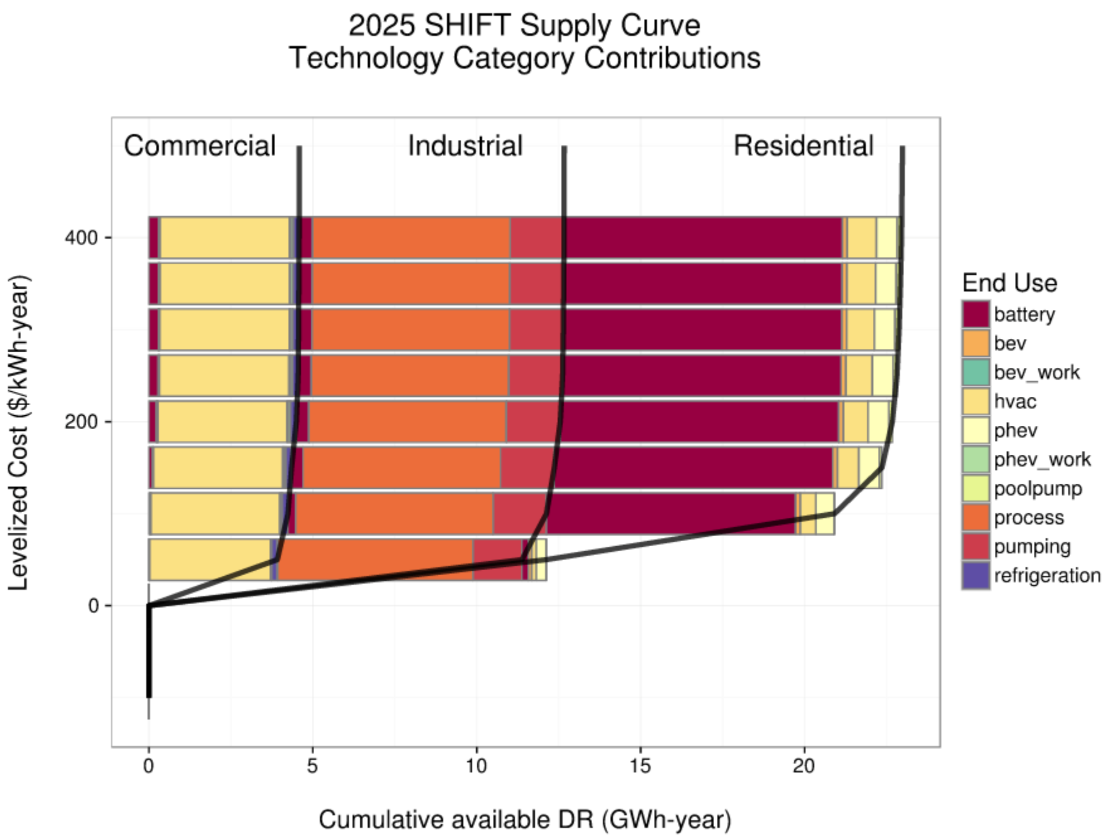

Figure 44: Shift DR supply curve in 2025, with contributions from end-use technology categories demarcated in stacked bar graphs.

For Shift and other resources, our analysis of potential was based on a large number of possible supply curves, each defined by a particular scenario with random variation in the DR technology and cost introduced. Figure 45 shows the full set of supply curve options included in the analysis. The box plots displayed at the bottom of Figure 40 are a representation of this uncertainty in results, showing the range in intersection points among the many supply curves shown in plots like Figure 45. The x-axis depicts mean available GWh/day and the y-axis represents the levelized costs in $/kWh-yr for the resource. This supply curve shows the unadjusted total costs for the service type under the Base, BAU, Medium and High scenarios, and includes the results from Monte Carlo analysis, illustrating the uncertainty bounds of the estimates for the resource. These are the full set of “stochastic” supply cures for Shift resource, and we focus on the mean supply curve for displaying many graphics below.

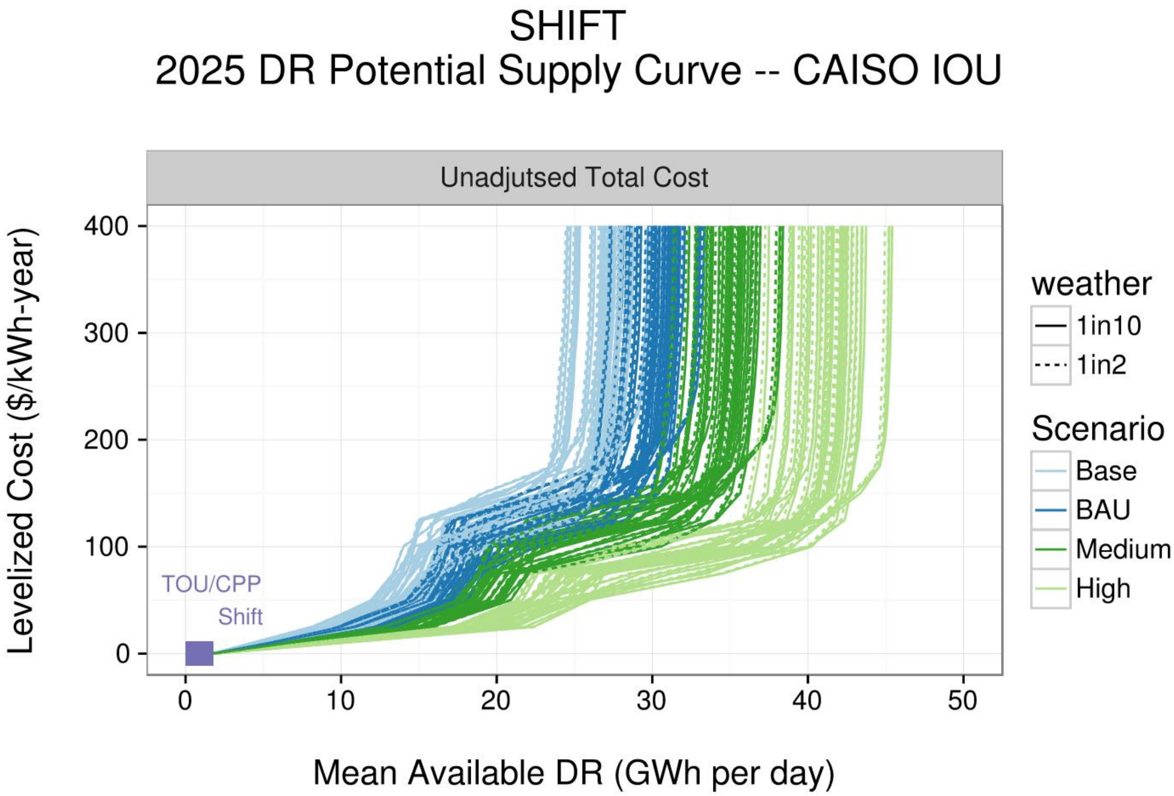

Figure 45: 2025 Shift service type DR potential with conventional TOU/CPP providing 1.8 GWh/day of Shift resource.

5.3.3. Price-Responsive *Shift* Pathways to Market Participation

The Shift service type resource is by far the largest opportunity we identified for DR to provide system-level value (up to ~$700 million/year). This value is derived from dispatchable daily energy shifts enabled with advanced control technology; economically effective DR amounts to up to ~10 percent of daily energy shifted in 2025 (for the high-curtailment, mid-AAEE scenario). Resources that shift load into high-curtailment hours can offer significant capital investment and operational cost savings by reducing renewable overgeneration, and prevent the need to overbuild renewables capacity to meet clean energy goals.

There remain significant market and regulatory barriers to capturing this value, as no market mechanism currently exists for compensating services like Shift DR. These services are technology-driven and responsive to hourly and daily changes in the needs of the system. When considering potential revenue streams from the supply-side market, Shift *potentially* could earn revenues from energy, capacity, AS and flexible capacity markets, but those markets are not currently organized to compensate a service like Shift DR. Shift resources would be dispatched on most days in the energy market, as their value is driven by California's daily solar generation.

Identifying appropriate and accurate baselines against which to compare response when there are not days *without* Shift also presents a significant challenge. Baseline estimation already poses a barrier to measurement and compensation of Peak Shed DR resources that are only dispatched a handful of times a year. It remains unclear whether compliance obligations would need to be restructured to qualify aggregations of shiftable loads to allow Shift-type resources to participate in flexible capacity markets.

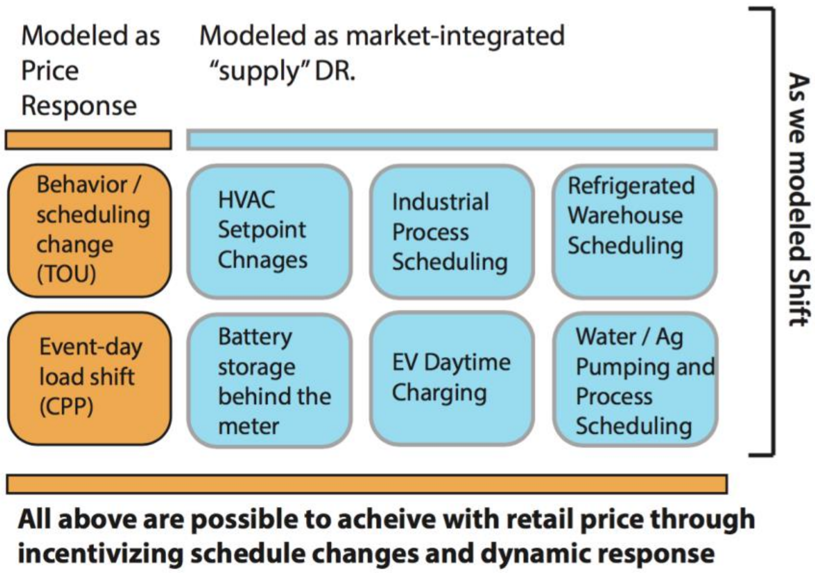

Figure 46: Categories of Shift resources in our modeling framework.

Because of these significant challenges to integration in the ISO-dispatched supply market, it makes sense to apply effort towards better understanding how Shift-type resources could be handled through the retail market through pricing programs paired with automated DR controls. This comes with its own challenges around incentivizing investment in control technology and customer adoption, but could accomplish the same fundamental dynamics with a more transparent pathway to market integration and lower transactions costs.

There have already been successful pilots of this approach to load-specific price response with electric vehicle charging in San Diego. The pilot showed that combining even simple control technology (user-controlled timers) with an aggressive price schedule can induce significant shifts in charging profiles.[20] Additional pilots and study could help uncover the most cost-effective and reliable pathways for developing Shift resource.

A key concept to keep in mind for Shift market and technology development is that it is a resource with an energy-based, cumulative value, rather than a power-based capacity value, placing it in a separate category from conventional Shed DR. Unlike with Shed, where the value of a resource derives strongly from its reliability and usefulness in real-time dispatch, the value of Shift resources come from multi-hour changes and accumulate through the years. As more renewable electricity that would otherwise be curtailed is captured, the value increases.

The first order contours of the ideal Shift profile appear to be relatively simple and predictable (use less in the night and more in the day), suggests that there is a strong potential role for permanent load shifting and rescheduling efforts. In addition, notification with day-ahead price schedules could let loads with day-to-day flexibility optimize operation further. The current stock of conventional DR technology is fast enough to respond to these day-ahead signals, and may present a low-cost alternative to enabling new DR sites.

5.4. Targeted Load Curtailment with *Shed*

Conventional DR has typically been procured and dispatched to decrease systemwide load during peak day events. Demand response is dispatched to offset operation of peaking power plants, relieve transmission system congestion, reduce pressure to invest in conventional generation for serving peak load, and respond to contingency events. However, system needs are quickly changing. The combination of widespread expansion in the renewable generation fleet and aggressive energy-efficiency policies that reduce load growth have led to an “overcapacity” condition on the system level in which there is little value for Shed in normal system operations—there are more than enough power plants to carry the typical net load today and well into the future. This suggests that the core goal of conventional DR and many other efforts aimed at cost-effectively maintaining service during peak demand periods should be rethought or restructured. Targeting non-critical loads that can be reliably curtailed in times of critical need, can serve the local transmission pockets’ and distribution system needs.

“Shed” resources as modeled in this study are those that provide the conventional form of downward DR, by which load is reduced to lower peak demands on the grid. California has a long history of implementing DR programs to encourage load reduction. The California Energy Action Plan (EAP) issued in April 2003 placed energy efficiency and demand response as

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[20] SDG&E Electric Vehicle-Grid Integration Pilot Program Semi-Annual Report, Sept. 2016 https://www.sdge.com/sites/default/files/documents/1699906766/VGI%20Semi%20Annual%20Report%202016.pdf?nid=19236

preferred resources and set a goal of meeting 5 percent of peak loads with demand response by 2007.[21] Building on the avoided cost framework developed for distributed energy resources, E3 supported the CPUC in developing DR cost-effectiveness protocols first adopted in 2010 and updated in 2015.[22] As for distributed energy resources in general, the protocols include several categories of benefits or avoided costs, including energy, system capacity value, transmission and distribution deferral, GHG emissions, ancillary services, losses and an RPS adder.

By far, the largest value for DR in existing DR cost-effectiveness protocols is the generation capacity value. The second is deferred transmission and distribution upgrades, though to-date the vast majority of DR has been called based on system rather than local distribution conditions. The DR cost-effectiveness protocols include several adjustment factors to properly evaluate the capacity value of DR resources to the traditional supply side resource of a combustion turbine. The adjustment factors are designed to account for limitations on DR as a resource, including advance notification requirements and the maximum frequency and duration of calls permitted.

There are, however, still significant opportunities for Shed DR to provide value to the grid. First is local capacity. While there is a surplus on the system level, the local availability of generation is a binding constraint in some transmission-constrained areas. The Los Angeles Basin, San Diego and Ventura County all currently experience local capacity constraints that must be met either with costly local generators (which produce emissions in densely populated areas), fixed energy storage, or demand response and other IDSM approaches. About half of the statewide Shed capacity is located in these transmission-constrained regions, and our estimates suggest resources dispatched locally can respond quickly enough to meet relatively fast dispatch needs compared to systemwide peak shedding.

Our findings suggest that Shed DR resources could provide ~4.2 GW of RA credit capacity in 2025 under the 1-in-2 weather, mid-AAEE, Rate Mix #3 scenario utilizing the price referent of $200/kW-yr. The Shape-shed DR results are additive and provide an additional 1 GW of reduction (labeled "TOU/CPP"), for a total of 5.2 GW.

Below we present supply curves estimating Shed DR potential. This conventional DR is dispatched to decrease load during a peak day event, meant to either offset the need for peaking power plants or to respond to contingencies. The units of analysis are as follows:

- **Quantity:** GW-year, the average amount of load shed during the top 250 net load hours

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[21] The document "California Demand Response: A Vision for the Future (2002–2007)" is included in D.03-06-032 as Attachment A. http://www.caiso.com/1f5d/1f5dafda37730.pdf

[22] See CPUC Decision D 10-12-024, Rulemaking R 13-09-011 and Decision D. 15-11-042.

of the year

- **Cost:** $/kW-year, the levelized cost of providing 1 kW of peak load shed throughout the year

Figure 47 presents the estimates for 2020 Shed DR potential with net revenues (i.e., market revenues applied to the supply curve that reduce the cost of DR in hours when DR participates in the supply markets). The figure includes the Price Referent of $200/kW-yr, as discussed in the Economic Valuation section. The supply curve estimates developed for the Base, BAU, Medium, and High scenarios and a 1-in-2 and 1-in-10 weather year. Estimates include approximately 1 GW of Shape-shed potential from TOU and CPP.

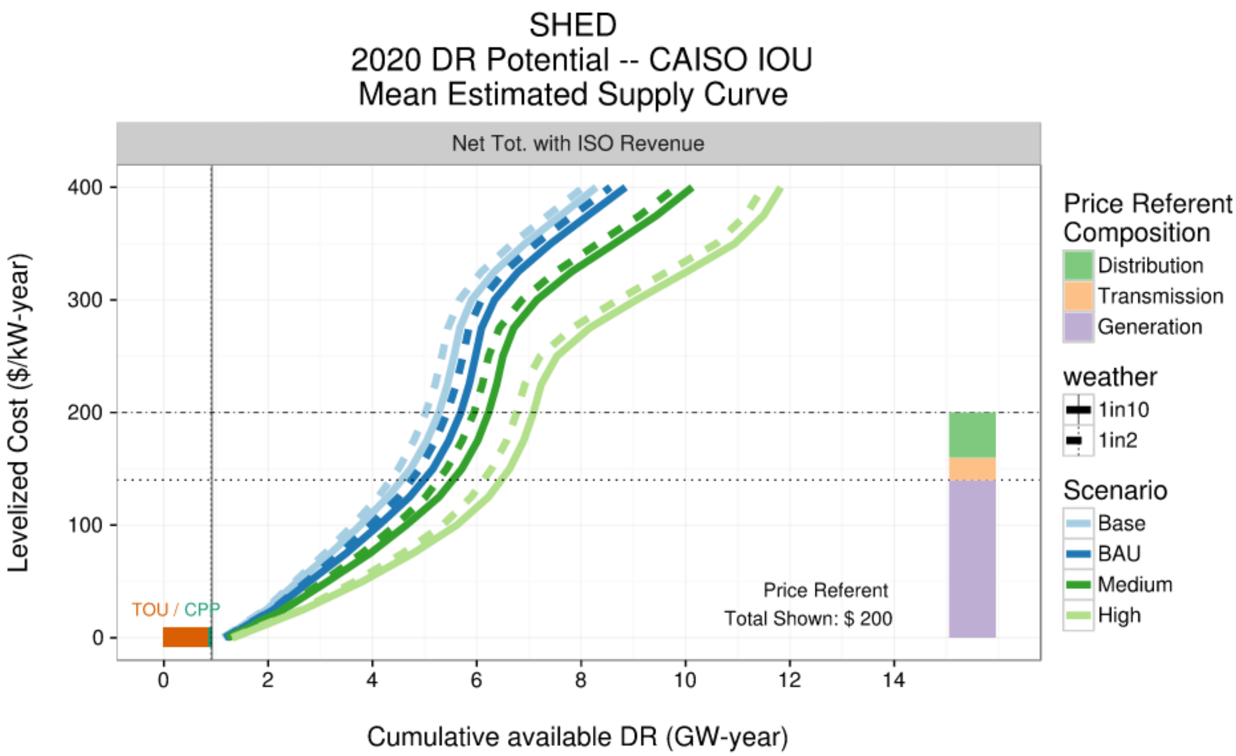

Figure 47: 2020 Shed DR potential supply curve including market revenue and the $200/kW-yr price referent.

5.4.1. Site-level Energy Management

Investments in DR technologies can often be bundled with energy-efficiency upgrades and energy management/building management systems, and provide cost efficiencies when procuring DR and EE technologies simultaneously. We capture these efficiencies as "co-benefit streams."

> *Bundling EE, DR and other DER technologies can improve the cost effectiveness for customers and program administrators, as well improving the operation of end uses at the service premise. Program administrators that can utilize funding from various customer service program budgets to create optimal energy service solutions can improve energy management for customers and the distribution system.*

Enabling a building or end use with the control and communication systems necessary to provide DR often presents an opportunity to simultaneously upgrade equipment with energy efficiency measures, improve the operation and scheduling of a load to better serve site needs, and ultimately reduce energy service costs for building owners. These integrated demand-side management (IDSM) measures can lead to a lower effective cost for providing DR service since the installation and purchase of control equipment can be underwritten by a portfolio of benefit streams. We did not undertake a detailed study on the dynamics of site-level electric bill impacts or strategies for IDSM, but included a set of likely possible levels of portfolio benefits to show the implications of comprehensive IDSM measures on DR markets; we incorporated these various benefit streams as *co-benefits* associated with installation of DR enabling technologies.

When we included co-benefits, the effective costs for DR service from batteries and other DR technology options with identifiable parallel value streams was substantially reduced, and made more cost-competitive DR available, as shown in Figure 48. The colors in the lines (top) and bars (bottom) represent qualitative DR market scenarios. The dotted lines correspond to 1-in-2 weather and the solid lines are 1-in-10 weather years. The $200 price referent includes a generation (**PURPLE**), transmission (**ORANGE**), and distribution (**GREEN**) component. All of the estimates for supply Shed DR are shifted based on the contributions of TOU/CPP rates, which are shown in **ORANGE** and **GREEN**. Case: Year 2025, Rate Mix #3, mid-AAEE trajectory. For example, including the specified co-benefits resulted in an increase of approximately **3 GW of additional Shed DR** capacity compared with a model run without co-benefits (an increase of roughly 60 percent, mainly from the residential customer sector, where batteries become cost-effective when co-benefits were included).

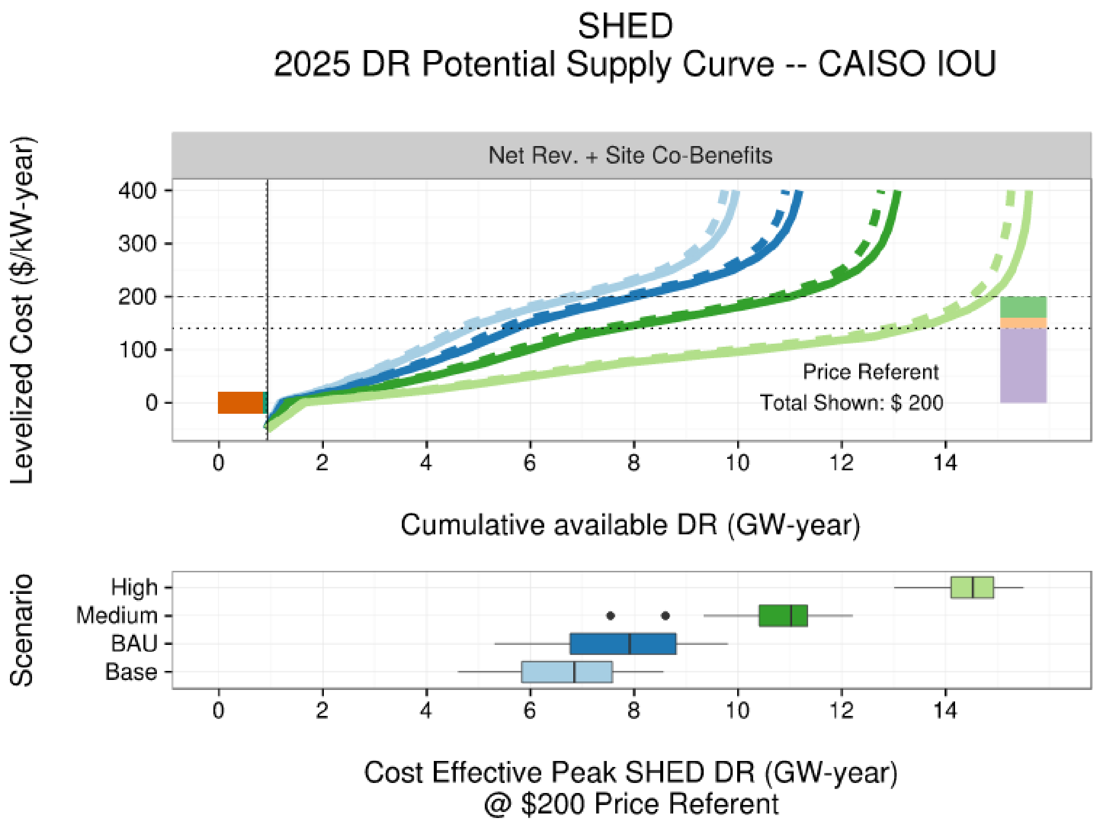

Figure 48: (top) Shed DR potential supply curve results compared to a conventional $200/kW-yr price referent, and (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.

Figure 49 shows estimates of Shed DR potential under the various economic valuation options. Beginning with the upper left quadrant, going clockwise: Supply curves with unadjusted total costs, net total costs with ISO revenue, net revenues with site-level co-benefits, and net revenue with site and distribution system benefits incorporated into Shed supply curves. The unadjusted total costs valuation in the left quadrant presents estimates of approximately 6 GW. As we added revenues and co-benefits to the supply curves, buying down the costs of the DR technologies, we increased the cost competitiveness of the DR resources. In the lower right quadrant, we included net costs (market revenues), site level co-benefits, and distribution system co-benefits, which increase the quantity of cost-competitive Shed DR to ~11 GW at the $200/kW-yr level.

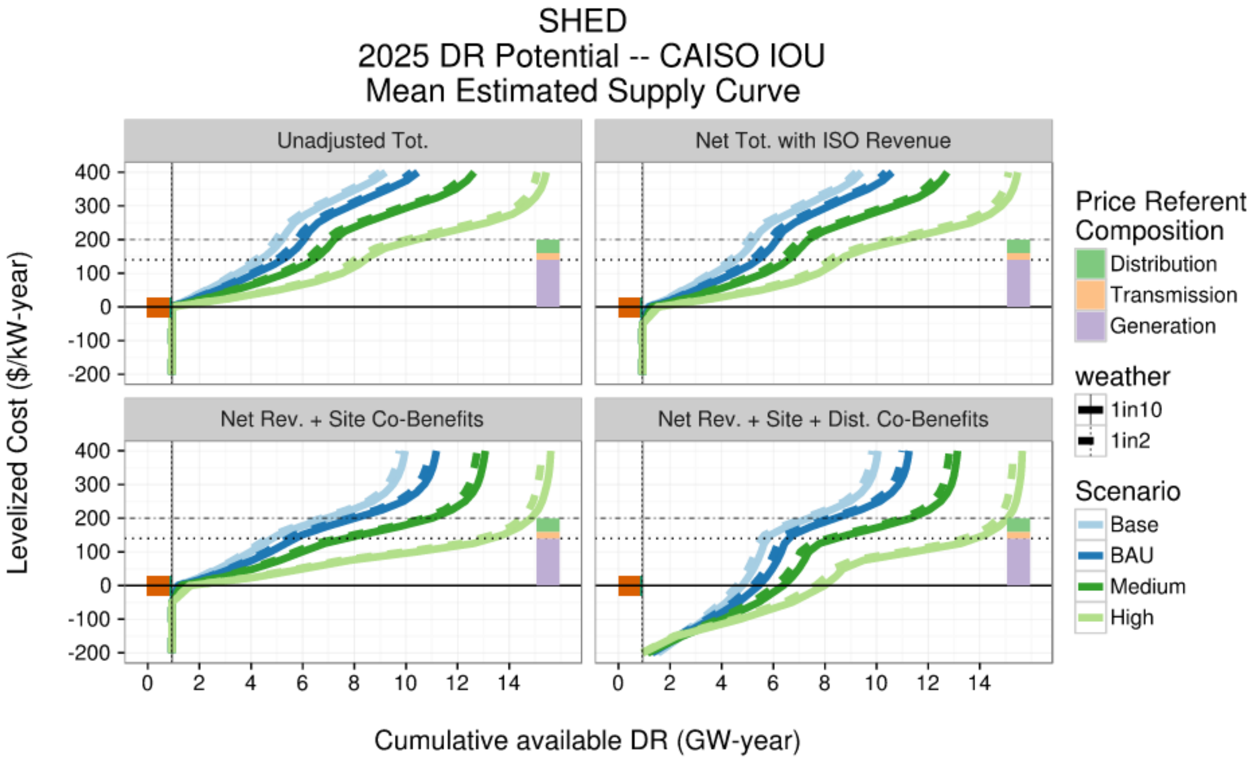

Figure 49: 2025 Shed-type DR potential supply curves with various estimates of revenue streams contributing to the economic efficiency of DR technology costs.

Figure 50 shows the 2025 Shed DR results broken out by utility, sector, and end use. For PG&E, approximately 1,500 MW of the 3,000 MW of Shed potential comes from the industrial sector, while about 800 MW comes from commercial sector, and 600 MW from residential sector. For SCE, Shed potential is driven equally by the commercial and industrial sectors, with approximately 1,250 MW from each sector, and another 400 MW from the residential sector. For SDG&E, commercial sector lighting and HVAC are key end uses that provide the majority of the available Shed DR. Table 14 presents the Shed DR potential in megawatts by sector for each IOU in 2025.

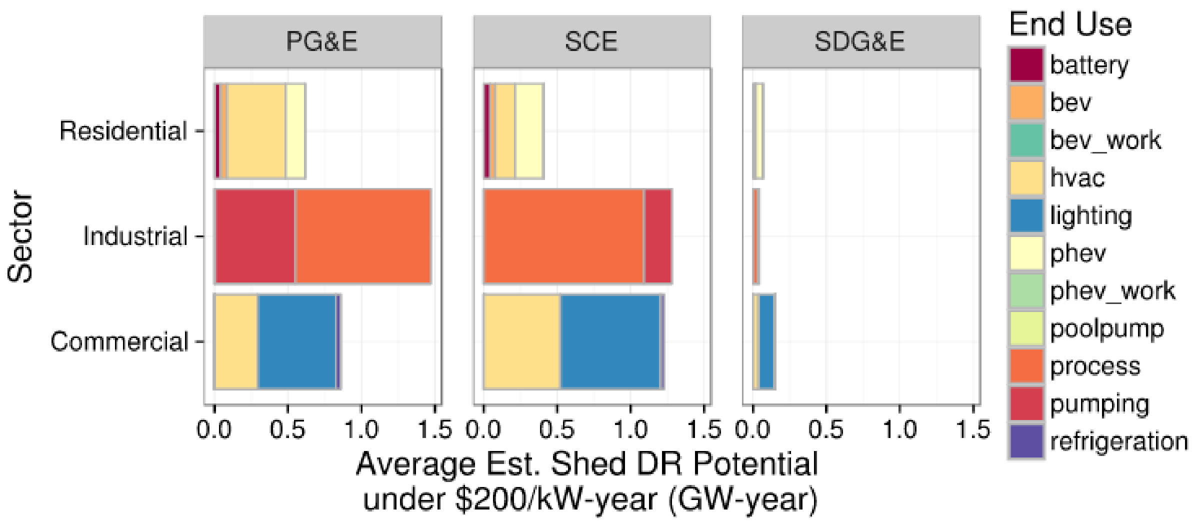

Figure 50: 2025 Shed DR potential by IOU service territory and end-use contributions, under the 1-in-2 weather year, mid-AAEE, Medium scenario with a $200/kW-yr price referent.

These results are particularly helpful for determining what types of DR, based on average costs, provide the greatest contributions to the DR fleet at different price referent levels. This may be helpful for approaching DR program recruitment through targeted marketing. One way to target DR participation that results in high returns on investment could be to identify customers within each sector that have:

- Eligible end-uses with strong coincidence between end-use load baselines and times of system need
- Large potential load reduction, i.e., typically customers with high annual kWh
- Characteristics that show a propensity to participate, such as utility program participation or other demographic factors

Rather than approaching all customers with an offer of DR, a targeted approach to recruiting customers with end-uses that are most cost competitive is efficient. For example, based on our results, targeting Commercial HVAC is in general more cost effective than Residential AC, on an average costs basis. However, the Residential AC end-use is capable of providing more cumulative DR than Commercial HVAC, and the distribution in customer-to-customer cost for DR within the technology are such that it is possible to target a set of very cost-competitive opportunities within the customer base.

Table 14: MW of Shed DR potential by customer sector for each utility, under $200/kW-yr, in 2025.

Sector	Utility	Shed DR Estimated in 2025 under $200/kW (MW)
Industrial	PG&E	1472
Residential	PG&E	616
Commercial	PG&E	859
Industrial	SCE	1281
Residential	SCE	409
Commercial	SCE	1227
Industrial	SDG&E	43
Residential	SDG&E	68
Commercial	SDG&E	151

Figure 50 shows the potential for a given price referent level ($200/kW-year), which is one among many possible appropriate levels depending on the location of shed resources, and our modeling framework leads to estimates across a range of other price levels as well. In Figure 51 below, we show how the end-use technology contributions to Shed vary across price from $0-400 /kW-year. The each sector's contribution is grouped, with boundaries between the sectors shown using black lines. The levelized cost estimates are net of expected market revenue and site-level co-benefits from automation. The variety of resources included in the model reflects the emphasis that DR Shed has gotten over the past decades, with a range of application technology that has gone from pilot phase to deployment. For areas where the value of Shed is very high (local capacity areas, and distribution system constrained circuits) there are opportunities that are market ready across several customer classes.

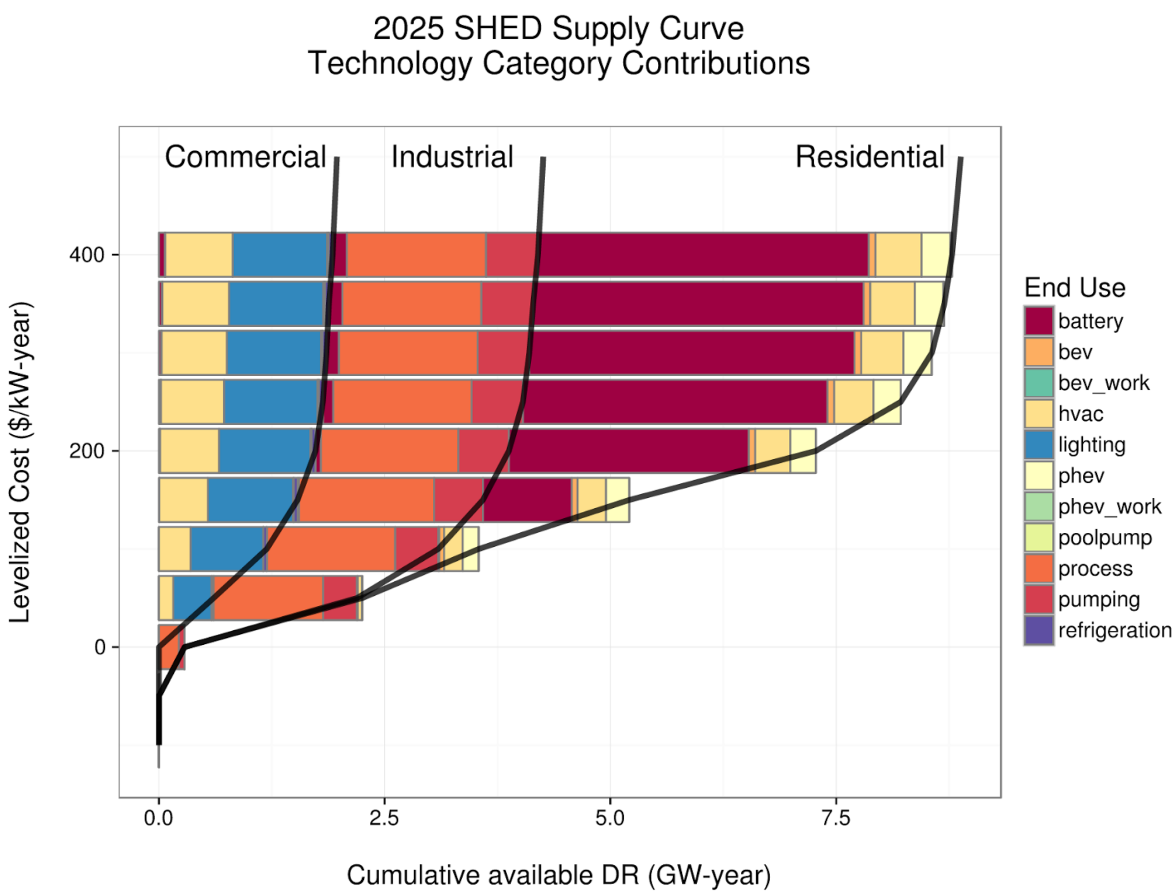

Figure 51: Shed DR supply curve in 2025, with contributions from end-use technology categories demarcated in stacked bar graphs.

5.4.2. The Importance of Information and Variation in the Model

Recall that we used Monte Carlo simulation to estimate how uncertainty in modeling assumptions for DR technology cost and performance would affect the levelized cost of DR enablement. We simulated variability in modeling assumptions due to both sources of uncertainty by using stochastic sampling to populate the enabling cost, performance, and lifetime of each enabling technology for each cluster. Figure 52 shows supply curves that illustrate the variability in DR technology measure costs. The case here, for illustrative purposes, is a 2025, mid-demand, mid-AAEE, Rate Mix #3, total cost accounting case. (A) Shows all of the stochastic input file runs, (B) shows just the runs for the "deterministic" or static input file (these were the types of runs we conducted in the study's Phase 1), (C) shows the stochastic and deterministic runs together, and (D) shows the deterministic runs in black and the mean of the stochastic runs (mean quantity x-value for each y-value cost level). The variability of the DR measure has the effect of increasing the estimated Shed potential. The Monte Carlo analysis includes parameters to simulate the effects of uncertainty in the pace of technology development and in site-to-site differences in the actual cost of DR enablement. DR potential increases when market participants can identify and target highest-value sites and enabling technologies.

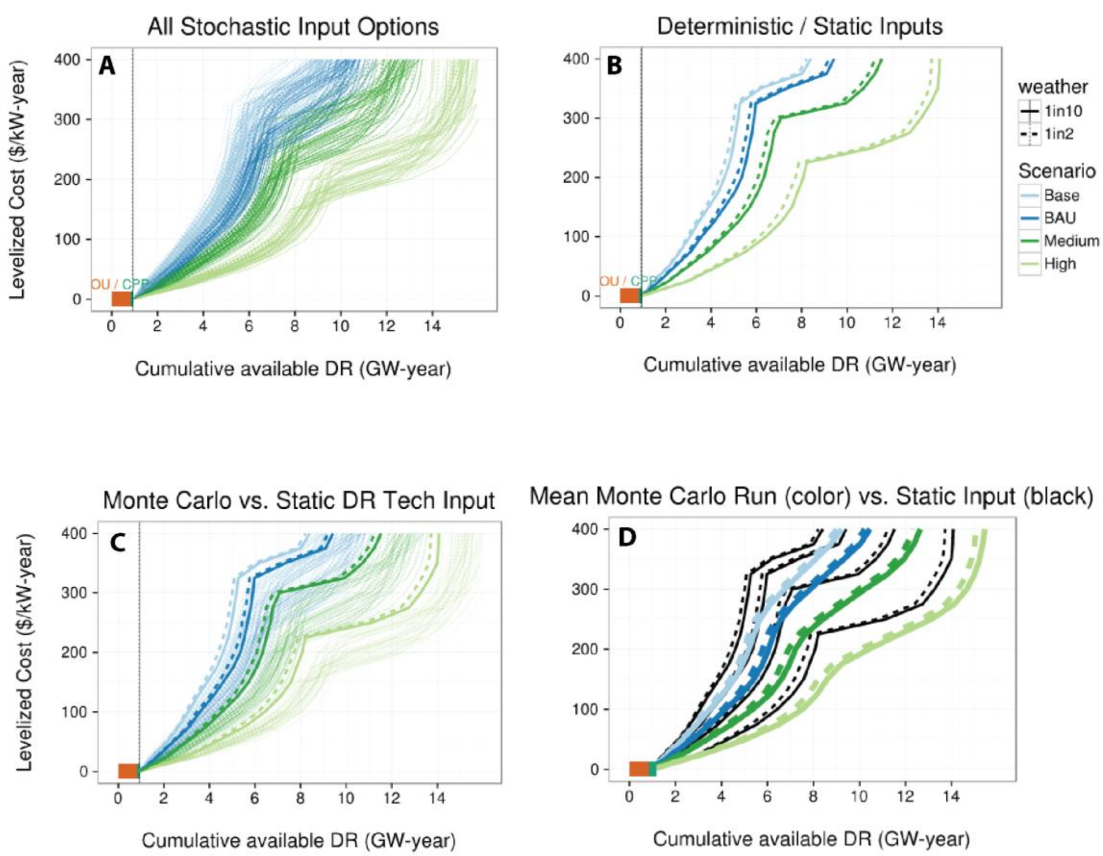

Figure 52: Illustrations of how variation in the technology inputs leads to increased mean potential due to choices available in the market.

5.4.3. Shed DR Value to the Grid

'Shed' resources as modeled in this study are those providing the conventional form of downward DR, by which load is reduced to lower peak demands on the grid. California has a long history of implementing DR programs to encourage load reduction. The California Energy Action Plan (EAP) issued in April 2003 placed energy efficiency and demand response as preferred resources and set a goal of meeting 5% of peak loads with demand response by 2007.[23] Building on the avoided cost framework developed for distributed energy resources (DER), E3 supported the CPUC in developing DR cost-effectiveness protocols first adopted in 2010 and updated in 2015.[24] As for DER in general, the protocols include several categories of benefits or avoided costs, including energy, system capacity value, transmission and distribution deferral, GHG emissions, ancillary services, losses and an RPS adder.

By far the largest value for DR in existing DR cost-effectiveness protocols is the generation capacity value. Shed DR has historically provided value by reducing system peak demand. This has been valuable because these highest demand hours generally correspond with the highest variable cost of electricity. A reduction in peak demand allows deferral of investment in peaking capacity, resulting in cost savings to ratepayers.

Transmission and distribution deferral has been the second largest value, though the vast majority of DR has been called based on system rather than local distribution conditions. The DR cost-effectiveness protocols include several adjustment actors to properly evaluate the capacity value of the DR resource to the traditional supply side resource of a combustion turbine (CT). The adjustment factors are designed to account for limitations on DR as a resource, including advanced notification requirements and the maximum frequency and duration of calls permitted.

The capacity value of DR is calculated based on the estimated cost of procuring capacity resources to meet Resource Adequacy (RA) requirements. RESOLVE incorporates this convention through its annual peak capacity requirement. RESOLVE adds new capacity resources as needed, and demand-side resources provide value by deferring the need for this new capacity. When there is generation capacity significantly in excess of peak load, RESOLVE attributes a low system capacity value for Shed DR.

RESOLVE shows relatively low value for Shed DR in the 2020 – 2030 timeframe: $0.72-1.32/kW-yr. for the first kW-yr. of Shed resource added to the grid in 2020, $3.80-4.10/kW-yr. in 2025, and $4.76-4.94/kW-yr. in 2030. See Figure 53. The value per kW also decreases as more Shed resources are added to the grid: in 2025, the 10,000th MW of Shed resource added to the grid is valued at approximately $2.50/kW-year (See Figure 54). The value that the Shed resource provides stems largely from reductions in fuel costs due to reduced load, as well as the value that flexible capacity resources have in in alleviating ramping and capacity constraints to

[23] The document "California Demand Response: A Vision for the Future (2002-2007)" is included in D.03-06-032 as Attachment A. http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/26965.ht

[24] See CPUC Decision D 10-12-024, Rulemaking R 13-09-011 and Decision D. 15-11-042

reduce integration costs and curtailment of renewable generation.

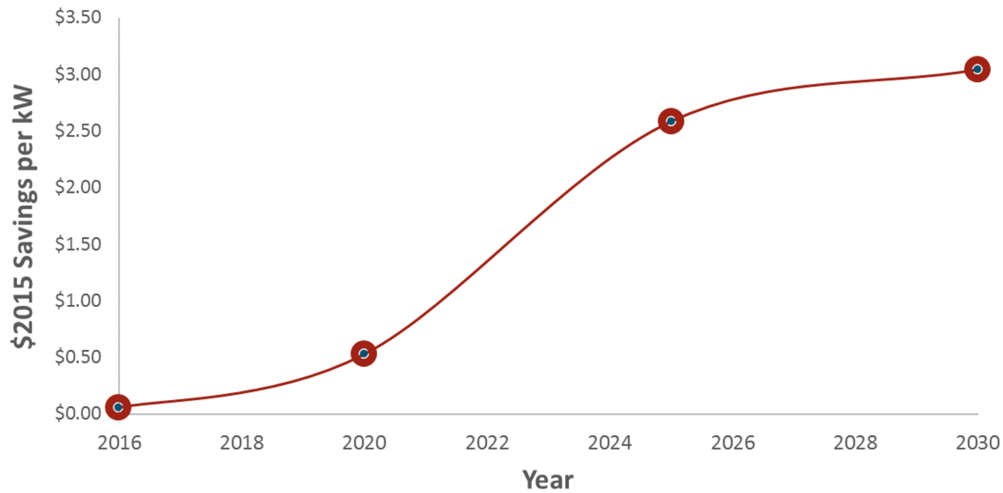

Figure 53: Value of first kW-year of Shed over time, High Curtailment Future, Mid AAEE scenario

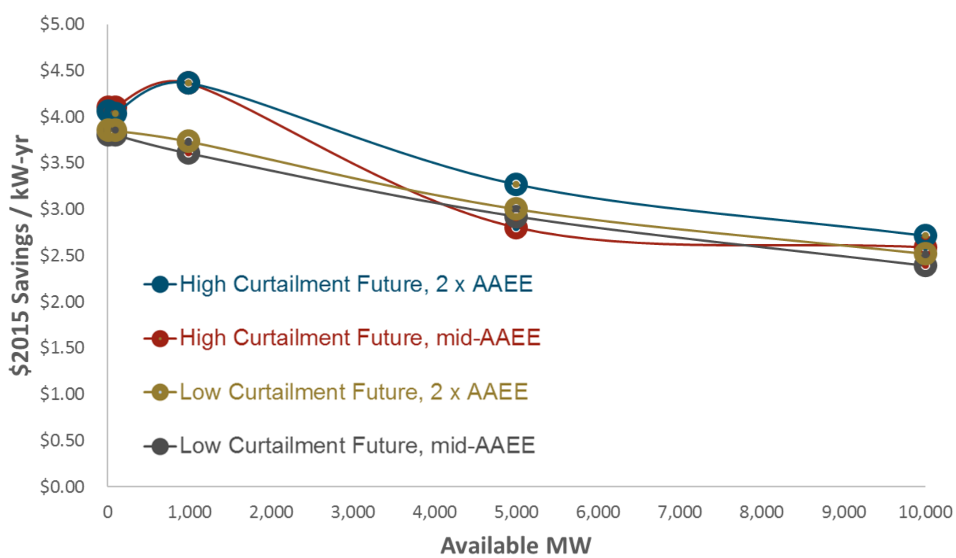

Figure 54: Marginal savings per added MW of Shed Resource, 2025

RESOLVE finds that Shed DR does not avoid significant operating or investment costs for utilities and their ratepayers. This is due largely to the fact that RESOLVE does not need to add any new system generation capacity at any point during the modeling period because of the capacity surplus assumed in the CPUC's 2016 LTPP scenarios. The LTPP scenarios reveal a sizeable excess supply in the 2017 – 2030 timeframe. Figure 55 below shows this 'Net System Balance' from the CPUC's 2016 LTPP Scenario Tool: the surplus of forecasted supply resources (for this analysis we excluded DR) above forecasted demand in August of each year.[25] This positive net system balance significantly reduces the value of Shed DR, since there are no capacity additions that can be deferred over the modeling time horizon.

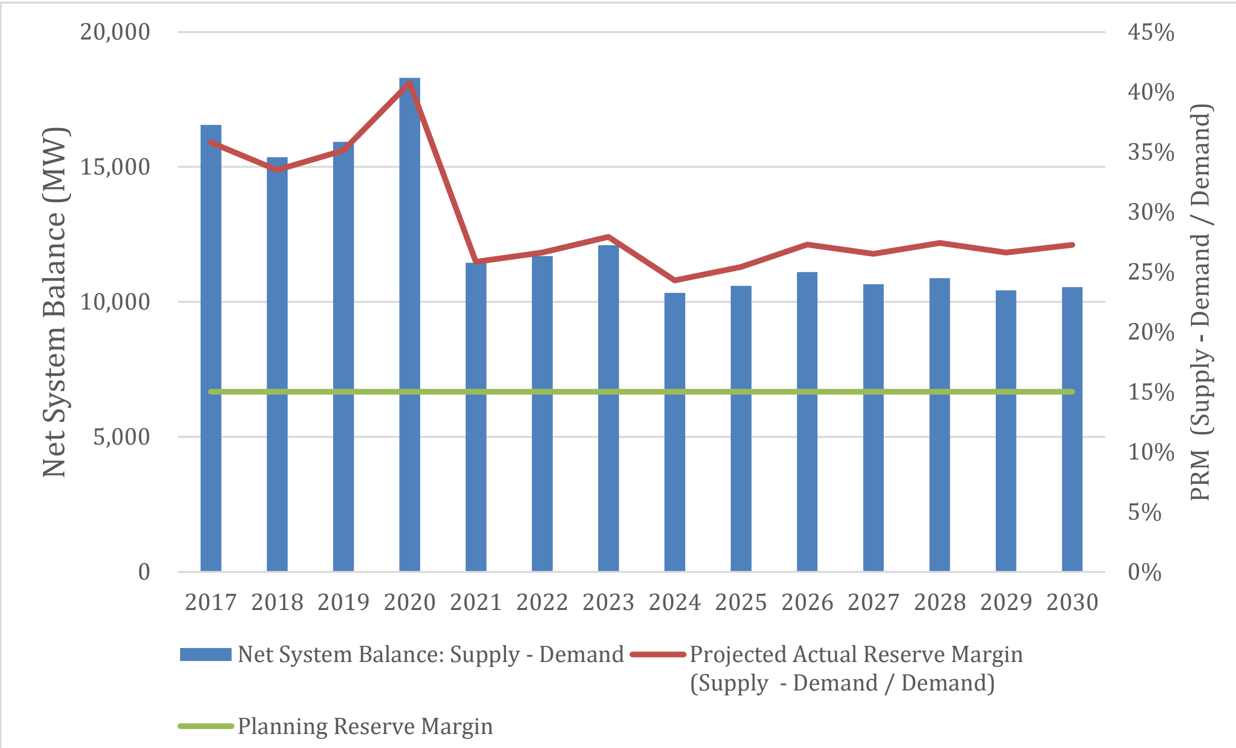

Figure 55: Net System Balance, CPUC 2016 LTPP Scenario Tool, 2017 - 2030[26]

To understand the dynamics underlying the changes in Shed value over time (recall Figure 53),

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[25] CPUC Energy Division 2016 LTPP Scenario Tool for R.16-02-007, August 2016, http://www.cpuc.ca.gov/General.aspx?id=11681 . August is the usual month of system peak capacity needs – see Assigned Commissioner's Ruling Adopting Assumptions and Scenarios for Use in the California Independent System Operator's 2016 – 17 Transmission Planning Process and Future Commission Proceedings, May 17, 2016, available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11673.

[26] Net System Balance (forecasted supply – forecasted demand) from the CPUC's 2016 LTPP Scenario Tool. This scenario assumes a mid (1-in-2) IEPR net load forecast, the California Energy Commission's 'SB 350 additional achievable energy efficiency' forecast, counts existing supply from CPUC's Net Qualifying Capacity list, assumes additional generating resources based on a screened list of CEC siting cases, and excludes behind-the-meter generating resources from the supply calculation. We have also excluded Dispatchable Demand Response from the analysis. Source: CPUC Energy Division 2016 LTPP Scenario Tool for R.13-12-010, February 2015, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6636

it is useful to look at changes in system dispatch on a high Shed day over time. Recall that RESOLVE models 37 day types (see Appendix H-2.2 for further detail on day type methodology). The following figures show system dispatch resulting from the RESOLVE model on day type 29, which is a high net load day in August and displays the highest Shed dispatch of any day type in 2030. The scenario modeled in these figures is the High Curtailment Future, Mid-AAEE scenario, with 10,000 MW of Shed resource added to the system. This corresponds to the farthest right, red data point in Figure 54.

In interpreting these figures, recall that RESOLVE models each generating resource with an associated operational cost and availability, *with the exception of Shed*. Shed is modeled at zero cost, and in the case shown here is modeled as 10,000 MW of Shed resource available in any hour, up to a 200,000 MWh annual cap. Note that there are no limits on the number of Shed calls, only on the total annual MWh. The *amount* of Shed made available to the system is thus exogenous to RESOLVE, but the *dispatch* decisions over the days and years are made by RESOLVE to create maximum value to the CAISO system over the 2016 – 2030 period. This value comes in the form of reduced investment and operational costs (see Appendix H for further detail on RESOLVE optimization logic and DR modeling). The scenario shown here includes the California Storage Mandate, plus any additional storage that RESOLVE finds cost-effective to dispatch.

The California storage mandate[27] calls for 1,325 MW of storage to be installed by California's IOUs by 2025. This mandate is included in all RESOLVE scenarios as a block of four-hour duration batteries, and is treated as exogenous to all DR modeling. That is, none of the resources installed as part of the Storage Mandate are assumed to be available as Shift or Shimmy DR resource, and none of the benefits from this storage are included in our Shift and Shimmy results.[28]

Figure 56 shows dispatch on day type 29 in 2016, and displays conventional use of Shed DR to minimize peak net load. Storage is dispatched in the same way.

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[27] For more information on AB 2514 regarding energy storage systems, see

http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514

[28] E3 conducted a sensitivity analysis in RESOLVE to evaluate the impact of the Storage Mandate on Shift DR services and estimate the change in system level value for Shift. **Appendix H-5** presents the findings of this Storage Mandate sensitivity analysis.

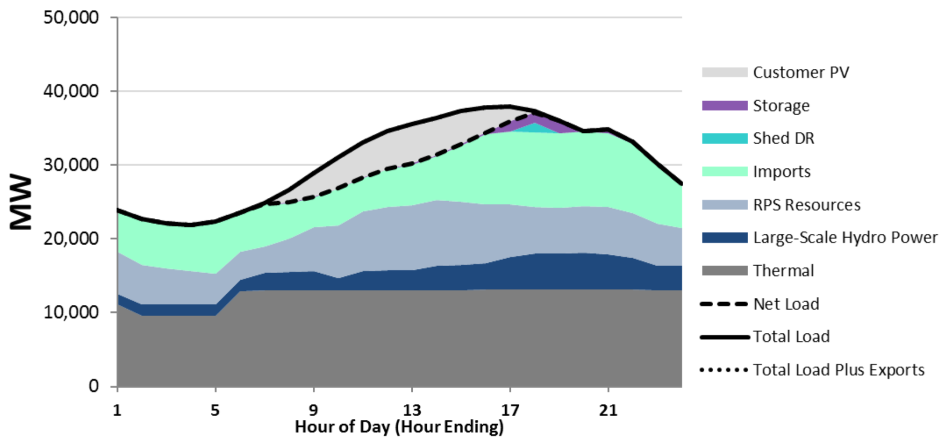

Figure 56: System dispatch on RESOLVE Day Type 29 (high net load day in August), 2016. High Curtailment, Mid AAEE scenario, with 10,000 MW of hourly Shed resource availability (max. 200,000 MWh per year) modeled at zero cost.

In 2020, we observe more RPS resources and customer-sited PV on the system – see Figure 57. Just as in 2016, we see the Shed DR resources called to reduce the system's peak net load.

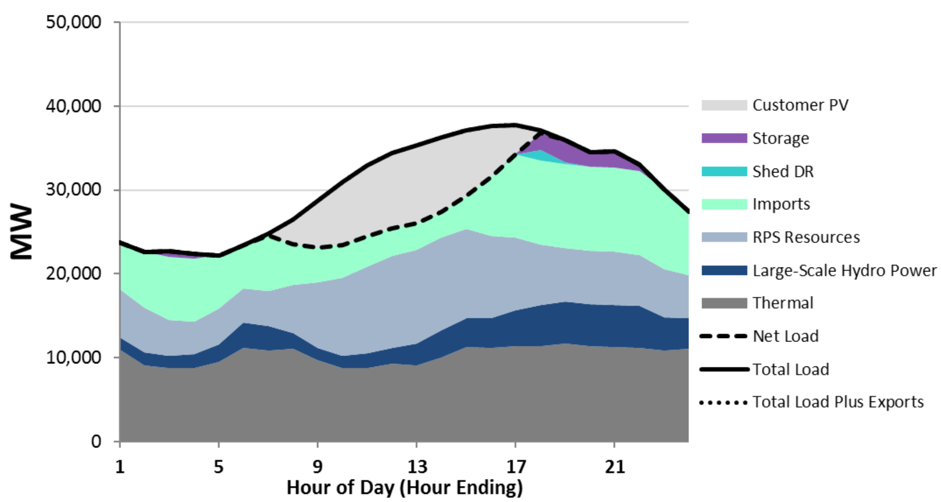

Figure 57: System dispatch on RESOLVE Day Type 29 (high net load day in August), 2020. High Curtailment, Mid AAEE scenario, with 10,000 MW of hourly Shed resource availability (max. 200,000 MWh per year) modeled at zero cost.

In 2025, we model significant renewable capacity contributing to the system's supply. At this point, RESOLVE starts to see slightly more economic opportunities for the utilization of conventional DR: meeting ramping needs. As customer-sited solar becomes a larger contributor to mid-day electricity supply, other generators must be ramped down to prevent curtailment. However, the sun goes down as the evening demand peak sets in, creating a need to rapidly ramp-up non-solar generators back to meet evening load. In the absence of DR, this need is met in the RESOLVE cases by a combination of increased California gas dispatch, higher imports, and energy storage discharge. When Shed DR is available, it is frequently dispatched by RESOLVE during these steep evening ramps. However, the low value for Shed resources even in 2025 and 2030 (recall Figure 53) suggests that RESOLVE does not find significant value for Shed resources in reducing renewable curtailment due to alleviating upward ramping constraints in the 2016 – 2030 timeframe. Rather, the value that Shed DR provides in dispatch is related to fuel savings from reduced conventional dispatch (this includes CAISO CCGT's, peaker plants, gas turbines, ICEs). This value is relatively small, even during the peak periods. As discussed in prior sections, significantly more value is created by DR resources that can move load into the middle of high renewable curtailment days to reduce curtailment.

It is worth noting that RESOLVE's hour alignment is in standard time, meaning that the net load peak displayed in the corresponding dispatch charts as hour-ending 18 is actually occurring at hour-ending 19.[29] This means, quite simply, the sun is setting by the time this peak occurs. In other words, regardless of how much solar is added, the net load peak can only be pushed so far back. With this in mind, we do not see a significant shift of the net load peak to later in the evening.

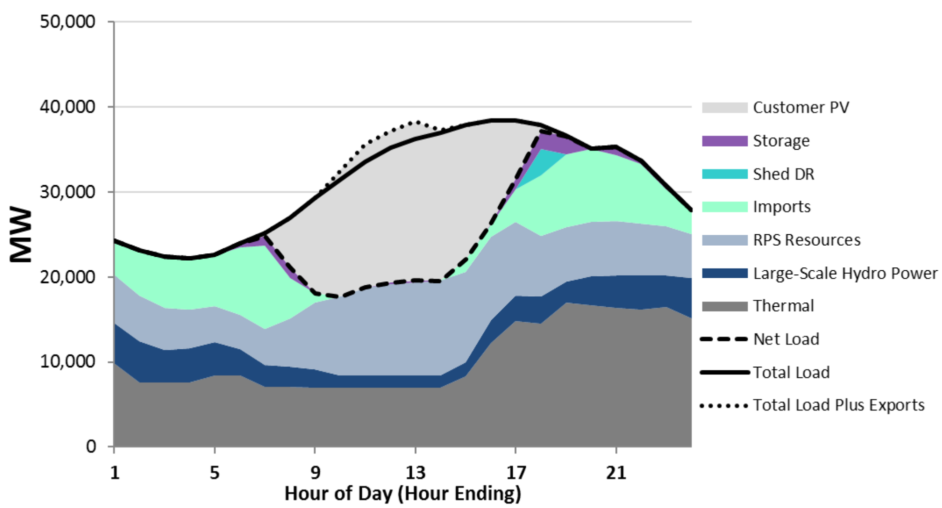

Figure 58: System dispatch on RESOLVE Day Type 29 (high net load day in August), 2025. High Curtailment, Mid AAEE scenario, with 10,000 MW of hourly Shed resource availability (max. 200,000 MWh per year) modeled at zero cost.

The story in 2030 is similar to that of 2025, only further exacerbated. On this high net load day in 2030, we observe a very small amount of renewable curtailment. This is an outcome of the system's inability to meet a steep ramping constraint, as non-renewable generators must be kept on-line to meet the evening uptick in demand. On this day, we see that Shed DR is dispatched

[29] This is true for all of RESOLVE's dispatching. That is, any figure featuring a 24-hour timeframe on the X-axis is in standard time.

during the steepest ramping hours to try and minimize this challenge to grid operations. It is worth noting here that, because Shed DR is a free resource (that is, RESOLVE sees no operational cost of dispatching Shed DR), dispatching it simply reduces energy demand. This reduces operational costs. With this in mind, RESOLVE will always dispatch Shed DR up to whatever its annual dispatch budget is. If the annual energy budget of Shed DR were increased, RESOLVE would continue to all of it up. More specifically, because the variable cost of serving energy is highest when demand is highest, RESOLVE will dispatch its Shed DR budget to reduce the observed net load peak.

The sequence of dispatch figures reveals an increase in the magnitude of the conventional DR being dispatched on this individual day over time. Here, it is important to note that the above dispatch represents only one of the 37 day types included in RESOLVE (see Appendix H for further description of the day type methodology). In 2016 and 2020, RESOLVE chooses to dispatch a maximum of 1,279 and 1,274 MW of Shed, respectively, on each day of this type, and spreads the remaining Shed availability across other day types. In 2025 and 2030, as the variable (renewable) generation on the grid increases, we see more variance across days in system-level dispatch. In other words, the 37 day types in RESOLVE look *more similar* in the earlier years of our RESOLVE modeling, but take on more variance in later years. Because of this, RESOLVE optimizes for lowest grid costs by dispatching a more significant quantity of Shed DR in later years (a maximum of 3,051 MW in hour 18 in 2025, 3,206 MW in hour 18 in 2030) during this particular high net load day. That is, as the supply and demand profiles (net load, supply mix, renewable generation, etc.) of day types become more varied over time, the potential value of a MW of Shed DR changes drastically. A high net load day, which features steep ramping needs and a high net load peak, as displayed in the above Figures, creates a much more valuable Shed DR dispatching opportunity than a low net load day, which would have both more moderate ramping and peak demands. We see this consolidation of Shed DR dispatching into fewer days and at more extreme levels in Figure 60.

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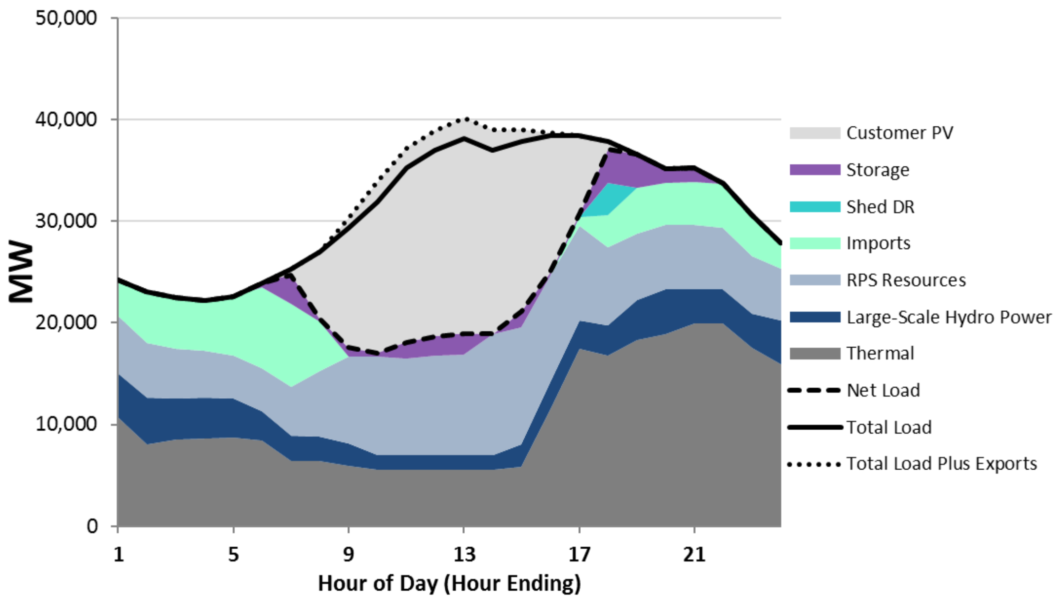

Figure 59 System dispatch on RESOLVE Day Type 29 (high net load day in August), 2030. High Curtailment, Mid AAEE scenario, with 10,000 MW of hourly Shed resource availability (max. 200,000 MWh per year) modeled at zero cost.

Figure 60 shows the total MW of Shed DR dispatched for each day type in RESOLVE in each year (2016, 2020, 2025, 2030). Arrows indicate the direction of significant movements in Shed dispatch over from 2016 to 2030. Note that each day type has been weighted by its associated weight to show the full Shed dispatch for the day type across the relevant year. 2016 and 2020 display relatively flat Shed DR dispatch across the 37 day types. For 2025 and 2030, however, most of the Shed DR dispatch is found during fewer day types. Days 17 and 29, in particular, show large uptakes in shed dispatching as time goes on.

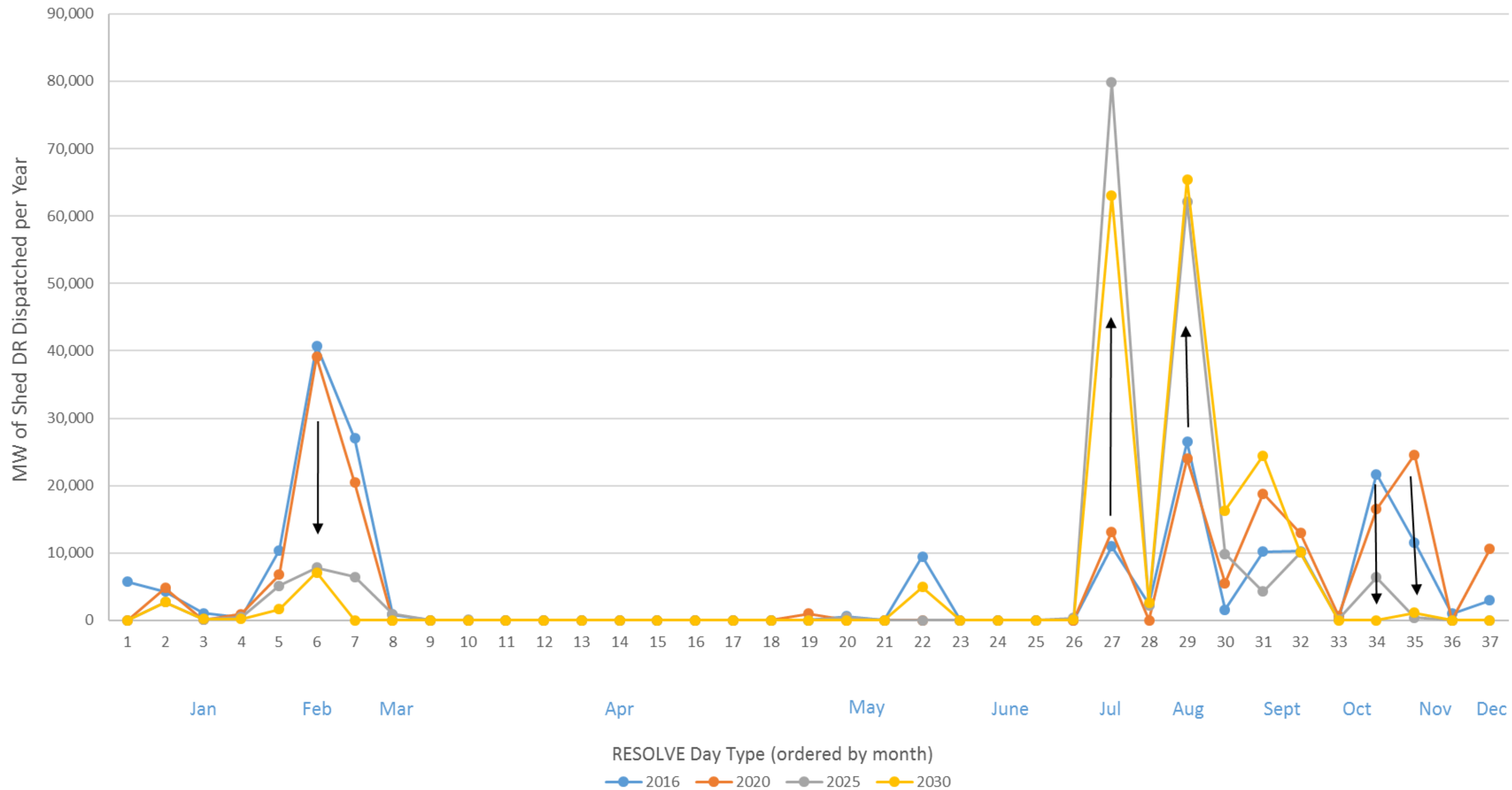

Figure 60: Annual Shed DR dispatched during each RESOLVE Day Type. High Curtailment, Mid AAEE scenario, with 10,000MW of hourly Shed resource availability (max. 200,000 MWh per year)

It should be noted that Shed DR may have additional value beyond that modeled in RESOLVE. RESOLVE captures the value of Shed in providing System Capacity, but does not capture any additional value of DR that is located in specific areas. For example, DR resources in certain areas such as the Los Angeles Basin may have Local Capacity Reliability (LCR) value by providing a capacity resource in a transmission-constrained area. Shed DR in some locations may also have value in deferring transmission and distribution system investments that are not captured in RESOLVE. In addition, RESOLVE does not capture a reduction in the need of Load-Serving Entities to procure RA capacity from existing resources.

5.4.4. Valuing Shed Service Type DR with Supply Curves and Levelized Demand Curves

As noted previously, our analysis included two economic valuation methodologies. The second methodology, that of using RESOLVE to generate system *demand* curves, resulted in drastically different conclusions as to what the economically cost-effective amount of Shed DR is. Figure 61 shows the Shed supply curve for 2025 and includes the system levelized value approach under the high-curtailment case. The green and blue colors in the lines (top) and bars (bottom) represent qualitative DR market scenarios. The dotted lines correspond to 1-in-2 weather and the solid lines are 1-in-10 weather years. The Low-Curtailment case (**RED**) and High-Curtailment case (**ORANGE**) horizontal lines represent the levelized demand curves. The equilibrium price is at the intersection of the levelized demand curves and the supply curves. All supply Shed DR estimates are shifted based on the contributions of TOU/CPP rates, which are shown in **ORANGE** and **GREEN**. (Case: Year 2025, Rate Mix #3, mid-AAEE trajectory.) When examining Shed DR resource value under the RESOLVE levelized demand curve, we found that Shed-type resources are not cost-competitive; that is, there was no value for Shed resources in either 2020 or 2025, because there was no shortage of generation capacity.

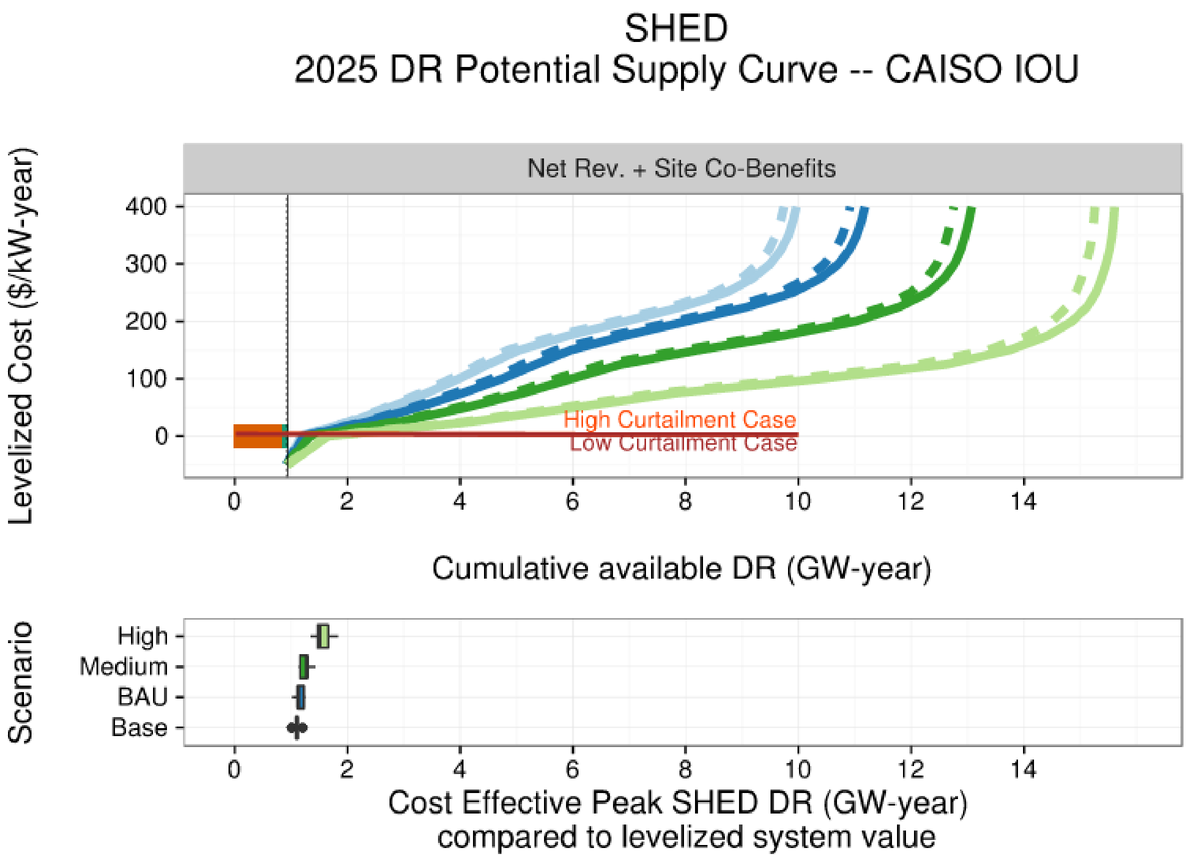

Figure 61: (top) Shed DR potential supply curve results compared to the levelized demand curve, and (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.

The levelized demand curve potential (Figure 62) indicates cost-competitive Shed resource DR to be about 0 MW. In other words, the value of Shed-type resources is virtually zero because there are no constraints on capacity type resources over the next 15 years. We note that if one considers revenue that should be available in peak hours of the market, there is some economically viable Shed resource (on the order of 500 MW in 2025).

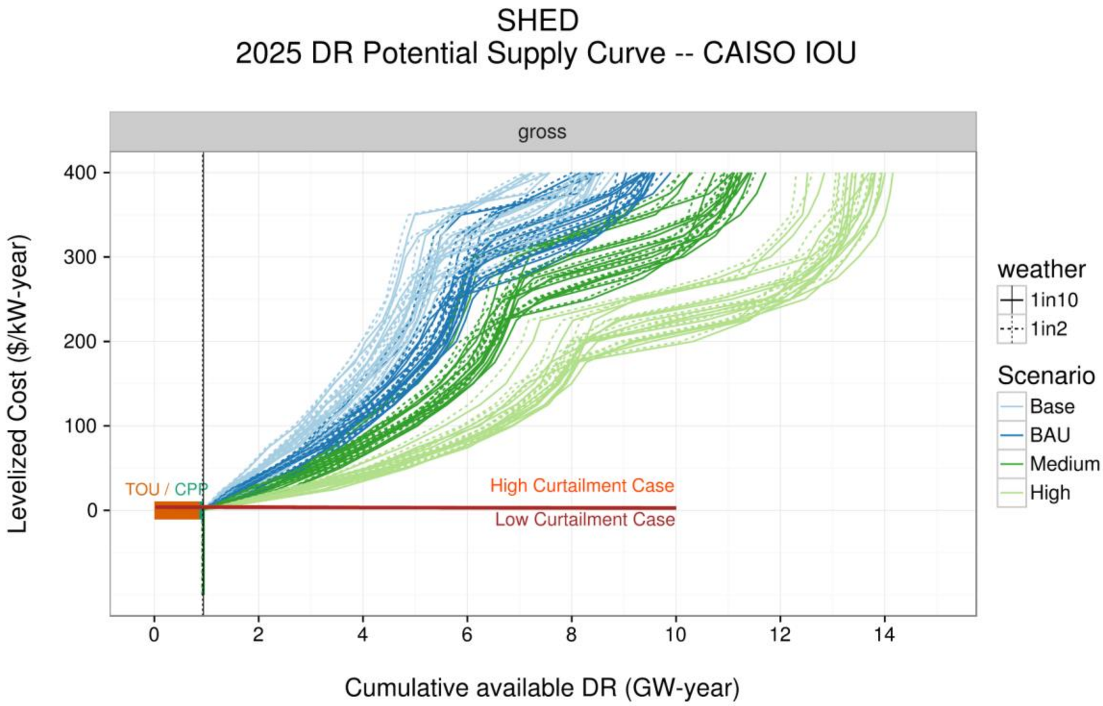

Figure 62: Combined supply-demand curves for Shed DR in 2025. The levelized demand curve shows Shed DR with approximately zero value, leading to approximately no cost-competitive Shed DR.

Below, in Figure 63, we incorporate the first-order distribution system level benefits into the economic valuation of the DR potential supply curves. Beginning with the upper left quadrant, going clockwise: the Supply curves providing the Shed service type DR to the grid are represented with unadjusted total costs, net total costs with ISO revenue, net revenues with site-level co-benefits, and net revenue with site and distribution system benefits incorporated into Shed supply curves. Each quadrant depicts the estimates developed for the Base, BAU, Medium and High scenarios using Monte Carlo analysis to estimate the range of uncertainty. In the lower right quadrant, we include potential revenue streams from serving the distribution system and avoiding investment in infrastructure upgrades; these results are discussed in detail below.

In Figure 64**,** box plots depict the 2025 Shed-type DR potential as compared to the system-level value from the levelized demand curves. Each quadrant includes estimates of revenue streams contributing to the economic efficiency of DR technology costs. Beginning with the upper left quadrant, going clockwise: the unadjusted total costs, it shows the net total costs with ISO revenue, net revenues with site-level co-benefits, and net revenue with site and distribution system benefits. Each quadrant depicts the range of DR potential estimates developed for the Base, BAU, Medium and High scenarios and the range of values from a Monte Carlo analysis that examined the range of uncertainty in DR enabling technologies' costs and performance.

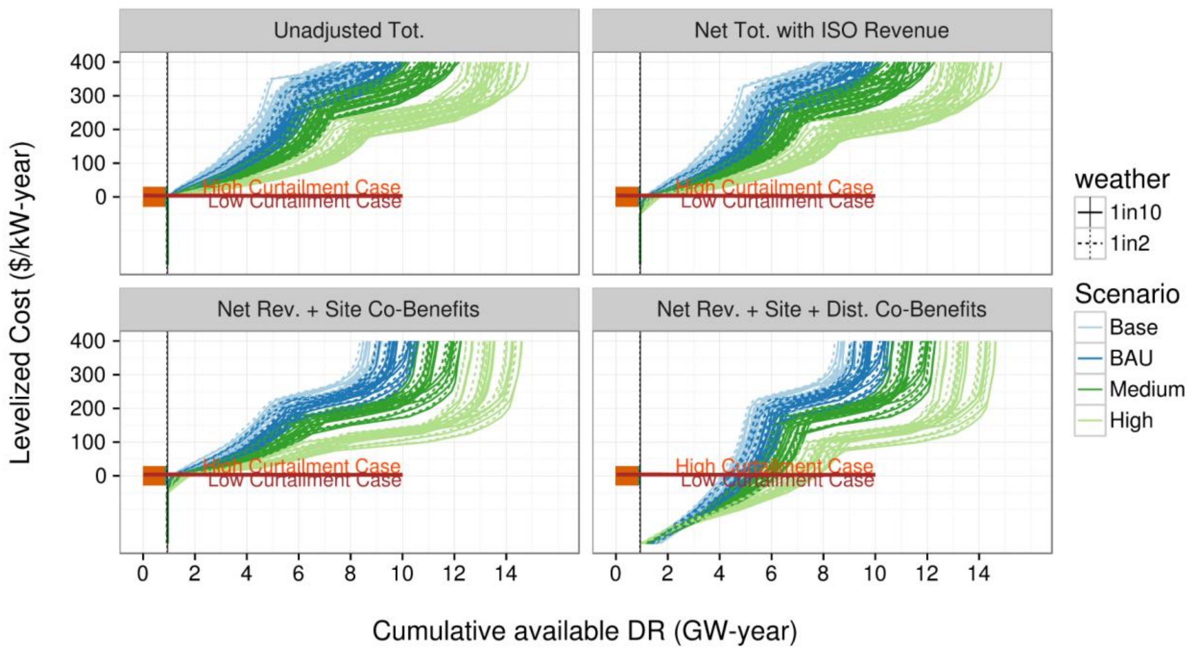

Figure 63: 2025 Shed-type DR potential supply curves as compared to the system level value supply curveswith various estimates of revenue streams contributing to the economic efficiency of DR technology costs.

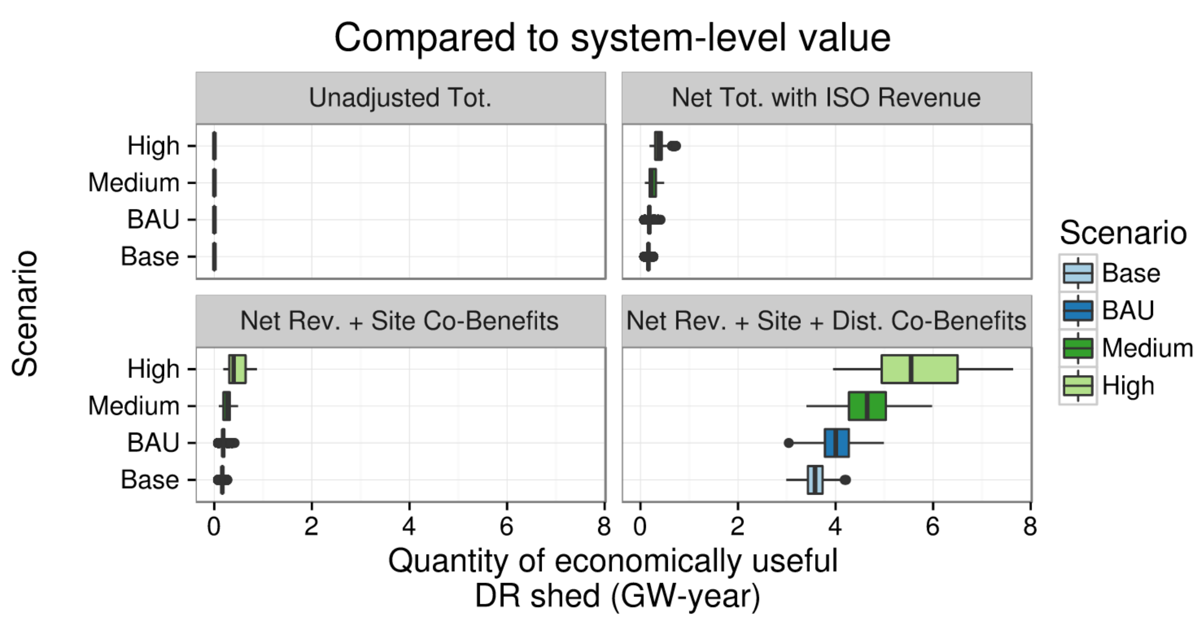

Figure 64: Box plots depicting the 2025 Shed-type DR potential as compared to the system-level value from the levelized demand curves.

Table 15 and Table 16 present the cost competitive prices and quantity for Shed DR from the DR Futures supply curves and the RESOLVE levelized demand curves under the medium scenario, and represent the price at the intersection of each curve. The price and quantity reflects the levelized cost and value to the grid; in other words, the price for each DR unit (MW or MWh) is economical when compared to the costs of other generation resources. The costs and quantities are segmented by percentiles that capture the variance around the intersection of the demand and supply curves for each service type. Note that Shed has no value to the grid under the “Total” cost framework, and only provides value once benefits streams are incorporated, such as site level co-benefits and distribution system benefits.

Table 15: Levelized Price and Quantity of Cost Competitive Shed DR by Percentile (Low Curtailment Scenario)

Shed DR (Low Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Site Co-Benefits	Net Revenue + Site + Distribution System
25th Percentile Price per kW ($)	$0	$0	$0	$0
25th Percentile Quantity (MW)	-	246	246	4,920
50th Percentile Price per kW ($)	$0	$0	$0	$0
50th Percentile Quantity (MW)	-	360	360	5,082
Mean Price per kW ($)	$0	$0	$0	$0
Mean Quantity (MW)	-	335	339	5,112
75th Percentile Price per kW ($)	$0	$0	$0	$0
75th Percentile Quantity (MW)	-	369	372	5,250

Table 16: Levelized Price and Quantity of Cost Competitive Shed DR by Percentile (High Curtailment Scenario)

Shed DR (High Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	**Total**	**Net ISO Revenue**	**Net Revenue + Site Co-Benefits**	**Net Revenue + Site + Distribution System**
25th Percentile Price per kW ($)	$0	$0	$0	$0
25th Percentile Quantity (MW)	-	242	242	4,920
50th Percentile Price per kW ($)	$0	$0	$0	$0
50th Percentile Quantity (MW)	-	360	360	5,082
Mean Price per kW ($)	$0	$0	$0	$0
Mean Quantity (MW)	-	331	331	5,112
75th Percentile Price per kW ($)	$0	$0	$0	$0
75th Percentile Quantity (MW)	-	369	369	5,250

Table 17 below summarizes the expected Shift DR potential by utility, by year. It shows the breakdown of expected potential by utility service area, and the implications of the portfolio benefits of multiple value streams (through cost accounting framework modifications). The core value from widely distributed Shed resources derives from serving the distribution system, discussed in Appendix I. Under the assumptions we used to estimate potential for distribution system support, we identified up to 4–5 GW of Shed DR that is cost-effective (which is illustrated by the Cost Frameworks in the table). Since distribution system operations are managed below the ISO level by individual utilities and load-serving entities, Shed DR servicing the distribution system falls into the load-modifying DR classification.

Table 17: Shed potential (MW-year) by year, by utility, for a range of cost accounting frameworks. The results are the 50th percentile for the case defined by the Medium DR market scenario, mid-AAEE energy efficiency trajectory, 1-in-2 weather, the "High Curtailment" RESOLVE case, and Rate Mix #3.

	2020			2025		
Cost Framework	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Unadjusted Tot.	0	0	0	0	0	0
Net Tot. with ISO Revenue	110	210	2	130	250	2
Net Rev. + Site Co-Benefits	110	210	2	130	250	2
Net Rev. + Site + Dist. Co-Benefits	2100	2200	150	2500	2500	210

5.4.5. Shed Service Type DR Potential: Local Capacity Areas

Although Shed-type DR is expected to provide little value to bulk power system operation and investment planning, we found that there can be significant value in geographically targeted Sheds for certain areas, as illustrated in Figure ***65***. These supply curves show how DR could meet the needs of capacity constrained areas. The figure shows a subset of the system-wide Shed resource: only fast-responding (20 minute dispatch) resources that are located in current-day capacity constrained areas (Los Angeles Basin, Big Creek/Ventura, and San Diego), where many of the needs must be met with local generation. Significant DR resources are located in these areas of California where local capacity constraints create need for local DR. If the value of Shed in these constrained "local capacity areas" (LCAs) is equal to $200 per kW-year (an alternative technology price referent), we found that by 2025 there could be approximately 2–6 GW of local, cost-effective Shed DR. Table 18 shows a range of potential for "local" DR, with the system-wide potential for fast DR and the current local capacity area totals indicated.

Many DR technologies are able to respond within a 20-minute dispatch window. Those that are unable to respond within this timeframe, based on our estimation, include "manual" response in the residential sector (i.e., those responses where homeowners must take action) and some industrial processes that cannot be interrupted without longer notice.

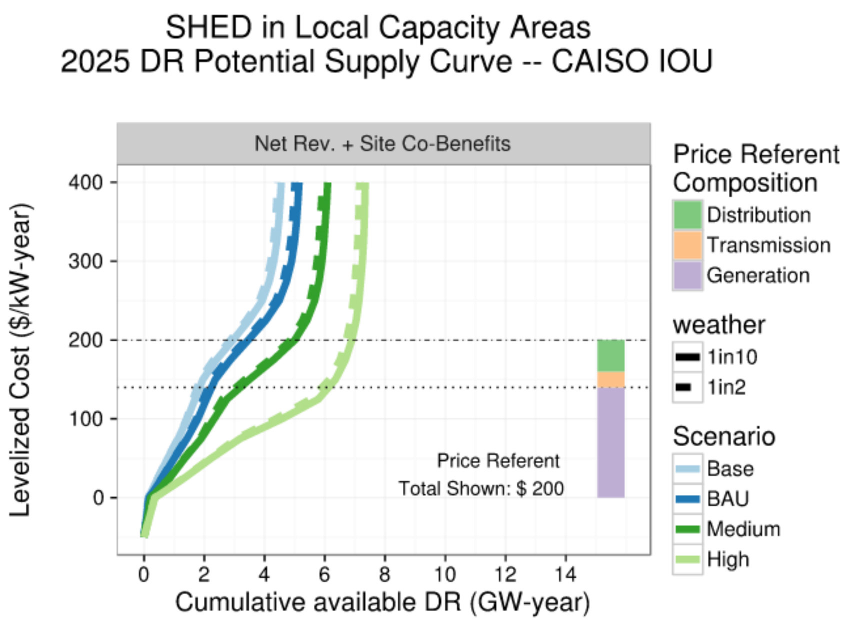

***Figure** 65: Supply curve for DR Shed available in significant local capacity-constrained areas (Los Angeles Basin, Ventura/Big Creek, and San Diego).*

Table 18: Local shed potential (MW-year) by year, by utility, for a range of cost accounting frameworks. The results are the 50th percentile for the case defined by the Medium DR market scenario, mid-AAEE energy efficiency trajectory, 1-in-2 weather, a $200/kW-year price referent, and Rate Mix #3. The results for the whole service territory are given along with the current local capacity constrained areas (LCA) results (in parentheses) for: LA Basin, Big Creek/Ventura and San Diego.

Cost Framework	2020			2025		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Unadjusted Total	2300 (0)	2400 (2100)	170 (170)	2900 (0)	2900 (2500)	260 (260)
Net Total with ISO Revenue	2400 (0)	2400 (2100)	180 (180)	3000 (0)	3000 (2600)	280 (280)
Net Revenue + Site Co-Benefits	2900 (0)	3100 (2700)	320 (320)	4300 (0)	4600 (4100)	660 (660)
Net Revenue + Site + Dist. Co-Benefits	3000 (0)	3200 (2800)	330 (330)	4400 (0)	4700 (4100)	670 (670)

5.4.6. Emergency and Contingency DR

In this study, we do not explicitly model Contingency Reserves and Emergency DR, but both could create value and revenue opportunities from appropriately designed Shed DR.

Contingency reserves are maintained to support system reliability in transmission-scale loss events. These "Spinning" and "Non-spinning" reserves are currently procured in operational capacity markets. It is plausible fast Shed DR could participate in these markets in the future with appropriate telemetry and rules, but this may not be a significant driver for additional DR potential since there are modest market clearing prices ($0.50-$7.00/MW were the average prices in the 2015 CAISO market[30]) and relatively low quantities needed (800 MW each for spin and non-spin). Future work could seek to better-understand the future value of contingency reserves as a DR strategy.

Emergency DR are resources that only are dispatched in extreme events when contingency resources are not sufficient to prevent blackouts and maintain system reliability. Emergency DR can add value by avoiding or limiting the extent of a blackout. Future work is needed to quantify the value of this type of service, as there is not sufficient evidence available to the study team to make an estimate of how likely it is that an emergency DR event will successfully prevent a blackout, particularly because every blackout has unique characteristics and causes.

Broadly speaking, blackouts are caused by a range of factors but the most typical proximate causes for those at the system level are widespread natural disasters or contingency events that lead to cascading failures in the transmission system. We would not expect DR to be able to mitigate blackouts caused by natural disasters but it is plausible that DR could enhance the capabilities of system operators to prevent or contain cascading failures. Future work is required to estimate the likelihood of DR both being available for dispatch and avoiding blackout.

If DR were able to avoid blackouts, the value to society is uncertain, but potentially large. Estimates of the value of lost load range from $0-$35,000/MWh, depending on the types of loads and services that are affected, and are highly variable depending on the circumstances for the customer[31]. There are wide-ranging estimates for the economic losses from large blackouts, up to billions of dollars in aggregate annually on the national level[32]. Future work to better understand both the value of avoiding blackout and the potential role for DR in mitigating

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[30] https://caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

[31] *Estimating the Value of Lost Load* by London Economics for ERCOT (2013)

[32] *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers* (2004) K. LaCommare and J. Eto LBNL-55718 and

cascading failure is needed.

5.4.7. Shed Service Type Pathways

Our research suggests that a large potential resource of Shed DR exists in 2025, ranging from between 2 and 10 GW depending on the technology costs and performance scenario. However, as system capacity is overbuilt in pursuit of achieving the 50 percent RPS, there is little need for system-level peak-shed DR through 2025. Rather, the value of Shed DR is derived from servicing local capacity and distribution system needs.

Based on an expected future generation fleet consistent with long-term procurement planning and reasonable facility retirement schedules, the RESOLVE model found Shed to have a very low system-level value compared to price referent values that are often cited. For example, 10,000 MW of available Shed resource saves the CAISO system only $31 million in 2025, or about $4 per kW-year. In our system levelized value analysis, we examined the equilibrium price at the intersection of the supply and demand curves for the DR service types. Results from that analysis suggest that there is 100–400 MW of cost-competitive Shed DR resources in 2025 that can compete based on energy market participation.

For the vast majority of the Shed DR resources, the costs of enablement exceeded the value they provided to the grid. However, about half of the Shed DR resources in California are in one of three LCAs where a higher price referent may be called for, based on local capacity and distribution system needs. When we accounted for opportunities to service these local system needs, we observed 1–4 GW of Shed DR that is cost-effective for avoiding or deferring feeder and substation-level upgrades that would otherwise be required.

> *"Our research suggests that the focus on system-level Shed (peak load capacity resources) should be redirected to focus on local and distribution-system needs, and that the control technology and business relationships in place could be the foundation of new portfolios that combine targeted and/or fast Shed with Shift."*

These findings challenge the conventional wisdom of peak capacity DR programs in California. For years, the greatest need to the electricity grid was to manage peak demand; however, with the mass implementation of renewable generation and mandates to meet even higher RPS standards of 50 percent, the challenges of the grid have shifted away from peak capacity shortfalls, thus drastically reducing the need for Shed-type resources for serving the CAISO balancing authority over the coming decade and beyond. This suggests that the focus on system Sheds should be redirected to focus on local and distribution-system needs, and that the control technology and business relationships in place could be the foundation of new portfolios that combine targeted Shed and/or Shift.

5.5. Ancillary Services with *Shimmy*

Fast DR that operates on seconds-to-minutes (“regulation”) and minutes-to-hours (“load following”) timescales are collectively referred to in our study as *Shimmy* resources. Rapidly responsive loads can provide Net Load Following and Regulation services to system operators and reduce the need for traditional generation resources. These resources derive value by managing short-term fluctuations in net load. The Shimmy DR service type is separated into two key products: load following and regulation. Load-following DR resources are those capable of responding within five minutes of being dispatched, and enable load to participate in both the real-time energy and spinning reserves markets. Regulation DR resources must be capable of responding within four seconds, and enable load to participate in regulation markets.

Fixed behind the meter battery storage is in a sense “the ideal” DR technology. When combined with a battery, any load can provide flexible services that meet the requirements of the Shed, Shift and Shimmy service types. Residential and Commercial batteries have potential to provide significant services to the distribution and transmission grid along with highly-valued site-level reliability and bill savings benefits. Unlocking that potential will require simplified procedures for interconnection and processes for presenting these resources to the wholesale markets as a resource.

We used the RESOLVE model to explore the value of Shimmy resources to grid operation. We found that Shimmy-type DR changes the dispatch profiles of battery storage. Without Shimmy-type DR, batteries provide load following and regulation. However, when other DR resources service these grid needs, batteries are instead dispatched to charge during hours with high renewable generation. Thus, Shimmy DR enables batteries to provide additional Shift-type DR rather than managing short-term variability in load, thereby increasing the value of battery storage.

The technology options for Shimmy are limited compared to Shed and Shift DR due to the requirements for fast-response capabilities and the need for installing advanced telemetry and control that can make some applications cost prohibitive. Figure 66 and Figure 67 below show that for the fastest response resources (Shimmy – Regulation) the main contributions based on our model assumptions come from lighting and commercial HVAC control, with the potential for significant contributions from residential behind-the-meter storage if the cost of storage is lower than we project. In Figure 66, the contributions of each sector are grouped, with boundaries between the sectors shown using black lines. The levelized cost estimates are net of expected market revenue and site-level co-benefits from automation. Load following is somewhat slower (5 minutes) and in addition to HVAC and lighting we expect contributions from industrial processes and pumping could be important opportunity areas in the future.

The relatively higher costs, when compared to the other DR service types, for Shimmy resources are driven by the automated controls, the telemetry requirements for granular energy measurement, and the real-time, or near real-time communication platform requirements, (i.e. RIGs or SEGs).

In Figure 67, the contributions of each sector are grouped, with boundaries between the sectors shown using black lines. The levelized cost estimates are net of expected market revenue and site-level co-benefits from automation.

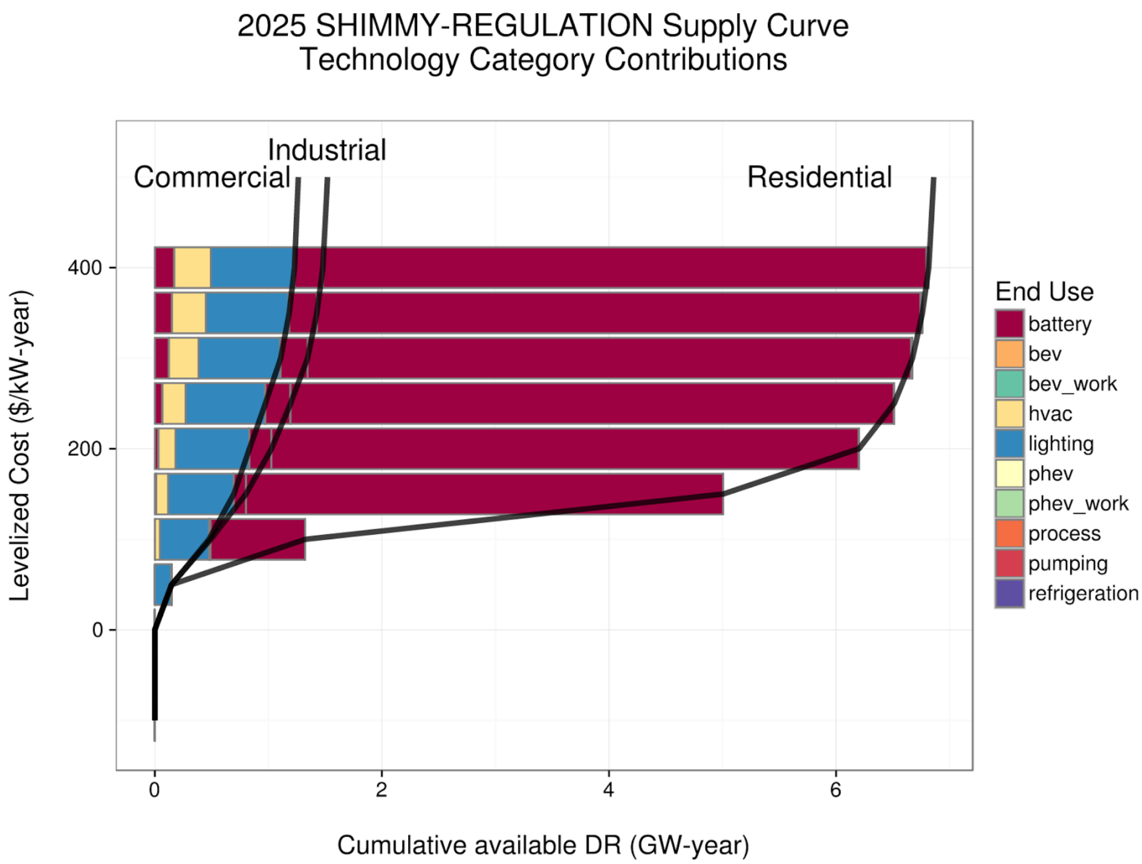

Figure 66: Shimmy (Regulation) DR supply curve in 2025, with contributions from end-use technology categories demarcated in stacked bar graphs.

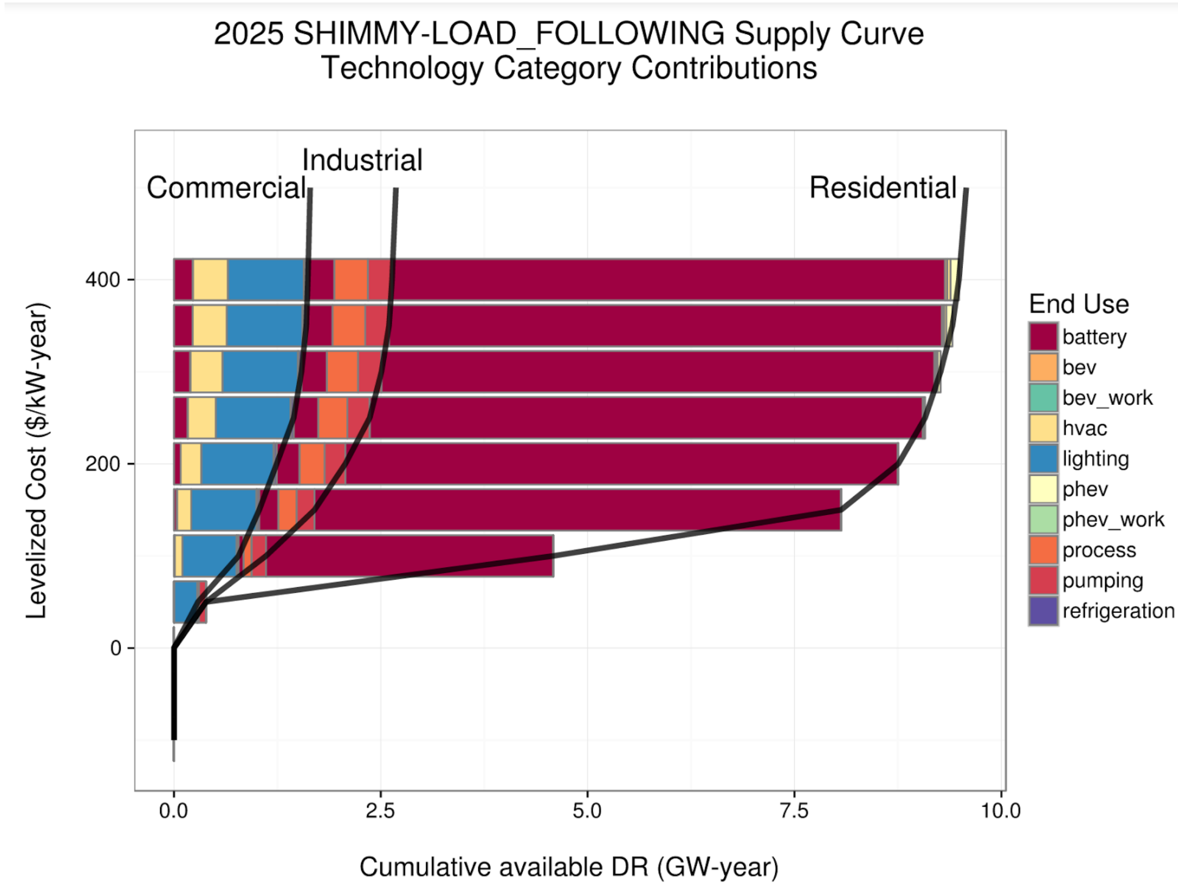

Figure 67: Shimmy (Load Following) DR supply curve in 2025, with contributions from end-use technology categories demarcated in stacked bar graphs.

5.6. The Value of Shimmy DR to the Grid

Shimmy is modeled as a reduction in the amount of load following and regulation that must otherwise be provided by non-DR resources. To limit complexity, we modeled equal megawatt amounts of load following and regulation in separate RESOLVE runs, even though the depth of the load following and regulation markets differ. That is, both parameters shown in Table 19 were modeled as taking the same set of values: 100, 300, and 600 MW.

Table 19: Shimmy parameters modeled in RESOLVE.

Shimmy Parameter	Description
MW of load following available by hour	Hourly amount by which a "Shimmy" DR resource offsets the load-following requirement for non-DR resources
MW of regulation available by hour	Hourly amount by which a "Shimmy" DR resource offsets the regulation requirement for non-DR resources

By providing load following and regulation, Shimmy resources free up other resources that currently provide these services to provide other grid services. In particular, the fast-response capabilities of batteries installed to meet the CAISO storage mandate mean they are often used to provide load following and regulation. However, Figure 68 illustrates that replacing batteries with other fast-response Shimmy DR resources enables batteries to instead charge during midday hours when renewable generation is high, thereby limiting renewables curtailment and decreasing the cost of meeting RPS goals. The latter scenario (with Shimmy DR) results in greater utilization of battery storage capacity.

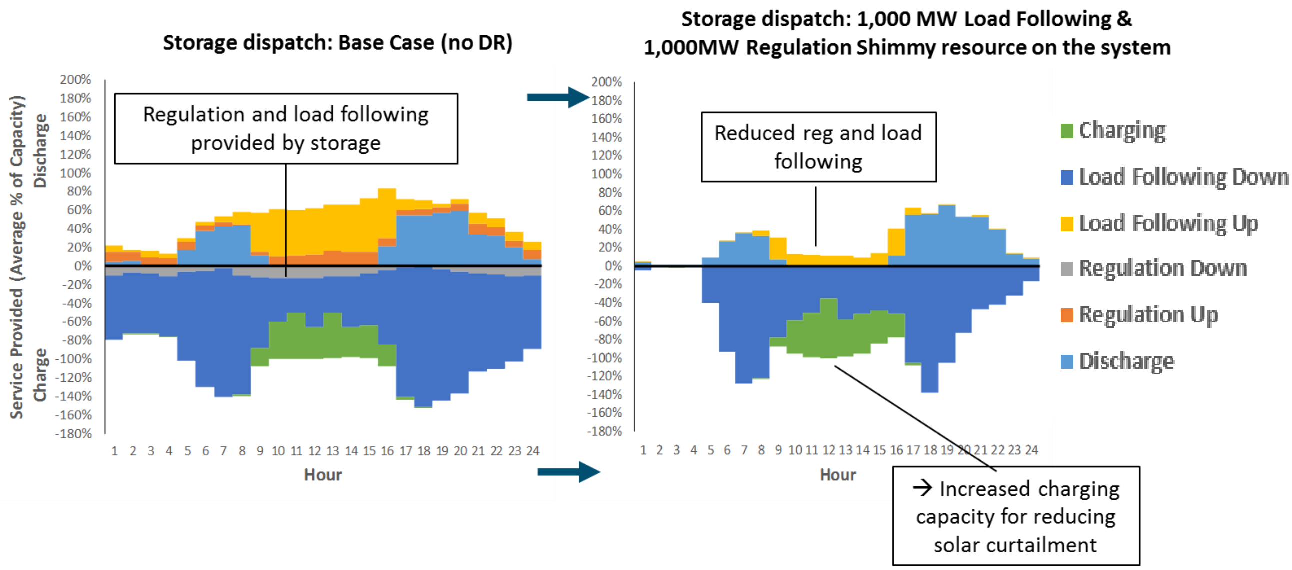

Figure 68: Storage services dispatched, without and with Shimmy resources.

Our modeling suggests that Shimmy resources have the potential to provide significant value to the CAISO system over the 2016–2030 timeframe. For example, we found a total of $21 million in benefits for 600 MW of load following in 2025, and $22.5 million in benefits for 600 MW of regulation in 2025.

Just as the savings offered by Shift resources decline as the system becomes saturated with Shift, the savings per megawatt of Shimmy fall as we add more Shimmy resources, as shown in Figure 69 and Figure 70. Low-Curtailment and High-Curtailment scenario results for mid-AAEE and double the AAEE forecasts are shown. The x-axis presents the available megawatts for load following DR, while the y-axis presents the savings to the system in $/kW-yr (2015). In Figure 70, we also see that 600 MW is close to the limit of the market depth for regulation, whereas the market for load following is deeper.

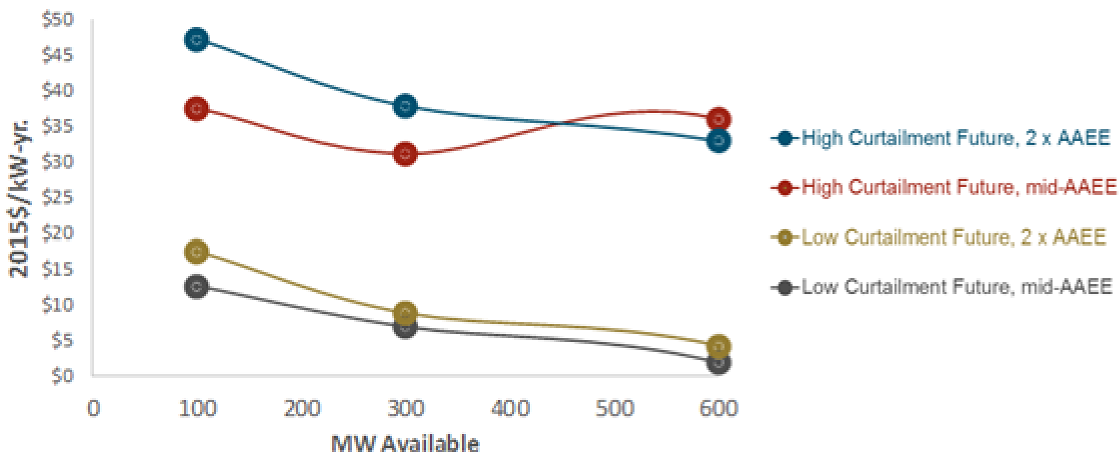

Figure 69: Load following marginal value as a function of availability.

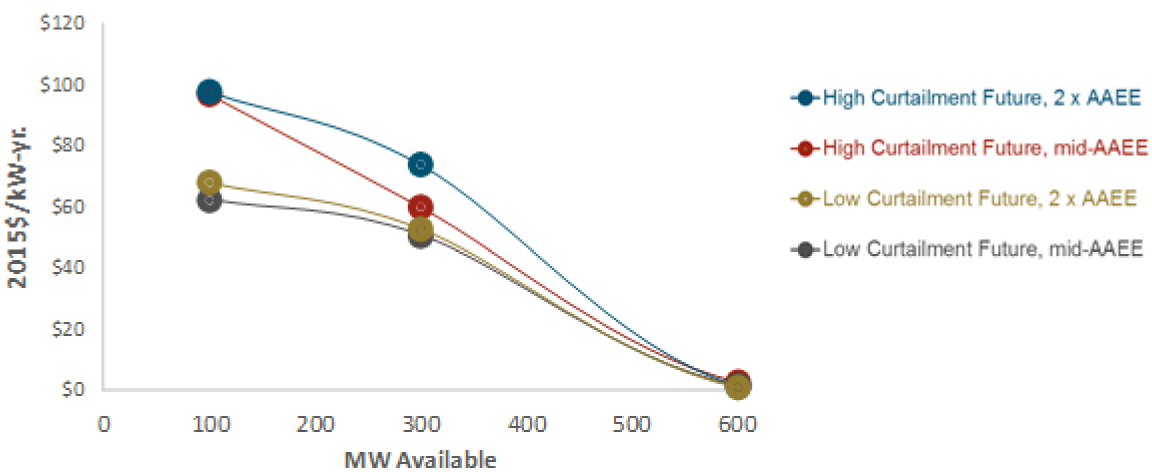

Figure 70: Regulation marginal value as a function of availability. Low-Curtailment and High-Curtailment scenario results for mid-AAEE and double the AAEE forecasts are shown.

Further, as was the case with Shift, reassigning total load following and regulation savings across the investment periods of 2016, 2020, 2025 and 2030 based on relative curtailment amounts in these years shows high savings in 2025 and 2030. The results are shown in Figure 71 and Figure 72.

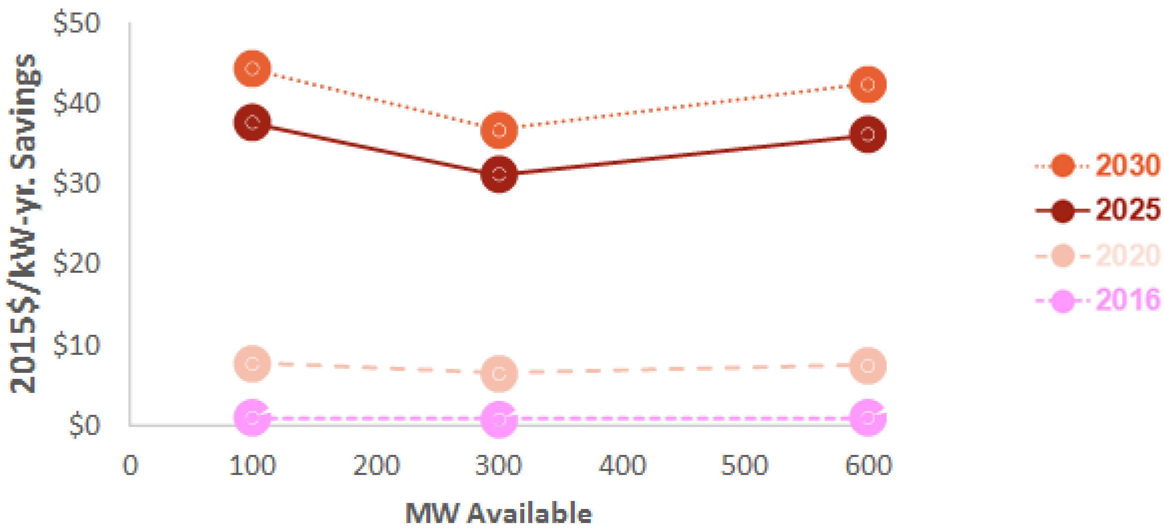

Figure 71: Annual marginal savings per kW of load following available by year, High-Curtailment, mid-AAEE scenario.

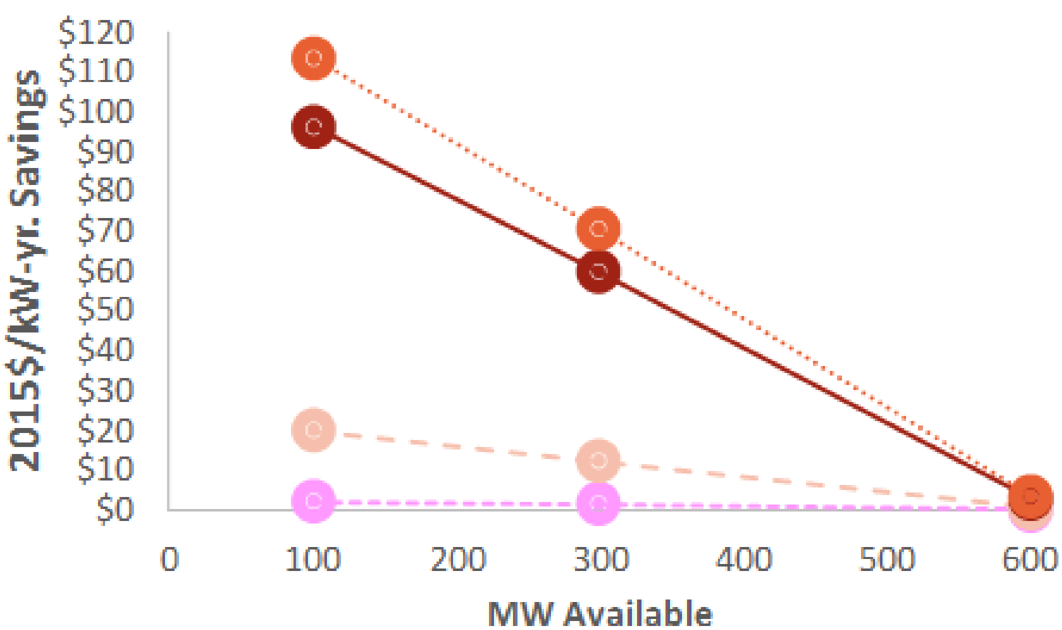

Figure 72: Annual marginal savings per kW of regulation available by year, High-Curtailment, mid-AAEE scenario.

5.7. Valuing Shimmy Service Type DR with Supply Curves and Levelized Demand Curves

Demand response potential supply curves for the 2025, mid-AAEE, rate mix 3 scenario are shown in Figure 73 and Figure 74 for load-following and regulation DR, respectively. In Figure 73, the RESOLVE demand curve intersects with the supply curve at ~350 MW, indicating the cost-competitive amount of Shimmy DR. Note that the levelized system value curves were not estimated beyond 0.6 GW of resource, but some supply curves do not intersect them. To estimate the box plots beyond the margins of the RESOLVE runs, we implemented a linear model fit that is shown by the dotted line. The fit is limited to the interval 0, 900 (extending the demand curve by about 40%). Case: Year 2025, Rate Mix #3, mid-AAEE trajectory. Shimmy load following resources are cost competitive for roughly 350 MW at about $40 per kW-year. Shimmy regulation DR is shown to be cost-competitive up to approximately $70 per kW-year in the medium scenario, resulting in a DR potential of about 350 MW across all three IOUs. As more DR is added, it becomes less valuable, resulting in a cost-competitive DR potential of 500 MW up to approximately $40 per kW-year in the high scenario.

These system-level values only describe the value of the Shimmy services to the grid, not the monetary value that would be adequate to compensate Shimmy participants that are participating in a frequently dispatched DR program. Our results do not intend to prescribe the level of compensation for participants in any way; rather, we have described the market value to the grid- the dollar value that is cost competitive for this service type resources as compared to alternative resources in the wholesale market. Our analysis was not intended to determine what compensation customers ought to receive for participating in each service type resource/program. In the cost estimates we include standard incentives that are on the same scale as those customers currently receive for Shed service.

In Figure 73, the RESOLVE demand curve intersects with the supply curve at ~ 300 MW, indicating the cost-competitive amount of Shimmy load following DR. The **GREEN** and **BLUE** colors in the lines (top) and bars (bottom) represent qualitative DR market scenarios. The dotted lines correspond to 1-in-2 weather and the solid lines are 1-in-10 weather years. The Low-Curtailment case (**RED**) and High-Curtailment case (**ORANGE**) horizontal lines represent the levelized demand curves. The equilibrium price is at the intersection of the levelized demand curves and the supply curves. Case: Year 2025, Rate Mix #3, mid-AAEE trajectory.

In Figure 74, the RESOLVE demand curve intersects with the supply curve at ~ 300 MW, indicating the cost-competitive amount of Shimmy Regulation DR, under the same parameters and scenarios as described above.

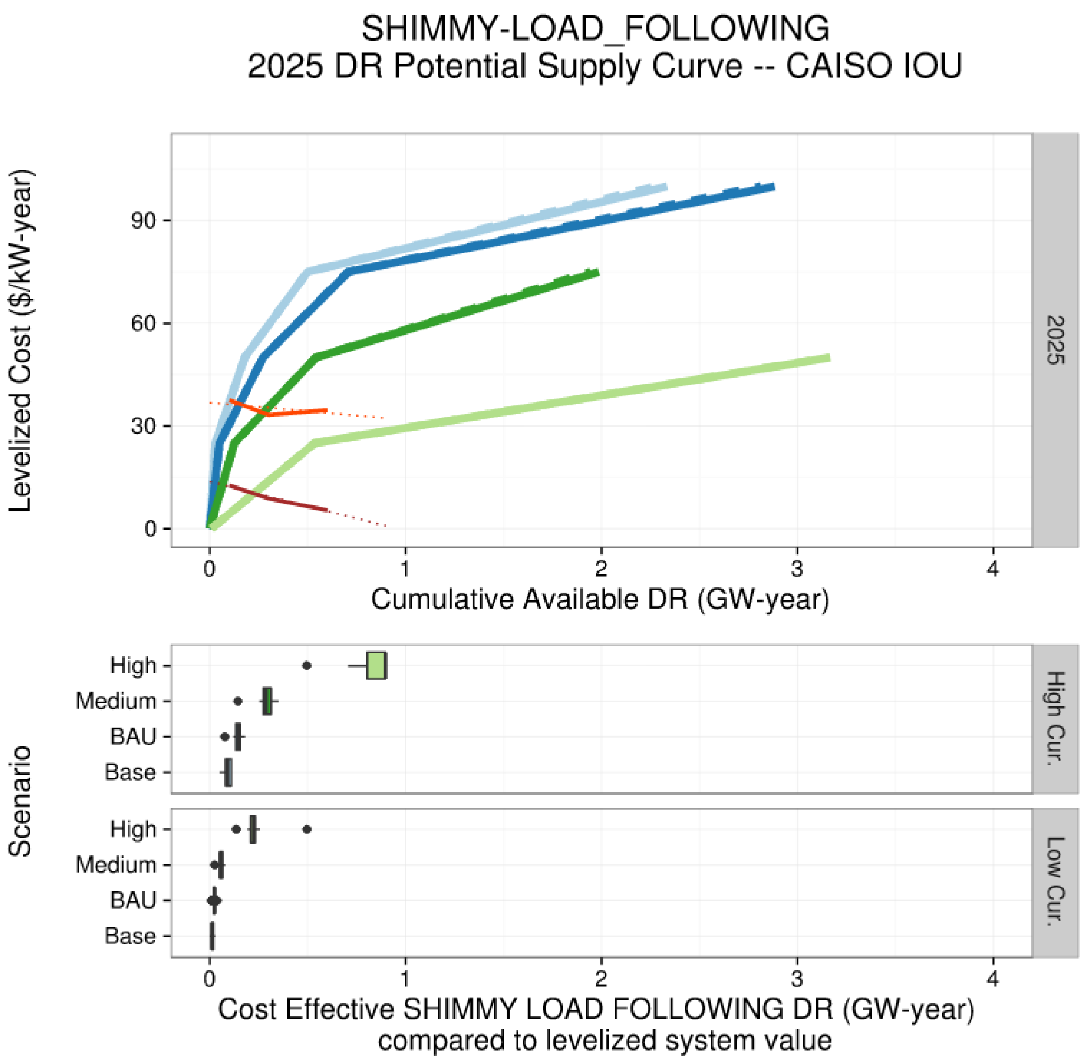

Figure 73: (top) 2025 Shimmy load following DR potential supply curve compared to the levelized demand curve; (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.

Table 20 and Table 21 present the cost competitive prices and quantity for Shimmy Load Following DR from the DR Futures supply curves and the RESOLVE levelized demand curves, and represent the price at the intersection of each curve. For each service type, the costs and quantities are segmented by percentiles that capture the variance around the demand and supply curves' intersection. Table 23 and Table 24 show similar results for Shimmy Regulation DR. Table 22 and Table 25 shows an expanded set of results by IOU service territory, including 2020 and 2025 estimates for the expected cost-effective Shimmy DR.

Table 20: Levelized Price and Quantity of Cost Competitive Shimmy Load Following DR by Percentile (Low Curtailment Scenario)

Shimmy Load-Following DR (Low Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue, Co-Benefits + Distribution System Payments
25th Percentile Price per kW ($)	$0	$0	$11	$0
25th Percentile Quantity (MW)	-	-	52	1,647
50th Percentile Price per kW ($)	$0	$0	$11	$0
50th Percentile Quantity (MW)	-	-	56	1,677
Mean Price per kW ($)	$4	$4	$12	$0
Mean Quantity (MW)	10	10	58	1,703
75th Percentile Price per kW ($)	$8	$8	$12	$0
75th Percentile Quantity (MW)	14	14	65	1,765

Table 21: Levelized Price and Quantity of Cost Competitive Shimmy Load Following DR by Percentile (High Curtailment Scenario)

Shimmy Load-Following DR (High Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue, Co-Benefits + Distribution System Payments
25th Percentile Price per kW ($)	$35	$35	$35	$0
25th Percentile Quantity (MW)	91	91	273	1,647
50th Percentile Price per kW ($)	$35	$35	$35	$0
50th Percentile Quantity (MW)	104	104	286	1,677
Mean Price per kW ($)	$35	$35	$35	$0
Mean Quantity (MW)	105	105	289	1,703
75th Percentile Price per kW ($)	$36	$36	$35	$0
75th Percentile Quantity (MW)	113	113	313	1,765

Table 22: Shimmy - Load Following potential (MW-year) by year, by utility, for a range of cost accounting frameworks. The results are the 50th percentile for the case defined by the Medium DR market scenario, mid-AAEE energy efficiency trajectory, 1-in-2 weather, the "High Curtailment" RESOLVE case, and Rate Mix #3.

Cost Framework	2020			2025		
	PG&E	SCE	PG&E	SCE	PG&E	SCE
Unadjusted Total	0	1	0	21	70	4
Net Total with ISO Revenue	0	1	0	21	70	4
Net Revenue + Site Co-Benefits	1	11	0	100	170	12
Net Revenue + Site + Distribution Co-Benefits	600	770	68	730	880	87

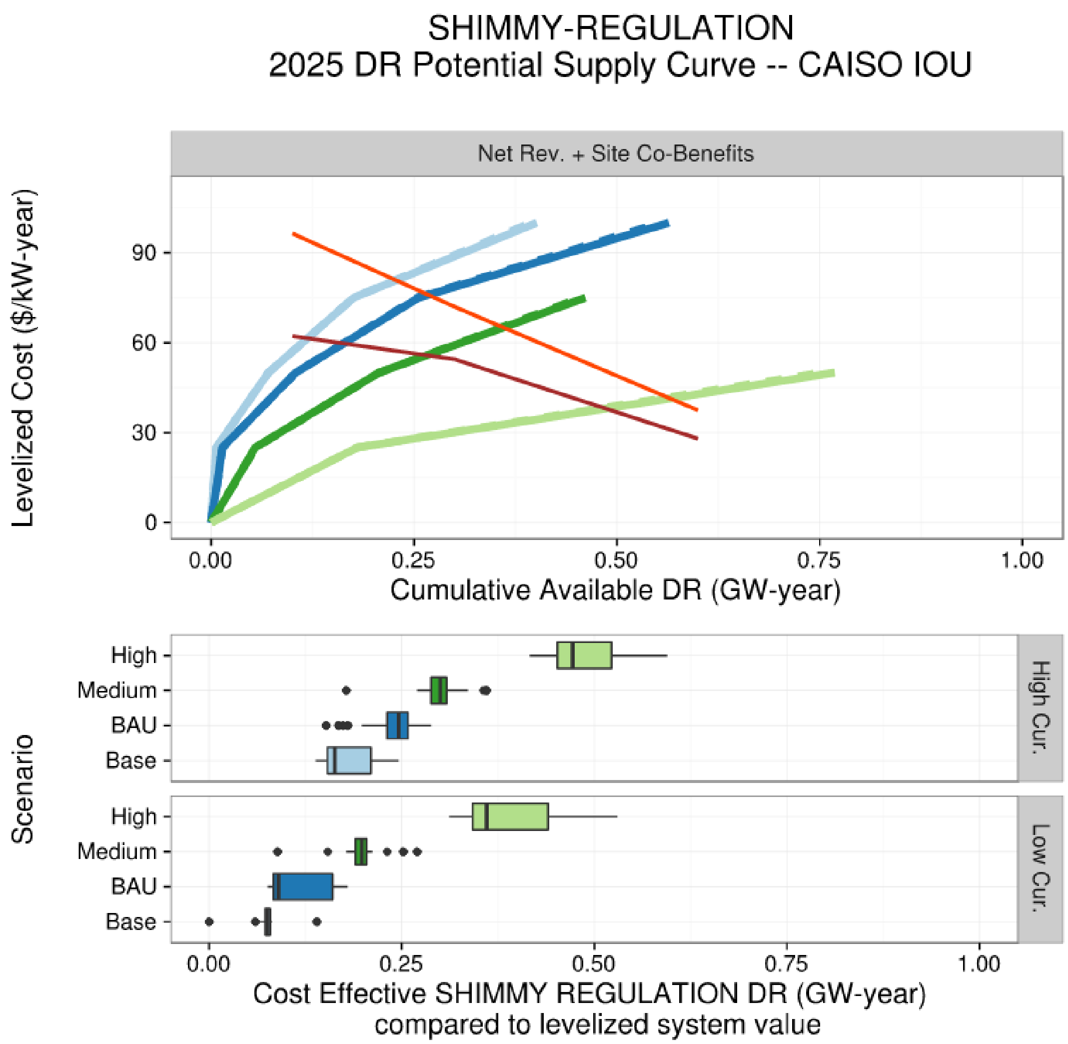

Figure 74: (top) Shimmy regulation DR potential supply curve results compared to the levelized demand curve, and (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.

Table 23: Levelized Price and Quantity of Cost Competitive Shimmy Regulation DR by Percentile, Low Curtailment Scenario

Shimmy Regulation DR (Low Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue, Co-Benefits + Distribution System
25th Percentile Price per kW ($)	$50	$50	$45	$0
25th Percentile Quantity (MW)	94	94	189	848
50th Percentile Price per kW ($)	$52	$52	$47	$0
50th Percentile Quantity (MW)	98	98	195	878
Mean Price per kW ($)	$51	$51	$47	$0
Mean Quantity (MW)	96	96	193	885
75th Percentile Price per kW ($)	$54	$54	$50	$0
75th Percentile Quantity (MW)	102	102	204	918

Table 24: Levelized Price and Quantity of Cost Competitive Shimmy Regulation DR by Percentile, High Curtailment Scenario

Shimmy Regulation DR (High Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue, Co-Benefits + Distribution System
25th Percentile Price per kW ($)	$67	$67	$57	$0
25th Percentile Quantity (MW)	190	190	287	848
50th Percentile Price per kW ($)	$52	$52	$47	$0
50th Percentile Quantity (MW)	199	199	300	878
Mean Price per kW ($)	$51	$51	$47	$0
Mean Quantity (MW)	205	205	298	885
75th Percentile Price per kW ($)	$54	$54	$50	$0
75th Percentile Quantity (MW)	210	210	308	918

Table 25: Shimmy - Regulation potential (MWh-year) by year, by utility, for a range of cost accounting frameworks. The results are the 50th percentile for the case defined by the Medium DR market scenario, mid-AAEE energy efficiency trajectory, 1-in-2 weather, the "High Curtailment" RESOLVE case, and Rate Mix #3.

Cost Framework	2020			2025		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Unadjusted Total	0	0	0	64	130	11
Net Total with ISO Revenue	0	0	0	64	130	11
Net Revenue + Site Co-Benefits	0	13	0	100	180	18
Net Revenue + Site + Distribution Co-Benefits	260	480	51	320	530	65

5.8. Pathways to Market Participation for *Shimmy*

We estimate that Shimmy resources have the potential to provide significant but bounded value to the CAISO system over the 2016–2030 timeframe. Although Shimmy resources are of relatively high value per kW-year, they are bounded by the fact that system needs (and markets for ancillary services) are finite and based on the short-term variability on the electricity system. Fast-response DR resources that provide regulation and load-following add further value by freeing up storage resources to reduce renewable curtailment. The first 600 MW of load-following Shimmy is worth $21 million to the system, while the first 600 MW of regulation Shimmy is worth $22.5 million in the high-curtailment mid-AAEE case in 2025. The value of advanced DR will increase over time, as the CAISO system integrates additional renewables and curtailment becomes more significant during the midday hours.

The results from our levelized system value analysis indicate that about 350 MW of Shimmy Load Following Service resources are cost competitive under $50 per kW-year. For Shimmy Regulation DR, we found

Fast DR technology pilots:

Advanced end use control technologies that can provide fast response DR, such as variable frequency drives (VFDs) and pumps (VFPs) with DR control technologies should be piloted to determine their effectiveness in providing flexible and fast DR services, such as Shimmy Regulation and Load Following. Additional opportunities for these technologies include Shift and Shed service types. These technologies can be installed with commercial HVAC units and agricultural pumps, and could offer opportunities for customers to maintain comfort and production levels while providing flexible service to distribution and transmission systems.

roughly 450 MW to be cost competitive under $85 per kW-year.

The markets for regulation and load following DR are already playing out in various balancing authorities in the United States. For example, the PJM has a strong track record of successfully utilizing DR to provide Shimmy services.[33] The CAISO is working to establish rules and transaction requirements that would enable DR to more readily participate in AS markets, but these changes have not yet been realized. However, the current market prices for AS, in particular regulation up and regulation down, are depressed, and may not reflect future pricing trends for products participating in these markets in 2020 or 2025. Nonetheless, these low market prices do not readily encourage new market entrants for Shimmy service providers, since the telemetry and control technology costs can be quite high, given the fast transactive nature of the services. One theory for the reason AS prices are low is that they are a result of inter-market dynamics with the energy market, where prices have been depressed due to zero marginal cost renewables and low natural gas prices. AS price formation depends strongly on the opportunity cost for holding resources out of the energy market, and it is unclear how future energy and, AS markets will compensate generators. The opportunities for DR to obtain revenue for Shift is thus linked with broader trends in electricity markets.

Our study results indicate that there is economic value for Shimmy DR service types, that Shimmy can bring value to the CAISO system, and that DR technologies and potential customers exist today to provide that service. We estimate that the commercial customer class, with end uses that contain variable frequency drives/pumps or lighting controls will likely have the greatest potential to provide Shimmy DR. However, the market rules for DR participation in these markets, coupled with AS market prices, will continue to be barriers for DR market participants wishing to address the load-following and regulation needs of the grid with Shimmy DR services.

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[33] See *PJM Manual 11: Energy & Ancillary Services Market Operations* at https://www.pjm.com/~/media/committees-groups/committees/mrc/20141120/20141120-item-06-residential-demand-response-draft-manual-11-revisions.ashx, and Cutter, Eric, et al. 2012. "Beyond DR – Maximizing the value of responsive load." http://aceee.org/files/proceedings/2012/data/papers/0193-000395.pdf.

6. Key Takeaways

Advanced DR programs can help California meet the challenges of a high-renewables future. Resources that shift load into high-curtailment hours can offer significant capital investment and operational cost savings by reducing renewable overgeneration.

6.1. Shape: Summary

We estimate that the effects of TOU and CPP pricing provide the equivalent of approximately 1 GW in Shed resource and 3 GWh/day in Shift resource. The average total daily load in 2025 is 600–700 GWh, so the Shape-Shift resource represents approximately 0.3 percent of load shifted. This result is based on estimates of how "static" TOU retail pricing structures are expected to change load, and how those modifications provide service equivalent to Shed and Shift service described above. With more significant investments in automatically price-responsive technology and exposure to real-time dynamic prices, it could be possible to achieve a significant portion of the dispatchable "Shift" resource we identify using price signals as opposed to conventional dispatch. A distributed price-responsive portfolio of loads that can shift may be more cost-effective than using centralized dispatch and payments through specific supply side markets for the "Shift" resource.

6.2. Shift: Summary

The Shift service type resource is by far the largest opportunity we identified for DR to provide system-level value for the future grid. With 20% of load shiftable, there is up to ~$700 million/year in benefits, and we estimate economically cost-effective DR up to ~10 percent of daily energy shifted in 2025 (for the high-curtailment, mid-AAEE scenario). Resources that shift load into high-curtailment hours can offer significant capital investment and operational cost savings by reducing renewable overgeneration (and overbuilding to meet a given set of clean energy goals). There are significant market and regulatory challenges, however, for capturing this value, since currently no market mechanism exists for services like Shift DR that are technology-driven and responsive to hour-to-hour and daily changes in the needs of the system. When considering potential revenue streams from the supply-side market, Shift could *potentially* earn revenues from energy, capacity, AS, and flexible capacity markets, but those markets are not currently organized to compensate a service like Shift DR, primarily because of the way those markets are presently defined. Shift resources could be dispatched on the majority of days in the energy market, as the value is fundamentally driven by daily solar generation in California. It would be a significant challenge to identify appropriate and accurate baselines against which to compare response when there are not days *without* Shift. Baseline issues are already challenging for Peak Shed DR that is only dispatched a handful of times a year. It is not clear how Shift-type resources would fit in flexible capacity markets, and whether there would need to be restructuring of the compliance obligations to qualify aggregations of "shiftable" loads.

Because of these significant challenges to integration in the supply market, LBNL recommends the Shift-type resources be handled in the retail market, through pricing programs and automated DR controls. This comes with its own challenges around incentivizing investment in control technology and customer adoption, but it could accomplish the same fundamental dynamics with much more transparent market integration. We note here that Shift resources do not necessarily need to be fast responding. The daily need for shifting is relatively predictable, and a day-ahead price schedule may achieve significant fractions of the ideal shift pattern. The current stock of conventional automated DR technologies are fast enough to respond to these signals, and may be candidates for parallel use or low-cost upgrades compared to new DR sites. These co-developing market, policy, and technology systems for Shifting could also result in some hybrid approach that mixes price response with awarded flexible capacity credits based on an expectation of future response as buydown for appropriately specified control technology.

6.3. Shed: Summary

Our research suggests that a large potential resource of Shed DR exists in 2025, ranging from 2 to 10 GW, depending on the technology costs and performance scenario, when evaluating the value of DR using the $200/kW price referent. However, as system capacity is overbuilt in pursuit of achieving the 50 percent RPS, there is far reduced need for system-level peak-shed DR by 2025. The RESOLVE model demand curves estimates the value of Shed to be at $4/kW-yr, far below the price referent value of $200/kW-yr.

Based on an expected future generation fleet consistent with long-term procurement planning and reasonable facility retirement schedules, the RESOLVE model estimates found Shed to have a very low system-level value compared to price referent values that are often cited: the availability of 10,000 MW of Shed resource would save the CAISO system only $31 million in 2025, or about $4/kW-yr. Our system-levelized value analysis (which examined the equilibrium price at the intersection of the supply and demand curves for the DR service types) found that there would be 100–400 MW of cost-competitive Shed DR resources in 2025 that could compete based on energy market participation.

The vast majority of Shed DR resources' costs exceed their value to the grid, but it is notable that accounting for possible service to local distribution system capacity needs can flip the potential back to a significantly large value. Half of the Shed DR resources in California are in one of three local load pockets, where a higher price referent may be called for based on the binding need in the future to maintain reliability with generation investment. When we included a set of possible distribution system values as a portfolio element, we found that 1–4 GW of

Shed resource may be cost-effective for avoiding or deferring feeder and substation-level investment. The technology area with the largest increases in potential was residential behind-the-meter batteries, which become cost-effective when including site-level co-benefits, namely, from reduced energy charges from TOU pricing and/or coincident demand charges. These dynamics are repeated across other DR resource types. We note as well that local capacity Shed resources could still provide significant value as well in generation and transmission constrained areas – up to 4 GW in the Medium DR scenario.

These findings challenge the conventional wisdom of focusing solely on peak capacity DR programs in California. For years, the greatest need to the electricity grid was managing peak demand; however, with the mass implementation of renewable generation and mandates to meet even higher RPS standards of 50 percent, the challenges of the grid have shifted away from peak capacity shortfalls, thus drastically reducing the need for Shed-type resources to serve the CAISO balancing authority over the coming decade and beyond. This suggests that the focus on system Sheds should be redirected to focus on local and distribution-system needs, and that the control technology and business relationships in place could be the foundation of new portfolios that combine targeted and/or fast Shed with Shift.

6.4. Shimmy: Summary

We estimate that Shimmy resources have the potential to provide significant but bounded value to the CAISO system over the 2016–2030 timeframe—significant in having a relatively high value per kW-year but bounded by the fact that the size of need (and markets for ancillary services) are finite and based on the short-term variability on the electricity system. This fast-response DR that provides regulation and load-following can create value by freeing up storage resources to reduce renewable curtailment. The first 600 MW of load-following Shimmy is worth $21 million to the system, while the first 600 MW of regulation Shimmy is worth $22.5 million, both in the high-curtailment, mid-AAEE case in 2025. The value of advanced DR will increase over time, as the CAISO system integrates additional renewables, and curtailment becomes more significant during the midday hours.

The study's levelized system value analysis indicate that ~300 MW of Shimmy Load Following Service resources are cost competitive under $50/kW-yr. For Shimmy Regulation DR, we found ~300 MW to be cost competitive under $85/kW.

The markets for regulation and load-following DR are already playing out in various balancing authorities in the United States, with the PJM having a strong track record of success utilizing DR to provide Shimmy services.[34] The CAISO has been working to establish rules and

[34] See *PJM Manual 11: Energy & Ancillary Services Market Operations* at

transaction requirements to enable DR to more readily participate in AS markets, but this has not yet been realized. However, the current market prices for AS—in particular, regulation up and regulation down—are depressed, and currently may not reflect future pricing trends for products participating in these markets in 2020 or 2025. Nonetheless, these low market prices do not readily encourage new market entrants for Shimmy service providers, since the telemetry and control technology costs can be quite high, given the fast transactive nature of the services.

Our study results indicate that there is economic value for Shimmy DR service types, that Shimmy can bring value to the CAISO system, and that DR technologies and potential customers exist today to provide that service. We estimate that the commercial customer class, with end uses that contain variable frequency drives/pumps, or lighting controls, will likely have the greatest potential to provide Shimmy DR. However, the market rules for DR participation in these markets, coupled with AS market prices will continue to be barriers for DR market participants wishing to address the load-following and regulation needs of the grid with Shimmy DR services.

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https://www.pjm.com/~/media/committees-groups/committees/mrc/20141120/20141120-item-06-residential-demand-response-draft-manual-11-revisions.ashx, and Cutter, Eric, et al. 2012. "Beyond DR- Maximizing the value of responsive load". http://aceee.org/files/proceedings/2012/data/papers/0193-000395.pdf

7. End-Use Enabling Control Technologies

Our bottom-up model for estimating DR potential is based on the sum total of a range of different end-uses, combined into a portfolio of resources on the future grid. The results should be considered as one of many possible futures for DR, and in aggregate defines a reasonable estimate of potential, but not a prescriptive or definitive set of technology. Put simply, the model is not designed to pick technological winners but is designed instead to identify what is possible overall, and points towards likely but not certain trends in where DR resource can be achieved. We expect that the particulars of specific technology options --- smart thermostats in commercial buildings, dynamic EV charging, industrial process control, and others --- will end up either more or less favorable as the technology and implementation strategies evolve.

During the study we worked to understand the current and potential future technology landscape. A key element of this was engagement with our technical advisory committee and deep-dive interviews with a dozen industry experts from utilities, energy service providers, and DR technology manufacturers to solicit information on current trends, barriers, and opportunities for advanced DR in the next decade. In this section we synthesize the findings and trends on key enabling technology areas, and provide a dive into the details of our model results for end-use categories.

7.1. Existing and Emerging DR technologies

Our study evaluated the DR potential for a number of different end uses and technologies. This set of end uses was limited to manage the scope of the study and we recognize that there are a number of end uses, such as major household appliances (e.g. refrigerators, dryers, and plug loads) that could provide additional DR services but were not included in this Phase of the study. Below we discuss the existing and emerging technologies that were included in this study and a brief discussion of residential hot water heaters, which were not specifically modeled in this study phase.

7.1.1. Cost competitive DR technologies

The cost competitive prices and quantities presented in this section were developed using the DR Futures supply curves and the RESOLVE levelized demand curves. In Table 26, the costs for each service type are segmented by percentiles that capture the variance around the intersection of the demand and supply curves for each service type. Note that the price for Shed is zero, meaning that there is no cost competitive value for Shed services for any of the end uses. In other words, Shed services are not economically viable because there is adequate capacity from existing and less expensive generation resources.

The unit prices in Table 26 are representative for all of the end uses and customer sectors. Each technology/end use DR service type quantity (MWs and MWhs) described in the end use specific sections below is the quantity of DR available at the prices presented in Table 26.

Table 26: Competitive Levelized Costs for DR service in kW-yr for Shed and shimmy services, and in kWh-yr for Shift services.

Commercial Lighting: Competitive Levelized Costs	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Levelized Price per unit of DR	kW-yr	kWh-yr	kW-yr	kW-yr
25th Percentile Price	$0	$28	$35	$57
50th Percentile Price	$0	$29	$35	$60
75th Percentile Price	$0	$30	$35	$62

7.1.2. Industrial processes

Industrial processes are foundational for current-day DR programs and we expect will continue to be high-value, low-cost opportunities for load flexibiilty in the future. This sector is well understood from the perspective of conventional "Shed" DR, and much of that practice could translate well to locally-focused Sheds. More frequent load shifting would require structural adjustements to the scheduling of facilities, and the kinds of Shifts that are suggested by our work (from night into day) could be well-matched to the preferences of the labor force to complete work during the day,

Industrial customers are not the same as commercial and residential, and one approach does not fit all (or sometimes even two) customers. We heard from stakeholders in the sector that there are challenges with maintaining facility autonomy and concerns that the kind of "every day" DR from Shimmy and Shift may not be well suited to the kinds of operational strategies that have worked for Shed DR in the past. Careful work to understand the needs in the industrial sector for transitioning from conventional to advanced DR will be important to unlock the potential we estimate, shown in Figure 75 below across a range of resource types. The left side set of plots show Shed and Shimmy, and the right-side plot is for Shift. The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the "medium" DR case in 2025, with 1-in-2-weather mid-AAEE efficiency trajectory and Rate Mix #3.

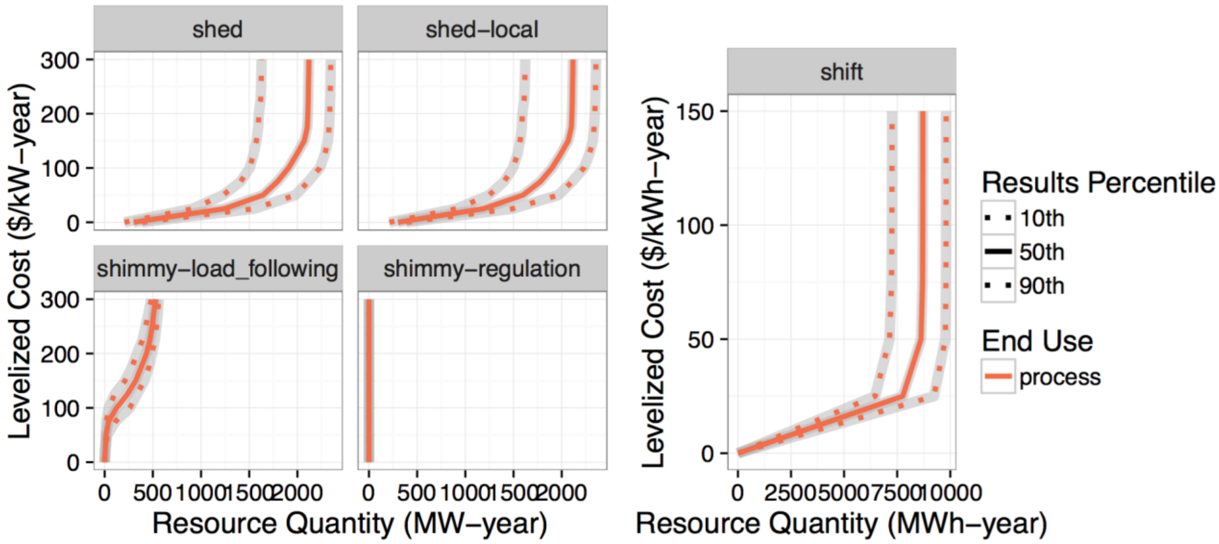

Figure 75: Industrial process end-use level supply curves.

Table 27 below indicates the cost competitive quantity of DR from Industrial processes for each of the service types. Shift and Shimmy Load Following are the only DR service resources that are cost competitive for Commercial HVAC, which can provide 7,978 to 8,017 MWh-yr of Shift service with cost ranging from $28-$30 per kWh-yr. Advanced end uses such as VFD with ADR can provide 11 MW-year of cost competitive Shimmy load following service to the grid. The levelized costs for load following services is $35/kW-yr. Although there is 827 MW-year for Shed available, we find that it is not cost competitive as compared to other resources on the grid.

Table 27: Quantity of cost competitive Industrial Process DR by MW-yr for Shimmy and MWh-yr for Shift.

Industrial Process End-Uses: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	827	7,978	11	0
50th Percentile Quantity	827	7,998	11	0
75th Percentile Quantity	827	8,017	11	0

7.1.3. Residential HVAC

Residential HVAC is one of the most promising end-uses for delivering peak capacity DR when needed, but controls that facilitate fast response DR are still emerging. Today, there are some HVAC controls that could potentially provide service with a five minute signal, but would need to be aggregated to produce reliable DR service, because the optimal compressor runtime ranges from 7-10 minutes, and anything less than that could cause discomfort to the customer. In order to aggregate the impacts from HVAC units that provide fast DR service, there is a need to collect compressor runtime information in real time, according to several survey participants.

In Figure 76 below, the left side set of plots show Shed and Shimmy, and the right-side plot is for Shift. The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the "medium" DR case, in 2025, with 1-in-2 weather, mid-AAEE efficiency trajectory and Rate Mix #3. Table 28 below indicates the cost competitive quantity of Residential HVAC DR for each of the service types. Shift is the only DR service resource that is cost competitive for residential HVAC, with cost ranging from $28-$30 per kWh-yr and providing 32-43 MWh-year. Although there is 2 MW-year for Shed available, we find that it is not cost competitive as compared to other resources on the grid.

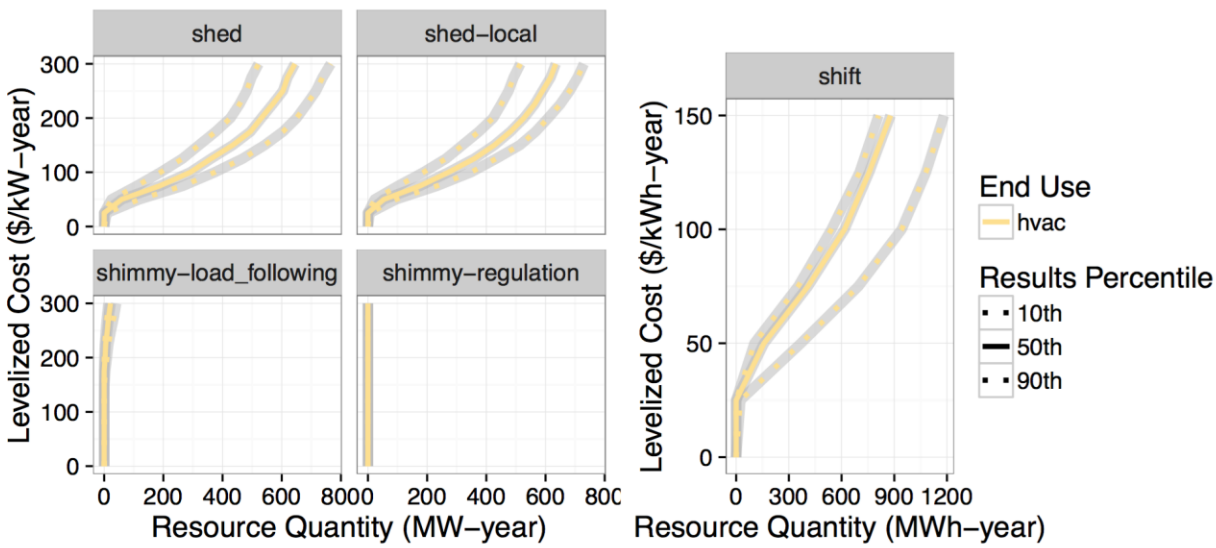

Figure 76: Residential HVAC end-use level supply curves.

Table 28: Quantity of cost competitive Residential HVAC DR by MW-yr for Shimmy and MWh-yr for Shift.

Residential HVAC: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	2	32	0	0
50th Percentile Quantity	2	38	0	0
75th Percentile Quantity	2	43	0	0

7.1.4. Commercial Variable Frequency Drives (VFDs)

VFDs in commercial HVAC have the potential to provide fast DR but these resources haven't been piloted in the IOU service territories, according to survey respondents. Aggregation of commercial HVAC units with VFD, coupled with "plug-and-play" access to markets, could provide Shed, Shape, and Shimmy services to the grid. The functionality of the VFDs allows for full automation technology to maintain customer comfort levels, limit disruption to operations, and provide fast response DR service to the grid. These technologies should be piloted to test scalability, interconnection, and performance for distribution and transmission system services.

DR-enabled variable frequency drives (VFDs) in Commercial HVAC are an extremely responsive technology that can provide DR services at the system and local level. These technologies should be piloted to test performance and scalability for transmission and distribution system services.

In Figure 77 below, the left side set of plots show Shed and Shimmy, and the right-side plot is for Shift. The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the "medium" DR case, in 2025, with 1-in-2 weather, mid-AAEE efficiency trajectory and Rate Mix #3.

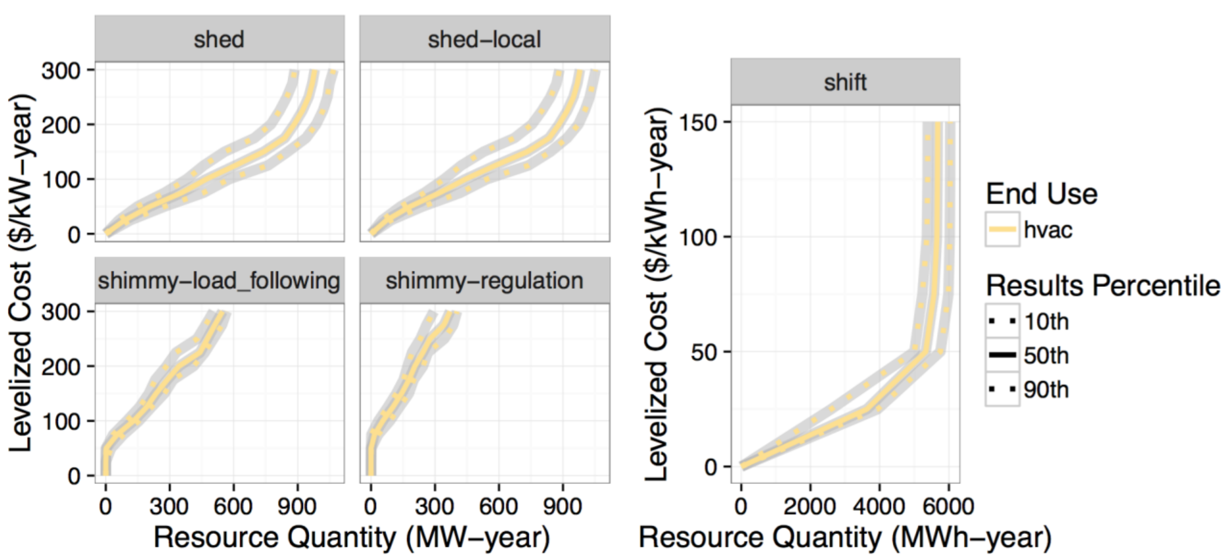

Figure 77: Commercial HVAC end-use level supply curves.

Table 29 below indicates the cost competitive quantity of Commercial HVAC DR for each of the service types. Shift, Shimmy Load Following and Shimmy regulation are the DR service resources that are cost competitive for Commercial HVAC, which can provide 3,643 to 3,749 MWh-yr of Shift service with cost ranging from $28-$30 per kWh-yr, capitalizing on the thermal load capacity. Advanced end uses such as VFD with ADR can provide cost competitive Shimmy service to the grid of around 3 MW-year for load following and between 6-9 MW-year of regulation service. The costs for load following services is $35/kW-yr and for regulation, the costs range from $57-$62 kW-year. Although there is 59 MW-year for Shed available, we find that it is not cost competitive as compared to other resources on the grid.

Table 29: Quantity of cost competitive Commercial HVAC DR by MW-yr for Shimmy and MWh-yr for Shift.

Commercial HVAC: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	59	3643	3	6
50th Percentile Quantity	59	3698	3	7
75th Percentile Quantity	59	3749	3	9

7.1.5. Commercial Lighting

While industry stakeholders agree that commercial lighting as an end use has a huge potential to provide DR services to the grid, most acknowledge that there are significant barriers to realizing that potential. Stakeholders report that commercial and industrial customers have not been receptive to lighting upgrades that include DR technologies, primarily because the existing lighting stock has either been addressed with retrofits in the last decade, the upgrades are disruptive to business, and/or the costs for lighting DR control technologies can be prohibitive. This current condition is changing with the widespread adoption of lower cost, more efficacious LED luminaires networked with wireless controls.

Courtesy of: Schreiber Foods Home Office and Global Technology Center, HGA Architects and Engineers, Darris Lee Harris Photography

In Figure 78 below, the set of plots show Shed and Shimmy, and there is no resource available for Shift (no storage inherent in lighting). The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the "medium" DR case, in 2025, with 1-in-2 weather, mid-AAEE efficiency trajectory and Rate Mix #3.

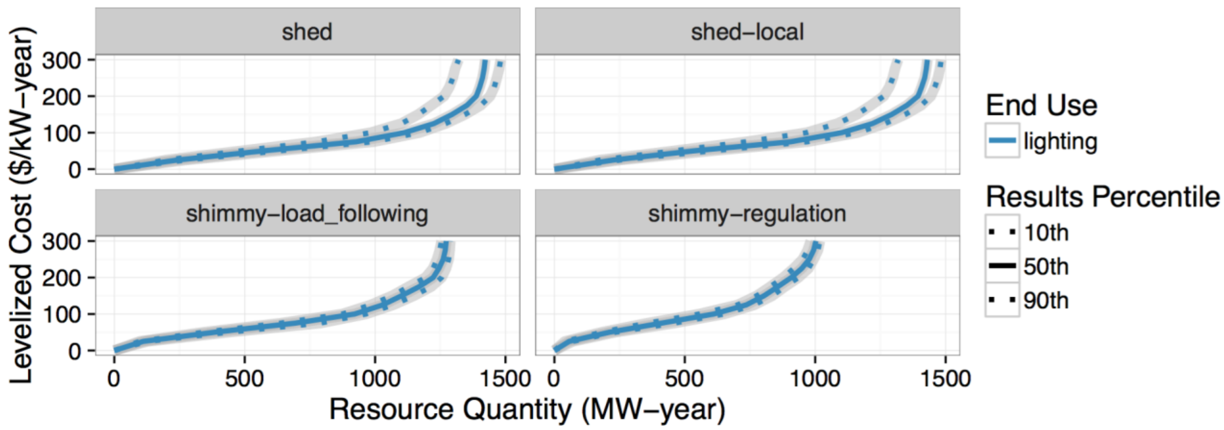

Figure 78: Commercial Lighting end-use level supply curves.

Table 30 below indicates the cost competitive quantity of Commercial Lighting DR for each of the service types. Shimmy load following and Shimmy regulation are the DR service resources that are cost competitive for Commercial Lighting. Advanced end uses such as ADR controlled luminaires can provide 216-221 MW-year of cost competitive Shimmy service to the grid for load following and between 265-303 MW-year of regulation service. The costs for load following services is $35/kW-yr and for regulation, the costs range from $57-$62 kW-year. Although there is 156 MW-year for Shed available, we find that it is not cost competitive as compared to other resources on the grid.

Table 30: Quantity of cost competitive Commercial Lighting DR by MW-yr for Shimmy and MWh-yr for Shift.

Commercial Lighting: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	156	N/A	216	265
50th Percentile Quantity	156	N/A	218	284
75th Percentile Quantity	156	N/A	221	303

7.1.6. Industrial Wastewater processes and pumping

This end use holds significant potential because of the resource size and energy demand at each site, but is generally always in operation which makes it difficult to curtail. There are technologies available today that offer variable speed pumps and drives that could provide faster DR services, but the costs for upgrading equipment and potential downtime create barriers for these facilities. In Figure 79 below, the left-side set of plots show Shed and Shimmy, and the right-side plot is for Shift. The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the "medium" DR case, in 2025, with 1-in-2 weather, mid-AAEE efficiency trajectory and Rate Mix #3.

7.1.7. Agricultural Pumping with Variable Frequency Pumps

Variable frequency pumps (VFPs) technologies control the rotational speed of an electric motor by controlling the frequency of the electrical power supplied to the motor. They are proven to substantially reduce energy use. Irrigation pumps with VFPs and automation have the best potential to participate in DR and permanent load shifting while requiring limited customer interaction with the controls. Nearly all irrigation pumps used for agriculture in California are manually controlled.[35] In addition to upgrading pumps to the efficient VFDs, in order to be automated, the Agricultural customer must have controls with access to the internet so they can receive price signals or DR event triggers from the aggregator or utility. The automated controller at the pump can receive the DR signal and adjust the irrigation schedule according to the DR event. This automation can permit ramping pumping up during off peak hours and down during on peak hours with no manual customer interaction. While these pumps are available today and could provide fast DR services, the costs for upgrading equipment can be a confounding factor

[35] Marks, et.al. Opportunities for Demand Response in California Agricultural Irrigation: A Scoping Study. January 2013. LBNL. https://esdr.lbl.gov/sites/all/files/LBNL-6108E_0.pdf

for many agricultural industrial customers. It is also possible that agricultural customers are not aware of EE and DR incentives offered by the CA utilities, or that the installation would cause and interruption to service that is undesirable for production.

Our estimates for Agricultural pumping were based on actual 2014 weather and customer load data. We did not adjust based on precipitation or other factors in our estimates for agricultural pumping DR potential, and 2014 was in the midst of a long-term drought. Future estimates based on a range of weather years could be useful for planning in the context of colinearity with hydroelectricity availability.

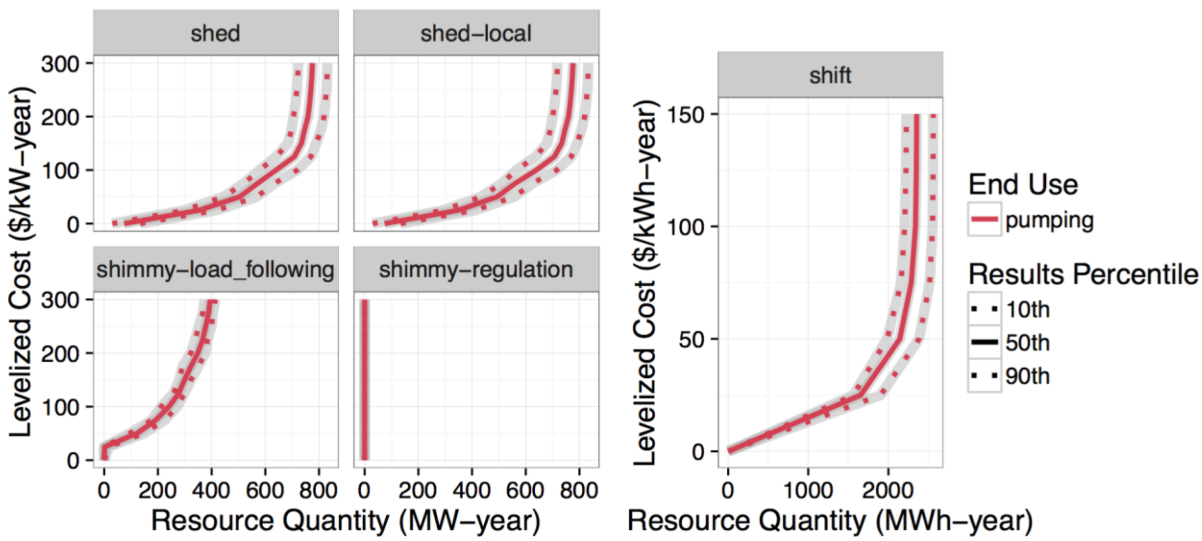

Figure 79: Water pumping end-use level supply curves for the industrial and agricultural sectors.

Table 31 indicates the cost competitive quantity of Industrial Waste Water and Agricultural Pumping DR for each of the service types. Shift and Shimmy load following are the DR service resources that are cost competitive for Industrial WW and AG Pumping which can provide 1,768 to 1,792 MWh-yr of Shift service with cost ranging from $28-$30 per kWh-yr, Advanced end uses such as VFP with ADR can provide 49- 51 MW-year of cost competitive Shimmy load following service to the grid. The costs for load following services is $35/kW-yr. Although there is 240 MW-year for Shed available, we find that it is not cost competitive as compared to other resources on the grid.

Table 31: Quantity of cost competitive Industrial Waste Water and Agricultural Pumping DR by MW-yr for Shimmy and MWh-yr for Shift.

Industrial Waste Water and Agricultural Pumping: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	240	1768	49	0
50th Percentile Quantity	240	1780	50	0
75th Percentile Quantity	240	1792	51	0

7.1.8. Residential Water Heaters & Pool Pumps

Market barriers include customer adoption of DR technology controls for these end uses, pool pumps in particular. The controllers can provide fast and slow DR services, but the challenge has been customer enrollments into DR programs, and when coupled with low penetration of these end uses in the IOU service territories, this has been a confounding factor. Although we included pool pump end use technologies in our analysis, there was no cost competitive DR available from the resource.

Water heaters were not explicitly modeled in this study, but could potentially offer shift and shimmy services to the distribution and transmission systems. At the time of this study, we are not aware of any pilots for electric or heat pump hot water heaters in CA. We estimate that the penetration of this residential end use is around 15% for the IOU service territories. This end use load can act as thermal storage, and when aggregated could provide flexible and fast DR services. Additionally, electrification of this end use (retrofitting existing gas water heaters with electric) could increase the potential for this resource to provide thermal storage for shiftting load and/or providing shimmy services, especially in constrained service areas. We recommend that water heater DR technologies be piloted to determine the effectiveness of this end use in providing Shift and fast DR services.

7.1.9. Data centers

Strategies for data centers to shift or shed short term energy needs include (1) virtualization[36], by which loads are consolidated, (2) colocation[37] where operators move loads to an offsite location when time of use electric pricing is lower and (3) changes directly impacting facility operations such as lighting and HVAC (curtailment or precooling). Many workloads, or batch processes that are energy intensive, in data centers are delay tolerant and can be scheduled to finish before a scheduled deadlines. This enables significant flexibility for managing power demand. Data centers are already highly automated, thus are excellent candidates for Shift services.

Stakeholders agree that data centers have potential to provide DR services, but assert that there is little chance for utility operated automation at these sites due to the highly sensitive nature of operations and reluctance of data center operations to relinquish control of batch processes or server room cooling.

7.1.10. Refrigerated Warehouses

Refrigerated warehouses and cold storage facilities could provide several hundred MWh of Shift DR to the system without compromising the quality of products stored in these facilities. Several energy service providers (ESPs) have developed technologies specifically for cold storage facilities and are currently provide EE and DR services for a number of companies around the country. These facilities can provide curtailment services, but more importantly, their thermal load is an excellent resource for absorbing renewable solar energy during the day, by shifting cooling cycles to reduce the temperature in the facility during the day, and then shutting off electricity to refrigeration units during off-cycles to save energy, thus holding the temperature. Full automation technologies are readily available and can optimize energy operations for DR and EE for these facilities.

Table 32 below provides details on the costs and quantity of DR (in MW or MWh) services

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[36] Data center virtualization involves using software to virtually host processes across a server network, rather than having specific servers dedicated to particular tasks. This enables more uniform loading on server infrastructure, can improve energy efficiency, offers opportunities for redundancy, and lets processes scale up and down with less difficulty.

[37] A colocation is a data center facility in which a business can rent space for servers and other computing hardware.

from refrigerated and cool storage facilities. The cost competitive price for shift resources is approximately $30/kWh at a quantity of 207 MWh-yr. These facilitates can also provide cost competitive Shimmy load following service of around 6 MW-yr at a cost of $35/kW-yr. Our analysis indicates that currently, there is no cost effective Shed or Shimmy- regulation services for refrigerated warehouses.

Table 32: Quantity of cost competitive Commercial Refrigerated Warehouses DR by MW-yr for Shimmy and MWh-yr for Shift.

Commercial Refrigerated Warehouses: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	8	206	6	0
50th Percentile Quantity	8	207	6	0
75th Percentile Quantity	8	209	7	0

Plug and Play DR: *The ability to acquire technology from different vendors, specify the communications interface between products and have all such products install and work together easily and quickly is known as “plug-and-play”. This concept is a critical assumption that we make in the study; enabling technologies will be able to communicate and interface together to provide end use control and response to signals from an aggregator, consumer, or utility. Over the next decade, we assume that a “plug-and play” grid will continue to evolve and that communication standards will improve to make device connection and response easier and quicker than is currently the case today. This can be accomplished through coordination of standards with organizations like the OpenADR Alliance. The standards and requirements for telemetry of distributed DR resources can be simplified to allow for great access to the wholesale market in California.*

7.1.11. DR and Storage

Shift and Shimmy DR depends fundamentally on energy storage to operate. Some DR storage is based on the thermal capacity of buildings and refrigerated goods, and others on flexibility in scheduling. There are also two key emerging technology areas where electrochemical battery storage is a key driver: behind-the-meter fixed batteries and electric vehicles.

Behind-the meter Battery Storage

One of the key findings in our study is that the potential for behind-the-meter battery storage can significantly shift the capabilities of sites to present demand response potential to grid operators. Advances in the cost and performance of modern batteries with lithium-based chemistry could significantly contribute to the resource pool of DR technologies. Because batteries are inherently scalable, there are not the same physical limits on flexibility resource as controllable load DR. This means that if the cost of batteries (net any other revenue streams) falls below the cost-effective threshold level for DR services, it is the long-run average cost of storage that sets a “price referent” for other resources to compete against. The outcomes in Figure 80 reflect this dynamic, that there is little-to-no “very low cost” resource below $50/kW-year or /kWh-year but a large resource base that is only limited by the assumptions of our analysis above that level.

Currently, rules and requirements for interconnecting behind the meter (BTM) storage to the transmission system has been a barrier for bringing these resources to the CA wholesale markets. Stakeholders have indicated that the current telemetry requirements are costly, and in some cases, BTM resources require three meters to participate in the supply side markets. In our analysis of BTM storage, we assumed that the telemetry and communication costs would be consistent with other advanced technologies, (i.e. a single meter and communication platform at the site) and did not assume that in 2020 or 2025 that the BTM storage resources would require multiple meters. Therefore the BTM storage DR potential to be realized in 2025, the telemetry and communication requirements should be examined in an effort to address this barrier.

For the purposes of this study, we have defined a notional, example fleet of behind the meter batteries with reasonable capacity given trends in the battery market. If the full cost of batteries is to be covered by capacity payments and limited participation in the energy market, the supply curves in show that while the potential resource is large, there is limited cost-competitive DR from batteries. Nearly the full potential resource is above $100/kW-yr. Figure 80 below indicates the quantity of available DR from batteries, however, the cost competitive price for each kW and kWh of the Shift and Shimmy resource ranges between $28 to $62/kW. Therefore, the DR potential for batteries is above the economically competitive value. Our findings indicate that there is no cost competitive DR from commercial batteries; all availability comes from the industrial and residential sectors. Breakthroughs in battery cost and market offerings could reduce the levelized cost of capacity and dramatically shift the quantity of cost-competitive DR available from batteries.

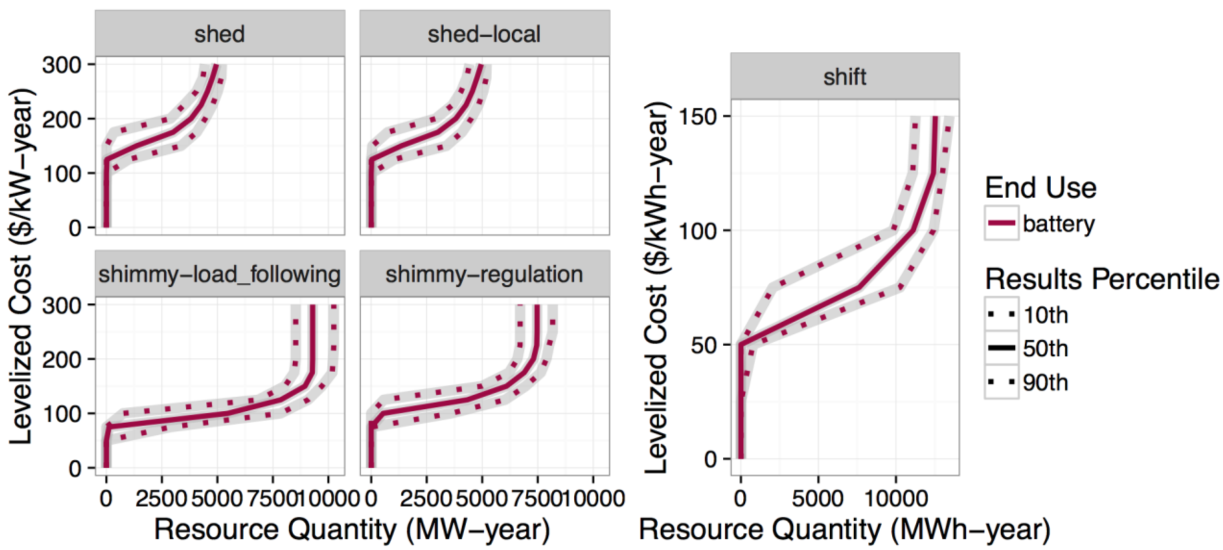

Figure 80: Battery end-use level supply curves.

Table 33 below provides the cost competitive quantity of DR from industrial batteries for each of the service types. Shift, Shimmy load following and Shimmy Regulation are the cost competitive DR service resources for industrial batteries which can provide 2 to 3 MWh-yr of Shift service with cost ranging from $28-$30 per kWh-yr, ADR enabled batteries can provide 1-3 MW per year of cost competitive Shimmy load following and regulation service to the grid. The costs for load following services is $35/kW-yr and between $57-$62/kW-yr for Shimmy regulation services.

Table 33: Quantity of cost competitive Industrial Batteries DR by MW-yr for Shimmy and MWh-yr for Shift.

Industrial Batteries: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	-	2	1	2
50th Percentile Quantity	-	2	1	3
75th Percentile Quantity	-	2	1	3

Table 34 below indicates the cost competitive quantity of DR from residential batteries for each of the service types. Shift and Shimmy regulation are the only DR service resources that are cost competitive and can provide 38 to 54 MWh-yr of Shift service with cost ranging from $28-$30 per kWh-yr, ADR enabled battery technologies can provide 7-11 MW-year of cost competitive Shimmy regulation service to the grid. The costs for regulation services is $57-$62/kW-yr. There is no cost competitive Shed or Shimmy load following resources available from residential batteries.

Table 34: Quantity of cost competitive Residential Batteries DR by MW-yr for Shimmy and MWh-yr for Shift.

Residential Batteries: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	-	38	-	7
50th Percentile Quantity	-	46	-	9
75th Percentile Quantity	-	54	-	11

Electric Vehicles

Electric vehicles are critical for addressing the challenge of avoiding climate change (Williams et al 2012) and a significant roll-out of EV in the near future would be consistent with California's recent policy directions on addressing Greenhouse Gas pollution. EVs are a new load category with significant technology potential to provide DR, and early pilots have shown the feasibility of using EV for Regulation[38] .

A pilot project for Shifting EV charging was run in San Diego[39] that included an experimental rate that applied only to sub-metered EV charging. The results were significant and dramatic, with customer EV loads essentially all shifted into the late evening after midnight when prices were low for the experimental rate. The participants in the study controlled the shifts with the built-in charging timer functions on their at-home chargers, set to start charging at the time when the price changed in the TOU tariff. It led to a large EV charging peak between midnight

[38] See Los Angeles Air Force Base Vehicle to Grid Pilot Project; https://drrc.lbl.gov/sites/all/files/lbnl-6154e.pdf, Marnay, Chris, et al. 2013.

[39] See Final Evaluation for San Diego Gas & Electric's Plug-in Electric Vehicle TOU Pricing and Technology Study, Cook, Ph.D., Jonathan, et al. Nexant, 2014. https://www.sdge.com/sites/default/files/documents/1681437983/SDGE%20EV%20%20Pricing%20%26%20Tech%20Study.pdf.

and 5 AM. While the particular timing of the Shift in the study does not match all of the needs we identified for electricity system operation in the future, it indicates the potential for using simple EV charging features to enable DR response to a price.

In order to use EV as a Shift resource, the optimal pattern will sometimes include nighttime charging, but nearly always will include significant Shifts into the middle of the day, between 9 AM - 4PM with reductions in the early evening (see Figure 81). Sometimes the Shifts to late night usage (like the pilot described above) are also optimal. This highlights the value of charging infrastructure, since while some Shift is possible with at-home charging scheduling, it would be important to have significant charging infrastructure available to enable daytime charging as well. Commercial charging stations, workplace parking lot charging, and public stations could be important near-term technology deployments to support a flexible EV fleet that can match the needs and capabilities of the next-generation grid.

This example of EV Shifting to daytime charging is an opportunity to show how the analytic framework we developed can also be useful for testing back-of-the-envelope analysis on the effective cost of Shifted energy. We considered the case of installing EV charging at a workplace parking lot, where a commuter's EV may be parked for 6-8 hours or more. A basic analysis is in Table 35 below and shows that the cost of achieving energy Shift with daytime charging infrastructure may be in the range of \$30 /kWh, competitive with many categories and consistent with the range of grid-scale value from shift (\$20-50 /kWh).

We used a basic EV availability model in our current implementation of DR-PATH, and the dynamics of Shifting charging from at-home to at-work are not captured explicitly in our model, but implicitly through assumptions that enable "home" charging to be flexible and Shift into the day (for example, see the detailed supply curves for Residential battery-electric vehicles in Figure 81 below). The left-side shows a set of Shed and Shimmy plots, and the right-side plot is for Shift. The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the "medium" DR case, in 2025, with 1-in-2 weather, mid-AAEE efficiency trajectory, and Rate Mix #3. EVs could be a significant Shed resource as well, particularly for locally focused sheds that may not line up with the system-level Shift profiles.

Better understanding the potential of EVs both in terms of climate mitigation from transportation and DR potential is an area where additional research and linking with EV simulation models could help refine our estimates. There are fast changes in the capabilities and use-cases for EVs and uncertainty in the forecast for adoption—because this is a new load category these same uncertainty elements inform planning for renewable generation planning, the distribution system, and other interlocked planning processes. The prospect of autonomous fleets of electric transportation in the future could also be a significant and qualitative re-structuring of the transportation sector, which would have implications for the planning and operation of the power grid as well. This all suggests that continued work across several policy areas (electricity resource planning, system planning, transportation policy, local permitting, etc.) is needed to understand and capture the opportunities from electrification of transportation.

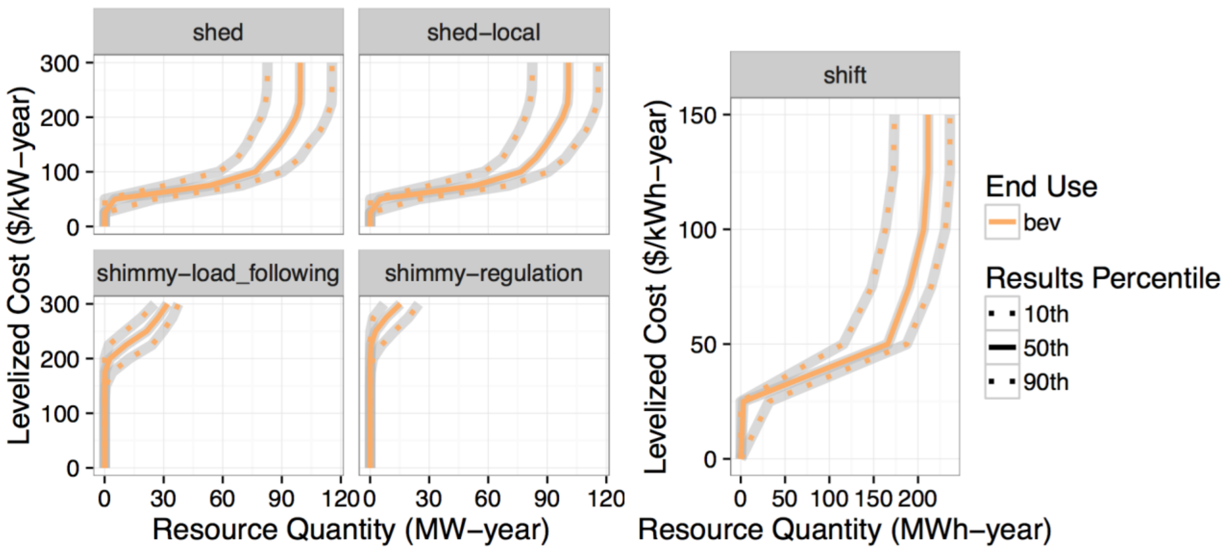

Figure 81: Residential Battery-electric Vehicles (BEV) end-use level supply curves.

Table 35: Levelized costs for Electric Vehicle Shift DR by kWh-yr

Electric Vehicle End-Use: Cost-Competitive Levelized Costs for Shift DR (all sectors)	BEV	PHEV	BEV-Work
Levelized Price per unit of DR	kWh-yr	kWh-yr	kW-yr
25th Percentile Quantity	$28	$28	$28
50th Percentile Quantity	$29	$29	$29
75th Percentile Quantity	$30	$30	$30

Table 36 below indicates the cost competitive quantity of DR from residential electric vehicles for the Shift service type. Residential electric vehicles can provide DR service ranging from 30 to 38 MWh/year from BEVs and 59-83 MWh/year from PHEVs. For commercial EVs, in Table 37, available Shift DR resources include 7-8 MWh/year for BEVs, 2-3 MWh/year for PHEVs and an additional 3 MWh/year for BEV charging at work. EV Shift service is cost competitive with prices ranging from $28-$30 per kWh-yr. These estimates are relatively low, but we expect this is a load category where significant technology innovation and opportunities for dynamic price could introduce lower-cost pathways to flexibility than what is modeled.

Table 36: Quantity of cost competitive Residential EV Shift DR by MWh-yr

Residential EVs: Quantity of Cost-Competitive DR	BEV	PHEV
Quantity of DR (Unit)	MWh-yr	MWh-yr
25th Percentile Quantity	30	59
50th Percentile Quantity	34	71
75th Percentile Quantity	38	83

Table 37: Quantity of cost competitive Commercial EV Shift DR by MWh-yr

Commercial EVs: Quantity of Cost-Competitive DR	BEV	PHEV	BEV-Work
Quantity of DR (Unit)	MWh-yr	MWh-yr	MW-yr
25th Percentile Quantity	7	2	3
50th Percentile Quantity	8	2	3
75th Percentile Quantity	8	3	3

7.2. Energy Analysis with Shed, Shift and Shimmy

The model we developed for this report runs with complex inputs and large datasets, requiring significant computing resources. There is, however, an underlying simplicity to the way we defined the framework for Shed, Shift, and Shimmy that enables quick and first-order analysis of the potential with a few key assumptions. We describe these in brief in this section, and refer technical readers who are interested in the details to the appendices and other supporting material for this study.

Using back-of-the envelope (or spreadsheet-based) estimates of some potential future technology or advance in DR deployment, compared to the results to the prices and quantity of competing resources, could be important tools to help stakeholders engage in the regulatory process, act as a coarse filter for technology R&D targets, and provides insight into the model.

For Shed DR, a first order estimate of the resource quantity for any resource is simply the expected value (average) of the load during the top hours of the year (in the near future, the 5-9 PM period) times the fraction of that load that can be shed by the control technology. The costs depend on the control technology.

For Shift DR, a first order estimate is based on the expected quantity of kWh that are shifted on the average day. An example for EV infrastructure is presented in the text box below.

For Shimmy DR, the simplest way to define a first-order estimate is based on multiplying the average load by a fraction that represents the symmetric availability to turn up/down on either the 5-minute (load following) or 4-second (regulation) timescale.

Back of the Envelope Analysis of Shift from Commercial EV Charging

This example shows how a first-order analysis can be used to estimate the effective cost for DR from a possible technology system. This case is one for Shift, but similar approaches could be taken for Shed and Shimmy resources.

Example: What is the effective cost of Shifted Energy from installing level 2 commercial EV charging stations, based on an expected use pattern and implicit Shifts away from evening charging? The example shown here is illustrative and not meant to be an authoritative result. It suggests an approach for making basic screening assessments of technology.

Step 1: Estimate the all-in average annual cost.

Assume the installation cost per charging point is $5,000, each lasts 10 years, and the operating cost is $200 / year in skilled labor for maintenance. Below we use a financing rate at 7%, which results in a capital recovery factor of 0.14 over the 10-year lifetime.

The annual average cost including financing is thus $5000 x 0.14 + $200 = $900

If the charging point were part of a specifically administered DR program or were incorporated into the ISO market or distribution system operations, additional costs would accrue as well.

Step 2: Estimate the total resource available, matching the characteristics of the DR Type.

Shift DR requires shifting energy from the evening to the daytime, nearly every day of the year. In this example we assume that on an average day the commercial charging station is used during the 8 critical mid-day hours at a capacity factor of 30% (compared to a 6 kW peak charging rate) -- resulting in 14.4 kWh used in daytime hours. Furthermore, we assume that each kWh offsets a kWh that would have otherwise been consumed in the evening.

Step 3: Estimate the effective cost of Shift.

At an annual cost of $770, and a typical daily energy shift of 14.4 kWh, the effective levelized cost of the Shift is $63 /kWh. The expected levelized value of Shift to the grid in 2025 includes the range from $20-50, and there are additional value streams from charging related to the convenience that could lower the effective cost of the Shift resource similar to our treatment of "co-benefits" in the study. This implies that if the assumptions about the cost and usage dynamics we use in this example apply, the value from facilitating energy shifts could defray half of the cost of charging infrastructure.

This back of the envelope demonstrates how new technology can be vetted on first order compared to the framework for Shift DR and suggests that the renewables integration value of daytime-use EV charging infrastructure investment deserves a careful analysis, beyond the treatment in this study.

7.3. Policy considerations

7.3.1. Percieved Market Participation Risk

Survey participants identified that there is great uncertainty on the value for providing DR in the real time market. Questions they posed included:

- What are the potential additional revenues from fast DR enabling technologies?
- How many participants will be in this market?

Stakeholders perceive a risk for investing in fast DR technologies that have poorly defined markets for DR participation and compensation in CAISO.

Market education: technology and energy service providers could benefit by knowing more about the financial benefit of providing DR in real time and day of markets. Survey participants stated that knowing how much money could be available in real time markets and how often resources would be dispatched could drive market adoption. Stakeholders identified the complexity of the CAISO market as a process barrier for evaluating the business case for investment in fast DR technologies in the California markets.

Another form of market participation risk is related to shifting policy landscapes. If the rules and protocols for DR in organized markets and regulatory environments are unstable or poorly implemented, it can lead to aversion to invest in long-term R&D and deployment. As DR expands to provide new service beyond Shed, the predictability and incentives presented to actors in the market will help define the risk associated with third-party and utility investment in market development.

7.3.2. Developing Third Party Markets

Policies that can address the barriers to market entrance to wholesale markets include education on the CAISO markets, standardization of telemetry requirements, easing of dispatch and communication constraints for non-generator resources, and standardized rules for aggregation of DR resources that seek to participate in wholesale markets. The process for integration of aggregated Distributed Energy Resources (DERs) (such as batteries and DR technologies) into the wholesale market and grid could be simplified. The rules and requirements for participation are complex and not well understood by potential market participants, including 3rd parties. Additionally, retail customers do not have ease of access for participation in wholesale power markets nor do they receive compensation for services provided to distribution systems.

7.4. Model Sensitivity and Key Drivers for Potential

We included scenarios and cases in the modeling framework that let us explore the sensitivity of

DR potential to a range of potential futures. The figures and narrative in the sections below express the sensitivity of the model results across key dimensions we included. Each figure shows a baseline quantity for 2025 DR Potential and expresses a range in potential based on sensitivity for the following:

- **DR Market Scenario:** The pace of technology cost and performance improvements.
  - Baseline: Medium scenario.
  - Upper: High scenario
  - Lower: Low Scenario
- **Level of Portfolio Benefits:** A measure of business model integration, defined by the ability of DR aggregators and/or utility programs to capture revenue from a range of services enabled by DR technology.
  - Baseline: Costs are net ISO revenue and site-level co-benefits.
  - Upper: Also includes revenue from hypothetical distribution system service.
  - Lower: Only including ISO revenue, without site-level co-benefits.
- **Monte Carlo Analysis:** The result of uncertainty analysis we conducted on the future cost and performance of DR technology. The range shown (from 25th to 75th percentile) is analogous to the range of the box plots in Figure 3 and other similar figures.
  - Baseline: 50th Percentile outcome from analysis
  - Upper: 75th Percentile outcome from analysis
  - Lower: 25th Percentile outcome from analysis
- **Weather, EE Scenario, and Rate Mix:** We simulated many combinations of weather (1-in-2 vs. 1-in-10), Energy Efficiency trajectory (without "additional achievable energy efficiency", AAEE, and with a "mid" level of AAEE), and different mixes of retail rates (Rate Mixes 1, 2, and 3).
  - Baseline: The average of all combinations
  - Upper: The maximum of the combined options
  - Lower: The minimum of the combined options
- **Renewable Integration Status:** We included two different "bookend" cases in the RESOLVE model to estimate system-level value from demand response, one with "high" levels of renewable curtailment and the other with "low" curtailment due to other renewable integration activities (transmission expansion, regional coordination, etc.).
  - Baseline: High Curtailment
  - Lower: Low Curtailment

Shift Sensitivity:

The DR market and technology scenario is the strongest influence on the cost-effective quantity of Shift DR (with a ~40% difference between the "medium" and "high" scenario), closely followed by the level of renewables integration and the ability of DR businesses to access a portfolio of value streams with their investments. There is little sensitivity related to the uncertainty in technology cost and performance inputs or the weather, retail rates and EE trajectories we included (Figure 82; Note: The baseline is defined for 2025, with the baseline scenario setting indicated in square brackets on each sensitivity category label). The strong influence of renewables integration is expected for Shift since the original source of value for the resource is from exactly that kind of service (capturing more renewable energy, avoiding curtailment).

The sensitivity of Shift to DR scenario is emblematic of the structure of the model; because the scenarios include both cost and performance dimensions there are interactive effects on the unit costs (which divide cost by quantity). These effects tend to amplify the combined change in performance and cost. For example, in a case where the cost of technology is reduced by 25% and the performance is increased by 25%, the net effect is that there is 25% more resource available at a unit cost that is reduced by 40% compared to the base case.

Our results suggest that a focus on technology development and cost reduction (i.e., pushing towards a “high” DR scenario) could have significant influence on the availability of Shift resources, along with enabling Shift resources to also serve the distribution system. There are interactive tradeoffs between decentralized renewables integration like Shift and system-level investments like centralized storage and transmission infrastructure. The reduction in Shift cost effectiveness when there are other renewables integration solutions employed suggests that Shift (and DR in general) should be considered part of an integrated set of solutions.

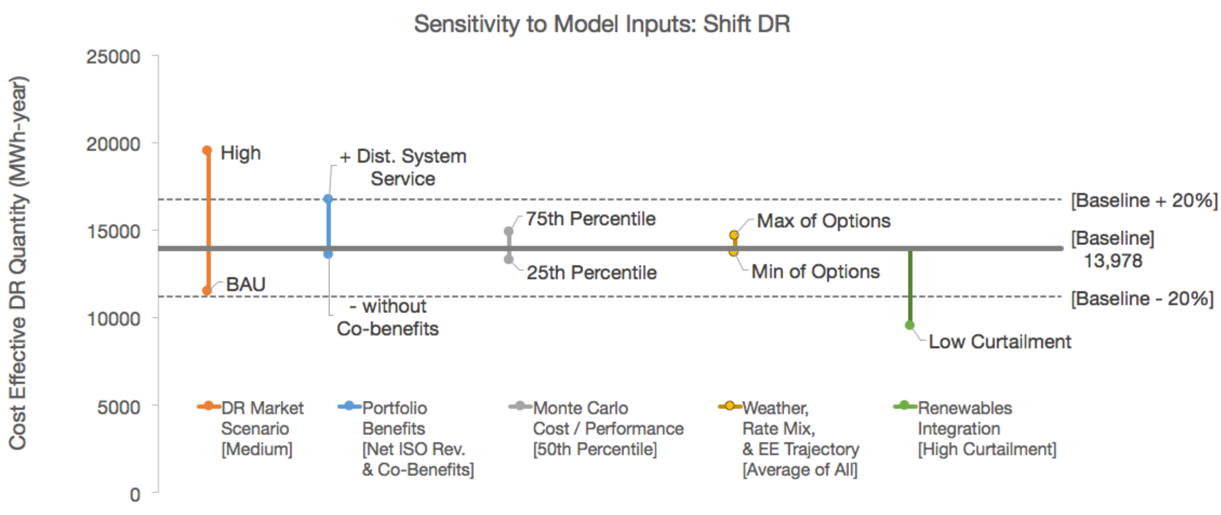

Figure 82: Sensitivity analysis for Shift DR.

Shimmy Sensitivity:

For Shimmy DR (both load following (Figure 83) and regulation (Figure 84)) the strongest influence on potential is the ability to build portfolio benefits and access site-level co-benefits and distribution system service revenue (Note: The baselines in both figures below are defined for 2025, with the baseline scenario setting indicated in square brackets on each sensitivity category label). There are also strong effects from the DR market and technology scenario. Similar to Shift DR, there is little effect from the weather, retail rates, and EE trajectories we simulated. The range of outcomes from our Monte Carlo uncertainty analysis were within the +/- 20% bounds around the baseline we show on the figures as well.

Renewables integration has a significant influence on the cost effective quantity of Shimmy DR. In a low-curtailment scenario where there are other options, the value of Shimmy is reduced and the cost-effective quantity drops from near 300 MW to 60 MW for load following and 200 MW for regulation.

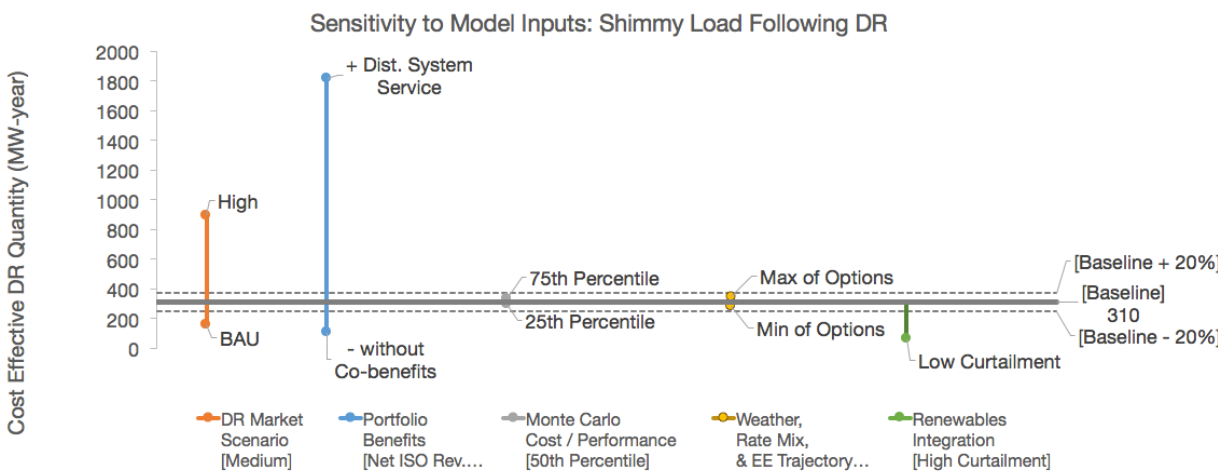

Figure 83: Sensitivity analysis for Shimmy Load Following DR.

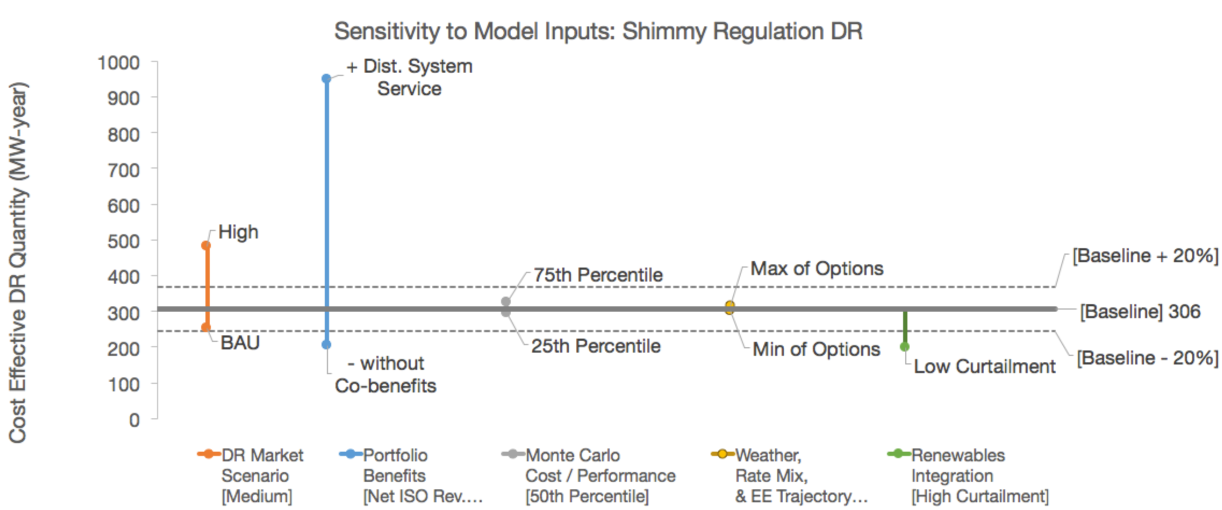

Figure 84 Sensitivity analysis for Shimmy Regulation DR.

Shed Sensitivity

We show two metrics for Shed sensitivity—one for system-level Shed (Figure 85) and the other for “local” Shed, that is, Shed resources that can respond in less than 20 minutes and are located in a current capacity constrained local area. The baseline is defined for 2025, with the baseline scenario setting indicated in square brackets on each sensitivity category label. The baseline for system-level shed is low – only about 400 MW – because the resource costs are being compared to a very low system-level value for Shed (as we describe above, there is sufficient capacity for carrying the system peak through our study period, and thus no generation capacity investment deferment opportunities). It is notable that if Shed resources are focused on serving the distribution system, there could be substantial usefulness across the system, targeted on feeders where there is a need (and an opportunity to defer investment in distribution infrastructure to manage the local loads and generation).

The local Shed results (Figure 86) paint a different picture, with a baseline cost-effective resource availability on the order of 5 GW-year. The baseline is defined for 2025, with the baseline scenario setting indicated in square brackets on each sensitivity category label. Unlike the other plots in this section, in this case the cost-effective DR quantity is determined by a price referent instead of simulated system-level value. This is based on resources valued at $200/kW-year and in place of the sensitivity to renewables integration we show how the cost effective quantity changes based on a change in price referent, with $100 /kW-year and $300 /kW-year as benchmark values. There is 3x the gap from $100-200 compared to $200-300 because at $300/kW-year nearly every available resource is cost effective (saturation in supply). The specific avoided cost is the strongest influencing factor on the cost-effective quantity of local Shed and would depend on the details of a local area. For local Shed, the influence of DR technology and market progress is strong as well (manifested in sensitivity to the DR scenario).

Taken together these Shed sensitivity results provide support to the concept of refocusing Shed DR in targeted areas – local capacity constrained areas and on the distribution system.

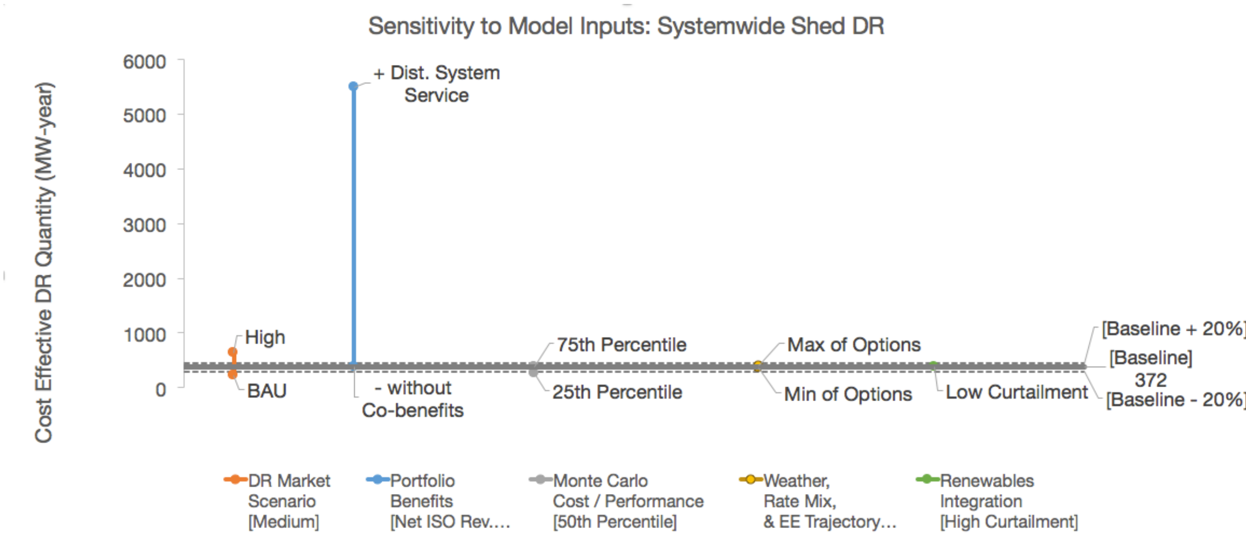

Figure 85: Sensitivity analysis for Systemwide Shed DR.

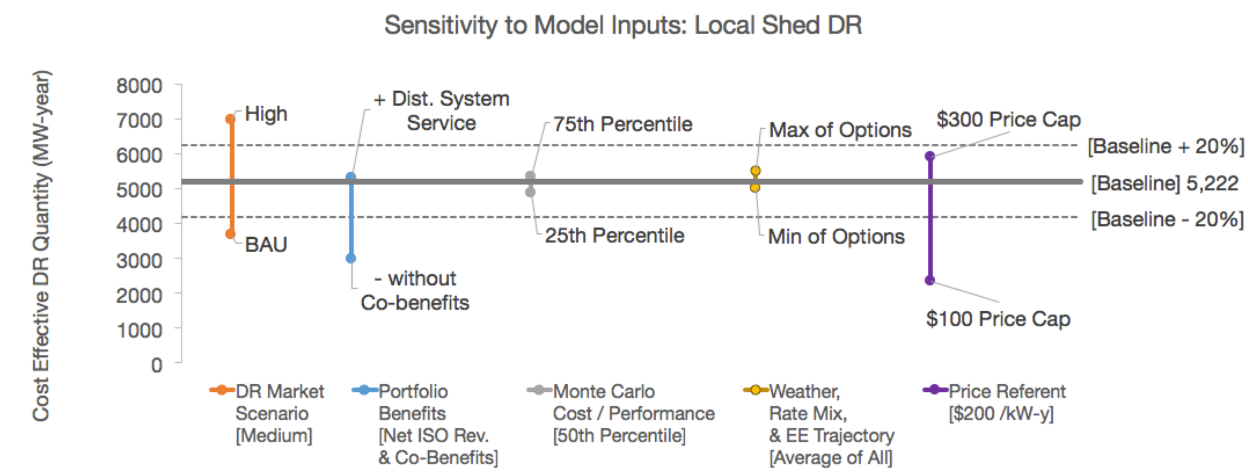

Figure 86: Sensitivity analysis for Local Shed DR.

8. Achieving DR Potential: Evolving Policy Context for DR

Ultimately the scale of DR potential in California will depend on how the policy environment, market design, and technology research and development progress over the coming years. Below we describe the context of the emerging next-generation grid DR landscape:

8.1. Importance of market design

The CAISO and the CPUC are undergoing a parallel set of reforms to create space in the energy and ancillary services market for distributed resources and DR. As these processes of market definition continue, important design decisions are being made that will influence the ability of and incentives for demand response to participate. Stakeholders we heard from raised issues about a range of market design choices that bear directly on the potential for DR (and are core to defining it). Telemetry requirements can have significant influence on the cost of fast DR, requirements for continuously variable dispatch present challenges to some DR-ready processes that run as a continuous batch, and there are constraints in the capabilities of advanced metering infrastructure to support settlement of fast resources.

Controllable DR resources, including behind the meter battery storage, can provide flexible services to existing wholesale markets that can potentially defer the need for additional conventional generation resources, with sufficient penetration. Controllable DR resources can support the integration of renewable energy sources, and support policy targets for renewable standards and a low carbon future. CAISO and the CPUC continue to develop rules that encourage broader participation of non-generator resources in the wholesale markets, including load following ancillary services.

8.2. Energy Efficiency, Load-Modifying DR and Supply DR

There is an ongoing discussion around interactive effects of energy efficiency and demand response, and the bifurcation of DR into load-modifying and supply resources facilitates a new way of viewing these effects. One could broadly consider energy efficiency (EE) as a load-modifying DR measure, whereby the net load is decreased by an efficiency investment (and the timing of service remains unchanged). Thus EE investments in general have “load-modifying” DR effects, reducing the need to procure peak capacity because the peak load is reduced. Depending on the load types that are upgraded or improved, it is possible as well that less flexible ramping capacity and other advanced grid products will be required due to energy efficiency.

On the other hand, improved efficiency for an end use that also participates as supply DR reduces the availability of baseline load to actively shed. It is an important point, however, that the net sum of the DR resource is unchanged in general, and could be increased through EE investment. Consider an example of an HVAC load that is 10 kW baseline and can be reduced by half of the service level (5 kW) with dispatchable control as supply DR. If the load is efficiency upgraded with one that uses 75 percent of the original energy load (i.e., an EE benefit of 25 percent), the baseline is now 7.5 kW for the same baseline level of service. If the service level is still reduced to half during a DR event, this means that there is only 3.75 kW available for supply DR (less than the original 5 kW shed), but the overall effect of the combined EE and DR on the net load is a reduction of 6.25 kW—an increase in total DR compared to the original configuration that also comes with all the benefits of EE upgrades. If one only considers the availability of supply DR in the absence of the underlying load-modifying effects, however, an efficiency investment can appear to reduce the quantity of available demand response.

Energy-efficiency upgrades often present opportunities for cost-effective controls upgrades (either as part of an integrated project or as controls built into new equipment in an Internet-of-things approach) that can reduce the cost of enabling DR. An instructive example is the case of energy-efficient lighting. Light-emitting diode (LED) lighting is now an established market segment and is rapidly improving in efficiency, recently surpassing the incumbent fluorescent technologies prevalent for the last few decades. The efficiency benefits of LED lighting are often large, reducing the theoretical quantity of dispatchable DR available from the load, but the upgrade is an opportunity to simultaneously make the lighting stock more controllable for both occupant service and demand response. The markets for distributed energy technologies that provide multi-attribute services like these are still evolving, and often there are challenges to ensure the services are appropriately valued. The DR market for lighting is still in its infancy, and growth will depend on numerous market transformation activities occurring simultaneously: building product availability, lowering technology cost, increasing reliability, improving market knowledge (i.e., designers, specifiers, contractors, building owners/occupants, building officials, and facility managers all becoming conversant in the technology), and aligning capital investment support.

Solutions for addressing the DR lighting in particular are the subject of a recent California Energy Commission Electric Program Investment Charge (EPIC) PON 15-311 solicitation, and LBNL's awarded contract, to develop "The Value Proposition for Cost-Effective, DR-Enabling, Nonresidential Lighting System Retrofits in California Buildings." This project will explore energy and non-energy benefits in California for DR-enabling, advanced lighting control systems leading to a more comprehensive and accurate financial analysis for the technology. The goal is to support enhancement of California's Title 24 and integrated demand-side management program offerings, to accelerate market adoption for the technology. Targeted market transformation efforts like these are critical for technology areas with significant overlap between traditionally separate value areas like EE and DR.

The overall effect of EE and DR integration could be an overall increase in combined load-modifying and supply DR availability for meeting system capacity needs, with supply DR at a lower cost compared to DR-only technology investments. Achieving this synergy will however require significant effort to align policy and market frameworks.

8.3. DR Targets and the Importance of Baselines

There is a significant need for careful integration between CPUC and CAISO policies to ensure that the market designs and real-world integration are matched well with the most cost-effective pathways for DR service. A critical awareness of how baselines are set for participating load in ISO markets is needed. With "every day" DR like Shift it is particularly challenging to accurately measure and compensate load-based resources in the same framework as conventional generation. Price response is a viable and potentially useful tool, particularly if individual DR-enabled loads with low-cost submetering can be subject to a special rate schedule (e.g., EV charging rates with sub-metered chargers).

The challenges of measuring the counterfactual baseline for DR is well documented, and the way DR is measured and accounted for in the market will strongly influence the competitiveness of DR and the ability of market participants to provide resources that meet policy targets for resource adequacy and other applications. The DR we include in our modeling effort inherently has a known counterfactual expected baseline—this is the load profile that is the basis for the expected DR resource. If operational practice fails to accurately measure the load impact of DR, the apparent resource could deviate from its actual value or become obscured by noise in the measurement.

There are also similar baseline issues at play for considering policy targets for DR. In many cases policy is set in terms of minimum thresholds for procurements that are a fraction of total procurement or an absolute minimum. In addition to bias or imprecision that is introduced from operational measurement and verification, which would affect any kind of policy compliance, the magnitude of DR resources also depends on exogenous effects of weather (as shown in the comparison between weather cases for our model) and economic cycles (not shown in the model). During the recent recession there was a decrease in DR related to slowed economic activity. This slower activity can result in lower industrial electric loads and lower rates of energy use in office and retail buildings.

9. Opportunities for Breakthrough in Technology and Markets

9.1. Building Codes

The California Energy Commission has developed requirements to install DR automation technology as part of Title 24. These requirements' success could greatly reduce the new DR systems' first cost. Not only can the Title 24 requirements reduce the cost for automated DR in new buildings, they could also help to disseminate key information to control companies about the commitment to formal communication standards for DR automation. For large building control systems, the DR automation cost could be extremely low if the DR automation was available in conventional building automation system controls. The majority of large commercial and industrial DR is installed with gateway boxes. Unfortunately, there is great confusion about the current DR requirements in Title 24, and the code officials and key market players have received little to no education on the intent of these DR requirements. Similarly, control companies and design engineers have expressed concerns about the lack of consistency in interpreting the code requirements. Careful attention to this issue is needed to address the market confusion generated by inclusion of this DR requirement in Title 24. The CPUC and the IOUs can help address this problem by evaluating the knowledge gaps that exist around the DR code issues and develop training and information to address these gaps. Given the language in Title 24 on DR automation, there are opportunities to ensure that retrofits and new buildings that require code compliance are provided with clear information about the DR programs for which the building may be eligible.

9.2. Internet of Things (IoT)

California is fortunate to be the home of many established and emerging companies and industries taking advantage of the incredible opportunities for using the Internet in new ways. One of the most promising areas for DR is the capability of new packages of technologies to control, measure, and automate demand response. A recent study by Lanzisera et al. (2015) showed that new DR technology platforms could be capable of providing fast load shed for between $20 and $300 per kW of available load. The study noted:

> "Many new technologies will be installed for energy efficiency or non-energy benefits (e.g., improved lighting quality or controllability), and the ability to use them for fast DR is a secondary benefit. Therefore, the cost of enabling them for DR may approach zero if a software-only solution can be deployed to enable fast DR after devices are installed for other reasons."

Some of the lowest-cost DR technologies are new communicating thermostats that are installed by the customer for energy management and convenience, but these can also qualify for automated DR programs because they support open automated demand response (OpenADR).

9.3. Integrated DSM (IDSM) and Locational Targeting

In recent years, the utilities' EE and DR goals have been planned, managed and evaluated separately from each other. Customers are approached separately for EE and DR programs, which produces customer confusion. The customer engagement activities will be more cost-effective if the technology costs for EE and DR technologies are integrated. For example, at the Sacramento Municipal Utility District (SMUD), when new building HVAC automation or lighting controls are incentivized with energy efficiency DSM funds, they require the technology system to support OpenADR, so it will be less expensive for the building to join a DR program in the future. This integration creates a "future-proofed" DR-enabling technology platform when implementing EE project investments. There is a need to better link EE and DR measures so that they are more cost-effective when bundled. To achieve this will require some creative new measurement and verification methods to value both the EE and the DR performance of an IDSM measure.

Furthermore, the visibility into the distribution system and bulk power operations is only growing. As techniques emerge for geographically targeted information on needs, an integrated mix of DR, EE, onsite generation, and storage could provide significant value to the customer and local operations.

9.4. Customer Feedback and Behavior Based Programs

Recent research (Cappers and Sneer 2014; Todd et al. 2014) has found that utilities and aggregators that focus program efforts on customer feedback, engagement, and behavior have successfully encouraged DR participation and energy conservation during peak hours. Residential in-home displays and monthly "home energy reports" have been shown to help raise awareness of energy use and provide some conservation effects. Similarly, in large commercial and industrial (C&I) programs, aggregators have experience providing custom feedback to C&I customers on their DR strategies' performance. This feedback occurs quickly after DR events and helps to provide direct information about the customer's electric load shape and the economic incentives. This customer feedback stands in sharp contrast to the IOU program feedback.

9.5. DR Aggregators' Role

California needs to continue to explore how to partner optimally with aggregators to expand the capabilities of responsive load in the state. A competitive, multi-party market for DR services would help drive innovation in technology and business models for delivering flexibility from loads and DER broadly. To support this market and drive it towards ratepayer interests, the firms should face incentives and revenue opportunities that are related to the full value provided to the grid by DER. The current market setup discourages collaborative support for resources between parties. For aggregators to target the highest-value sites, there is a need for ongoing and cyber-secure methods of focusing investments based on customer characteristics and the context of the distribution feeder and location on the system.

Efforts like the DRAM and other innovative procurement mechanisms, along with newly available data from the Distributed Resources Plan proceeding could help clarify the potential opportunities for aggregated resources to serve system and local needs.

10. Recommendations for Guiding California's DR Pathways

Our study presents a new framework for assessing the needs of the grid and potential of DR to support significant shifts in the generation mix and architecture of the system. In the course of building the modeling framework and analyzing the results we identify a range of needs for to inform the business community, policymakers, and technology developers who are active in the space.

10.1. Policy Direction

Data-driven Energy Markets and Policy

This study represents a new framework for approaching demand-side energy analysis in support of public policy for demand response. With a foundation of large AMI data samples, we show how a bottom-up, hourly-resolution electricity system model can provide important insight into demand-side resource potential coincident with weather and renewable generation. We worked with the CPUC to make both available in an open source format the input datasets, with protection against customer privacy, and the supply curve model. Using transparent models and up-to-date data not only improves the results of the study by providing many more avenues for feedback but could also, over time, enable stakeholders to engage in the regulatory process with better quantitative capabilities.

In order to catalyze spin-off work, alternative scenarios, technology R&D and market intelligence, we recommend implementing a demand-side, electric load data release at high spatial and temporal resolution that is: 1) publicly available; 2) predictably distributed; and 3) uniformly-formatted.

Additional work will be needed as well focused on data access for third-party implementers, streamlining the settlement and telemetry with CAISO, integrating transmission-level and distribution system operations, and other information technology challenges. With an underlying foundation of data about distributed energy systems' operation that reveals California's electricity users' and investment opportunities' diversity, the public and private sector can build the knowledge to chart a cost-effective and high performance DR technology future.

Catalyze Shift

Shifting energy demand from early morning and evening hours to the middle of the day is a robust strategy for supporting renewables integration, and it creates significant value to ratepayers by making it less expensive to meet RPS targets. We identified that this DR category could be achieved through either a market-integration or prices pathway, and that further research on an accelerated timeline is needed to understand the best approach. A key difference between conventional load-shed DR and shift we identified as valuable is the operational strategy: Shift involves day-to-day and frequent (or permanent) changes in the patterns of load with a depth appropriate to maintain satisfactory energy service, instead of infrequent and deep sheds. There is significant work needed to understand the ability of current DR sites to achieve shifts, and identify new application areas that match the resource.

Different sectors and applications may lend themselves to different Shift flexibility pathways as well – highly automated processes may be able to subtly shift based on day-ahead dynamic price forecasts while behavioral and structural changes are driven by longer-run prices. Layering long-term shifts with automated dispatchability for shorter-term could provide low-cost portfolios.

The core challenge for appropriately driving shifts is balancing overall CAISO-level system requirements with local distribution-level IOU requirements with, in turn, local facility/DER requirements. Different market structures, business models and rates/tariff designs can be reflected in further analyses to better bound and evaluate these parameters to better inform policymakers and key stakeholders regarding the most effective way to invoke Shift resources moving forward into the future.

In our analysis of the Shift resource potential we highlighted the tension between the bifurcation concept and Shift resource potential. There are discussions and working groups at the CAISO underway to create frameworks for exposing shiftable loads to the price in the energy market through a bidirectional bidding and dispatch system, but with significant challenges in measuring baselines for settlement and with additional transactions costs compared to a simple dynamic tariff for those loads. On the other hand, without the organizing principle of the ISO market it could present a challenge to build business models that push enabling technology out to the thousands of sites that would need upgrades to dynamically respond to day-to-day needs.

This is an area where significant additional work is needed to better understand the dynamics of energy Shifting using automated control. Questions to be explored include:

- How much energy Shift is achievable with differentiated pricing at the end-use level? With low-cost sub metering it could be possible to have different devices face different price timescales, providing certainty to users in terms of their directed service but allowing autonomous cycling devices like refrigerators and HVAC to meet finer-scale system needs.
- Early studies on EV's (a SDG&E pilot) indicate that sub-metered loads with dedicated prices can be effective, but would the results hold for broader applications?
- What is the business case for energy service providers who indicated that "static" time-of-use rates that apply broadly are not likely to achieve significant Shifts?
- How can existing control technology be deployed for energy shifts? What are the gaps in technology that can be filled with pilots and R&D?

We note that there is already work underway to pilot test and develop programs and resources that shift energy to capture mid-day renewable generation, some of which are listed below. These are important initiatives to expand the knowledge base around Shift broadly, and the results could help inform policy and R&D directions going forward.

- **New TOU price structures:** All three IOU in California have proposed new TOU peak periods that are in the late afternoon / early evening designed to incentivize shifting some of that evening consumption to the middle of the day. This represents an important change, and is notable because for years customers have been told that time-varying prices are designed to move consumption out of the mid-afternoon and into morning and evening hours. The new TOU proposals from the IOU turn this conventional wisdom around, and it is likely that a significant consumer education campaign will be needed to help clarify the new opportunity.
- **Special pricing pilots**: There have been a few targeted pricing pilots that aim to build mid-day demand. One is the "Matinee Pricing" pilot in the context of the Water-Energy Nexus rulemaking[40], which provides periods of low pricing in the middle of the day during key times of year. Two pilots are underway with EV charging; one is a partnership between PG&E and BMW[41] with early indications of high satisfaction among drivers and meaningful shifts of energy in response to the program signals. Another EV pricing pilot run by SDG&E[42] provides day-ahead dynamic pricing at multi-unit dwelling and workplace charging locations, enabling customers to optimize their charging schedule based on information about the expected marginal cost of electricity on the bulk power system and local circuit conditions. More pilots like these, with targeted pricing for particular sectors and end-uses, could help reveal the depth of Shift that is possible with the combination of pricing and automated response.
- **Excess supply initiatives:** Broader work that includes demand response, distributed storage, energy efficiency, and other mechanisms to address "excess supply" were approved for the three IOU in CPUC decision 16-06-029. Each utility proposed unique approaches, including pricing, water pumping control, energy storage, integration of ancillary services with shiftable load, and others.

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[40] CPUC Decision 16-11-021

[41] http://www.pgecurrents.com/2016/11/14/pge-bmw-partner-on-next-phase-of-pilot-studying-advanced-electric-vehicle-charging/

[42] CPUC Decision 16-01-045

Fast DR and Shimmy

DR can likely provide significant value to the system for regulating frequency, reducing the impact of short-run deviations and ramps, and meeting contingency needs. This will require technology investment to enable loads, software integration with CAISO markets, and new approaches to engage customers with devices or equipment that can respond. Integration between ISO market practices and supporting policy for fast DR is important for supporting an appropriate scale for DR capabilities in this area.

Benchmark IOU Demand Response Programs

Existing IOU DR programs have traditionally been evaluated for effectiveness on an annual basis. There is a strong need to evaluate the persistence of DR programs, customer engagement, and investments in technologies. Understanding these programs' and technologies' long-term value can help inform investments for the IOUs and policymakers of "what works". One of the DR program challenges is customer attrition and churn, which can have an adverse effect on technology investments and program performance if assets are left stranded. By examining a DR program's effectiveness over a three year period, or longer, policymakers can gather greater insights on whether investments in DR technologies persist. We recommend that there be program evaluation, data collection and a framework to examine the long-term value of DR systems.

Additionally, we recommend that program evaluations be benchmarked to include technology costs, measures of response capabilities across a range of dimensions (not just load shed), and customer profiles. As DR investments evolve beyond conventional peak capacity curtailment programs, a focus on tracking and understanding data-driven investments in DR services could help ensure policy keeps pace with the fast-changing market.

Future Rate Design for Residential and Non-Residential Customers

Over the next decade, future rates in California will play a major role in managing energy consumption patterns. The CPUC has committed to instituting default TOU tariffs for residential customers in 2019, however, those rate structures are undetermined. As this study indicates, there is an opportunity to use electricity rates to encourage customers to shift load from evening hours into the middle of the day. Retail rates should be designed to assist with renewable generation resource integration as a main objective. In the next few years, retail rates for all non-residential and residential customers that include an aggressive off-peak period during mid-day hours that encourages load consumption, should be piloted to determine the appropriate price signals and off-peak-to-peak ratios under a default scenario. Pricing pilots can ensure that rates are designed incorporating elasticity estimates from empirical data.

Our research indicates that using retail rates to promote load shifting may be among the most cost-competitive methods to both reduce renewable curtailment and peak load reduction. We did not model specific rates or rate structures to determine the best way to accomplish this, and therefore, we advocate for additional rate impact analyses both for individual IOU service territories and at CAISO transmission system levels.

Developing Market Mechanisms for Market Entrance

Third party aggregators and energy service providers have been challenged in recent years to gain access to and participate in energy and capacity wholesale markets. Recently, the Demand Response Auction Mechanism (DRAM) pilots have improved the ability for these third party participants to engage in supply side DR markets. Programs, such as DRAM, should be piloted to encourage a diverse pool of DR resources that can provide services to the transmission system.

10.2. Future Business Models for Energy Service Providers and Utilities

The future of the utility business model and **business models for third party energy service and DR aggregators** have been the subject of much debate and discussion in the past several years (e.g., see Satchwell et al 2015), and we expect this will only amplify going forward as the grid and distribution system conditions evolve, bringing to fruition many of the concepts that up to now have only been hypothetical scenarios for renewable penetration, distributed resources, etc. In our model we do not explicitly account for the nuances of particular business models – instead focusing on what is possible if the technology is available and incentives are aligned to roll it out. Thus it is important here to note the key areas of work that will be needed to achieve business models that can sustainably deliver DR resources, capturing enough revenue to properly incentivize the deployment of DR.

Portfolio Approaches

It is notable that in our sensitivity analysis a significantly large factor for determining DR potential is the ability of resources to access **portfolio** benefits from the technology (ranging from +20% to +1000% and up compared to baseline cases. It is simply much more economically effective if the same widget that provides DR to system or local needs also can provide monetizeable value to the distribution system and/or site-level applications. This suggests that there is a strong incentive to identify business models that span large spatial domains – from the building site to the distribution feeder to the transmission system. In the context of California's bifurcation of demand response (separating the operation of resources for transmission system benefits from other resources) this could be particularly challenging.

Our study considered a range of DR applications, and we constructed portfolio-based resources across spatial domains (e.g., including site-level "behind-the-meter" co-benefits and distribution system benefits for estimating the effective cost of transmission system-level service). These portfolios are predicated on the assumption that it is possible both technically and from a business model perspective to offer service across scales. Work is needed to understand the technology capabilities to provide multi-scale service and where "co-benefits" and parallel uses of control technology are possible. This should be carefully coupled with a focused effort to understand the necessary business and market conditions to incentivize integrated demand-side energy planning. These discussions and rulemakings are underway and the results of our study points toward significant gains in cost-effective DR potential if the barriers to portfolios of decentralized energy service are overcome. Our sensitivity analysis showed that access to portfolio-based revenue streams is greater than or equal to the differences between our DR technology progress scenarios for capacity-based DR like Shed and Shimmy. Shift exhibits lower sensitivity to both factors (technology and portfolio approaches).

In particular, we identify the need for several linked efforts that help unlock the portfolio-based potential our model suggests could be available:

- Study and pilot test the business case for combined EE and DR offers. The installation of EE upgrades is a critical moment of opportunity to engage customers to participate in DR programs and improve controllability of loads (and vice versa). If EE and DR programs remain in separate silos, the site-level co-benefits we identify would not come to fruition.
- Continue work on locally focused and targeted Sheds in support of the distribution system and local generation capacity constraints. The management and investment planning of the distribution system is a critical element of this. Our study used only notional and randomly assigned value for distribution system DR. In part, the way forward should include more explicit modeling of the opportunity for combining transmission and distribution system service that is spatially resolved in the context of the customers on constrained circuits. A vital outcome, if third party aggregators are going to provide combined service, would be identifying a framework for enabling non-utility actors in the market to have good access to data that helps them understand where specifically the opportunities are to support the distribution system, without compromising customer privacy.
- The core challenge of portfolio-based DR which spans transmission, distribution, and behind-the-meter service is the future of the utility business model. Bifurcation of DR suggests that utilities could take more of a supporting role in enabling aggregators to connect customers with the ISO market, but these aggregators are at a distinct disadvantage when it comes to access to customers and information on the distribution system. What will the utilities' future expectations be for cultivating access to information about customers in their service territory and conditions on the distribution system? Cost effective DR potential increases when market participants can identify and target highest-value sites and enabling technologies, and work towards sharing

information and standardized platforms and protocols for engagement between enterprises will be key to unlocking the potential we identified is technically and economically achievable with the proper support.

- While we explored the upside potential from participation across the transmission, distribution, and behind-the-meter portions of the electricity system, we did not simulate multiple participation in system-level markets, which could change the single-market results and reduce the effective cost of providing DR. It will take a combination of technology pilots, improvements to the modeling framework, and understanding the market and policy implications for multi-objective DR to understand and achieve the additional potential that could be captured with integrated portfolios.

Transition from System to Local Sheds

Our study identified that the "conventional" system-wide peak shed DR is unlikely to provide significant value to the grid in the future, but there are still important uses of the existing and future Shed technology stock for meeting local capacity needs, and these resources could support distribution system operation and planning. Our background research indicated the value on the distribution system is highly concentrated on a small fraction of constrained circuits, highlighting the need for targeting granular, load control investment. Key to unleashing this value is working closely with pertinent stakeholders to clearly identify building local shed resources that evolve over time to provide grid services to a changing system need. In other words, to mitigate future requirements, paths must be identified that avoid investing in DERs that represent 'technological cul-de-sacs' that render sites mal-adapted to future energy systems or foreclose on opportunities for integrated approaches later.

Community Choice Aggregation[43]

Community Choice Aggregation is rapidly expanding in California and it is not implausible that a majority of load in the state could be procured through CCA in the future. Because CCA also set local rates, their role in future retail pricing is a key factor for DR policy design. Thus far CCA rates have closely mirrored the benchmark set of rates offered by the IOU that serves load in the territory, but there is no guarantee this will persist. Because CCA have local boards and are not subject to the same regulatory oversight as IOU, there could be divergent sets of retail rates offered across the regions that reflect the particular goals, incentives and costs for the CCA. Whether this presents challenges for or helps catalyze achieving more effective price response is unknown and subject to the trajectory of CCA in California.

Will CCA be allowed to run DR and DER programs in parallel or on behalf of the IOU as the retail face of electricity consumption? In order for CCA to offer smart pricing programs, support

[43] These draw from "Community Coice Aggregation En Banc Background Paper" CPUC Staff, Feb 1 2017, available at: http://www.cpuc.ca.gov/general.aspx?id=2567

DER integration, and incentivize customer behavior to match a combination of bulk power and distribution system needs, tight integration with the hosting IOU may be needed.

10.3. Technology Development

Shift as Energy DR

A key concept to keep in mind for Shift market and technology development is that it is a resource with an energy-based, cumulative value, rather than a power-based capacity value, placing it in a separate category from conventional Shed DR. Unlike with Shed, where the value of a resource derives strongly from its reliability and usefulness in real-time dispatch, the value of Shift resources come from multi-hour changes and accumulate through the years. As more renewable electricity that would otherwise be curtailed is captured, the value increases.

The first order contours of the ideal Shift profile appear to be relatively simple and predictable (use less in the night and more in the day), suggests that there is a strong potential role for permanent load shifting and rescheduling efforts. In addition, notification with day-ahead price schedules could let loads with day-to-day flexibility optimize operation further. The current stock of conventional DR technology is fast enough to respond to these day-ahead signals, and may present a low-cost alternative to enabling new DR sites.

Shift DR could present high-value, low-cost opportunities because the notification time for system needs is sufficiently long. A technology development agenda for Shift could include:

- Study of how the existing stock of DR control technology could be adapted and modified to respond to bidirectional price and/or dispatch signals.
- Better understanding how a stack of Shiftable loads can be constructed that includes long-term load shifting / rescheduling for predictable shifts (night to day) with short-term dynamic flexibility to manage less predictable shifts (wind variability and hourly-timescale changes).
- Because Shift value is cumulative and not capacity-based, a different set of technology R&D targets from capacity DR are appropriate, suggesting in a sense a bifurcation of Shift from Shed and Shimmy DR. In particular, the reliability of Shed or Shimmy DR at times of binding system need are critical for creating value, but for Shift resources it could be possible to capture significant fractions of the potential value with slightly less reliable dispatch / price response. Work on pilots that are linked with market and electricity system modeling will be needed to identify the characteristics of technology for Shift, Shed, and Shimmy that are needed and help identify a development and deployment pathway.

Interoperability Standards for Plug and Play Grid

A significant barrier to achieving automation in California is the lack of interoperability in control technologies and communications platforms. Capitalizing on the Smart Grid infrastructure investments and the capabilities enabled by those investments requires significant integration of infrastructure elements. It is challenging to coordinate field devices, communication networks and management and control systems. Bringing together several different infrastructure systems to define an emerging DR capability means overcoming challenges including interoperability, standards and processes. Data from several disparate systems is needed to run a successful DR program. Additionally, the technologies' or processes' span or spectrum engages multiple stakeholders heavily dependent upon systems architecture and business perspective. Each business model requires a different analysis perspective although emanating from the same foundational data

In order to accelerate automated DR program and technology deployment, it would be helpful to develop a framework for interoperability standards that streamlines processes and flexibly addresses different business models and their attendant system architectures. The OpenADR Alliance has developed a set of standard data models for interoperable DR communications. For communicating devices, the ZigBee Smart-Energy Profile has been developed to create a standard and interoperable protocol that connects smart energy devices in the home to the Smart Grid. These standards assist in moving the market towards a plug and play grid, and facilitate the realization of AMI capital investments. We recommend that the CPUC continue to the use of an interoperability standards framework that can accelerate cost effective DR technology adoption and automated DR service capability provided to the grid.

Distribution System Automation

Distribution automation can be defined as automation used in distribution system planning, operation and maintenance, including transmission system, interconnected distributed energy resource (DER) and automated end-user interface communications. Automation can drastically improve visibility in congested areas, and facilitate DR program deployment and operation aimed at addressing congested local capacity areas. While distribution automation investments can be costly, they build upon the smart grid infrastructure and can provide greater visibility between end users and IOUs. Investments in distribution automation could potentially produce cost savings to ratepayers by reducing outages and advancing interconnected DER deployment that provide grid services in real time, helping to relieve congestion. These investments could be viewed as Virtual Power Plant (VPP) investments that address local capacity and DER integration issues.

Data Driven Decision Making

Using AMI data to target specific customer populations, end uses and technologies can help maximize the effectiveness of DR investments, including addressing customer churn issues. DR program business cases can be greatly improved by data analytics that couple utility demographic data, billing data and AMI data to identify customer populations that:

- Are less likely to move or opt-out of programs
- Provide the greatest load impact
- Are more likely to adopt technologies

Utilities have a tremendous amount of data that could empower the decision-making on investments in technologies and recruitment tactics to improve their DR portfolio performance. A genuine focus on developing the tools and resources for data analytics for customer targeting can improve DR investment performance and consequently benefits to ratepayers and the entities servicing them.

10.4. Opportunities and Recommendations for Future Research

10.4.1. Scenario Analysis

This category includes research topics that may build off the Phase 2 model results and/or capabilities but are largely new and/or separate analyses that are beyond the current model's functionality.

Time Varying Rates and Dynamic Pricing research

- Dynamic pricing programs are potentially some of the most cost effective methods to provide DR, particularly Shift. The IOUs are introducing new time varying rates that encourage load shifting and consumption as pilots, and it is important to incorporate customer responsiveness into our DR analysis, in particular when we examine the Shift service type. We suggest additional research on TOU, day-time super off-peak rates, CPP, variable peak pricing, and hourly day ahead real-time pricing scenarios along with testing the influence of automatically price-responsive devices on those approaches. This additional analysis permits examination of LMDR in a framework simultaneous with supply side DR and EE.
- We recommend that the IOUs undertake pilots that examine the impact of automated devices that respond to price signals dynamically to determine the effectiveness of automated DR enabling technologies and the incremental impact that technologies can provide in residential and commercial customer sectors.

Distribution System Level Benefits of DR

- The current DR potential study has provided limited insight on the value of DR at the distribution system level, rather, the study focused on bulk power system DR potential. Future work should utilize the methods developed in the current study and develop the capability to conduct the supply curve framework to constrained distribution feeders and assist in determining the value of DR to the distribution system. Key contributions are being made by other policy research that could be used to help focus investment in DR and DER broadly (e.g., DRP's LNBA and ICA outcomes and similar).

- Analyses that examine the impact of targeted DR customer recruitment for local capacity relief using granular customer and IOU distribution system data could identify potential load reduction within constrained distribution feeders from **targeted marketing** to particular residential, commercial, & or industrial customers. Optimized recruitment means more cost-effective capacity reduction where you need it most. Customers with higher kWh usage tend to have higher coincident peak load at system level- but what about distribution level?

Multi-DR Program Participation

- The current modeling framework analyzes the DR potential of given customers, end-uses, and technologies based on single-program participation. Analyzing DR potential in a multiple-program participation framework will allow us to understand the impacts such as a reduction in cost due to increasing the usage of enabling technologies or loss of DR potential for programs that may be competing for the same resources. This work will consider both technical impacts on the potential of DR as well as a review of policy and baseline issues. This analysis would significantly add to the capability of the current modeling framework and would require new modules, input structures, and accompanying analysis.

Unified IDSM potential model with EE and DR.

- The bottom-up modeling framework we developed could be augmented to estimate the joint potential for EE and DR among other DSM measures to serve the needs of the grid in a unified DSM potential framework. This analysis would be an expansion and improvement of the current "co-benefits" framework of evaluating IDSM. Further work is needed on evaluating what measures provide the best benefits of energy efficiency, DR, and integrated DSM systems. This work could also include site-specific impact analysis to evaluate various costs and benefits to individual customers.

Contingency Values of DR

- A key limitation of the current study is the omission of evaluating the value of emergency DR. Emergency DR can be thought of as voluntary or mandatory load reduction that is critical to maintaining stability in the bulk power system and is rarely called. This oversight impacted the results of the study by imposing an extremely low value of DR on a system that is not restricted by capacity. This analysis could examine the pros and cons of using RESOLVE to evaluate the value of DR, and will look to understand what other value streams exist and how we can best incorporate them into the modeling framework.

10.4.2. Model Enhancements

This category of priority topics includes work that improves the functionality, usability, and accuracy of the current model framework.

Public Tool, Model Training and Tutorials.

- A public tool that is based on production-level code could have a user interface for dynamic exploration of model inputs and/or tools for facilitating expert use of the software capabilities through an application programming interface (API). LBNL would collaborate with the CPUC and other stakeholders on the specific features of a public tool and the capabilities included in the code.

Expanded Study of Flexible Electric Loads

- The Phase 1 and Phase 2 study focused on loads that are highly likely to be significant contributors to the DR resource by 2025. Further analysis of other loads that could be significant in the future will help utility emerging technology programs focus on key areas of opportunity. These include: refrigerators and other large appliances, plug loads (residential and commercial), electric water heaters, thermal cool storage, electric space heaters, HVAC and variable frequency drives, and municipal water pumping.
- DR through Codes and Standards – The current study has only limited consideration of technologies in Title 24. Additional exploration of the role of T24 and new buildings in the next 10-15 years would help understand the role of new construction and the role of T24 retrofits of automated DR systems. There may also be opportunities to consider DR in Title 20.

Electric Storage Co-Benefits, Value and Use Beyond DR

- There is potential for many customers to install electric batteries to ensure the home or facility will have electricity if there is a grid outage. Others install storage to reduce peak demand charges, manage TOU rates, or optimize self-generation. Additional research is needed on the storage economics to consider DR within the other values that electric storage offers and conduct this analysis with storage as an IDSM system.

Additional Analysis by IOU

- The current study was developed to provide high level analysis capability to forecast the magnitude (MW) of future DR at the bulk power system and to value the system level DR using advanced valuation methodologies. Further work that evaluates each IOU independently could help develop customer sector specific analysis for each IOU.

Electrification Scenario Analysis

- Aggressive future electrification scenarios for California have been identified as a likely necessity for the state to meet its GHG goals, however the impacts of these scenarios on the baseline loads, and therefore DR availability, have not yet been studied. This analysis would involve altering baseline loads to capture increased penetration of electric end-uses such as water heating, cooking, and vehicles, and examining the resulting grid impacts and DR potentials.

Deeper Study of the Agricultural Sector's DR Potential

- The agricultural sector in California has been identified as one of the industrial sectors with very low participation rates and an untapped technical potential (see Olsen et al., 2015). Deeper study of the emerging technologies (e.g., advanced sensing and automation) could identify highly flexible VFD/pumping loads. This analysis can also tie into State initiatives on water-efficient technology demonstrations.

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Lawrence Berkeley National Laboratory

Phase 2 Appendices A – J

2025 California Demand Response Potential Study

Charting California’s Demand Response Future

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March 1, 2017

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Glossary of Terms

Additional Achievable Energy Efficiency (AAEE): Energy efficiency measures not accounted for in baseline forecasts. This study utilizes two efficiency scenarios, no AAEE and mid-AAEE, as calculated in the California Energy Commission's demand forecasts.

Advanced Demand Response: Demand response technology that provides services other than conventional load shedding, either shedding load at very fast timescales, bi-directional service, or energy shifting. Often includes "fast" telemetry and control with seconds-to-minutes resolution.

Advanced Metering Infrastructure (AMI): An integrated system of smart meters, communications networks, and data management systems that enable two-way communication between utilities and customers.

Aggregator: An intermediary between an energy supplier and its customers, providing the utility with demand response by spreading the request among multiple consumers.

Automated Demand Response (ADR): Demand response programs where a third party (e.g. utility or aggregator) is able to control customer's load for DR purposes. ADR involves installation of advanced control and communication programs where an automated signal from the dispatcher (e.g. utility) triggers a pre-defined response from the customer's end use.

Baseline: A prediction of the expected electricity consumption, for example for a building, in the absence of a DR event. Used both to forecast DR requirements, and to assess whether consumers met their DR targets.

Behind-the-Meter (BTM) Storage: Energy storage devices such as batteries that are on the customer's premise and metered electrical system. These devices are owned and operated by the customer or a third party that has been contracted by the customer. This is in contrast to utility- or grid-scale storage that is owned and operated by a utility provider.

Bifurcation (of DR): The splitting of DR resources into two distinct categories: load-modifying DR and supply-side DR, as accomplished by CPUC's recent Decision D.14-03-026.

Bottom-up modeling: In general, the piecing together of systems to give rise to more complex systems. In this study, the use of individual load profiles to form load estimates for all of California's IOU customers, which are then assessed at the cluster level to determine DR availability and costs, and eventually DR potential. This is opposed to a "top-down" approach where the state as a whole is examined and then progressively broken down into smaller subsets.

Buy-down: A colloquial term for revenue from "alternative" uses of a technology that reduces the effective cost of the technology as it is applied to a "core" purpose

California Independent System Operator (CAISO): The organization that manages California's electrical grid. (See: Independent System Operator (ISO)).

Capacity: A power rating for generation or DR. Often the maximum amount of power able to be supplied by the electric grid at any time. Other usages include: to describe peak net load, i.e. the maximum need for generation from dispatchable energy resources; to describe a service that reduces the maximum generation ability needed (e.g. "DR has the potential to provide capacity").

Cluster: A group of customers/sites that are assumed to be identical for the purposes of the analysis, with the same location classification, sector, building type, end-uses, enabling technology, and demographic profile, etc. Each cluster has a unique and specific time-series dataset for total load, end-use disaggregated load, and other site-specific time series data.

Co-benefits: Non-DR economic benefits of DR technologies. Examples include energy efficiency or participation in other revenue-generating activities (e.g. TOU price arbitrage with batteries).

Control technology: (See: Enabling Technology).

Conventional DR: DR common in California that is procured and dispatched to reduce system-wide load during peak day events. This is sometimes colloquially referred to as "hot-summer-day DR", as those are typically times of peak net load and therefore dispatch of conventional DR. Specifically, this term could refer to existing DR programs in California such as Proxy Demand Resource, Reliability Demand Response Resource, and Base Interruptible Program.

Cost-Competitive DR: (See: Cost-Effective DR).

Cost-Effective DR: Demand response resources that provide a service at a cost less than or equal to the cost of providing the same service with typical generation technologies. Here, the "cost" may refer to the gross cost of procuring the DR technology and administering the program or may refer to a net cost that takes into consideration market revenue, co-benefits, and other economic factors. In this study's results, the amount of DR that is considered cost-effective can be seen on a graph of a supply curve and demand curve as the value on the x-axis where the two curves intersect.

Cost-Effectiveness Protocols: Methods outlined by the California Public Utilities Commission to measure the costs and benefits of demand response. In this study, certain aspects of the cost-effectiveness protocols are utilized to make adjustments to the cost of DR resources.

Critical Peak Pricing (CPP): Price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours.

Curtailment (of renewables): When the power used from a renewable energy generation facility is significantly less than the amount that is being generated at that time. This involves "spilling" or wasting renewables due to system conditions such as low demand or transmission constraints.

Demand Curve: The relationship between an amount of a service needed and the amount an entity would be willing to pay for that service. In this study, is is the economic value provided to the grid by DR as a function of the quantity of DR supplied. Demand curves are able to show the often-reducing marginal benefit of DR in a defined manner. In other words, the "first" 500 MW of DR may be very valuable, but once you have 10 GW of DR the next 500 MW may provide little benefit.

Demand Response: A mechanism through which an end-use's load profile is changed (by the user, a third party, or a utility) in response to system needs, often in return for economic compensation (e.g., payments or a different rate structure).

Demand Response Auction Mechanism (DRAM): A pay-as-bid auction where sellers bid aggregated demand response directly into the CAISO day-ahead energy market. It was a pilot program run in 2015 and 2016 by California's three IOUs.

Dispatchable DR: (See: Supply-Side DR).

Distributed Generation: Power generated at the point of consumption, as opposed to a centralized plant. Often refers to distributed solar such as roof-top panels, but also includes other behind-the-meter generation technologies such as fuel cell systems.

Duck Curve: Term used to describe a net load curve with very low net load during the day followed by a steep ramping in net load to an evening peak. This pattern is undesirable for the electric grid, as it often results in curtailment of renewables during the day and the need for expensive generation with high ramping ability to meet the evening peak.

Economic Evaluation: (see Economic Valuation)

Economic Valuation: A comparison of the costs and benefits of a technology investment to assess if it is "economic" (the benefits outweigh the costs).

Enabling Technology: A set of on-site hardware and software that enables a particular end use or set of end-uses to provide DR service across one or more products.

End Use: A service performed using energy (e.g. lighting, refrigeration) or a type of energy-using devices (e.g. refrigerators, pool pumps). These end-uses, and their demand for electricity make up customer load.

End-Use Characteristic: A descriptor of the technical capabilities of an end-use load, in the context of demand response (e.g., ramp rate of agricultural pumping, response duration of commercial cooling).

Equilibrium Procurement Price: The price below which DR is considered cost-effective. This price will usually represent the cost of providing the DR service using an alternative generation or other technology.

Flat Rate: A customer electric rate structure where the price of electricity does not change depending on the time of day or season of the year. This is in contrast to TOU or CPP pricing programs.

Flexible Loads: End-use load that is able to change its demand profile for DR purposes. This may refer to the total load of the given end-use, or some fraction of that load that is able to be modified. For example, only half of a customer's HVAC load may be "flexible", as the portion providing the ventilation services may be required to stay on at all times.

Grid Services: (See: Service Type).

Independent System Operator (ISO): An organization that coordinates, controls, and monitors the electrical system of a particular geographic area. They are responsible for matching power generation with demand, managing wholesale energy markets, and providing access to transmission lines in a non-discriminatory fashion.

Investment-Operational Value: Estimation of DR value that includes both the cost of operating the alternative technology (such as a peaking generation plant) as well as the investment cost of procuring those technologies beyond the current resource in the system.

Investor-Owned Utility (IOU): A business organization providing utility service(s) that is managed as a private enterprise rather than a function of government or a utility cooperative. In this study, we use this term to refer to California's three IOUs: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric.

Levelized Cost: The long-run average cost of providing a unit quantity of service. In this study we typically define this in terms of a "magnitude-duration" pair (e.g., kW-year).

Levelized Value: The average value created by providing a unit quantity of service (see Levelized Cost)

Load Profile: A time-series of load values over a given period, with a corresponding load value for each increment (often hourly values for a calendar year).

Load-Following Service: (See: Shimmy).

Load-Modifying DR: A resource that reshapes or reduces net load of consumers. In this study, this refers to DR services provided by rate structures such as TOU and CPP. (See: Shape).

Load Serving Entity (LSE): An organization such as a utility that supplies electricity to customers.

Low-Bid Dispatch: A market where the possible suppliers submit bids, and the lowest price bids are dispatched in a "loading order" until the needs of the market are satisfied, or if the marginal value of additional service is lower than the next available bid.

Marginal Cost Bidding: A bidding strategy where the supplier is willing to provide service or products at a cost equal to the marginal cost of production

Monte Carlo Analysis: A technique used to understand the impact of uncertainty in forecasting models by repeated random sampling of values (within defined probability distributions) to be used as model inputs. In this study, we use Monte Carlo analysis to allow for uncertainty in the cost and performance metrics of enabling technologies.

Non-Dispatchable DR: (See: Load-Modifying DR).

Opt-In Rate: A rate structure made available to utility customers but not assigned by default. For example, a customer who has been on the same flat rate for many years may be able to opt-in to a TOU rate.

Opt-Out Rate: The rate structure used by a utility customer who chooses to not participate in the rate assigned to them by default. For example, a customer who is automatically switched to a TOU rate may be able to opt-out to their previous flat rate.

Overgeneration: The condition of the electricity system when there is more electricity being generated than there is demand for. This almost always is due to high generation of renewables (as conventional generation is dispatchable), and results in curtailment.

Peak Capacity: (See: Capacity).

Product: A defined set of demand-response characteristics that match particular system needs to the technical capabilities of responsive end uses. A product could be the basis for a market or requirements for program participation.

Propensity Score: The fraction of customers in a given subset (typically a cluster) that are expected to adopt DR. Here we refer to DR in the general sense, not any specific program or service type.

Regulation Service: (See: Shimmy).

Renewable Generation: (to point out that we often use the term to solely refer to solar + wind)

Sector: A market or population segment sharing common characteristics. For the purposes of this study, the relevant sectors are: residential, commercial, and industrial (which includes agriculture).

Service Type: Term used in this study to describe what we consider the four key capabilities of DR: Shed, Shift, and Shimmy (See glossary entries below). These are the categories within which all DR resources are aggregated and supply curves are generated. In other words, multiple DR Products exist under a single Service Type category. Service Types are also the categories for which the RESOLVE demand curve analysis was run.

Shape Resource: The umbrella term used to describe load-modifying resources analyzed in this study. This resource consists of TOU and CPP rate programs, and is analyzed separately from other resources (i.e. cluster end-use loads) as it affects the baseline load, does not fit within the propensity scoring framework, and does not require enabling technologies. The Shape resource is different from the "Service Types" in that it is not a grid service for which supply and demand curves are generated. Instead, it is a resource that is able to provide other DR services, namely Shift and Shed.

Shed Fraction: A metric for describing enabling technologies; it represents the fraction of end-use load that can be Shed (i.e. reduced) by the technology during a DR event. There are four Shed Fractions defined for each technology: Peak, 1-hour, 2-hour, and 4-hour, which capture the potential fatigue of end-uses when asked to shed load for longer durations. For example, a 4-hour Shed for a HVAC technology may be lower than it's peak-shed, because shedding the full amount for 4 hours would reduce the end-use's ability to serve its basic function.

Shed Service: A reduction in load that provides relief to the grid during times of peak demand. This service includes conventional DR products as well as the peak load reduction that is realized through Shape (TOU/CPP) resources.

Shift Service: An energy-neutral movement of load from times of peak demand (typically evenings) to times of very low net load (typically mid-afternoon when solar generation is high). This service benefits the grid by reducing peak load, reducing curtailment of renewables, and reducing evening ramping requirements.

Shimmy Service: Load that is able to follow a fast dispatch signal in order to either increase or decrease load in order to make real-time generation match demand. This service supports frequency and voltage management on the grid and reduces the need for conventional generation to provide these services. Shimmy service can be provided on either a 5-minute or 4-second dispatch signal, in which case it is referred to as Load Following or Regulation, respectively.

Supply Curve: Describes the relationship between the quantity of DR available and the lowest average cost to procure that amount of DR. It follows an increasing path, as there are small amounts of DR available for very low costs, but to procure large amounts requires a higher average cost overall. This curve can be layered with a demand curve or price referent to determine the amount of economically efficient DR available.

Supply-Side DR: DR that alters load from the expected baseline (as opposed to load-modifying DR), and can be integrated into CAISO markets. All DR analyzed in this study besides the Shape resources would be considered supply-side.

System Levelized Value: (See: Levelized Value).

System Optimization Modeling: (In the context of electricity systems) a techno-economic model that typically seeks to identify an optimal portfolio of investment and/or operational strategy for electricity system assets that minimizes the total cost of service provided.

Techno-Economic Modeling: A general term for mathematical models that combine elements of engineering and economic analysis.

Telemetry: An automated communications process by which measurements are made and other data collected at remote or inaccessible points and transmitted to receiving equipment for monitoring.

Time-of-Use Pricing (TOU): A rate design strategy with multiple levels of retail pricing where relatively high/low prices during predefined periods of time (typically sets of hours, by season) provide incentives to shift loads.

Time Varying Pricing (TVP): (See: Time-of-Use Pricing (TOU)).

Transactive Devices: Appliances and other behind the meter devices that support bidirectional communication related to control of the devices and typically include decision support that is based on real-time (often hyper-local) prices and price forecasts for electricity.

Value Benchmarks: Heuristic estimates of the value provided by a unit of service.

Appendix A: Methodological Overview

The task of designing and executing a demand response potential study for a range of future grid needs calls for developing new frameworks and analytic tools. In support of the 2015 California DR Potential Study, LBNL worked with our partners to design and implement a number of linked datasets and analytical models that collectively estimate the potential for DR. *Figure A-1* is a visual representation of the study, and serves as a guide to the reader to aid their navigation of these Appendices.

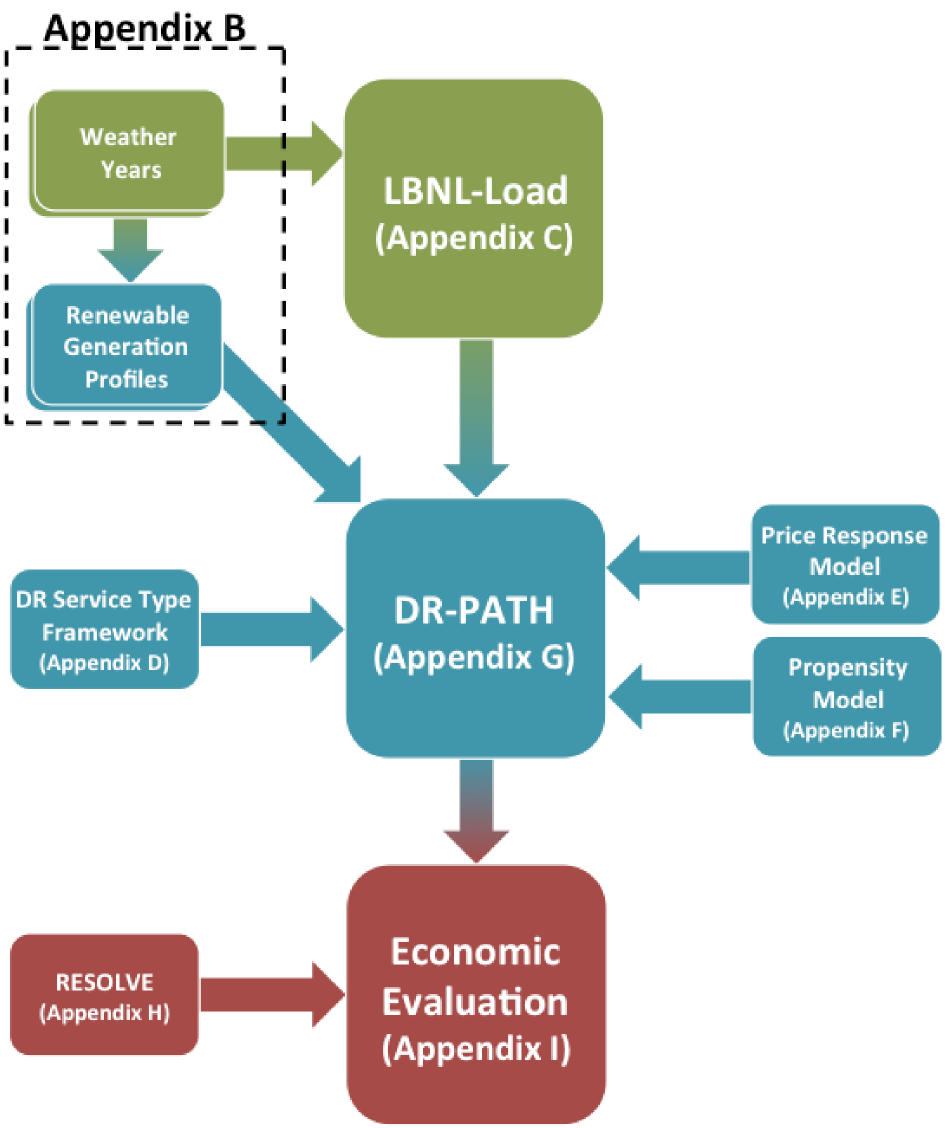

Figure A-1DR Future's methodology overview. Blocks represent major components and data flow by arrows.

The following paragraphs describe, at a high level, the contents of each appendix. Note that Appendix J, which contains a full list of Technical Advisory Group participants, is not represented in ***Figure A-1*****.**

Weather and Renewable Generation (Appendix B): Weather and renewable generation forecasts are a foundational component of the DR Futures model and are developed from 20 years of weather data from 54 weather stations in the IOU service territories. The renewable generation forecasts are for intermittent renewables sources (solar and wind), and were generated to match the weather years.

LBNL-Load (Appendix C): This model forecasts end-use level load profiles for "clusters" of customers. These customer clusters are based on demographic data for approximately 11 million customers, and their load profiles are based on interval meter data from 2014. LBNL-Load results in a set of forecasted baseline load shapes by end-use for thousands of representative clusters of customers that collectively represent the full population of customers in the study area.

DR Service Type Framework (Appendix D): In this study, we use a DR Product Framework to define and match these needs with the capabilities of DR resources, and a DR Service Type Framework to aggregate similar DR products and estimate the economic value they provide to the grid. We determine the quantity of DR service available using a bottom up analysis approach, matching the response and telemetry capabilities of specific enabling technologies and end uses with the response characteristics required to provide various grid services. We apply this framework to estimate the value to the grid procuring these services using DR resources.

Price Response Model (Appendix E): In this study, we assessed three TOU/CPP residential rate scenarios in addition to a flat rate scenario as a counterfactual baseline. Our Shape analysis is based on a model developed by Nexant to estimate of how retail pricing structure is expected to change load, based on pilots and past performance. We integrate these load impacts and translate them into magnitudes of effective Shed and Shift service. For the commercial and industrial customers, we used the predicted load impacts from a 2015 Christensen report, with TOU and CPP periods updated to reflect peak periods that occur later in the evenings.

Propensity Scores (Appendix F): A key feature of DR-PATH is estimating the likelihood of customer adoption for technology and DR program/market participation. Nexant Consulting, in collaboration with LBNL, developed a method for estimating the "propensity to adopt" DR based on a range of observable customer demographic variables and over a set of possible incentive levels. The outcomes of this analysis are used as a plug-in for DR-PATH.

DR-Path (Appendix G): DR-PATH applies a techno-economic model to estimate the potential for DR from specific DR enabling technologies that could provide service to the grid. The specific details on the costs for enabling DR technologies, end uses, and the load impact performance filters are detailed in this Appendix.

RESOLVE (Appendix H): E3's Renewable Energy Solutions ("RESOLVE") Model is an optimal investment and operational model designed to inform long-term planning questions around renewables integration in California and other systems with high penetration levels of renewable energy. RESOLVE co-optimizes investment and dispatch over a multi-year horizon with one-hour dispatch resolution for a study area, in this case the California Independent System Operator ("ISO") footprint.

Economic Valuation (Appendix I): The economic valuation methodology includes the value streams and adjustments to the DR costs, including the C/E protocol adjustments, that calibrate the Supply Curves to reflect the dynamics of cost and benefits streams in the DR market. The results of the economic assessments, when analyzed in conjunction with our DR supply curves, provide an indication of what quantity of DR is likely to be cost-effective given the calculated costs of the DR technologies.

Technical Advisory Group (Appendix J): A complete list of the technical advisory group (TAG) team members and their respective organizations.

Appendix B: Weather and Renewable Generation Forecasts

The weather and renewable generation forecasts are a foundational component of the DR Futures model. The weather forecasts are created from 20 years of data from 54 weather stations and built for regional variations for each of the clusters in the IOUs territories within the DR Futures model. We generate a "mild" (1-in-2) and "extreme" (1-in-10) weather forecasts that depicts the variance in DR potential that is dependent on weather. Rather than use a single year of historical weather for modeling, which fails to capture the range of possible conditions in any given month, it is better to produce two sets of weather predictions: one that represents a "mild" year and one that represents an "extreme" year. This section describes the process by which "mild" (1-in-2) and "extreme" (1-in-10) weather forecasts were derived for the 54 weather stations involved in the study. To maintain consistency, renewable generation forecasts that align with the 1-in-2 and 1-in-10 forecasts were also produced, which is also described in this section.

B-1. Weather Forecasts

Weather data was downloaded from weatherspark.com for all 54 NOAA stations for a 20 year period, from 1996 through 2015. The main variables of interest were temperature, cloud cover fraction, and wind speed. Because some weather stations did not keep complete information of these variables, especially in the earlier years and during late night/early morning hours, data was restricted to a 15 year period, from 2001 through 2015. Even then, there were some weather stations with significant data gaps. These gaps were filled by using a combination of techniques, as described below, which was repeated for gaps in temperature, cloud cover fraction and wind speed separately.

First, the data was subset into two equal and mutually exclusive samples by taking data from alternating days to create two datasets. This was done to ensure robust predictions of the missing weather. For the first of these two datasets, known as the in-sample dataset, the 2001 through 2015 weather variable of interest (either temperature, cloud cover fraction, or wind speed) for a particular weather station (the reference station) was regressed against the same variable for each of the other weather stations (the candidate stations) in sequence to generate regression models that could be used to make predictions. The model specification took the form of:

$$y_r = \alpha + \sum_{h=1}^{h=24} \beta_h * y_{h,c} + \sum_{m=1}^{m=12} \beta_m \quad \text{(B-1)}$$

In this equation, α is a constant and β_h is a coefficient that explains how the outcome variable of interest, y_r, changes with each unit of change of the candidate station for each hour h. For example, if β_h was equal to 2, and the regression was estimating a missing weather station temperature, the coefficient would indicate that for every degree Fahrenheit at the candidate station, the reference station would be twice as hot during that hour. By including β_m, the regression also takes into account the monthly average temperature at the candidate station, which allows predictions to vary according to the season.

Each of the models were then used to predict the reference station's weather, and the candidate weather station was selected based on choosing the candidate model that resulted in the lowest root mean squared error (RMSE) between the prediction and the out-of-sample (or withheld) days. For each reference weather station, the candidate weather station's data with the lowest RMSE was used to predict the missing data from the reference weather station. Root mean squared error is a measure of goodness of fit of an estimate, and is calculated according to the following formula:

$$RMSE = \sqrt[2]{\frac{\sum_{i=1}^{i=N}(\hat{y}_i - y_i)^2}{N}} \qquad \text{(B-2)}$$

Where N is the number of observations, is the estimated variable of interest, and is the observed value at the reference station. Large values of the RMSE indicate that there is a poor fit of the prediction, or a large difference between and observed values and predicted values. Because the difference between the predicted and observed variable is squared, RMSE does not take into account the directional bias of an estimate. Values of the RMSE for temperature ranged from 1.6 degrees to 5.7 degrees, with a median RMSE equal to 2.7.

This process reduced the number of missing data points by one to two orders of magnitude. However, in some cases both the reference station and the selected candidate station had a missing data point at the same time, so a prediction could not be generated. In these cases, which represented about 1% of total observations, a multi-level approach was taken to interpolate these missing values. For days with only one missing data point, the missing temperature value was calculated by averaging the prior and subsequent hour's temperature. For reference weather station days that had more than one missing data point at this point, the missing data was filled in by taking the average of the prior and subsequent days' temperature at the missing hour(s). This process was iteratively repeated 5 times, reducing the number of missing values by two to three orders of magnitude. The small number of data points that were still missing – approximately 0.001% of all observations – was interpolated using that day's average value.

For each weather station, the average daily temperature was calculated for each month of each year, which was then used to calculate the average CDD (cooling degree days) and average HDD (heating degree days) with a base of 65°F for each. These values were used to identify which years exhibited moderate and extreme weather conditions for each month. CDD values were used to classify the months of April through October, while HDD values were used for the remaining months. These values were then averaged across all of the weather stations.

The ex-ante weather forecasts were built by identifying individual months from different years that are representative of average and extreme conditions, and combining those individual months of weather data to create two full years (one for average, or 1-in-2, weather conditions and one for extreme, or 1-in-10, weather conditions). The year in which the median CDD/HDD value was observed for each month was identified, and the month of weather data associated with that year was used to build the 1-in-2 weather forecast. A similar process was used to identify the months that would build the 1-in-10 weather forecast, but by identifying the CDD/HDD values that fell in the 90th percentile rather than the median. The weather forecasts that were built for 1-in-2 and 1-in-10 conditions contained hourly temperatures, as well as hourly cloud cover fraction and wind speed.

B-2. Renewable Generation Forecasts

Renewable generation forecasts needed to be built that would match the weather forecasts. However, it was not possible to simply combine the historical renewable generation profiles that match up with the historical weather data in the 1-in-2 and 1-in-10 weather forecasts, since much of the renewable capacity in California had not yet been built in those historical periods. Instead, actual renewable data from 2013 to 2015 were used to build the generation forecasts.

To do this, each day in the ex-ante weather forecast was matched up with actual weather data from 2013 to 2015 for weather stations that were closest to major utility-scale renewable resources. Renewable generation profiles from the matched weather days were combined to produce 8760 generation profiles for the 1-in-2 and 1-in-10 weather years. For this, minute-level utility scale renewable generation data was pulled from the CAISO website, which breaks down utility-scale renewables into five different profiles: solar profiles for northern California, southern California, and central California and wind profiles for northern California and southern California. Based on the location of these resources, weather stations were mapped to these profiles as indicated by Table B-1.

Table B-1: Renewable Resources Weather Station Mapping

Renewable Type	Zone	Corresponding Weather Station
Solar	North (NP15)	Sacramento Exec. Airport
Solar	South (SP15)	29 Palms
Solar	Central (ZP26)	Meadows Field Bakersfield
Wind	North (NP15)	Livermore
Wind	South (SP15)	Edwards AFB

In order to account for the large increases in installed renewable capacities between 2013 and 2015, we first normalized the historical generation using monthly installed capacity. We derived the monthly installed capacities for the three-year period by linearly interpolating between the end-of-year annual installed capacities.[44]

Matching between the ex-ante forecasts and actual historic weather data was accomplished using a propensity score matching technique. In this process, certain weather metrics, called match variables, are calculated for each day of weather data for the ex-ante and historical weather datasets. The ex-ante weather data is first limited to only the weather stations listed in Table B-1. Then, each individual day from the ex-ante forecast is matched with the historical weather day that most closely resembles it based on those match variables by finding the historical day with the smallest aggregate difference in values for the match variables. In this study, the pool of historical days from which a match could be found allowed for individual historical days to be matched with multiple ex ante days (in other words, the matched historical days were not removed from the match pool after they were matched to an ex-ante day).

Match variables included daytime cloud coverage for solar weather stations and average daily wind speed and nighttime average wind speed for wind weather stations. Each day in the ex-ante weather forecasts was matched with the actual historical day that most resembled it within a three month rolling period that included the month containing the ex-ante day and the months immediately before and after. For example, an ex-ante day in April could be matched with a historical day in March, April, or May. Matches were restricted to days within a three-month period to ensure that solar profiles would match up with the sunrise/sunset times expected for that time of the year.

After matching up the ex-ante weather forecasts with the closest actual day in the period from 2013 to 2015, the hourly renewable profiles for the corresponding historical days were

[44] Source for annual installed capacities: http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html

combined to produce 8760-generation profiles for 1-in-2 and 1-in-10 weather years. The renewable generation profiles were then scaled to 2015 installed capacities to recapture actual MW output. Inter-day discontinuities in renewable generation (resulting from sudden changes going from midnight of one day to a nonconsecutive day, and mainly affecting the wind profiles) were smoothed out by using the rolling 3-hour average of the renewable profile between the hours of 10pm and 2am of each day, instead of the actual renewable output.

The final output consisted of four datasets—two sets of minute-level renewable generation profiles, a 1-in-2 profile and a 1-in-10 profile, and two corresponding sets of aggregated, 8760 renewable generation profiles that included both the smoothed generation profiles and the un-smoothed, actual output from the matching process. These forecasts represent utility-scale wind and solar generation that could be expected under the weather conditions of the 1-in-2 and 1-in-10 weather forecasts, respectively. Figure B-1 and Figure B-2 show the average daily generation profiles in the month of August for solar and wind, respectively, that are associated with the 1-in-2 and 1-in-10 ex ante forecasts. These figures sum up all of the various wind and solar resource zones, so they represent all utility-scale wind and solar in the state of California.

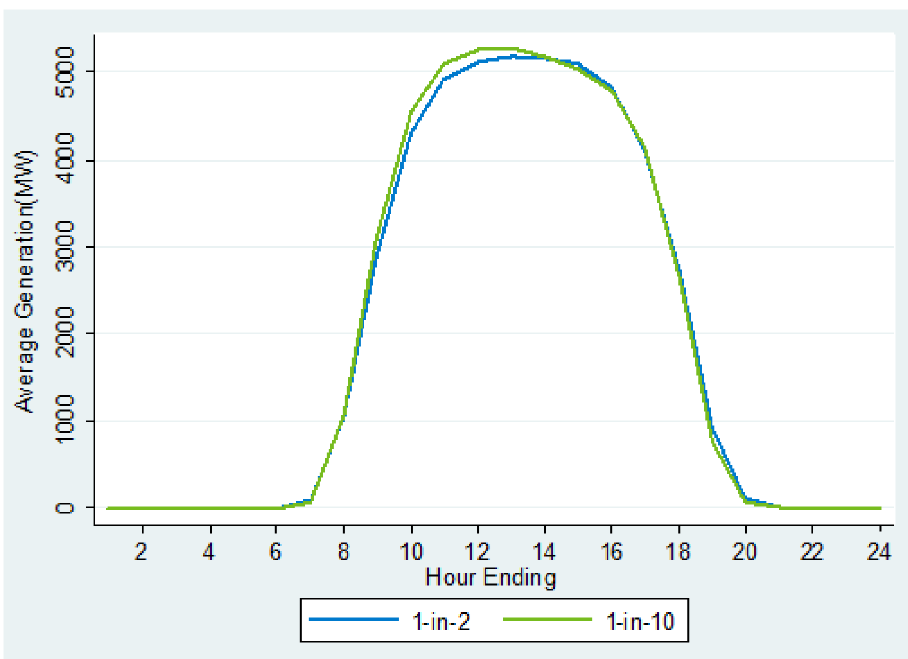

Figure B-1: Average Daily Solar Generation in August

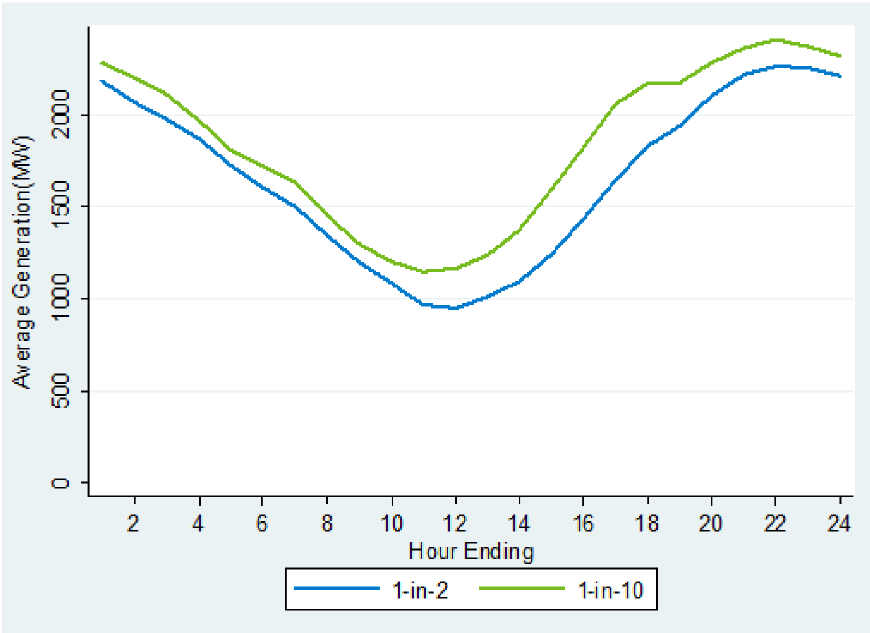

Figure B-2: Average Daily Wind Generation in September

Appendix C: LBNL-Load

This appendix describes LBNL's approach for forecasting end-use loads. Section C-1 describes primary data sources, section C-2 describes the aggregation of IOU customers into like-groups, or "cluster.", section C-3 describes methods for end-use disaggregation, and section C-4 describes how loads were forecasted to future years. Figure C-1 illustrates the overall analysis approach.

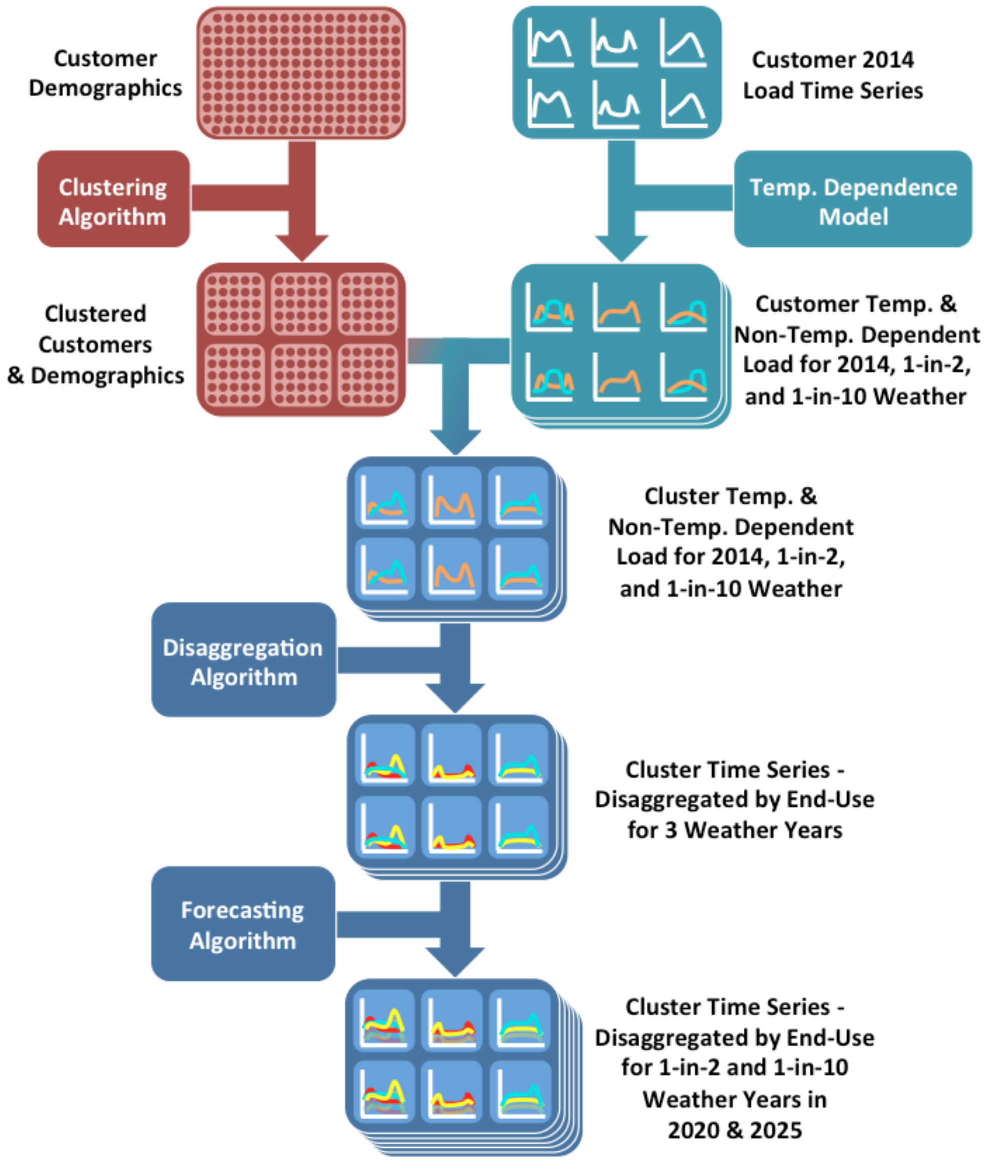

Figure C-1: LBNL-Load methodology overview.

C-1. Input Datasets

This section describes the source datasets used throughout the technical baseline methodology.

C-1.1. California Commercial End-Use Survey (CEUS)

The California Commercial End-Use Survey (CEUS) is a comprehensive study of commercial sector energy use (CEC, 2006). The latest survey was completed in 2006. It consists of energy use data and building characteristics from 2,790 commercial facilities in California. The survey is comprised of buildings from most regions, climates, and building types in California. Though the survey is a fraction of the number of facilities in California, it is believed to provide broad view of energy use in commercial buildings in California. Based on survey results, the CEUS data includes simulated hourly load profiles indicating the percent of commercial building loads attributable to individual end uses. We use these profiles to disaggregate commercial end uses from commercial building loads.

C-1.2. Manufacturing Energy Consumption Survey (MECS)

The Manufacturing Energy Consumption Survey (MECS) is a nationwide survey of energy use in the U.S. manufacturing industry (USDOE, 2010). The most recent survey was conducted in 2010. The survey provides a broad view energy use for most US industries, as classified by the North American Industry Classification System (NAICS). We use MECS to disaggregate industrial demand into process and non-process loads.

C-1.3. Residential Appliance Saturation Survey (RASS)

The Residential Appliance Saturation Survey (RASS) provides a broad view of appliance use and energy use in California residences (CEC, 2010). The last survey was conducted in 2009. It estimates the saturation of residential end uses statewide and for each of the IOUs. We use RASS to estimate the penetration levels of pool pumps installed in each of the IOUs.

C-1.4. NOAA Integrated Surface Database (ISD)

The Integrated Surface Database (ISD) provides historical hourly weather data for weather stations globally (NOAA, 2016). We use temperature data for 45 weather stations in California, selected to achieve geographic coverage across the state. The hourly weather data is combined with customer load data to estimate temperature-sensitive loads for residential customers.

C-1.5. Vehicle-to-Grid Simulator (V2G-Sim)

The Vehicle-to-Grid Simulator (V2G-Sim) (LBNL, 2016) is an LBNL tool for predicting vehicle-grid integration. We apply this model to predict total statewide electric vehicle (EV) demand in each hour of a typical week and weekend day for both commercially- and residentially-owned battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV). We also use V2G-Sim to predict 4-hour DR events at each hour of the day, in order to estimate the percent of load that could be shed without conflicting with mobility needs. Details of the tool are available at: v2gsim.lbl.gov.

C-1.6. Utility Demographics Files

For analysis specific to this study, the three California IOUs provided demographic information from nearly every customer in their service territories. The information provided includes annual energy use, peak power consumption (if available), and customer characteristics including ZIP code, rate class, and sector. This information was used to group (or "cluster") customers, as detailed in Section D-2.

C-1.7. IOU Customer Time Series

For analysis specific to this study, the three California IOUs provided hourly or 15-minute energy use data for approximately 100,000 residential, 78,000 commercial, and 25,000 industrial customers in their service territories. We use this data to predict customer end-use loads and temperature-sensitive customer loads in each utility service territory.

C-1.8. SCE Pool Pump Demand Response Potential Study

Reports on a survey of pool pump demand and pumping schedules in the SCE service territory (SCE, 2008). Includes average rated kW of pool pumps, and hourly pumping profiles indicating the percent of pumps on at a particular time of day. These results were used to estimate the energy demand for pool pumps, and the hourly shape of aggregate pool pump loads for residential clusters.

C-1.9. 2015 U.S. Gazetteer Files

The U.S. Gazetteer Files are data files released annually by the U.S. Census Bureau reporting geographic and census data at various geographic scales (US Census Bureau, 2016). Included in the dataset are latitude and longitude coordinates for U.S. ZIP Code Tabulation Areas. We use these as a proxy for ZIP codes, and used the centroid coordinates to locate the nearest NOAA weather station for each utility customer. We then used the weather data for the nearest weather station to estimate the temperature-sensitivity of residential and commercial loads.

C-1.10. 2015 IEPR Growth and Energy Efficiency Forecasts

The 2015 Integrated Energy Policy Report (IEPR). These data were collected from CEC staff and online at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03.

C-2. Customer Grouping

This section describes LBNL's approach to aggregate customers into like groups. The resulting groups, or clusters, represent the primary unit of analysis in this study. For this analysis, customers were grouped into clusters according to a set of characteristics that were selected to preserve the balance of geographic specificity and customer diversity while maintaining computational practicality. Section D-2.1 discusses characteristics were used for the clustering analysis, while Section D-2.2 describes the approach to generating the load profiles of the resulting clusters.

C-2.1. Grouping Characteristics

C-2.1.1. Sector

Customers were first grouped into residential, commercial, industrial, and "other" sectors based on the customer's rate class and NAICS code, if applicable. We identify residential customers by their rate class, commercial customers by NAICS code, and industrial customers by a combination of rate class and NAICS code, with the "other" sector including customers who did not meet the criteria for three primary sectors. We categorize Agricultural customers, as identified by their rate class, as a subset of the industrial sector.

C-2.1.2. Sub-Load Aggregation Points

California's Independent System Operator (CAISO) has defined 23 Sub-Load Aggregation Points (Sub-LAPs), which are geographic areas that divide the electric grid. Figure C-2 shows a map of the Sub-LAPs in California. PG&E's service territory is divided into 16 Sub-LAPs; SCE's service territory is divided into 6 Sub-LAPs; and SDG&E's service territory consists of one Sub-LAP. Sub-LAPs are the common unit at which day ahead load forecasting is done, and affect how loads can be aggregated into market bids.

Figure C-2: Map of sub-load aggregation point (sub-LAPs) in the CAISO. Brown areas are outside the CAISO (CAISO, 2010).

C-2.1.3. Building Type

Commercial customers are further clustered into the primary building types of interest for load disaggregation and DR: offices, retail, refrigerated warehouses, and "other". Offices and retail buildings are some of those most commonly targeted for DR programs, due to the flexible nature of the large HVAC and lighting loads. Refrigerated warehouses were included as a building type despite their low energy use as a fraction of the commercial sector, as past work identifies refrigeration loads as highly flexible because they are coupled with thermal storage. Lastly, "other" includes any buildings identified as commercial with NAICS classifications other than office, retail, or refrigerated warehouse.

C-2.1.4. Rate Class

While commercial customers are grouped by building type, residential customers are grouped by rate class. Customers on CARE rates are separated from those on standard rates. This is primarily to isolate the effects of pricing within clusters, as CARE customers react differently to price than non-CARE customers, and a lower price signal may affect their load profiles, annual energy consumption, and propensity to participate in DR programs.

C-2.1.5. Peak Load

Commercial and Industrial customers were also grouped by their peak annual load. Three static groupings were used: <50kW (small), 50kW-200kW (medium), and >200kW (large). For customers with no recorded peak load, their peak load was inferred using a linear regression model of all commercial and industrial customers with both annual consumption and peak load data.

C-2.1.6. Annual Consumption

Finally, within groupings of sector, Sub-LAP, and building type or rate class, the customers are evenly divided into clusters based on their annual electricity use. The number of clusters into which customers in a grouping are divided is dynamic, and based on the number of customers that match the sector, Sub-LAP, and building type or rate class criteria, as well as the number of time series available to represent that cluster. The maximum number of annual consumption clusters is 5, and the minimum is 1. For example, if grouping residential, non-CARE customers in the PGEB Sub-LAP results in 15,000 customers represented by 1000 hourly load profiles, they will likely be divided into 5 annual consumption clusters. Meanwhile, a Primary Metals industrial cluster in the PGNB Sub-LAP that has only 5 customers represented by 3 hourly load profiles will only be grouped into one annual kWh cluster, containing all 5 customers. This allows us to maintain a reasonable number of load profiles per cluster.

C-3. Temperature Dependence Model

C-3.1. Residential - Cooling

Cooling load is estimated using a three-parameter change point model, which is fitted to customer load data to identify and represent the relationship between outdoor air temperature and customer load (Walter, 2014). The form of the model is illustrated in Figure C-3, and is defined as follows:

$$\hat{y}(T) = \begin{cases} mT + b, & for\ T > T_{sp} \\ b, & for\ T \leq T_{sp} \end{cases} \tag{2}$$

Where $\hat{y}(T)$ is the estimated customer load at temperature T, and the parameters of the model include:

1. Set point temperature (T_{sp}): the temperature at which customers begin cooling; in other words, the temperature set on a customer's thermostat.
2. Temperature sensitivity (m): the incremental increase in load (kW) associated with an increase in temperature.
3. Base load (b): approximate magnitude of customer load when cooling load is zero.

We use a grid search to fit a model for set point temperatures T_{sp} ranging between 60 and 90 F (in increments of 5 F). For each set point temperature, we estimate base load by taking the mean load across hours where outdoor air temperature is below the set point temperature, and use least squares regression to estimate the temperature sensitivity of load during hours where outdoor air temperature exceeds the set point temperature. We evaluate the parameters m and b for all set point temperatures, and select the model with the smallest sum squared error ϵ, defined as follows:

$$\epsilon = \sum_{all\ hours}(\hat{y}(T) - y)^2 \tag{3}$$

Where y is the customer's reported time series data.

Once a model is developed, we evaluate whether or not the model indicates significant temperature sensitivity. For customers with low temperature sensitivity ($m \leq 0.01\ kWh/F$), we assume no cooling load. For customers with high temperature sensitivity $m > 0.01\ kWh/F$, we estimate cooling load as follows:

$$Cooling\ Load(T) = \begin{cases} mT, & T > T_{sp} \\ 0, & T \leq T_{sp} \end{cases} \tag{4}$$

Linking Equation 3 with hourly temperature data, we predict hourly cooling load for each customer. We compute cooling non-cooling load by taking the difference between total load and estimated cooling load, subject to the following constraint:

$$Cooling\ load_i \leq 0.9 \times Total\ load_i \text{ for all hours } i \tag{5}$$

In hours where this constraint is not met, we fix $Cooling\ load_i$ in that hour at 90% of total load in that hour. Using the resulting model, we can generate an hourly cooling load profile for each customer using any hourly temperature profile.

To estimate cooling load for a cluster, we sum cooling loads for all customers in the cluster. We then scale the resulting values using the same adjustment factors as are applied to the total cluster loads.

For the 1-in-2 and 1-in-10 weather scenarios, we assume non-temperature sensitive load to be the same as we compute for 2014. To estimate cooling load, we predict $Cooling\ Load(T)$ using Equation 4, with different input temperature profiles (T) for each scenario.

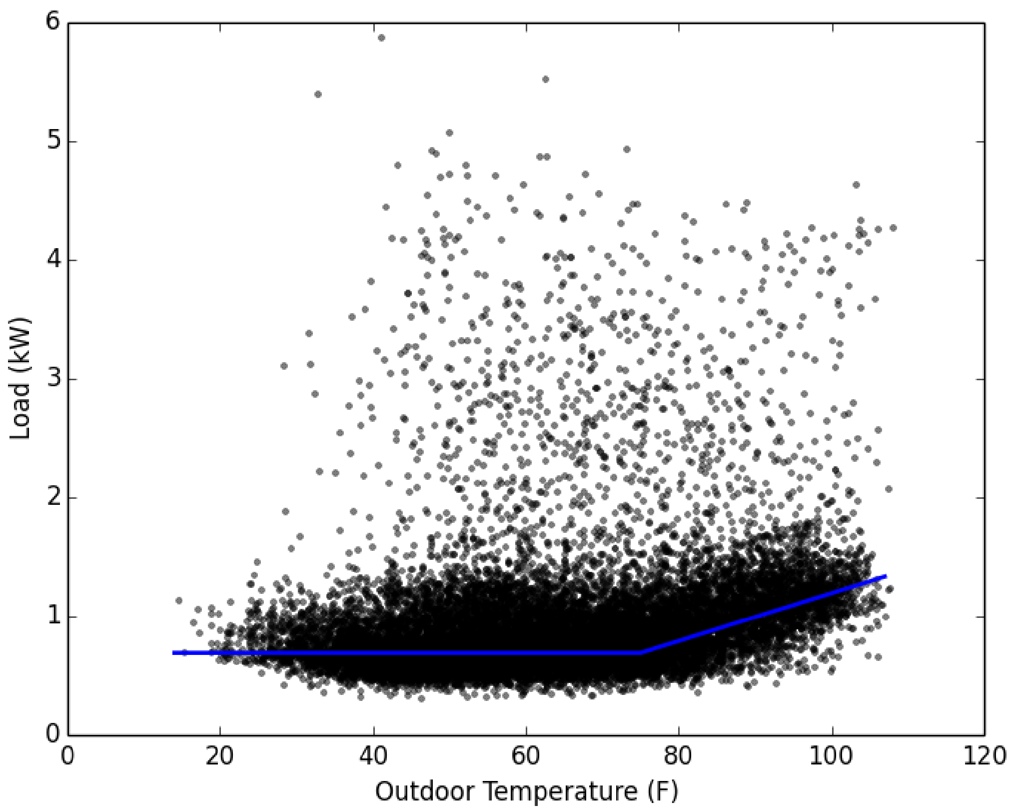

Figure C-3: Illustrative example of change point model for estimating temperature-sensitivity of customer load.

To estimate cooling load for a cluster, we sum cooling loads for all customers in the cluster. We then scale the resulting values using the same adjustment factors as are applied to the total cluster loads.

For the 1-in-2 and 1-in-10 weather scenarios, we assume non-temperature sensitive load to be the same as we compute for 2014. To estimate cooling load, we predict $Cooling\ Load(T)$ using Equation C-4, with different input temperature profiles (T) for each scenario.

C-3.2. Commercial - Heating and Cooling

Similar to residential cooling, we fit a change point model to identify temperature-sensitive loads in commercial buildings. We expand the model presented in Section XX to include both heating and cooling. The form of the model is given by Equation C-5: Similar to residential cooling, we fit a change point model to identify temperature-sensitive loads in commercial buildings. We expand the model presented in Section C-3.1.1. to include both heating and cooling. The form of the model is given by Equation 7:

$$\hat{y}(T) = \begin{cases} m_1 T + b, \ for\ T > T_{sp,cool} \\ m_2 T + b, \ for\ T < T_{sp,heat} \\ \qquad\quad b, \ for\ T_{sp,heat} \leq T \leq T_{sp,cool} \end{cases} \tag{7}$$

where $\hat{y}(T)$ is the estimated load at temperature T. Heating and cooling set point temperatures, $T_{sp,cool}$ and $T_{sp,heat}$ respectively, are determined using a grid search for all combinations of temperatures between 50 and 70°F for heating, and between 60 and 90°F for cooling. We choose the set point temperatures that minimize overall prediction error ($\hat{y} - y$), where $\hat{y}$ is computed based on temperature data coincident with the available interval data. We assign a minimum temperature-sensitivity threshold of 0.1% increase in load ($\hat{y}(T)$) per °F. Customers whose heating and/or cooling coefficients (m_1 and/or m_2) are below that threshold are assumed to have no heating and/or cooling loads.

Once the model coefficients and set point temperatures are selected, we compute the temperature-dependent load by predicting load for a given annual weather profile, and subtracting the base-load b.

These methods are applied to identify retail and office buildings with heating and/or cooling loads. We assume refrigerated warehouse loads to be largely independent of temperature; thus their temperature-dependent loads are assumed to be zero.

For the 1-in-2 and 1-in-10 weather scenarios, we assume non-temperature sensitive load to be the same as we compute for 2014. To estimate temperature-sensitive loads, we make predictions for $\hat{y}(T) - b$ using Equation 7 with different input temperature profiles (T) for each scenario.

Once the model coefficients and set point temperatures are selected, we compute the temperature-dependent load by predicting load for a given annual weather profile, and subtracting the base-load b.

These methods are applied to identify retail and office buildings with heating and/or cooling loads. We assume refrigerated warehouse loads to be largely independent of temperature; thus their temperature-dependent loads are assumed to be zero.

For the 1-in-2 and 1-in-10 weather scenarios, we assume non-temperature sensitive load to be the same as we compute for 2014. To estimate temperature-sensitive loads, we make predictions for $\hat{y}(T) - b$ using Equation 7 with different input temperature profiles (T) for each scenario.

C-4. Cluster Load Profile Aggregation

Once clusters have been defined, all customers in the IOU demographics files have been assigned a cluster, and a temperature dependence model has been fit to all time series, we aggregate the hourly temperature dependence and non-temperature dependent load time series available to estimate the cluster's load shape. To do so, we add all time series data available for customers in each cluster and scale the aggregate load profile so that the total annual load of the cluster time series agrees with the aggregate load for all customers in the cluster, as calculated using the IOU-provided customer demographics data.

C-5. End Use Disaggregation

C-5.1. Residential

We consider three end-uses for residential customers: cooling, pool pumps, and plug loads. Although other end uses are viable candidates for DR, we chose to focus on these end uses for this study.

C-5.1.1. Cooling

Cooling load is determined at the customer-level by the change-point model described earlier. The cooling loads determined for each customer time series are then aggregated to approximate the cooling load of the cluster.

C-5.1.2. Pool Pumps

Pool pump loads are estimated at the cluster level. We estimate the penetration of pool pumps in residential clusters for each IOU using RASS saturation estimates for the IOU (Table C-1). We use these values to estimate the number of pool pumps in a cluster, and estimate the coincident pool pump load using an average pump capacity of 1.4 kW (SCE, 2008). We then apply results from SCE 2008, shown in Figure C-4, to determine the fraction of pumps operating during each hour in the day.

Table C-2: Swimming pool saturation across IOU service territories. (RASS, 2009)

Utility	PG&E	SDG&E	SCE
Fraction of customers with a swimming pool	0.09	0.11	0.12

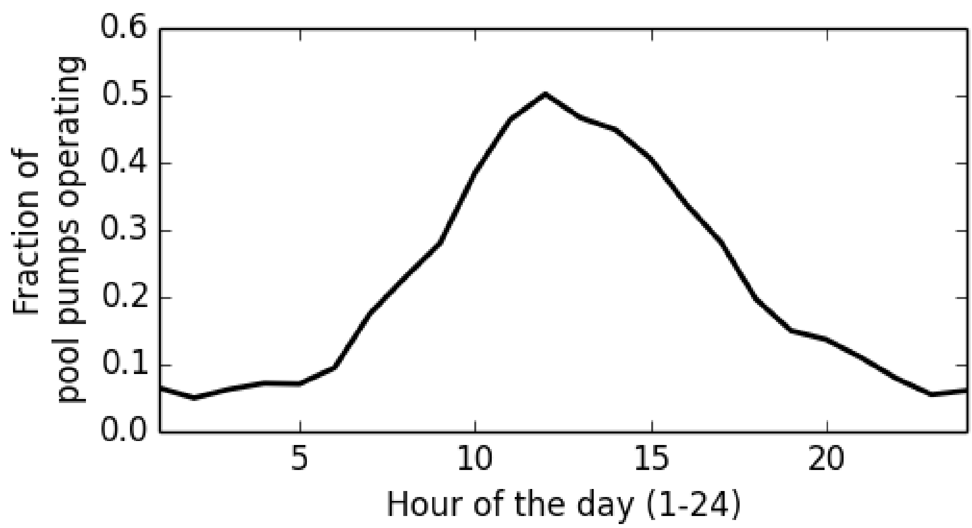

Figure C-4: Diurnal hourly shape of pool pumping load. (SCE, 2008)

C-5.1.3. Plug Loads

Plug loads are not readily observable, because sources of the load are not linked with specific environmental factors (e.g., temperature), and they do not follow fixed usage schedules (as do pool pumps). To estimate plug loads, we first compute unassigned load, defined as follows:

$$Unassigned\ load = Total\ load - cooling\ load - pool\ pump\ load \qquad (6)$$

We then assume that plug loads constitute 30% of unassigned load (RASS, 2009). Currently, we consider plug loads to be devices enabled for DR using smart strip technology. As such, small and large appliances are not included in the plug load estimate.

C-5.2. Commercial

We classify commercial buildings into building types based on their NAICS code: retail, office, refrigerated warehouse, and "other". The present study focuses on DR potential in retail and office buildings because they constitute the largest portion of commercial loads and are already readily targeted for DR. We also examine refrigerated warehouses because refrigerators provide large thermal storage reservoirs, making refrigeration loads very flexible. The following sections describe our methodology for estimating the breakdown of customer loads by end use. For retail and office buildings, we consider HVAC and lighting loads, where HVAC includes electric heating, cooling and ventilation. For refrigerated warehouses, we consider refrigeration and lighting loads.

C-5.2.1. Temperature-sensitive loads: heating and cooling

Heating and cooling loads are determined by the temperature dependence model described earlier in this appendix.

C-5.2.2. Non-temperature-sensitive loads: ventilation, lighting, and refrigeration

Non-temperature-sensitive loads are estimated using daily breakdowns of commercial loads available as part of the CEUS dataset (CEC, 2003). Daily breakdowns are available by climate zone, building type, and for weekends and weekdays. Using these daily profiles, we piece together an annual percent breakdown of customer loads into ventilation and lighting (for retail and office buildings), and refrigeration and lighting (for refrigerated warehouses).

To estimate the contributions of each end use, we filter to the customer's non-temperature-sensitive load using the annual end use breakdown specific to each customer's climate zone and building type. For customers with no temperature-sensitive load, the non-temperature sensitive load is equal to total load. For retail and office buildings identified as having no heating or cooling loads, we assume ventilation load is also zero. Finally, for office and retail buildings, we report an aggregate HVAC load, comprised of heating, cooling, and ventilation loads.

Once the relevant loads are computed (HVAC and lighting for office/retail buildings, and refrigeration and lighting for refrigerated warehouses), we assign the remaining uncategorized loads as "other". These loads are carried through our analysis to aid in identifying hourly and peak system load, but are not taken to be viable candidates for DR. As DR-enabling technologies evolve, end uses and building types currently classified as "other" can be integrated into our model.

C-5.3. Industrial

C-5.3.1. Manufacturing

The manufacturing subsectors included in our analysis are:

- Petroleum Refining and Related Industries
- Food Manufacturing, Beverage and Tobacco
- Chemicals - Industrial Gases
- Chemicals - Other
- Computer and Electronic Product Manufacturing
- Plastics and Rubber Products Manufacturing
- Primary Metals

The annual load profiles generated for the clusters of these subsectors are disaggregated at a coarse level by leveraging the national MECS dataset (MECS, 2010). MECS provides a breakdown of the energy inputs, and their associated end uses, for various manufacturing industries. MECS categorizes end uses as process and non-process, and has further breakdowns within these two groupings. For our analysis of the industrial sector, the process vs. non-process distinction provides sufficient resolution.

These energy breakdowns are at the annual consumption level, giving no information about the seasonal or daily distribution of energy use for the different end uses. As such, the annual consumption values for process and non-process loads are calculated as a fraction of the total load from the MECS dataset for each industry. These disaggregation fractions are then multiplied by every hour of the year in the industry's load profile.

C-5.3.2. Agriculture - Crops

The primary end use of focus in the agricultural sector is the electrical pumping load required for irrigating crops. Since very little work has been done to quantify and represent the pumping load patterns of on-farm irrigation loads, a coarse estimate was made that 80% of an agricultural customer's load is due to pumping at all hours of the year.

C-5.3.3. Water & Wastewater

The water and wastewater subsectors are comprised of a number of end uses, including water pumping, aeration, and centrifuges. An estimate that 75% of total facility load is due to DR-capable process loads was made based on past research (Olsen, 2012). This fraction was applied for every hour of the year.

C-5.3.4. Data Centers

The Information Technology (IT) and IT-related cooling loads in large data centers are estimated to consume 75% of the facilities total load (Ghatikar, 2012). As very little research has been done studying the temporal pattern of end use loads in large data centers, this fraction is applied for every hour of the year to estimate the IT-related loads available for DR events. The other 25% of load includes support end uses such as lighting and uninterruptible power supplies.

C-6. Load Forecasting

Once 2014 cluster load profiles are generated for the actual 2014 weather, we generate simulated load profiles for the 1-in-2 and 1-in-10 weather years, as described above. Then we forecast load growth out to 2020 and 2025. Load growth includes increasing both the customer population and electricity demand, and the introduction of new end uses. The following sections describe methods for forecasting load growth by cluster.

C-6.1. The 2015 IEPR Mid-Demand Growth Scenario

In Phase 1, a "frozen efficiency" assumption was used to forecast growth in the Residential and Commercial sectors, while the California Energy Demand Forecast was used to grow Industrial loads. In Phase 2, the clusters are forecasted using load growth assumptions from the 2015 IEPR's Mid Demand Growth Scenario, which was most widely accepted by stakeholders as a reliable forecast and would ensure the assumptions in this Demand Response Potential Study align with other energy and policy planning exercises. Table C-3 shows a summary of the load growth forecasts from the Mid Demand Scenario.

Table C-3: Summary of 2015 IEPR Load Forecast for the Mid-demand growth scenario, by sector, utility, and year.

Utility	Year	Annual Consumption (GWh)							
		Residential	Residential EV	Commercial	Commercial EV	Manufacturing	Agricultural	Other	Total
SDG&E	2014	7661	13	9816	21	1457	353	2155	21442
	2020	7948	114	10602	92	1434	354	2233	22572
	2025	8691	410	11157	156	1428	349	2279	23904
PG&E	2014	31610	44	36457	110	16535	8954	9870	103426
	2020	33567	461	38847	389	16607	9816	10030	108867
	2025	36953	1705	40868	658	16610	10169	10427	115027
SCE	2014	32836	39	39096	79	17355	8272	9032	106590
	2020	34206	403	41223	326	17274	11246	9300	113250
	2025	37121	1469	42951	556	17240	11390	9554	118256

C-6.2. Additional Achievable Energy Efficiency (AAEE)

The Mid Demand Scenario described above includes the forecasted impacts of "committed" energy efficiency measures, which are approved, finalized, and funded initiatives. However, additional energy efficiency initiatives are likely to begin and be implemented between now and 2020 and 2025, these initiatives and their impacts are referred to as Additional Achievable Energy Efficiency (AAEE). AAEE impacts are deemed reasonably expected to occur in the forecast period. This study includes a set of scenarios that incorporate the Mid AAEE scenario's impacts into the forecasting step, which are summarized in Table C-4. These are typically denoted "MidAAEE", as opposed to the forecasts that include only committed EE measures, which are denoted as "NoAAEE".

Table C-4: Summary of Mid AAEE load impacts (reductions), by utility, year, and sector.

Utility	Year	Forecasted Annual AAEE Load Reductions (MWh)				
		Agriculture	Commercial	Residential	Industrial	Other
PG&E	2020	101,188	1,830,012	1,307,146	263,012	60,507
	2025	402,096	3,597,038	2,262,535	533,837	104,671
SDG&E	2020	11,031	492,580	370,810	43,291	8,516
	2025	22,480	971,113	632,734	89,326	14,390
SCE	2020	62,694	2,231,418	1,437,832	310,662	160,697
	2025	126,193	4,514,904	2,492,203	626,975	234,221

C-6.3. Electric Vehicles

We estimate aggregate EV demand for all of California using vehicle adoption forecasts, California Clean Vehicle Rebate Project (CVRP) rebate data and EV owner surveys, and LBNL's Vehicle-to-Grid Simulator (V2G-Sim). We then distribute this demand amongst the clusters first geographically, according to state rebate data, then proportional to total annual consumption (kWh).

C-6.3.1. Estimating statewide demand

LBNL's Vehicle-to-Grid Simulator[45] (V2G-Sim) is used to estimate the hourly demand curve associated with future EV adoption. Inputs to V2G-Sim specific to this study are summarized in Table C-5. We utilize CEC forecasts to estimate statewide adoption of battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV) for high, mid, and low cases in 2020 and 2025 (CEC, 2014). EV adoption totals for the mid-case are shown in Table C-6. Vehicles were disaggregated as either individually- or commercially-owned using EV rebate data[46] collected from the California Clean Vehicle Rebate Project (CVRP) (CCSE, 2015). This disaggregation is important to allow V2G-Sim to predict the location of vehicle charging, so that we can then assign demand to residential and commercial clusters accordingly.

Table C-5: Statewide EV demand forecast assumptions.

Input	2025 Assumption	Source
Total number of BEV and PHEV in state	See Table D-5	CEC 2014-2024 Demand Forecast
Distribution of EV that are individually vs. commercially owned	98% of PHEV and 96% of BEV owned by individuals	CVRP state rebate data
Owners with Level 2 charging	Commercial: All Individuals: 46% of PHEV, 88% of BEV	CVRP survey
Individuals who charge at work on an average day	25%	Estimated from CVRP surveys

In addition to rebate data, the CVRP conducts periodic surveys of EV owners (CCSE, 2013). Data from these surveys were used to develop assumptions about the portion of EV owners with Level 2 charging stations and the number of EV owners who charge at their place of work on a given day. Charging level impacts the power demand and required duration of charging sessions, and was reported by the 2013 survey as Level 2 for 46% of PHEV owners, and 88% of

45 V2G-Sim models the driving and charging behavior of individual PEVs to generate temporally- and spatially-resolved predictions of grid impacts and opportunities from increased plug-in electric vehicle (PEV) deployment. (http://v2gsim.lbl.gov/)

46 CVRP data contains information on all alternative fuel vehicle rebates claimed in California since March 2010, including: owner type, vehicle category, ZIP code, and other information such as vehicle make and model.

BEV owners. For commercially owned electric vehicles and individual vehicles being charged at their place of work, we assume all charging takes place on Level 2 charging stations. The distinction of individually owned vehicles charging at work allows us to allocate the appropriate demand to commercial clusters. CVRP surveys report (1) the number of owners who have access to workplace charging (2) the portion of those with access for whom charging is free and (3) the frequency with which owners with free or paid charging charge at work. Using this information from the March 2012, October 2012, and May 2013 surveys, we estimate that in 2020-2025, approximately 25% of EV owners will charge at work on a given day.

Table C-6: California EV adoption forecast. (CEC, 2014)

Year	BEV	PHEV	Total
2015	30,478	195,466	225,943
2020	119,936	1,198,909	1,318,845
2024	340,013	2,009,710	2,349,722
2025*	395,032	2,212,410	2,607,441

**extrapolated*

Accordingly, the V2G-Sim model predicts aggregate hourly demand profiles for an average weekday and average weekend for six vehicle types: residentially-owned BEV and PHEV charging at "home" and "work" locations, and commercially-owned BEV and PHEV charging at their "home" location. We then use these to create six 8760-hour single-vehicle demand profiles. Weekday demand results for the 2025 mid-case are shown in aggregate in Figure C-5, and for a single average vehicle in Figure C-6.

C-6.3.2. Cluster-level EV demand

For each EV rebate claimed in the state, CVRP data provides the owner's utility provider and zip code. This information allows us to disaggregate statewide EV estimates into each Sub-LAP in the three IOUs. This allocation is computed for each owner type (individual vs. commercial) and vehicle type (BEV vs. PHEV). To account for geographical variation in rebate participation, and therefore bias in CVRP data, each rebate in the CVRP database is weighted by its county's estimated participation rate (Williams et al., 2015). Results for the allocation of PHEV and BEV across state utilities and owner types are shown in Table C-7.

In a given Sub-LAP, the total number of individually owned EVs is allocated to the residential sector, and the number of commercially owned EVs is allocated to the commercial sector. Additionally, 25% of the individually owned EV count in a given Sub-LAP is allocated to the commercial sector in that Sub-LAP to represent individually owned EVs charging at the owner's work location. The number of EVs in each sector and sub-lap is then allocated to individual clusters proportional to the cluster's total annual load. We assume no variation in propensity to adopt EVs between customers in various building types or rate categories. This results in a count of BEV and PHEV for each residential cluster, and a count of site-owned BEV and PHEV as well as "employee"-owned BEV and PHEV for each commercial cluster. These counts are multiplied by the appropriate single-vehicle load profiles to determine the cluster's total EV load.

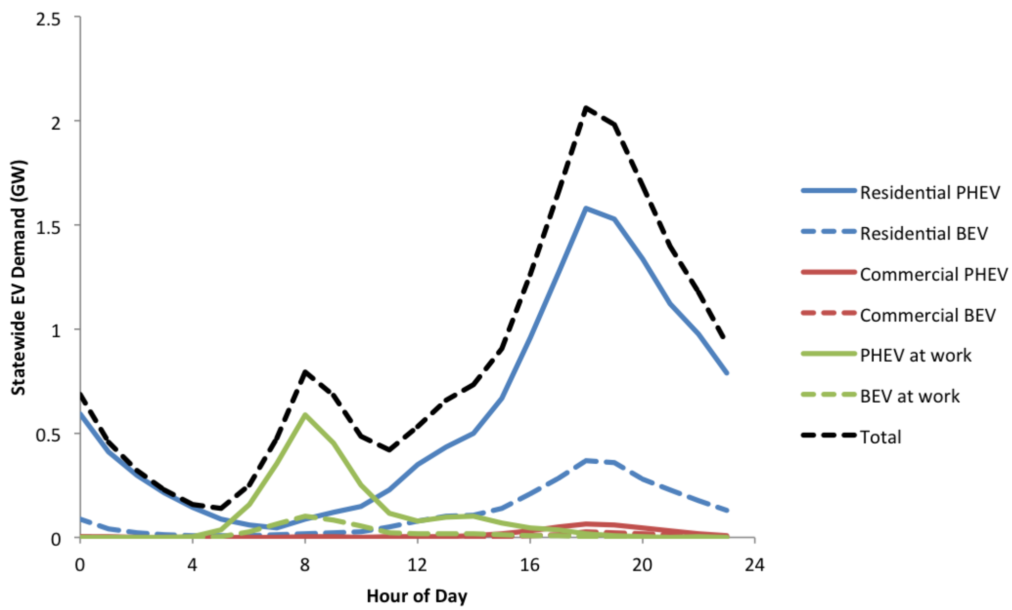

Figure C-5: 2025 Typical weekday California EV demand for six vehicle charging categories

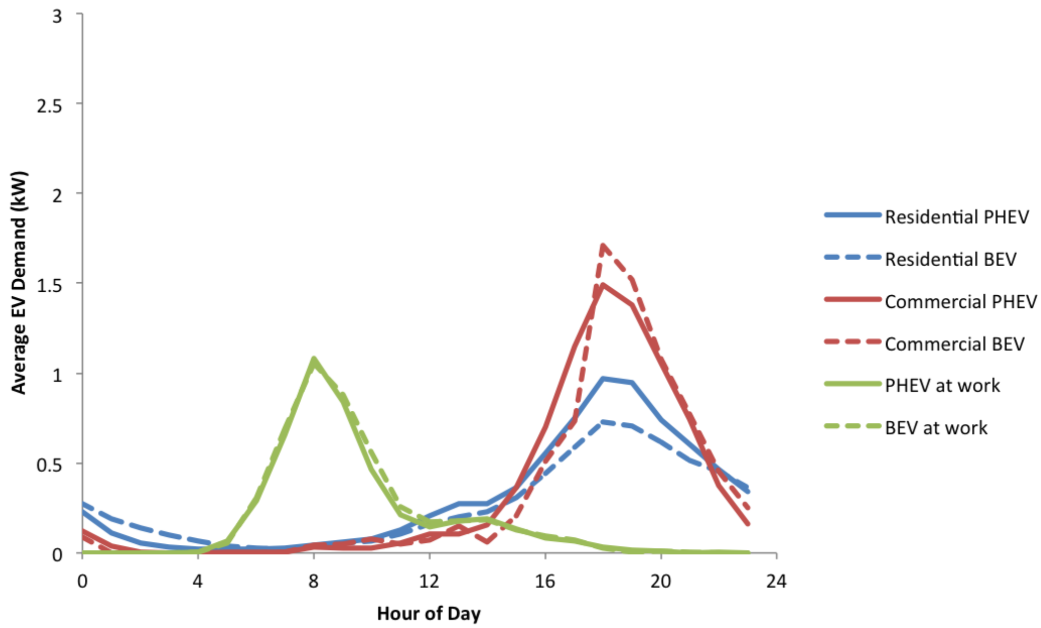

Figure C-6: 2025 typical weekday average per-vehicle demand for six vehicle charging categories

Table C-7: Portion of statewide EV totals in each utility by owner type.

(a) PHEV

Utility	Individual (Residential)	Commercial	Total
PG&E	36%	1%	36%
SCE	34%	1%	35%
SDG&E	9%	0%	9%
Other	19%	1%	20%
Total	98%	2%	100%

(b) BEV

Utility	Individual (Residential)	Commercial	Total
PG&E	46%	1%	47%
SCE	23%	1%	24%
SDGE	10%	1%	11%
Other	17%	1%	18%
Total	96%	4%	100%

C-6.4. Batteries

Behind-the-meter (BTM) batteries offer a potentially flexible resource capable of providing multiple DR products and other economic benefits (e.g. TOU price arbitrage, demand charge reduction). For this study, we assume that a customer installs batteries for the sole purpose of providing DR benefits. We are thus implying that (1) BTM batteries are available to provide DR at all hours of the day and (2) the full cost of the battery is borne by the DR program. Technically, any capacity of batteries could be purchased and operated solely for DR purposes in this way. Despite this, we chose to estimate a hypothetical installed battery capacity to aid in cost calculations, and to demonstrate a reasonable level of potential capacity. We do so by first assigning a "maximum practical" installed battery capacity (kWh) to each customer cluster, as described in the following section, and assuming the state of the battery's power (kW) availability.

C-6.4.1. Sizing methodology

We estimate a hypothetical battery capacity for California by first assuming that every customer installs a battery that is similar in size to batteries currently used for common non-DR applications. For residential customers, it is common for batteries to be paired with the installation of solar photovoltaic panels. Currently, batteries marketed towards residential consumers come in a somewhat narrow range of capacities: 6.4 kWh for Tesla's Powerwall

(Tesla, 2016) and 4 kWh-16kWh for sonnenBatterie's Eco (sonnenBatterie, 2016). For this study, we assumed a maximum practical battery capacity of 7 kWh for every residential customer.

For commercial and industrial customers, a common non-DR battery application is management of peak demand electricity charges. We estimate the potential capacity of these batteries using a methodology proposed by NREL in a 2015 Technical Report (Neubauer and Simpson, 2015). This methodology requires time series data for the site's energy consumption, which we do not have for the vast majority of customers in our analysis. Therefore, we first apply the NREL analysis to a sample of 2,400 commercial and industrial customers for whom we have time series data, and then examine how the resulting battery metrics relate to other site characteristics (peak kW and annual kWh) that are known for all customers. The results indicate that maximum practical battery size is linearly related to the customer's annual peak consumption with an R-squared value of 0.86, as shown in Figure C-7. This linear regression estimates that battery capacity in kWh is approximately 7.2% of peak consumption in kW. Using this relationship, along with the assumed system duration of 120 minutes (e.g. power to energy ratio of 1:2), we assign a maximum practical battery capacity and power rating for all commercial and industrial customer clusters.

This analysis greatly simplifies the battery market by only considering batteries that exist solely for DR purposes. Future work should additionally include batteries that have non-DR primary uses. This could involve analyzing battery market projections to forecast total installed capacity, and determining hourly DR availability based on the state-of-charge curves associated with the battery's primary use. Additionally, allocation of costs between the primary and DR uses would need to be determined. This analysis could result in additional battery DR potential that is at minimal (program-only) cost. Without this analysis, we are estimating the maximum cost of using batteries to provide DR, and showing a DR potential that is purely demonstrative.

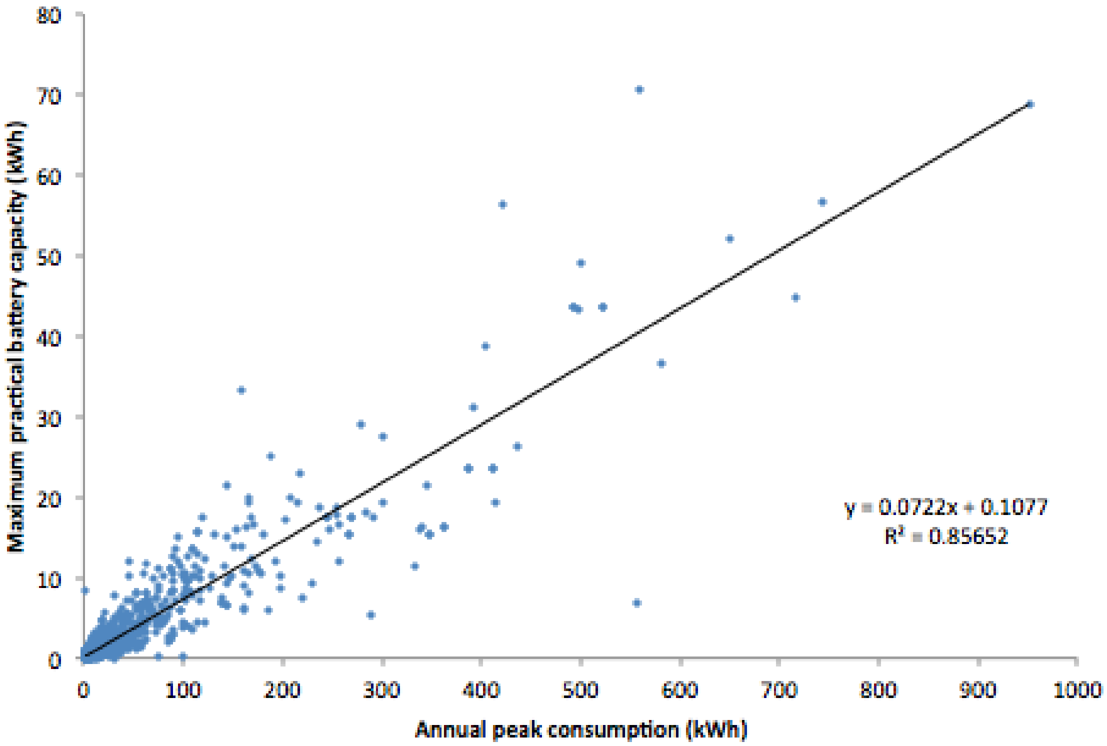

Figure C-7: Battery sized for demand charge using NREL (Neubauer and Simpson, 2015) methodology in relation to site peak consumption for 2,400 commercial and industrial utility customers.

C-7. Results

Results of the LBNL-LOAD model are detailed below. Table C-7 describes total annual energy consumption and customer forecasts by utility and sector in the 1-in-2 and 1-in-10 weather scenarios for each forecasting year (2020 and 2025). Figure C-8 describes the total hourly energy consumption across all three IOUs for each sector on the peak day in each forecasting scenario. Figure C-9 through Figure C-23 further disaggregate these peak day profiles by end use. Finally, Figure C-24 through Figure C-31 present heat maps of forecasted energy consumption (in MW) for each day in the year (x-axis) and each hour in the day (y-axis) in 2020 system-wide and by sector for the two weather scenarios. Figure C-32 through Figure C-35 present similar heat maps for residential end uses using the 1-in-2 weather scenario as an example.

Table C-8: Summary of forecasted customer populations and annual energy consumption for 2020 and 2025 by AAEE scenario, utility, and sector. Values shown are for the 1-in-2 weather year.

AAEE Scenario	Year	Utility	Sector	Number of Customers	Annual Consumption (GWh)
noAAEE	2020	PG&E	Commercial	575200	38500
			Industrial	199800	26000
			Other	439500	9900
			Residential	5374600	34500
		SCE	Commercial	579300	39600
			Industrial	119800	25300
			Other	257900	9000
			Residential	5032600	34100
		SDG&E	Commercial	144900	10600
			Industrial	23300	1800
			Residential	1391100	8100
	2025	PG&E	Commercial	612100	40700
			Industrial	222600	26300
			Other	439500	10300
			Residential	5647900	39100
		SCE	Commercial	616700	41500
			Industrial	131900	25400
			Other	257900	9300
			Residential	5213400	38100
		SDG&E	Commercial	154700	11200
			Industrial	26100	1800
			Residential	1434200	9200

AAEE Scenario	Year	Utility	Sector	Number of Customers	Annual Consumption (GWh)
midAAEE	2020	PG&E	Commercial	575200	37500
			Industrial	199800	25600
			Other	439500	9900
			Residential	5374600	33200
		SCE	Commercial	579300	38200
			Industrial	119800	25100
			Other	257900	8800
			Residential	5032600	32700
		SDG&E	Commercial	144900	10300
			Industrial	23300	1800
			Residential	1391100	7800
	2025	PG&E	Commercial	612100	38700
			Industrial	222600	25700
			Other	439500	10200
			Residential	5647900	36900
		SCE	Commercial	616700	38700
			Industrial	131900	25000
			Other	257900	9000
			Residential	5213400	35700
		SDG&E	Commercial	154700	10500
			Industrial	26100	1700
			Residential	1434200	8600

C-7.2. Area Plots Summarizing Peak Day Energy Consumption

C-7.2.1. System-Wide by Sector

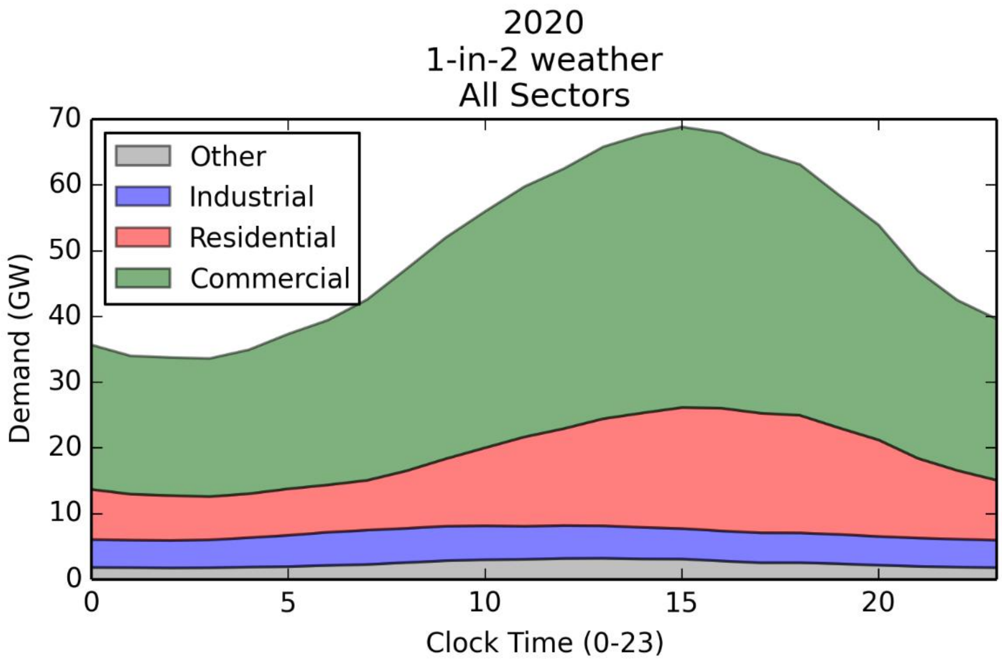

Figure C-8: Forecasted peak day hourly demand (in GW) across all three IOUs by customer type in 2020 for the 1-in-2 weather scenario.

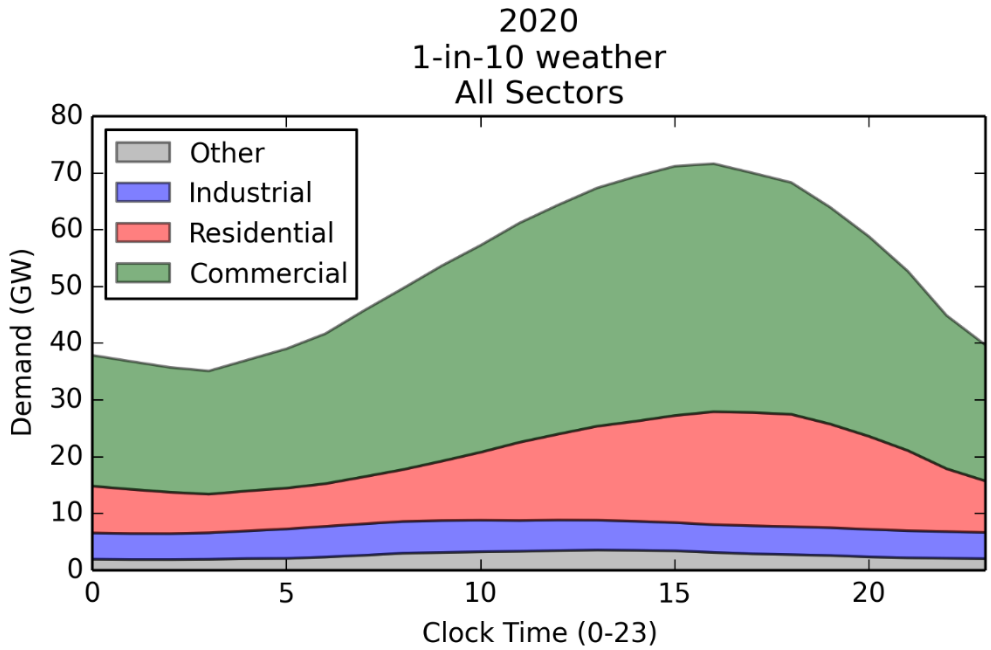

Figure C-9: Forecasted peak day hourly demand (in GW) across all three IOUs by customer type in 2020 for the 1-in-10 weather scenario.

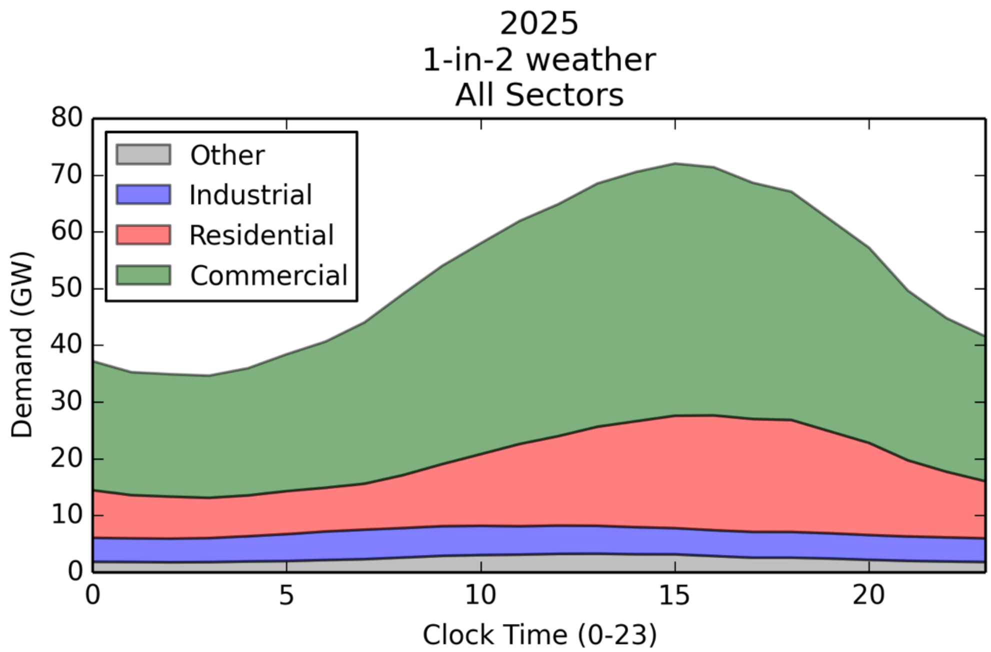

Figure C-10: Forecasted peak day hourly demand (in GW) across all three IOUs by customer type in 2025 for the 1-in-2 weather scenario.

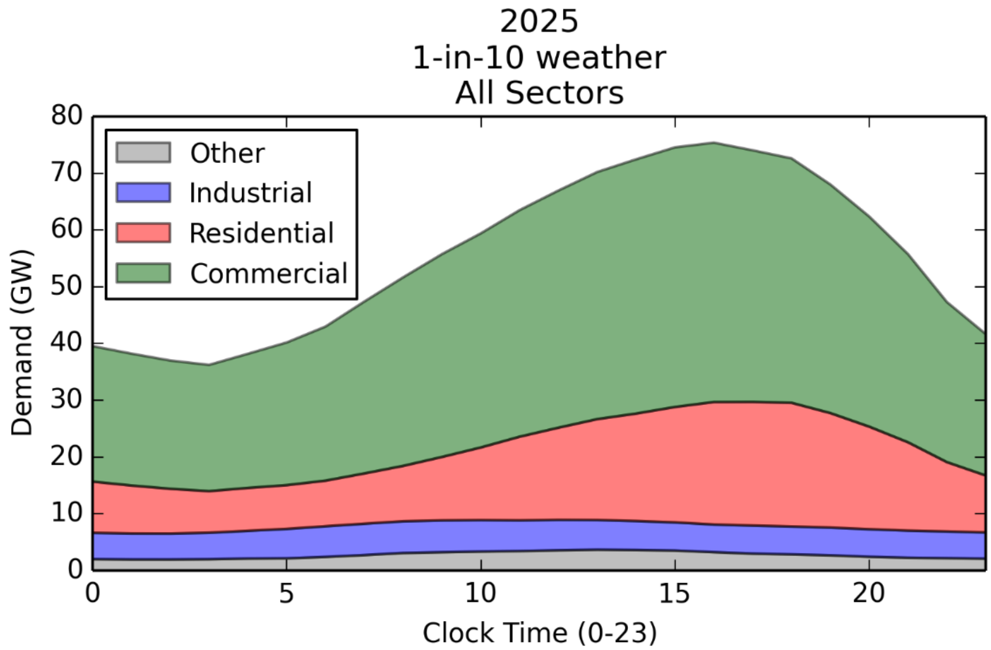

Figure C-11: Forecasted peak day hourly demand (in GW) across all three IOUs by customer type in 2025 for the 1-in-10 weather scenario.

C-7.2.2. System-Wide by Sector and End Use

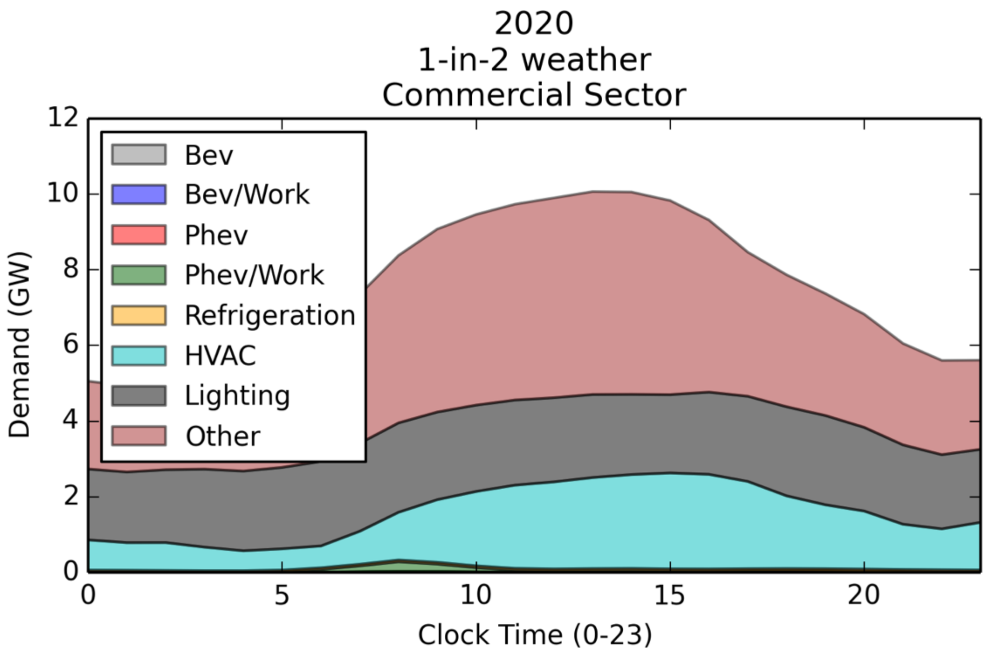

Figure C-12: Forecasted peak day hourly demand (in GW) for Commercial sector end uses in 2020 for the 1-in-2 weather scenario.

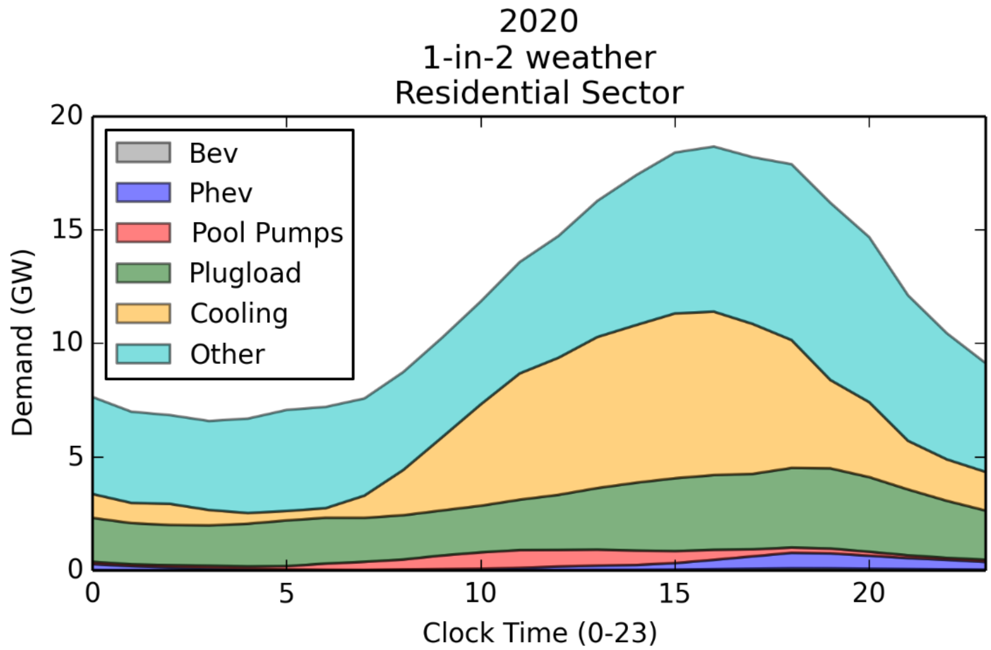

Figure C-13: Forecasted peak day hourly demand (in GW) for Residential sector end uses in 2020 for the 1-in-2 weather scenario.

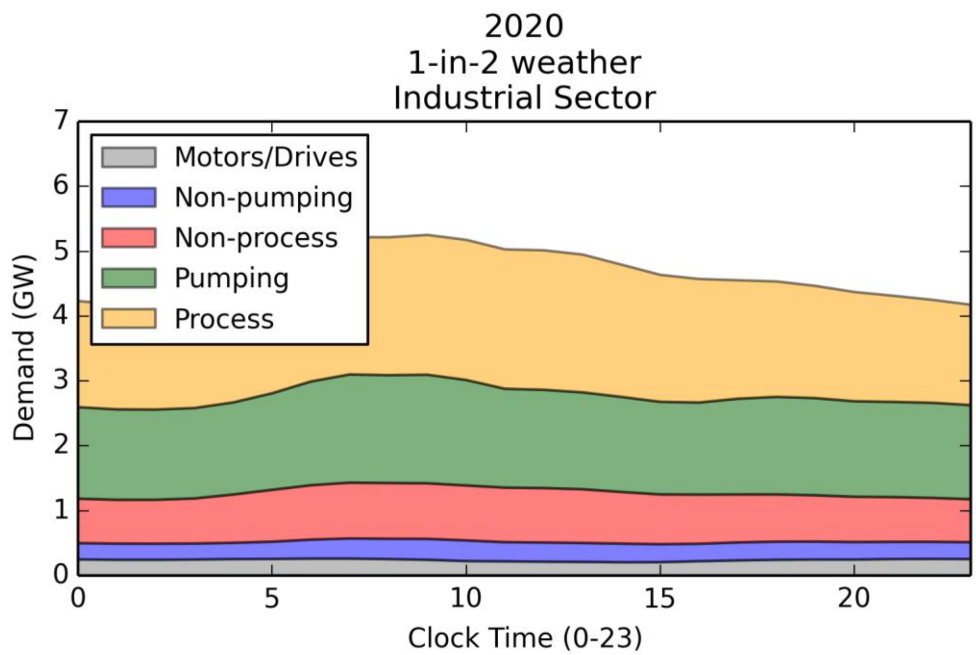

Figure C-14: Forecasted peak day hourly demand (in GW) for Industrial sector end uses in 2020 for the 1-in-2 weather scenario.

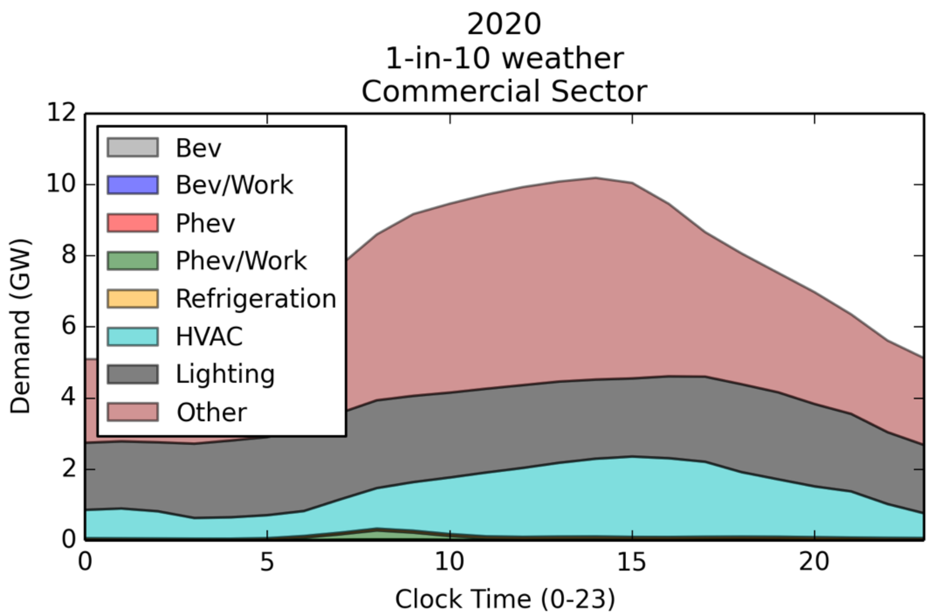

Figure C-15: Forecasted peak day hourly demand (in GW) for Commercial sector end uses in 2020 for the 1-in-10 weather scenario.

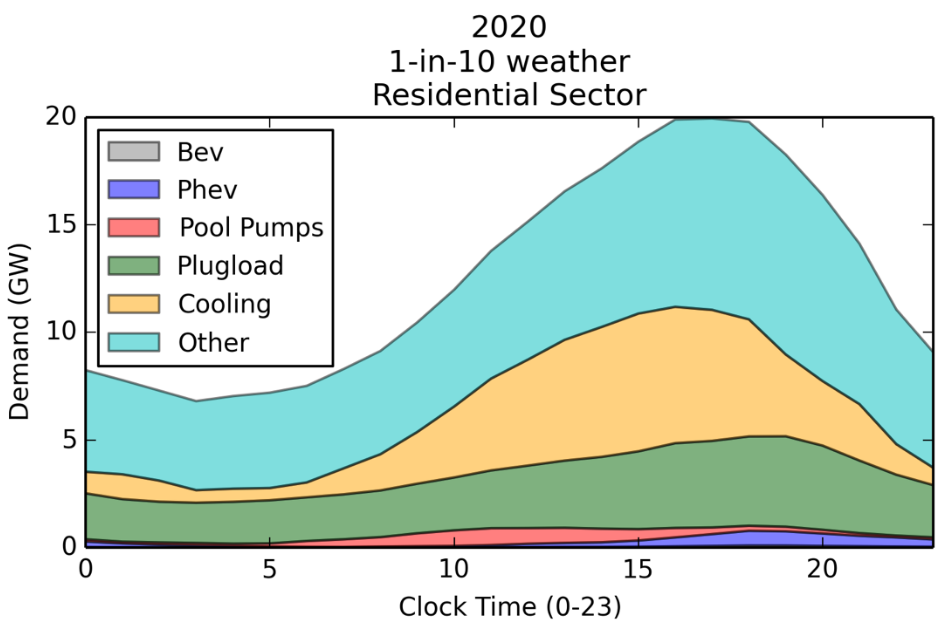

Figure C-16: Forecasted peak day hourly demand (in GW) for Residential sector end uses in 2020 for the 1-in-10 weather scenario.

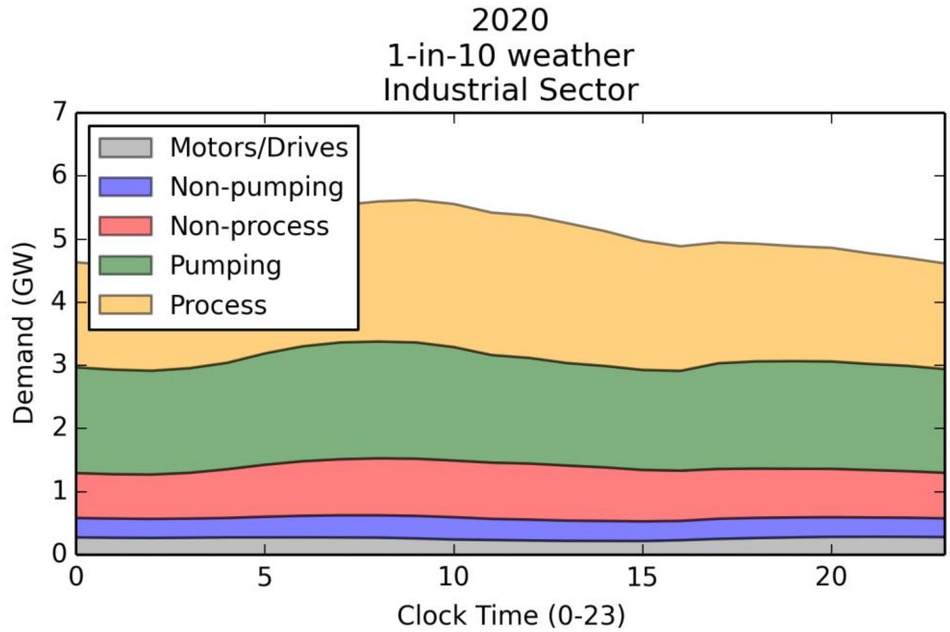

Figure C-17: Forecasted peak day hourly demand (in GW) for Industrial sector end uses in 2020 for the 1-in-10 weather scenario.

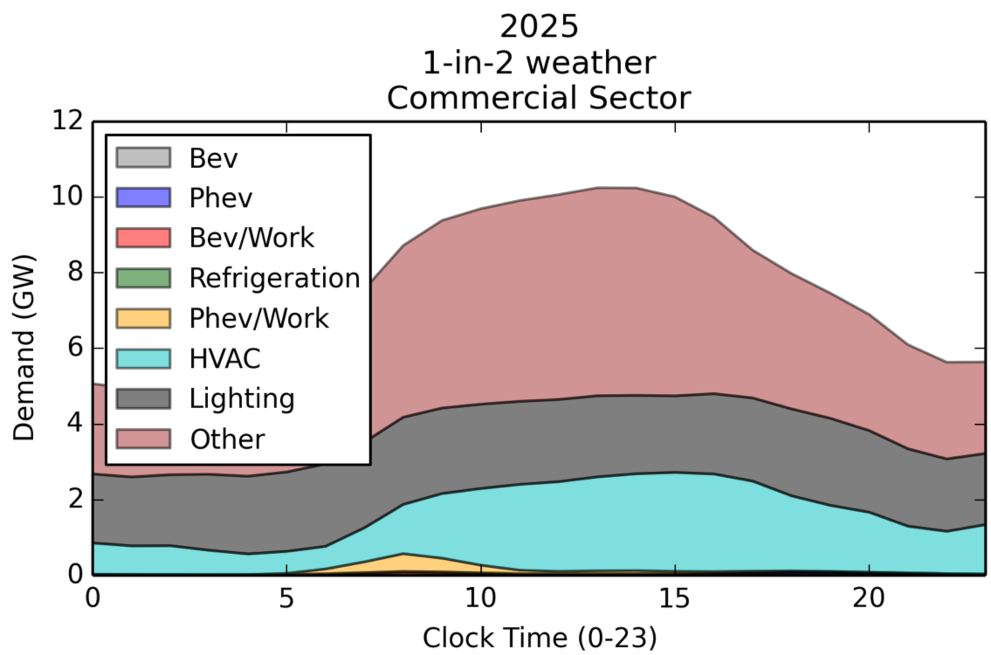

Figure C-18: Forecasted peak day hourly demand (in GW) for Commercial sector end uses in 2025 for the 1-in-2 weather scenario.

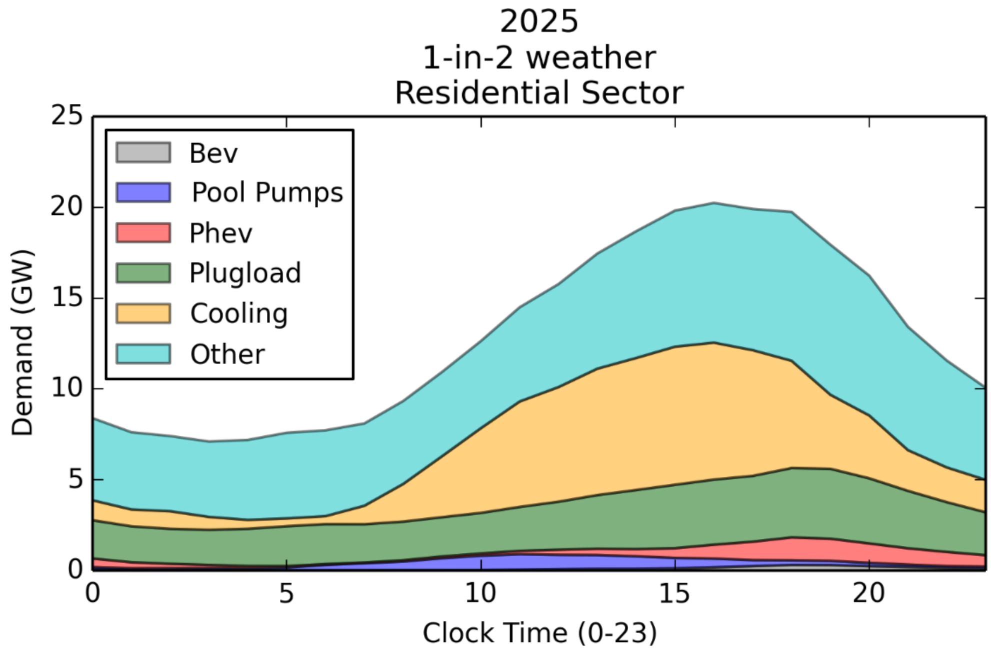

Figure C-19: Forecasted peak day hourly demand (in GW) for Residential sector end uses in 2025 for the 1-in-2 weather scenario.

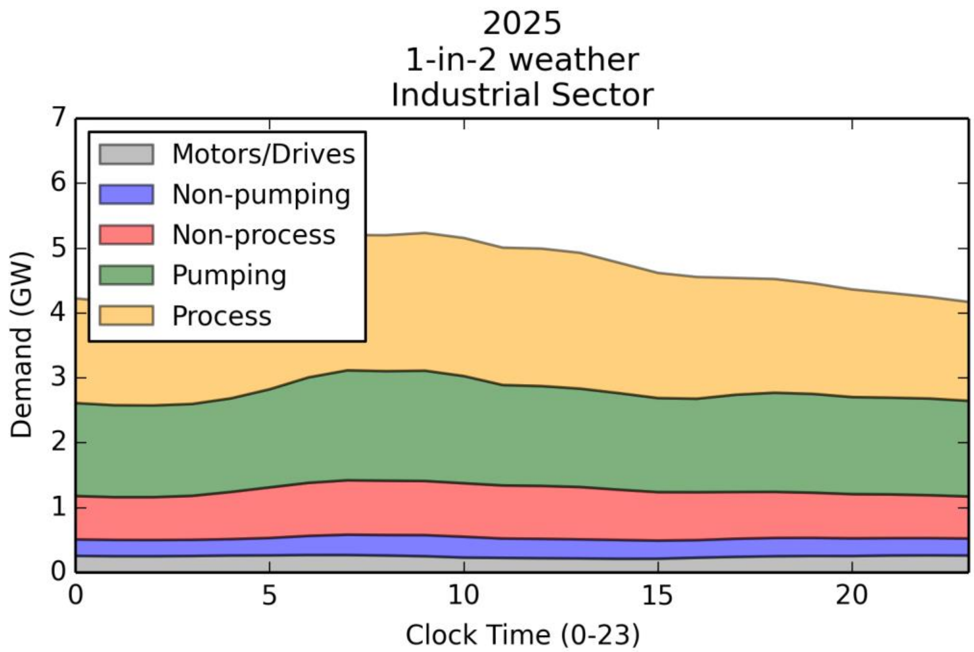

Figure C-20: Forecasted peak day hourly demand (in GW) for Industrial sector end uses in 2025 for the 1-in-2 weather scenario.

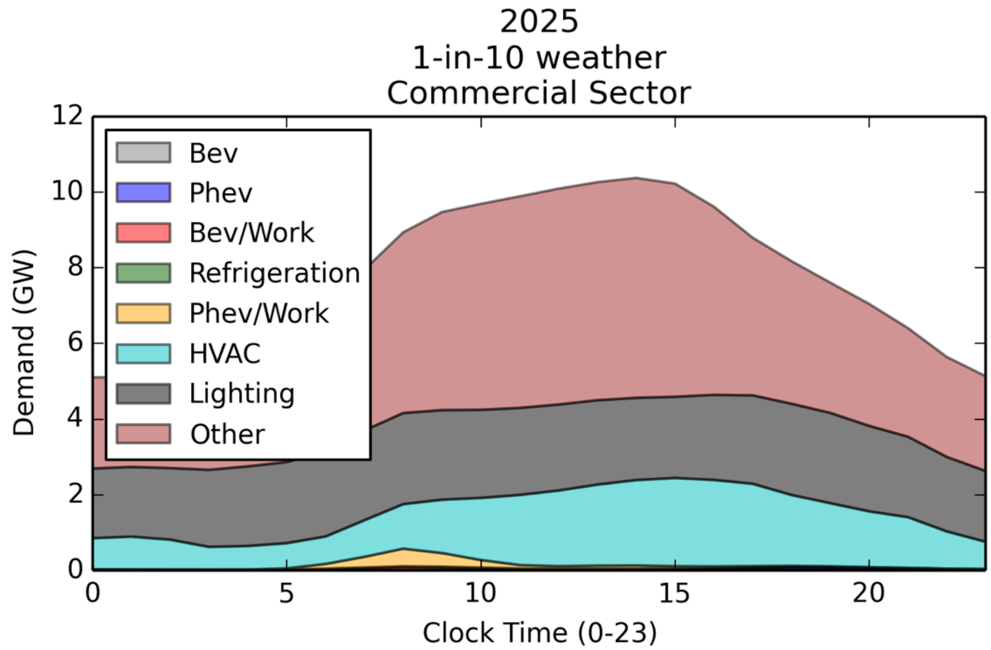

Figure C-21: Forecasted peak day hourly demand (in GW) for Commercial sector end uses in 2025 for the 1-in-10 weather scenario.

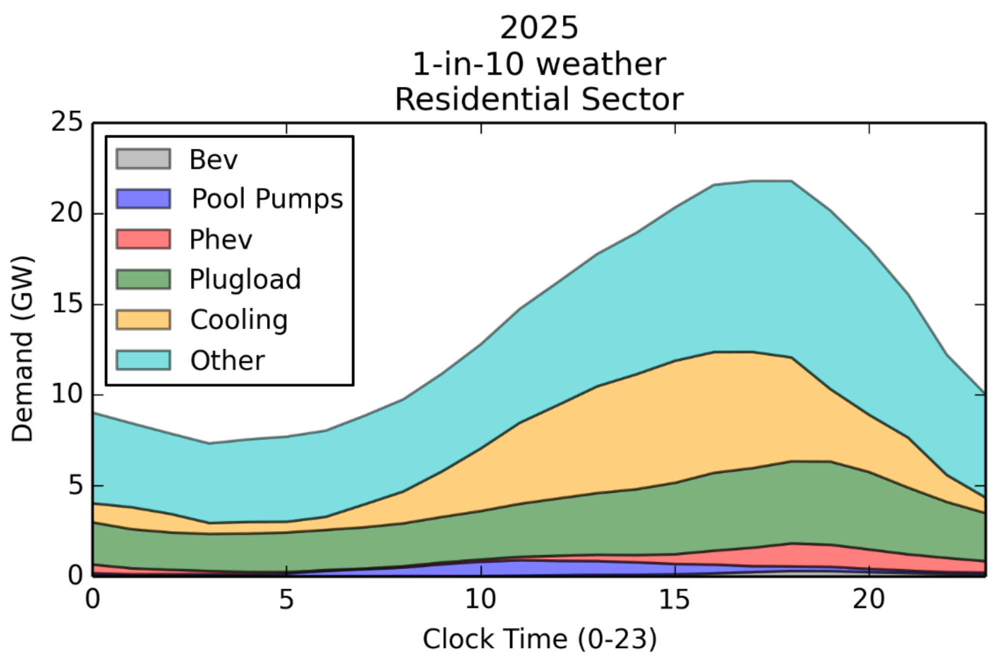

Figure C-22: Forecasted peak day hourly demand (in GW) for Residential sector end uses in 2025 for the 1-in-10 weather scenario.

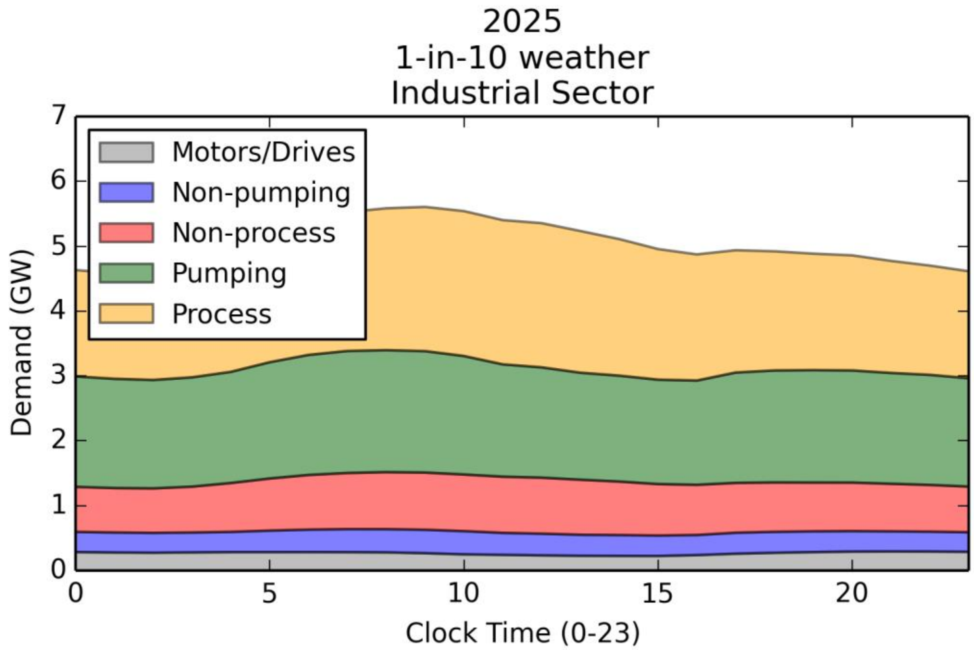

Figure C-23: Forecasted peak day hourly demand (in GW) for Industrial sector end uses in 2025 for the 1-in-10 weather scenario.

C-7.2.3. Energy Consumption Heat Maps by Sector

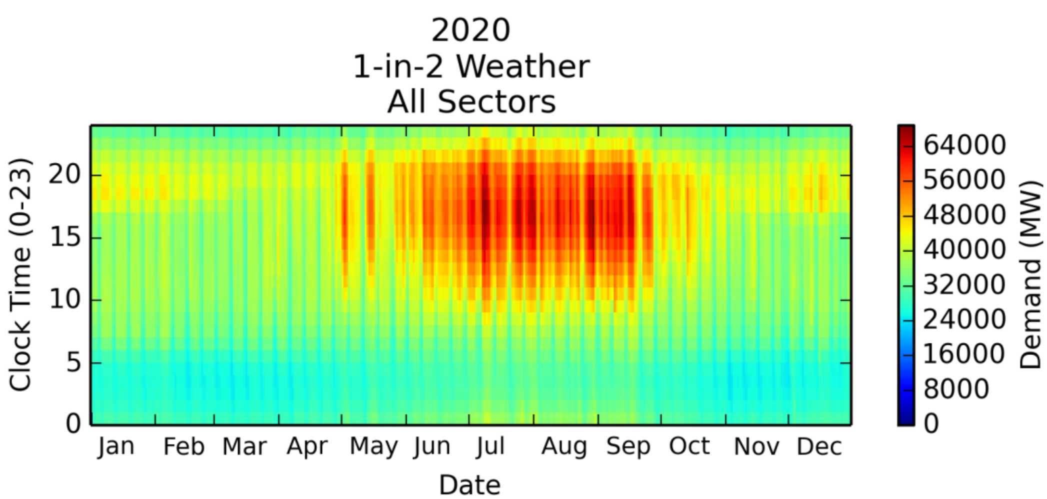

Figure C-24: Heat map of forecasted total energy consumption for all sectors in 2020 in the 1-in-2 weather scenario by date (x-axis) and hour (y-axis).

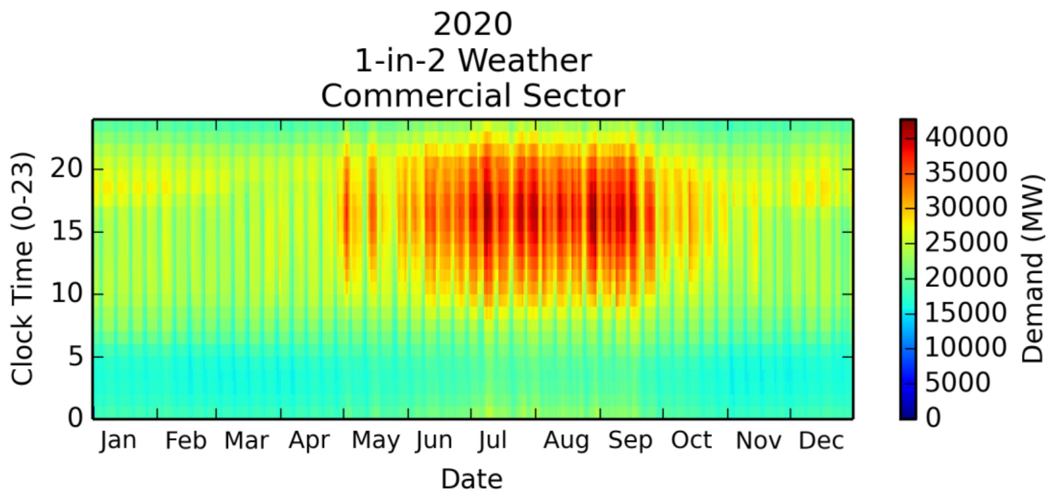

Figure C-25: Heat map of forecasted Commercial sector energy consumption in 2020 in the 1-in-2 weather scenario by date (x-axis) and hour (y-axis).

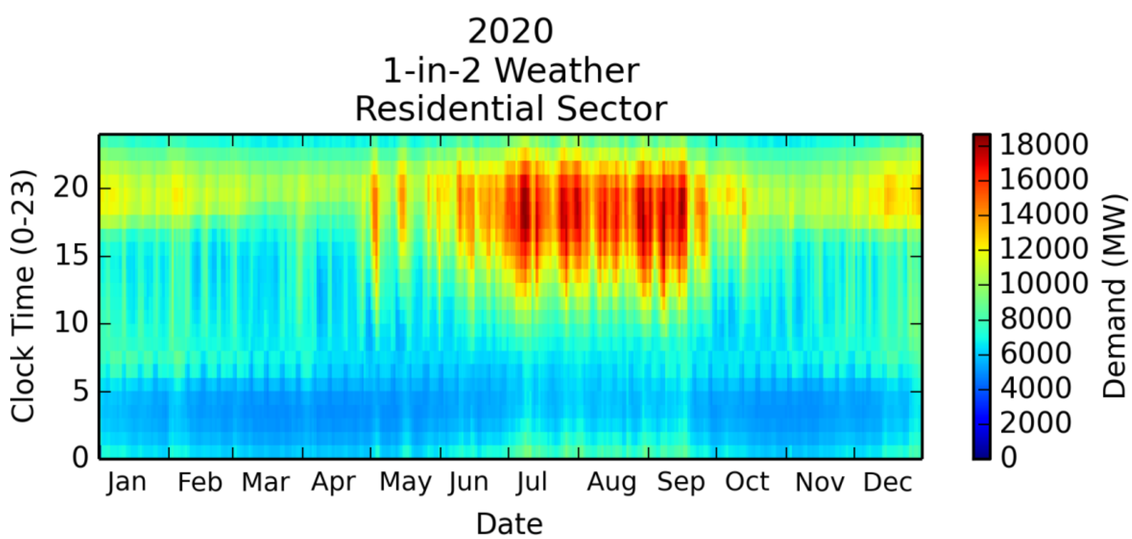

Figure C-26: Heat map of forecasted Residential sector energy consumption in 2020 in the 1-in-2 weather scenario by date (x-axis) and hour (y-axis).

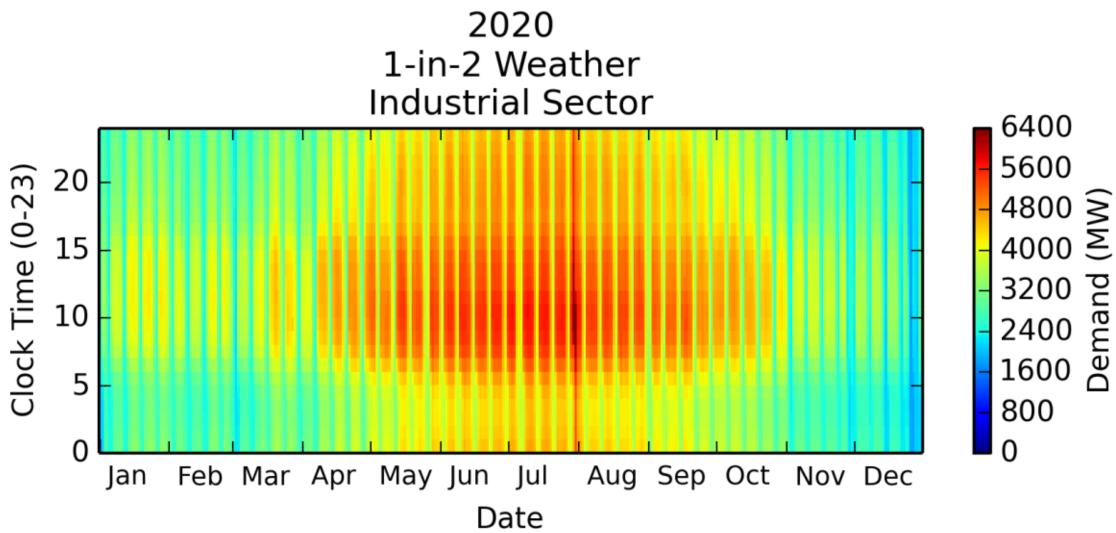

Figure C-27: Heat map of forecasted Industrial sector energy consumption in 2020 in the 1-in-2 weather scenario by date (x-axis) and hour (y-axis).

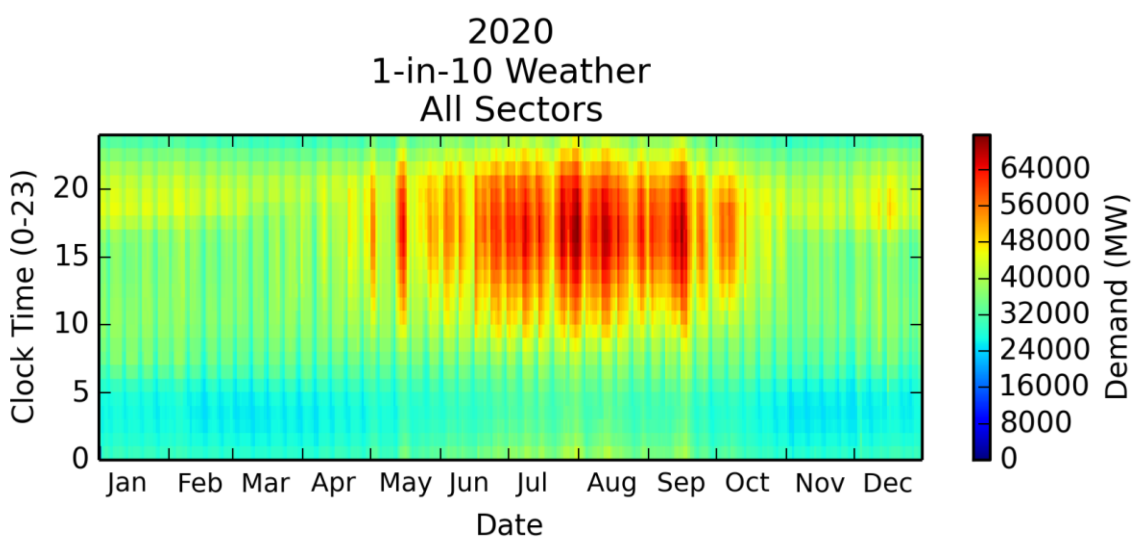

Figure C-28: Heat map of forecasted energy consumption for all sectors in 2020 in the 1-in-10 weather scenario by date (x-axis) and hour (y-axis).

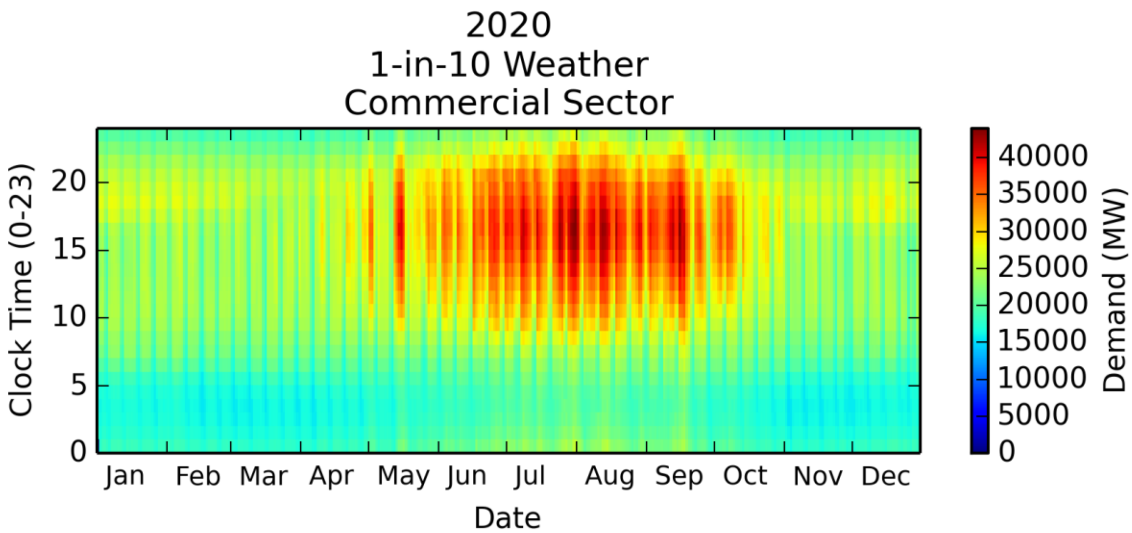

Figure C-29: Heat map of forecasted Commercial sector energy consumption in 2020 in the 1-in-10 weather scenario by date (x-axis) and hour (y-axis).

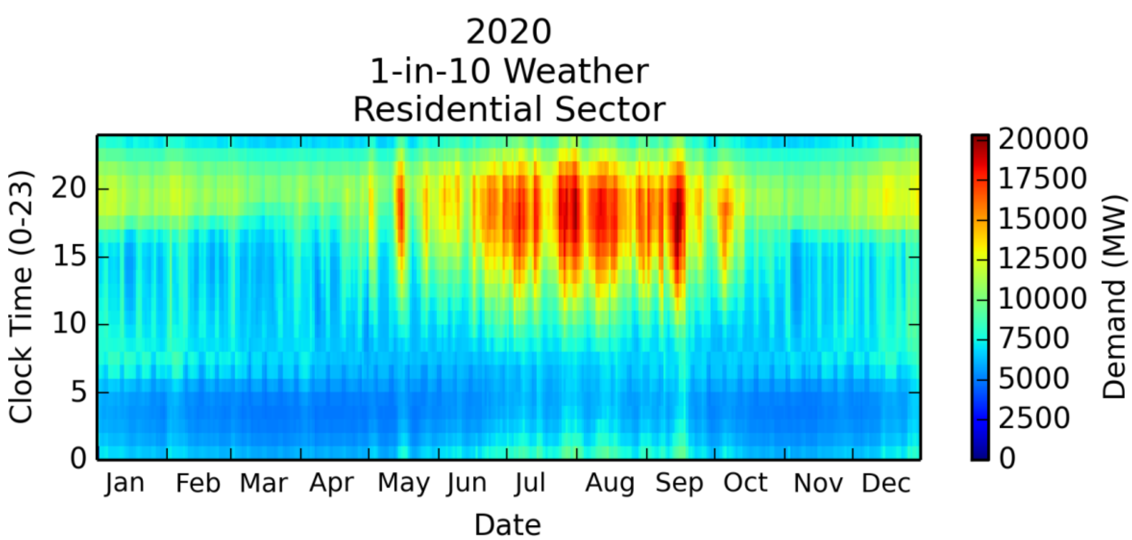

Figure C-30: Heat map of forecasted Residential sector energy consumption in 2020 in the 1-in-10 weather scenario by date (x-axis) and hour (y-axis).

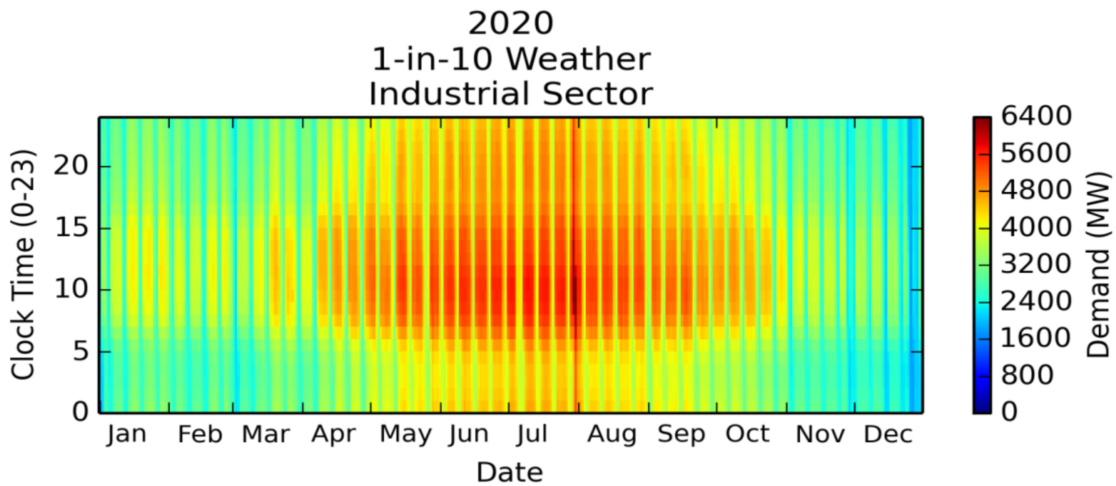

Figure C-31: Heat map of forecasted Industrial sector energy consumption in 2020 in the 1-in-10 weather scenario by date (x-axis) and hour (y-axis).

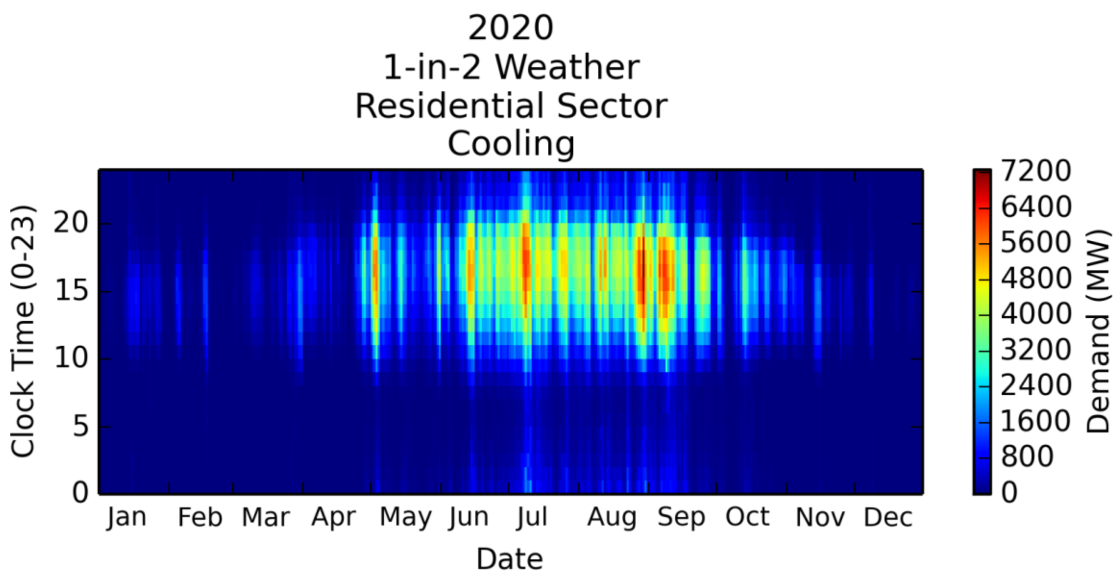

Figure C-32: Heat map of forecasted energy consumption for residential cooling in 2020 in the 1-in-2 weather scenario by date (x-axis) and hour (y-axis).

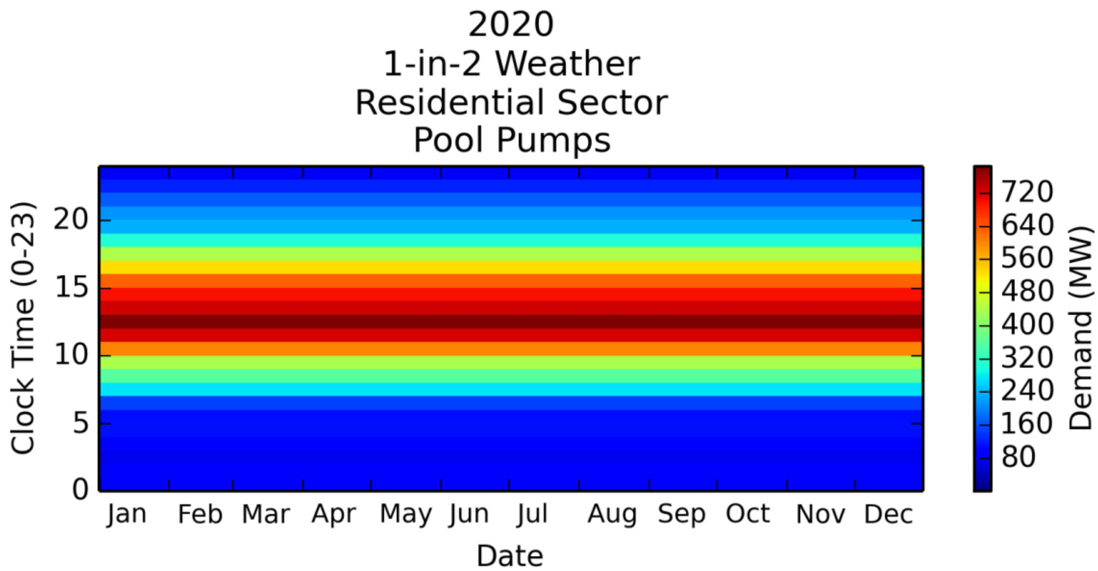

Figure C-33: Heat map of forecasted energy consumption for residential pool pumping in 2020 in the 1-in-2 weather scenario by date (x-axis) and hour (y-axis).

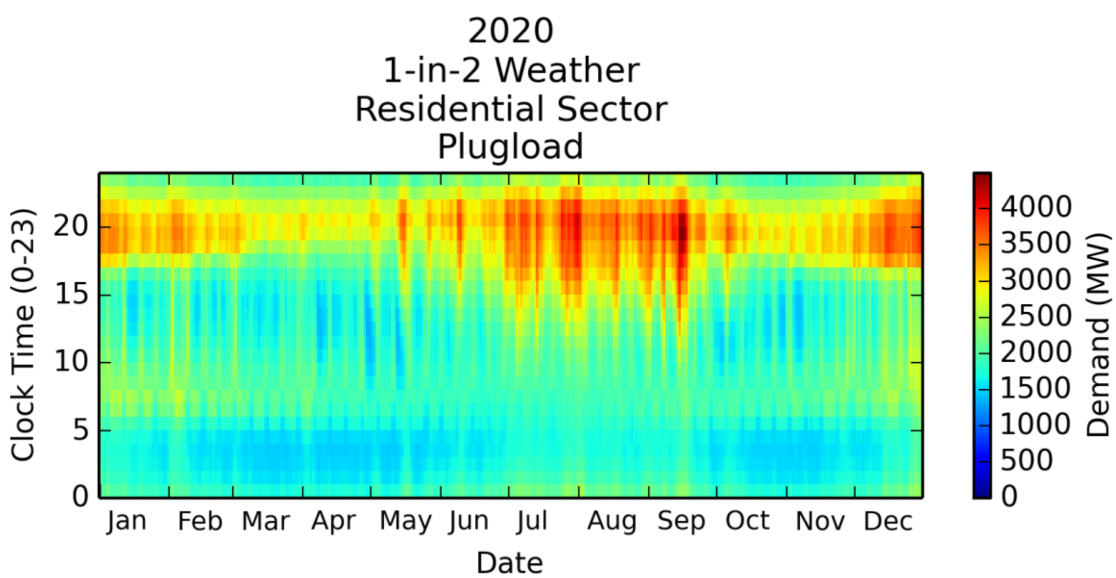

Figure C-34: Heat map of forecasted energy consumption residential plug loads in 2020 in the 1-in-2 weather scenario by date (x-axis) and hour (y-axis).

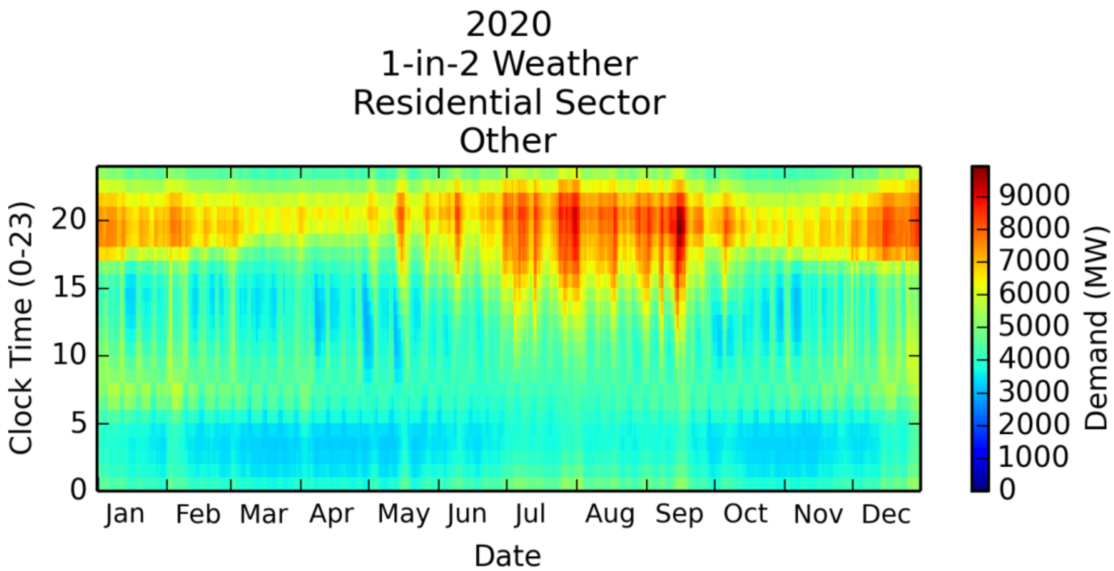

Figure C-35: Heat map of forecasted energy consumption for other residential loads in 2020 in the 1-in-2 weather scenario by date (x-axis) and hour (y-axis).

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Appendix D: DR Service Type Framework

System-level needs for flexibility and avoiding renewable energy curtailment are drivers for the development of many existing and new DR capabilities. In this study, we use a DR Product Framework to define and match these needs with the capabilities of DR resources, and a DR Service Type Framework to aggregate similar DR products and estimate the economic value they provide to the grid. We determine the quantity of DR service available using a bottom up analysis approach, matching the response and telemetry capabilities of specific enabling technologies and end uses with the response characteristics required to provide various grid services. We apply this framework to estimate the value to the grid procuring these services using DR resources.

The technical baseline analysis described in Appendix C estimates the magnitude of load for several end uses in each hour of the year. Using these magnitudes, as well as notification requirements and response capabilities of each end use, we classify end-uses based on their eligibility to provide various DR products designed to meet specific grid needs, or "products", such as flexibility or ramping. We aggregate DR potential for all end uses eligible to provide a particular grid product to build supply curves for three key Service Types. We compare the overall costs of procuring DR (including enablement costs, incentives, etc.) to the expected value to the grid.

Section 3.4 in the main report describes the DR Services Types we examine in this study (Shed, Shift, and Shimmy). Appendix D details the methods and metrics used to quantitatively estimate DR potential through the lens of various DR products. This appendix serves to: (1) qualitatively describe the DR products examined in the study and (2) relate the language we use to describe our own Product and Service Type frameworks to terminology, markets, and programs in California and elsewhere.

D-1. Defining System-Level Needs as Service Types

DR is capable of meeting a range of current and future system needs, including:

- System capacity - reduce peak system load to avoid constructing peaking units or purchasing peak power.
- Local capacity - support distribution system operation with local services that defer or eliminate the need to build distribution infrastructure.
- Short-run (seconds to minutes) load-following - reduce instability and provide frequency and voltage support.
- Medium-run (minutes to hours) ramps and curtailment - reduce reliance on unscheduled imports/exports (area control error) and limit the need to build flexible conventional generation to match net load with steep ramps.

- Renewable energy consumption - shift daily load to coincide with times of high renewable generation to reduce curtailment and help meet renewable portfolio standards.

Note: DR technology is additionally able to meet critical needs on the distribution system and support site-level operations. These focused services are handled with separate analysis in this study.

Based on these system needs, we analyze the potential for DR to provide three key services: Shed, Shift, and Shimmy (defined in Section 3.4 of the main report). Table D-1 relates these Service Types to the system needs defined above.

Table D-1: DR Service Types in Relation to Key System Needs

Service Type	Description	System Needs Supported
Shed	Reduction of demand during peak net load hours	Annual capacity, Local capacity
Shift	Energy-neutral shift in load from times of peak net load to times of minimum net load	Medium-run ramps and curtailment, Renewable energy consumption
Shimmy	Fast-responding load that can increase or decrease with system need	Short-run load-following and regulating reserve capacity

D-2. California Demand Response Programs, Markets, and Regulatory Terminology

D-2.1. Bifurcation

On November 19, 2015, the CPUC issued Decision 15-11-042, which clarified the commission's intent to proceed with bifurcation and defined the pathways for valuation of "supply-side" and "load-modifying" resources. In a bifurcation framework, supply-side DR is integrated into CAISO markets, and load-modifying resources are all other DR resources. The effects of load-modifying resources can reduce the need for supply-side procurement. For example, TOU price impacts that are embedded in the CEC load forecasts used to set resource adequacy targets can reduce the need for forward capacity procurement.

In the current study, we model two types of load-modifying DR: distribution system service (which is not integrated in ISO markets), and TOU/CPP rates. We define price-based load changes as *Shape,* and calculate the effective *Shed* and *Shift* provided. The Shape resource is different from the other Service Types examined in this study, as it is not a service in and of itself but rather an alternative pathway to provide services. The Shape resource is able to provide Shed service by reducing peak demand, and can also provide Shift service by moving demand from one time of day to another as needed.

All other resources analyzed in this study are considered supply-side resources, including end-use loads and behind-the-meter storage in residential, commercial, and industrial sectors. These loads, and the technologies which enable them, are able to provide Shed, Shift, and Shimmy services by modifying load on the supply side.

D-2.2. Resource Adequacy Capacity Credits

California currently employs three types of Resource Adequacy (RA) credits. Two of these types are Capacity RA: **System RA** refers to any resource that lowers the system-wide need for generation capacity by reducing peak demand, while **Local RA** is credited to resources that exist in specific areas where local capacity is constrained. The third type, **Flexible RA**, refers to resources that can participate in the energy market with ramping response availability.

D-2.3. RA Capacity Credits

We estimate the capacity value for the Shed DR service type based on the availability during the 250 hours of the year, see Section 3.4.3 of the report. These capacity RA credits are a source of revenue for the Shed service type, as discussed in Section 4.4 of the report. We recognize as well that the Shift service type would likely be able to receive both Capacity and Flexible RA credits, but we do not quantify these credits as frameworks and metrics for doing so do not yet exist.

D-2.4. Current California Demand Response Programs

Emergency DR is DR that serves the grid only in extreme circumstances to prevent power outages. California's Base Interruptible Program (BIP) is an example of emergency DR. This program pays customers monthly for the commitment to reduce load during very infrequent times of need. We do not specifically model Emergency DR as a product in the current study, but resources that provide Shed service are typically also capable of providing Emergency DR.

There is also existing supply market DR that participates economically in the ISO energy market -- sometimes called “economic” DR because the dispatch is based on price and no other triggers. California has two types of economic DR: Proxy Demand Resource (PDR) and Reliability Demand Response Resource (RDRR). PDR participates in the CAISO market in the same manner as a supply resource. PDR can bid into day-ahead and real-time energy and non-spinning reserve markets with minimum load curtailments of 0.1 MW and 0.5 MW for energy and non-spinning reserves, respectively. Loads may be aggregated to meet minimum resource requirements (in MW) for PDR. RDRR, on the other hand, can only bid into the day-ahead energy market to provide energy in response to a reliability event (which can occur at any time for the day that was bid into and would require immediate response). RDRR has a minimum curtailment of 0.5 MW which must be provided within 40 minutes of the dispatch signal and run for minimum of one hour (up to four hours). Appendix H details response characteristics required to provide PDR and RDRR, and describes how these requirements factor into how we estimate DR potential.

California utilities currently administer numerous TOU and CPP programs throughout their territories. We model demand based on 2014 customer load profiles (See Appendix C), thus load impacts from existing programs are embedded in our baseline load profiles. Future load impacts that we expect to come from an increase in programs and participation (Section 5.2.1 of the report) are captured by the Shape resource, which is able to provide both Shed and Shift services.

D-2.5. Ancillary Services

CAISO’s Ancillary Services market contains four types of products: spinning reserve, non-spinning reserve, regulation up, and regulation down. Spinning Reserve is the on-line reserve capacity that is synchronized to the grid system and ready to meet electric demand within 10 minutes of a dispatch instruction by the ISO. Spinning Reserve is needed to maintain system frequency stability during emergency operating conditions and unforeseen load swings. Non-Spinning Reserve is off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a dispatch instruction by the ISO, and that is capable of maintaining that output for at least two hours. Non-Spinning Reserve is needed to maintain system frequency stability during emergency conditions. Regulation (up and down) is used to control system frequency as generators change their output. Regulation resources must respond to automatic control signals to increase or decrease their operating levels depending upon the need. In this study, Spinning and Non-spinning Reserves fall in the Shed Service Type, while Regulation is considered Shimmy Service. Appendix D further discusses the requirements of ancillary services and how these requirements are used in estimating DR potential in this study.

D-3. Defining Demand Response Products

The existing grid needs, CAISO markets, and demand response programs described above were used to develop a set of DR "Products" for which technical potential can be estimated. Each product maps to one of our DR "Service Types", for which supply curves are generated and value to the grid is assessed. The products used in this study are shown in Table D-2, alongside the applicable Service Type and CAISO market. As shown in the table, the product framework is most relevant for Shed and Shimmy services, where existing programs and technical criteria exist. There is currently no program or market for Shift service, so we define it as a product in and of itself. And as mentioned before, Shape (i.e. load-modifying, or TOU/CPP) resources are not analyzed as specific products, rather calculated based on expected load impacts and the benefits those impacts provide.

Table D-2: DR Products and their respective Service Types and markets

Product	Service Type	Market Type	Market
Regulating reserves	Shimmy	Ancillary services	Regulation
Load following	Shimmy	Ancillary services	Load following
Local capacity	Shed	Energy	Real-time
Reliability - DAM	Shed	Energy	Day-ahead
Reliability - RTM	Shed	Energy	Real-time
Economic DR - DAM	Shed	Energy	Day-ahead
Economic DR - RTM	Shed	Energy	Real-time
Spinning reserve	Shed	Ancillary services	Spinning reserve
Non-spinning reserve	Shed	Ancillary services	Spinning reserve
Shift	Shift	--	--

Each DR product has a set of technical characteristics that set the criteria for determining whether or not a given resource (i.e. cluster + end-use + technology combination) will be able to provide that product. Table D-3 identifies the end-use technical characteristics, dimensions of DR, and examples of system needs mapped to each technical characteristic. Specific requirements of each DR product, as well as specific abilities of DR technologies, are defined in Appendix H.

Table D-3: Mapping of technical characteristics to example system needs

Technical Characteristic	DR Capabilities Definition	Measurement Categories or Units	Example match to system need
Response Duration	The minimum and maximum duration of time that an event is sustained	Time: e.g., at least in state for 15 minutes and at most for 3 hours	Match duration of need and responsiveness requirements for ramp, peak, or load-following instance
Response Frequency	The number of instances that DR is able to be called in a given period	Number of calls per time period (e.g., 10 air-conditioner curtail events per summer)	Determines whether option value for future performance is important in decision to engage
Response Speed	Time elapsed between system need identification and start of response	Time, e.g., 0	Determines whether valued for frequency / short-run stability support
Ramp Rate	Time elapsed between the beginning of response and full response achieved	Time, e.g., ~0.1 seconds for switched loads, 1 minute for ramped HVAC, etc.	Determines whether valued for frequency / short-run stability support
Charge Requirements - Recovery	The time until the full resource is available again after an event	Hours to 50%, 99% magnitude available	Defines degree to which system needs after event are influenced

Appendix E: Price Responsiveness to Time Varying Rates

E-1. Residential Customers

Multiple studies have shown that customer adjust behavior in response to time varying electricity pricing by shifting when they consume electricity. When electricity prices are higher they provide customers and incentive to reduce consumption and or shift it to periods when prices are lower. California is scheduled to default residential customers onto time varying prices in 2019. A number of pilots are currently being implemented to assess how to best communicate time varying rates to customers. The pilots are also designed to test price response to new time varying rates with peak periods that reflect net loads. The exact details of the implementation and the time varying rates to be implemented are still being determined.

A key element of the Demand Response Potential Study was estimating the impact of rates on customer loads. While the price response to default time of use rates cannot be dispatched, their implementation is foundational. It should lead to modifications in customer loads and influence the loads available for demand response options that can be dispatched. At a fundamental level, the process to estimate price response includes four main components:

- Price elasticities. Elasticities are a convenient parameter used by economists to summarize the relationship between changes in price and changes in usage. They are based on empirical studies where customers were offered different rates. By design, these studies estimate how customers change energy consumption in response to changes in prices. The main advantage of price elasticities is the ability to estimate price response for rates that may have not directly tested in a study but are within a reasonable range of the prices tested. For this study we rely on the constant elasticity of substitution (CES) model. It used to estimate changes to daily energy use in response to changes to the average daily prices faced by the customers and a shifting of electricity use from higher prices hours to lower priced hours (a substation effect).
- Baseline rates. These prices reflect the current rate structure, which does not vary prices over time and does not reflect the time varying nature of electricity costs.
- New rates. The new prices reflect proposed TOU rates by various parties. They are designed to better reflect electricity costs by signaling to customer when costs are high and low. This is accomplished by identifying different day types (weekday versus weekend), seasons, and time intervals. The prices vary by time of day and day type but are set for system. By design, the TOU rates are revenue neutral – if the customers do not change behavior, the average customer bill would be identical to the bill using the baseline rate. That is, absent changes in behavior, utilities would collect the same amount of revenue.

- Baseline electricity use. The baseline electricity use is the electricity consumption under the baseline prices.

At its simplest level, to estimate price response, the change in prices and prices elasticities are used to estimate the change in energy use. The remainder of this section details, the price elasticities employed, the baseline and new rates, and the electricity energy use. For completeness, we also document the mathematics of how the price elasticities were applied.

E-2. Price Elasticities

Residential price response has been widely studied, but mostly among customers who opted to enroll in a pricing pilot. Price response to default TOU rates has been studies far less. Because the focus is on default TOU in California, inferences from price elasticities are strongest if they are based on customers who were defaulted onto the rates, experienced similar weather, and have similar characteristics. A key challenge is reflecting the wide diversity of customers and weather conditions across California. In particular, air conditioner saturation and temperature conditions are highly correlated with the magnitude of the price response.

The most notable study of default time of use rates is SMUD's Smart Pricing Options pilot. The pilot strictly adhered to rigorous experimental design standards and implemented randomized control trials (using a recruit and delay design) and randomized encouragement designs to determine customer acceptance of and response to TOU, CPP and TOU/CPP tariffs under both opt-in and default enrollment. A key feature of the study is the granularity of the price elasticity estimates, which are presented in Table E-1. Not only was it used to produce price elasticities for default versus opt-in in enrollment but it also produced estimates of prices response based on low income status (SMUD's Energy Assistance Program Rate or EAPR), relative consumption size, and for customers with all electric homes versus those with electric and gas. In addition, the price elasticities reflect customer price response under different temperature conditions.

Table E-1: SMUD SPO Elasticity Estimates for Default TOU.

EAPR	Quartile	All Electric	EOS	EOS_CDD	DAILY	DAILY_CDD
EAPR	1	0	-0.015	-0.001	-0.045	0.003
EAPR	2	0	0.043	-0.003	-0.229	0.012
EAPR	3	0	-0.038	-0.003	-0.097	0.005
EAPR	4	0	-0.048	-0.003	-0.144	0.008
Non-EAPR	1	0	0.007	-0.006	-0.298	0.017
Non-EAPR	2	0	0.002	-0.006	-0.175	0.011
Non-EAPR	3	0	-0.063	-0.005	-0.079	0.004
Non-EAPR	4	0	0.030	-0.007	-0.154	0.007
EAPR	1	1	0.053	0.000	-0.069	-0.003
EAPR	2	1	-0.004	-0.004	0.056	-0.005
EAPR	3	1	-0.045	0.002	-0.289	0.015
EAPR	4	1	0.029	-0.005	-0.221	0.004
Non-EAPR	1	1	-0.051	-0.006	-0.720	0.036
Non-EAPR	2	1	-0.071	-0.004	-0.347	0.018
Non-EAPR	3	1	-0.098	-0.003	0.053	-0.002
Non-EAPR	4	1	-0.115	-0.002	0.092	-0.001

Elasticity measurements are provided for each quartile of energy consumption and consist of four components: the elasticity of substitution (EOS) constant, the daily elasticity constant, and the cooling degree days (CDD) component of the EOS and daily elasticities. EOS is a measure of how much electricity usage will shift from the peak to off peak period of the day as a function of the intraday price ratio. Daily elasticity is a measure of how overall electricity usage for the day will change in response to the change in the average daily rate. For each of these elasticity measures, there is a constant component and a component that varies as a function of CDD, which is defined as either zero or the average daily temperature minus a base temperature value (in this case 65°F), whichever is greater. CDD is a common predictor of how much air conditioning will be used.

The key limitation of the SMUD price elasticities is that they are based solely on customers in the SMUD service territory, where AC saturation is 89%. Because response to TOU is highly dependent on AC saturation, they cannot be directly applied to other regions in California with lower AC saturation levels and fewer extreme temperature days without some calibration. To calibrate the price elasticities for different levels of air conditioner penetration, we used publicly available load impact results from the 2012 evaluation of PG&E's SmartRate program, which estimated price response for customers with various AC saturation levels.

The SMUD pilot included an opt-in, pure critical peak pricing (CPP) rate with similar price ratios and structure as PG&E's SmartRate program. In addition, PG&E's territory encapsulates the Sacramento areas served by SMUD and, thus, included neighborhoods with similar housing, AC saturation, and demographics.

To understand how load reduction from time varying prices is a function of AC saturation, the estimated load impacts from the 2012 PG&E SmartRate program evaluation was used to build a regression model with load impact as a function of AC saturation. Load impact estimates from this study are presented in **Error! Reference source not found.** E-2. In this table, CARE refers o California Alternate Rates for Energy (low income status) and "CAC Ownership Likelihood" refers to customers who fall in different categories of likelihood of owning AC. Customers who are dually enrolled (also enrolled in the SmartAC program) necessarily own AC, and therefore have a likelihood of 100%.

Table E-2: 2012 SmartRate Load Impact by Likelihood of AC Ownership.

CARE	CAC Ownership Likelihood	Percent Impact
Non-CARE	0-25%	13%
Non-CARE	25-50%	12%
Non-CARE	50-75%	19%
Non-CARE	75-100%	20%
Non-CARE	Dually Enrolled	28%
CARE	0-25%	5%
CARE	25-50%	4%
CARE	50-75%	3%
CARE	75-100%	7%
CARE	Dually Enrolled	20%
All	0-25%	11%
All	25-50%	8%
All	50-75%	10%
All	75-100%	13%
All	Dually Enrolled	25%

These scaling factors were then applied to the uncalibrated elasticity estimates to produce EOS and daily elasticities for a variety of AC saturation levels. The resulting set of elasticities can be used to estimate change in load reduction using the following pair of equations. The first equation expresses the ratio of peak and off-peak energy use as a function of an intercept term and the ratio of peak and off-peak prices,

$$ln\left(\frac{Q_1}{Q_2}\right) = a_{12} + b_{12} * ln\left(\frac{P_1}{P_2}\right) \tag{1}$$

where Q_i is electricity use in period *i* in kWh/hour and P_i is the price of electricity in period *i*. The term a_{12} is the intercept and b_{12} is the EOS. Equation 1 captures tradeoffs in electricity consumption that occur between rate periods in the same day.

The second equation pertains to daily electricity consumption and has the following specification:

$$ln(Q_d) = c + d * ln(P_d) \quad (2)$$

In this equation, Q_d is the total electricity consumed in a day and P_d is the average price for that day, which is a weighted average of the peak and off-peak prices. Equation 2 is often called the daily equation since it captures changes in electricity consumption at the daily level that result from changes in prices and the term *d* is the daily elasticity. The equations were extended for multi-period TOU rates.

E-3. Changes in Prices

Nexant estimated the expected load impacts for 13 rate structures taken from the statewide TOU pilot Working Group and the Statewide TOU Scenario Modeling Policy Report[47]. Nexant calculated the revenue neutral, counterfactual flat rate for each utility. Rates structures proposed by one utility were applied to other utilities by retaining the same time periods, seasons, and price ratios between periods. All price ratios were relative to winter off-peak rates. Nexant estimated the counterfactual flat rate to ensure the rates were revenue neutral for the year. That is, if the customers do not change behavior, the average customer bill under the flat rate and TOU rate would be identical.

For each rate structure in question, revenue neutral rates were calculated by applying the price ratios of the rate structure to an average residential annual load profile for each utility, then finding the rates that would produce the same bill under a flat rate. Table E-3 gives an example of how the price ratios from a particular rate structure were used to calculate revenue neutral rates. With an old flat rate of $0.217/kWh, the total annual bill is $1465. Applying the price ratios from option two of the TOU Working Group for PG&E yields rates that range from 0.173/kWh in off-peak winter months to 1.33/kWh for CPP

[47] Hansen, D.G., Braithwait, S.D, and Armstrong, D. Statewide Time of Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report, November 2015.

periods, but that when multiplied by the usage in each rate block, yield the same $1465 per year.

Table E-3: Revenue Neutral Rate Calculation Example

Day Type	Season	Rate Block	Usage (kWh)	Price Ratio	Flat Rate	Revenue Neutral TOU Rate
Weekday	Winter	Peak	332.8	1.091	$0.217	$0.189
		Off Peak	1,590.6	1.000	$0.217	$0.173
	Spring	Peak	167.7	1.091	$0.217	$0.189
		Off Peak	862.2	1.000	$0.217	$0.173
	Summer	CPP	95.8	Summer Peak + $1.00	$0.217	$1.330
		Peak	274.0	1.905	$0.217	$0.330
		Part Peak	279.7	1.668	$0.217	$0.289
		Off Peak	1,193.2	1.224	$0.217	$0.212
Weekend	Winter	Peak	134.7	1.091	$0.217	$0.189
		Off Peak	677.8	1.000	$0.217	$0.173
	Spring	Peak	66.9	1.091	$0.217	$0.189
		Off Peak	356.0	1.000	$0.217	$0.173
	Summer	Peak	120.1	1.905	$0.217	$0.330
		Part Peak	120.8	1.668	$0.217	$0.289
		Off Peak	482.2	1.224	$0.217	$0.212

Bill with Flat Rate	$1,465.73
Bill with TOU rate	$1,465.73

Table E-4 presents the rate structures from the TOU working group. Table E-5 summarizes the rate structures from the Statewide TOU Scenario Modeling Policy Report.

Table E-4: TOU Working Group Proposed Rates

Weekday Rate Periods - TOU Working Group Rates

Tariff	Season	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E Rate 1	Spring	Off-peak																Peak					Off-peak		
	Summer	Off-peak																Peak					Off-peak		
	Winter	Off-peak																Peak					Off-peak		
PG&E Rate 2	Spring	Off-peak																		Peak			Off Peak		
	Summer	Off-peak																Partial Peak		Peak			PP	Off-peak	
	Winter	Off-peak																		Peak			Off-peak		
PG&E Rate 3	Spring	Off-peak										Super Off Peak						Peak					Off-peak		
	Summer	Off-peak																Peak					Off-peak		
	Winter	Off-peak																Peak					Off-peak		
SCE Rate 1	Spring	Off-peak														Peak						Off-peak			
	Summer	Off-peak								Partial Peak						Peak						Partial Peak		Off-peak	
	Winter	Off-peak														Peak						Off-peak			
SCE Rate 2	Spring	Super Off Peak								Off-peak									Peak			OP		Super Off Peak	
	Summer	Super Off Peak								Off-peak									Peak			OP		Super Off Peak	
	Winter	Super Off Peak								Off-peak									Peak			OP		Super Off Peak	
SCE Rate 3	Spring	Off-peak											Super Off Peak					Peak					OP		
	Summer	Off-peak											Partial Peak					Peak					Partial Peak		OP
	Winter	Off-peak																Peak					Off-peak		
SDG&E Rate 1	Spring	Off-peak						Partial Peak										Peak					Partial Peak		
	Summer	Off-peak						Partial Peak										Peak					Partial Peak		
	Winter	Off-peak						Partial Peak										Peak					Partial Peak		
SDG&E Rate 2	Spring	Off-peak																Peak					Off-peak		
	Summer	Off-peak																Peak					Off-peak		
	Winter	Off-peak																Peak					Off-peak		

Weekend Rate Periods - TOU Working Group Rates

Tariff	Season	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E Rate 1	Spring	Off Peak																							
	Summer	Off Peak																							
	Winter	Off Peak																							
PG&E Rate 2	Spring	Off Peak																		Peak			Off Peak		
	Summer	Off Peak																Partial Peak		Peak			PP	Off Peak	
	Winter	Off Peak																		Peak			Off Peak		
PG&E Rate 3	Spring	Off Peak										Super Off Peak						Off Peak							
	Summer	Off Peak																							
	Winter	Off Peak																							
SCE Rate 1	Spring	Off Peak																							
	Summer	Off Peak								Partial Peak														Off Peak	
	Winter	Off Peak																							
SCE Rate 2	Spring	Super Off Peak								Off Peak														Super Off Peak	
	Summer	Super Off Peak								Off Peak														Super Off Peak	
	Winter	Super Off Peak								Off Peak														Super Off Peak	
SCE Rate 3	Spring	Off Peak											Super Off Peak (16.7¢)					Partial Peak					Off Peak		
	Summer	Off Peak																Partial Peak					Off Peak		
	Winter	Off Peak											Super Off Peak (16.7¢)					Partial Peak					Off Peak		
SDG&E Rate 1	Spring	Off Peak														Partial Peak		Peak					Off Peak		
	Summer	Off Peak														Partial Peak		Peak					Off Peak		
	Winter	Off Peak														Partial Peak		Peak					Off Peak		
SDG&E Rate 2	Spring	Off Peak																Peak					Off Peak		
	Summer	Off Peak																Peak					Off Peak		
	Winter	Off Peak																Peak					Off Peak		

Table E-5: Statewide Pricing Pilot Rate Structures

Weekday Rate Periods

Tariff	Season	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E Rate 1C	Summer	Off Peak										Partial Peak			Peak						Partial Peak		Off Peak		
	Winter	Off Peak																	Partial Peak			Off Peak			
PG&E Rate 2C	Summer	Off Peak																Peak					Off Peak		
	Winter	Off Peak																Peak					Off Peak		
SCE Rate 1C	Summer	Super Off Peak								Off Peak						Peak						Super Off Peak			
	Winter	Super Off Peak								Off Peak						Peak						Super Off Peak			
SDG&E Rate 1C	Summer	Off Peak						Partial Peak					Peak							Partial Peak				Off Peak	
	Winter	Off Peak						Partial Peak											Peak			Partial Peak		Off Peak	
SDG&E Rate 2C	Summer	Off Peak						Partial Peak								Peak							Partial Peak		
	Winter	Off Peak						Partial Peak											Peak				Partial Peak		

Weekend Rate Periods

Tariff	Season	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E Rate 1C	Summer	Off Peak																	Partial Peak			Off Peak			
	Winter	Off Peak																							
PG&E Rate 2C	Summer	Off Peak																							
	Winter	Off Peak																							
SCE Rate 1C	Summer	Super Off Peak								Off Peak												Super Off Peak			
	Winter	Super Off Peak								Off Peak												Super Off Peak			
SDG&E Rate 1C	Summer	Off Peak																							
	Winter	Off Peak																							
SDG&E Rate 2C	Summer	Off Peak						Partial Peak																	
	Winter	Off Peak						Partial Peak																	

E-4. Modeling the Shape Service Type: Rate Mix Assumptions

In Figure E-1 below, we illustrate the hourly TOU pricing structure for PG&E's option 2[48]and SCE's Option 3[49], from the Residential TOU pilot Advice Letters filed in the December 2015. PG&E's Option 2 features a peak period from 6-9 p.m. during all seasons, with an addition off-peak from 4-6 p.m. and 9-10 p.m. in the summer. SCE's Option 3 features similar, but longer, peak (4-9 p.m.) and partial peak (11 a.m.-4 p.m. and 9-11 p.m. in the summer) periods, with an additional "super off-peak" period from 11 a.m. to 4 p.m. in the Spring. These two rate structures, along with a standard flat rate and a CPP option, are combined to generate the three rate mixes used in this study (Table E-4).

[48] PG&E AL 4764-E Residential TOU pilot rates https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4764-E.pdf

[49] SCE AL 3335-E and 3335-E-A Residential TOU pilot rates https://www.sce.com/NR/sc3/tm2/pdf/3335-E-A.pdf

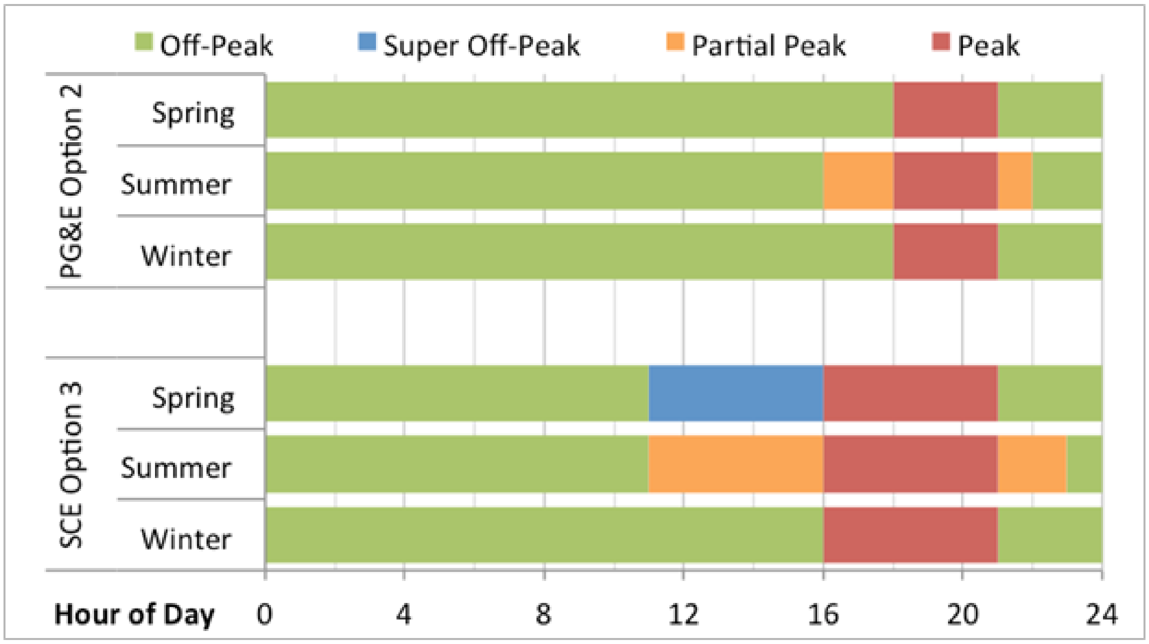


Figure E-1: Time of Use hourly structure for PG&E Option 2 and SCE rate option 3 Peak,Off-Peak, Super Off-Peak, and Partial Peak periods.

Table E-6: Shape Resource Retail Rate Mixes

	Residential			**Non-Residential**
	Default	**Opt-in**	**Default Opt-out**	
Rate Mix 1	PG&E Opt 2	SCE Opt 3	PG&E Flat	TOU and CPP impacts derived from Christenson, 2015.
Rate Mix 2	PG&E Opt 2	CPP	PG&E Flat	
Rate Mix 3	PG&E Opt 2	--	PG&E Flat	

Below we describe the assumptions and methods for each of the Rate Mixes.

Rate Mix #1 is structured as follows for all residential customers in the IOU service territories:

- ✓ PG&E Option #2 as the default rate with 75% enrollment
- ✓ SCE Option #3 as an opt-in rate with 15% enrollment
- ✓ Standard rate for customers that opt out of the default tariff with 10% enrollment

In Phase 2 of the study, we examined a moderate TOU scenario from PG&E's option #2 scenario. The structure of this rate included a summertime peak price signal. The load impacts were derived from existing literature on elasticities from summertime TOU pricing pilots, of which there is a large body of empirical research. Figure E-1 above illustrates the structure of the PG&E Option #2 Pilot Tariff that was used in Phase I and also here in Phase II of the DR Potential Study analysis.

Of interest to the Commission is the inclusion of a multi-season, moderately aggressive residential TOU rate scenario that includes focused load building during times when there is often a surplus of generation. We used SCE's option #3 rate design from the 2016 Residential TOU Pricing Pilots in the study. This design includes three seasons, with the following price signals: off-peak, super off peak, partial-peak, and peak. The super off peak price signal intends to encourage consumption during hours when renewable generation is high and loads are typically low, while the peak and mid-peak rates encourage load reduction later in the evening, (the Option #3 rate captures the shift in peak to 5-9 pm, away from the conventional 12-6 pm).

It is important to note that SCE, PG&E and SDG&E are conducting "Matinee Pricing" pilots that are utilizing retail rates and incentives to address excess supply and renewable integration challenges. The Matinee Pricing ACR directed Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) to each develop a tariff that would encourage a shift in energy use by commercial, industrial, and agricultural users to alternative times of the day when abundant renewable and low-water-using energy are produced. the In Decision 16-11-021 and D.14-05-025, the Commission authorized the IOUs to conduct DR and pricing pilots, to explore how retail rates and DR programs could ease situations of over-generation, or excess supply, from the integration of solar and wind power supplies on the grid by shifting load consumption.

In Rate Mix #1, our estimates are based on an opt-in implementation of SCE option #3, with the PG&E #2 as the default tariff. We worked closely with Nexant and Energy Division staff to develop the enrollment/ acceptance rates for this scenario. Nexant developed the residential load impact estimates for each of the Rate Mixes used in the study.

In our analysis of TOU/CPP as a Shape resource, we examine TOU that results in shifting, and refer to this resource as a Shape-as- Shift resource. In the evolving grid with large shares of generation covered by renewables, large ramps occur almost on a daily basis. Our model estimates these future TOU rates can shift loads to fill the newly-established daytime valley and shave evening and morning peaks on a daily basis, perhaps with a CPP signal for more extreme days.

We have been mindful of seasonality and the challenges of estimating load impacts for TOU schedules that send mid-day price signals for consumption that differ from conventional TOU that focuses on evening peak reduction. With the exception of the 2003/2004 Statewide Pricing Pilot (SPP), which included winter events, nearly all of the pilots and program have focused TOU in summer months and mid-day loads. For SCE's Options #3 and ultimately for Rate Mix #1 of the study, the Nexant team applied the price elasticities from the SPP, Nexant's load impact evaluations of TOU and CPP programs throughout the state, and the Christensen study to produce increases in energy use during daytime hours; however we must note that these load impact estimates are a stretch for the empirical data. For future research, the applied empirical findings from the 2016 IOU residential pilot evaluations, due early 2017, will provide better evidence on elasticity for new TOU structures, albeit they were not available to incorporate into Phase 2 of our study.

Rate Mix #2 is structured as follows for all residential customers in the IOU service territories:

- ✓ PG&E Option #2 as the **default** rate with enrollment at 90% of customers.
- ✓ Critical Peak Pricing (CPP) as an **opt-in** rate with a 15% customer enrollment rate.
  - Customers that opt-in to the CPP rate are also enrolled in the PG&E Option #2 TOU rate (dual participation).
- ✓ PG&E Standard flat rate for 10% of customers that **opt out** of the default tariff

We consider CPP as a price signal that is event based with day ahead notification. Manual and automated response (e.g. PCTs) to CPP are included in the 2020 and 2025 DR potential forecasts. The CPP rate option is structured as a 5-9 pm event based price signal. We will coordinate with Nexant and Energy Division staff on the price ratios to be used in the residential CPP rate scenario. Based on the existing literature and evaluations from the CA IOUs, we will work with Nexant to evaluate and develop impacts for event based CPP rates for residential customers.

Rate Mix #3 is structured as follows, and maintains the same assumptions as the PG&E Option #2 rate explained under rate mix #1 and #2.

- ✓ PG&E Option #2 as the **default** rate with enrollment at 90% of customers.
- ✓ PG&E Standard flat rate for 10% of customers that **opt out** of the default tariff

E-5. Commercial and Industrial Customers Price Response and Time Varying Pricing Model Assumptions

For the commercial and industrial sectors, we relied on the empirical research conducted by Christensen and Associates that examine the effects of TOU and CPP pricing on load.[50] Since the majority of C&I customers in California are now on TOU rates, and many also on CPP rates, the impacts are largely embedded in the existing load profiles, with the exception of SMB customers, who have recently been moved to TOU pricing. For the SMB customers, several research efforts collected data on customers pre and post enrollment on the TOU rates, as well as holding some customers as control groups as the rates were rolled out over a period of a few years. Therefore, the SMB customers for SCE and PG&E in particular have more robust estimates of the TOU impacts. For the large C&I customers, almost all customers have been on TOU rates for a number of years, so estimating the impact of TOU is more challenging, and for our analysis, we assume that there is a 3% reduction for all seasons and periods for large commercial and industrial customers (greater than 200 kW). During our analysis, we followed the same process for estimating the large C&I CPP impacts as was done in the Statewide Time-of- Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report. We also use the TOU and CPP impacts for the SMB customers that were calculated in the Christensen report. Below, we describe at a high level the process, assumptions, and load impacts used for the C&I sector CPP load impacts.

E-5.1. Time of Use Periods for Commercial and Industrial Customers

For our analysis of the SMB customers for each IOU, we use the impacts from Table 5.3 from the Statewide Time-of- Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report (below in Table E-4), for understanding the embedded TOU response in our 2014 load profile data sets. These load impacts estimates are based on 2014 load impact studies for the TOU rates currently in effect for each IOU. We assume that with new proposed TOU peak/off-peak/part-peak periods, the response during period types stays the same but that the hours for the off/part/peak periods shift. We assume that there is an embedded 3%

[50] Statewide Time-of- Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report, Christensen & Associates. December, 2015 For more information, see http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207031_20151215T151300_Statewide_TimeofUse_Scenario_Modeling_for_2015_California_Energ.pdf

load reduction for all periods of the day from large C&I customers that will not change. For SMB customers in the SCE and PG&E territories, there is a conservation effect for all hours during each season and peak period.

Table E-7: Table E-4: Source: The Statewide Time-of- Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report, Table 5.3, page 33. Christensen & Associates. December, 2015[51]

Hour	SCE Small C&I	SCE Medium C&I	PG&E Small C&I	PG&E Medium C&I
1	-2.70%	-0.50%	-2.00%	-2.70%
2	-2.90%	-0.80%	-2.20%	-2.40%
3	-2.60%	-0.90%	-1.60%	-2.90%
4	-3.70%	-1.00%	-1.80%	-2.80%
5	-3.00%	0.00%	-0.90%	-2.70%
6	-3.50%	-0.40%	-1.30%	-2.50%
7	-0.60%	-0.50%	-3.30%	-3.10%
8	-2.60%	-0.50%	-2.70%	-2.40%
9	-2.60%	0.10%	-3.00%	-2.10%
10	-2.60%	0.00%	-2.90%	-2.00%
11	-2.40%	-0.20%	-2.70%	-2.10%
12	-2.60%	-0.60%	-2.60%	-2.10%
13	-2.70%	-0.30%	-2.60%	-2.20%
14	-3.10%	-0.40%	-2.20%	-2.30%
15	-2.80%	-0.40%	-2.00%	-2.20%
16	-2.50%	-0.40%	-1.90%	-2.40%
17	-2.60%	-0.30%	-1.80%	-2.60%
18	-2.20%	-0.30%	-2.00%	-2.50%
19	-2.10%	-0.10%	-2.20%	-2.30%
20	-3.10%	-0.20%	-2.40%	-2.50%
21	-3.90%	-0.50%	-2.80%	-2.90%
22	-3.80%	-0.60%	-2.20%	-2.20%
23	-3.60%	-1.00%	-2.20%	-2.30%
24	-2.80%	-1.40%	-2.10%	-2.80%
Peak	-2.60%	-0.40%	-2.10%	-2.40%
Part Peak	-3.00%	-0.40%	-2.50%	-2.30%
Off Peak	-2.70%	-0.70%	-2.10%	-2.60%

[51] For more information, see http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207031_20151215T151300_Statewide_TimeofUse_Scenario_Modeling_for_2015_California_Energ.pdf

We adapted the existing TOU period to reflect the proposed TOU rates schedules for C&I customer that shift the peak periods to the later evening hours, and introduce mid and off peak periods in the middle of the day. The steps we followed to estimate the TOU and CPP impacts for the commercial customers are as follows:

1) Based on the old time period and without including CPP, estimate the counterfactual baseline flat rate load by doing an inverse TOU load impact using the "OLD" off/part/peak hours.

2a) Find the "new TOU" load impacts by applying the TOU rates to the flat rate, but using "new" off/part/peak hours.

2b) Find the "new TOU+CPP" load impacts by applying the TOU+CPP rates to the flat rate, using new off/part/peak hours.

In Figure E-2 below, the output of our new TOU load impacts for SMB and large C&I with CPP adder of $0.50 is provided as an example. In Table E-5, we provide the input table of price response load impacts for each of the customer sectors and periods that was used in our analysis of Commercial time varying rate price responsiveness.

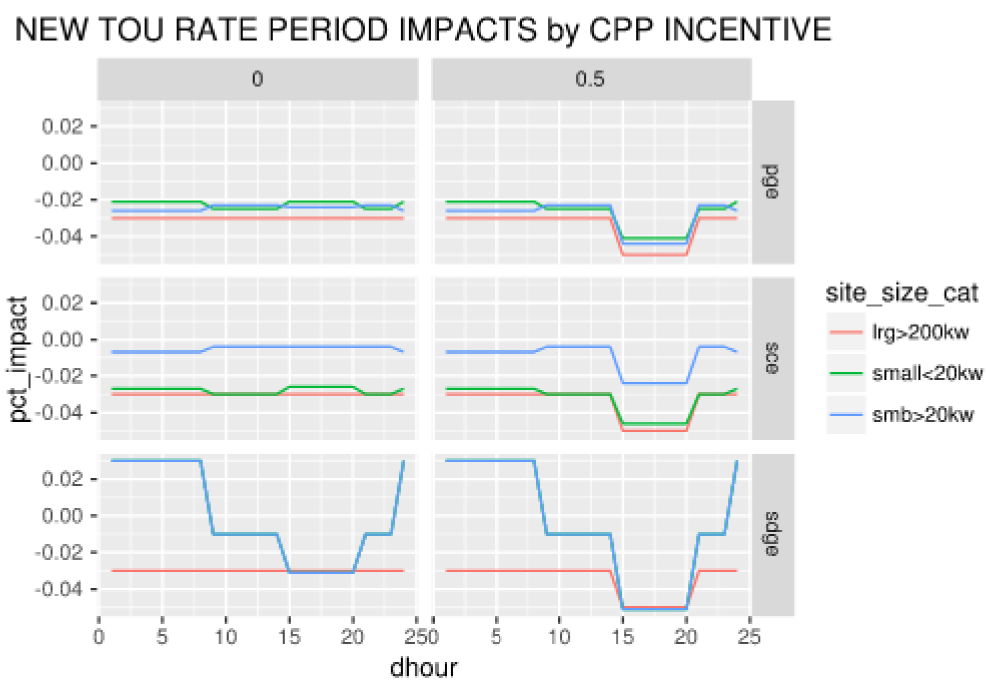


Figure E-2: Commercial customer modified TOU rate period load impacts with CPP adder used in the DR Futures model.

Table E-8: Table E-5: TOU and CPP load impacts by peak period, season and customer sector used in the DR Futures model.

Period	Util	Site_Size_Cat	Pct_Impact	Cpp_Impact
Peak	Sce	Small<20kw	-0.026	-0.02
Part	Sce	Small<20kw	-0.03	0
Off	Sce	Small<20kw	-0.027	0
Peak	Sce	Smb>20kw	-0.004	-0.02
Part	Sce	Smb>20kw	-0.004	0
Off	Sce	Smb>20kw	-0.007	0
Peak	Sce	Lrg>200kw	-0.03	-0.02
Part	Sce	Lrg>200kw	-0.03	0
Off	Sce	Lrg>200kw	-0.03	0
Peak	Pge	Small<20kw	-0.021	-0.02
Part	Pge	Small<20kw	-0.025	0
Off	Pge	Small<20kw	-0.021	0
Peak	Pge	Smb>20kw	-0.024	-0.02
Part	Pge	Smb>20kw	-0.023	0
Off	Pge	Smb>20kw	-0.026	0
Peak	Pge	Lrg>200kw	-0.03	-0.02
Part	Pge	Lrg>200kw	-0.03	0
Off	Pge	Lrg>200kw	-0.03	0
Peak	Sdge	Small<20kw	-0.031	-0.02
Part	Sdge	Small<20kw	-0.01	0
Off	Sdge	Small<20kw	0.03	0
Peak	Sdge	Smb>20kw	-0.031	-0.02
Part	Sdge	Smb>20kw	-0.01	0
Off	Sdge	Smb>20kw	0.03	0
Peak	Sdge	Lrg>200kw	-0.03	-0.02
Part	Sdge	Lrg>200kw	-0.03	0
Off	Sdge	Lrg>200kw	-0.03	0

E-5.2. CPP load impacts for Commercial and Industrial Customers

Assumptions for the CPP load impacts are summarized below:

- **For small C&I customers (under 20kW):**
  - For PG&E and SCE, load impacts were assumed to be 2 percent during event hours and zero elsewhere;
  - For SDG&E, we assumed no load impacts from these customers, which is consistent with their findings and assumptions to date.
- **For medium C&I customers (20 to 200kW):**
  - For PG&E and SCE, load impacts were assumed to be 1.5 percent during event hours and zero elsewhere;
  - For SDG&E, the load impact percentage is based on a 2.5 percent "base" value that is adjusted downward due to customer awareness assumptions. This results in load impacts of roughly 2.2 percent in later years (2020 and 2025).
- **The CPP event hours are assumed to be the following:**
  - PG&E: 4 to 9 p.m.
  - SCE: 2 to 8 p.m.
  - SDG&E: 2 p.m. to 9 p.m.

E-5.2.1. CPP Enrollment Assumptions

- **For PG&E, the enrollment assumptions are:**
  - In the current ex-ante forecast, 33% opt out after default and 20% opt out after bill protection expires;
  - In the high enrollment scenario for this study (Scenarios 1 and 2), 15% opt out after default and 10% opt out after bill protection expires; and
  - In the low enrollment scenario for this study (Scenario 3), 60% opt out after default and 40% opt out after bill protection expires.
- **For SCE, the enrollment assumptions are**:
  - In the low enrollment scenario for this study (Scenario 3), which matches the ex-ante forecast, 50% opt out prior to CPP enrollment and 60% opt out after bill protection expires;
  - In the high enrollment scenario for this study (Scenarios 1 and 2), 25% opt out after default and no customers opt out after bill protection expires.

Appendix F: Propensity Score Model

The magnitude of DR resources that can be acquired is fundamentally the result of customer preferences, program or offer characteristics (including incentive levels), and how programs are marketed. How predisposed are specific customers to participate in DR? What are details of specific offer and how do they influence enrollment rates? What is the level of marketing intensity and what marketing tactics are employed? Enrollment rates are a central element of estimating achievable DR potential.

The approach employed to estimate participation rates involved five general steps, the details of which are explained in the following sections;

1. Estimate an econometric choice model based on who has and has not enrolled in DR programs in order to produce information about predisposition or propensity of customer to participate based on their characteristics

2. Incorporate information from empirical studies in California about how different offer characteristics influence enrollment likelihood. This includes characteristics such incentive levels and requirements for installation.

3. Incorporate information from empirical studies in California about how marketing tactics and intensity of marketing influence participation rates.

4. Calibrate the models to reflect actual enrollment rates attained with mature programs given the incentive levels offered and the amount and type of marketing that has taken place

5. Predict participation rates using low, medium, and high levels of acquisition marketing for programs with and without installation requirements for various incentive levels.

Utilities provided granular customer data regarding DR participation, acquisition marketing information, prior study results, and information regarding the number of touches across direct mail, phone and email marketing to customers.

Estimates of a customer propensity to participate in DR programs were developed for each for the customer types, and divided in to segmentation groups according to size, region, industry, and low-income status as needed for each customer type. The enrollment likelihood estimates were then adjusted based on the incentive magnitude, level of marketing effort, and/or expected dispatch of the program.

Error! Reference source not found. summarizes achievable enrollment rates for residential ustomers as a function of incentive levels and marketing intensity. Attainable participation rates range between 20% and 30% for eligible customers, with higher levels of marketing intensity. The participation estimates are linked the eligibility, which is often related to whether a customers have a specific end use. In a territory like SDG&E's, where approximately 50% of customers have central air conditioners, the achievable penetration as a percentage of the population would be half as large as shown in the figure because only half of the customers meet pre-requisite eligibility criteria. The participation rates increase with higher incentives, but higher incentives have diminishing returns. Overall enrollment rates reflect the cumulative effect of repeated attempts to enroll customers.

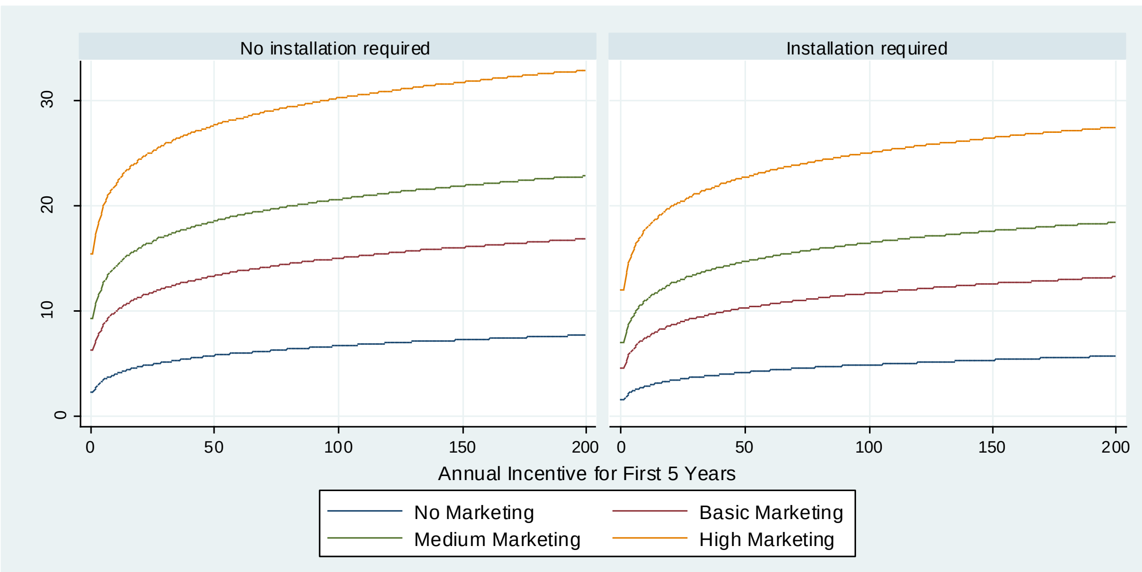


Figure F-1: Achievable Residential Participation Rates by Incentive and Marketing Level

Error! Reference source not found. summarizes achievable enrollment rates for small and edium customers as a function of incentive levels and marketing intensity. At the highest, the projections for SMB customers are roughly half of residential achievable participation rates. They are substantially lower when installations are considered. Historically, small and medium businesses have been difficult to enroll in demand response, energy efficiency, or pricing programs. They tend to lack dedicated energy managers, often are busy and thus difficult to engage, and prefer to avoid interruptions to their businesses.

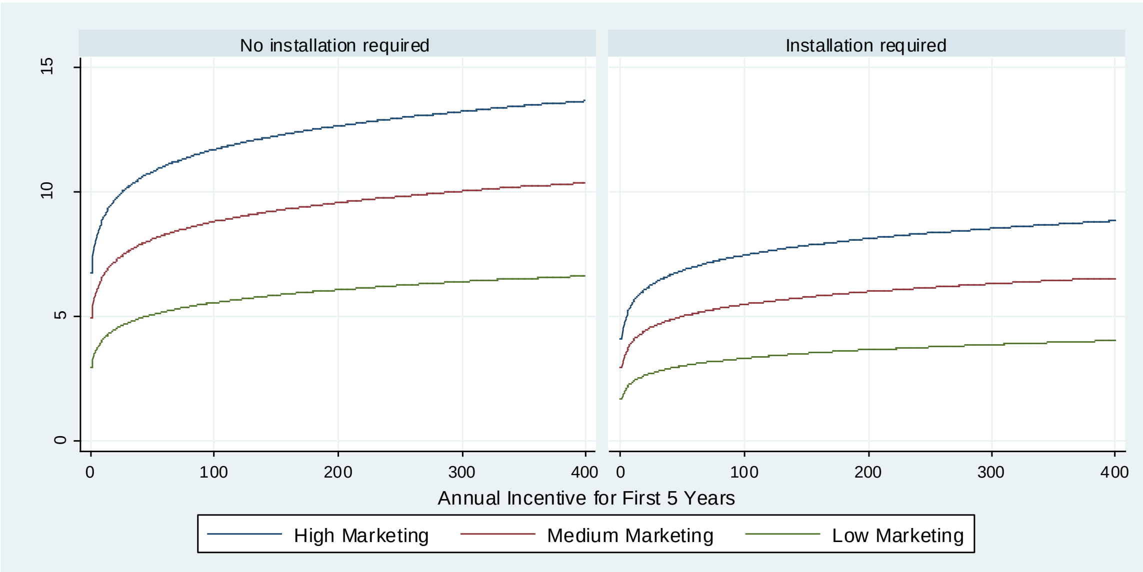


Figure F-2: Achievable Small and Medium Business Participation Rates by Incentive and Marketing Level

For large C&I customers (>200 kW), the achievable participation rates vary based on a number of factors: industry, customers size, incentive levels, and the expected number dispatch hours (which is different than a cap on annual dispatch hours). **Error! Reference source not found.** ummarizes overall enrollment rates a functions of incentives, in $kW-year, and different expected number of dispatch hours. The projected participation rates do not reflect policies such as default critical peak pricing and simply reflect opt-in participation in programs.

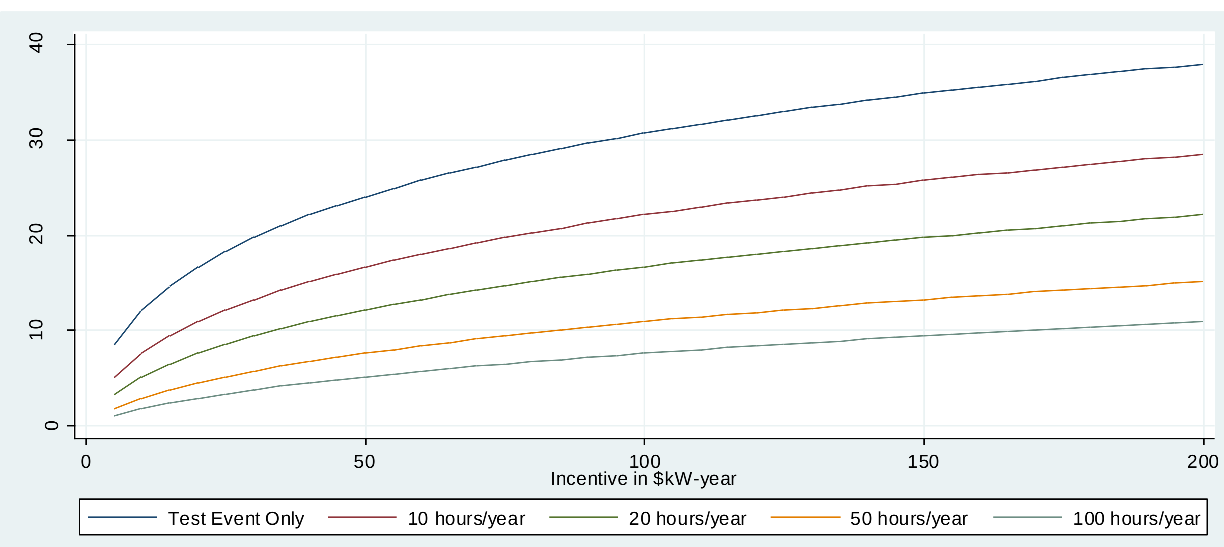


Figure F-3: Achievable Large C&I Participation Rates by Incentive and Average Annual Dispatch Hours

Enrollment levels are lower when large customers are dispatched more frequently but are paid the same incentive. A key question is how to better integrate DR into markets without exhausting it prematurely. In the case of HVAC loads, DR resources typically have low or no start-up costs and can deliver demand reductions for a short time period at little or no cost because of inherent storage in the form of heating and cooling. However, the more often and the longer DR is dispatched, the more expensive it becomes for businesses to sustain the reduction. Customers do not necessarily forego production when they reduce demand; more often than not, they either reduce a nonessential end-use load or are able to shift production to a different time period or day. Frequent or prolonged dispatch can inhibit the ability to shift or make up production for consumers who rely on this means to provide demand response.

F-2. Enrollment rates

The magnitude of DR resources that can be acquired is fundamentally the result of customer preferences, program or offer characteristics (including incentive levels), and how programs are marketed. How predisposed are specific customers to participate in DR? What are details of specific offer and how do they influence enrollment rates? What is the level of marketing intensity and what marketing tactics are employed? Enrollment rates are a central element of estimating achievable DR potential.

Many DR potential studies rely on top down approaches, which benchmark programs against enrollment rates that have been attained by mature programs. This approach, however, has several drawbacks in the context of California.

The study is designed to include the next generation of DR applications, which not only includes meeting peaking capacity, but also new and recent applications such as resources to meet longer and larger sustained ramps (ramping capacity), fast response to address renewable volatility and multiple up and down ramps throughout the day, and shifting of loads to avoid over-generation in the middle of the day. For most of these applications, there are no mature existing programs against which to benchmark.

Aggregated program results often do not provide enough detail to calibrate achievable market potential. In many cases, programs are not marketed to all customers, either because of it is not cost-effective to market to all customers or budgets are limited. Enrollment rates are a function of specific offers and the extensiveness of marketing over many years. They also vary based on the degree to which DR resources are utilized. Enrollment rates tend to be higher when payments are high but actual events are infrequent, particularly among large C&I customers.

Many jurisdictions rely on back-up or behind the meter generation for DR. California customers are required to deliver reductions and are not allowed to fire up back-up generators in response to curtailment events. Many jurisdictions including PJM, NYISO, and ISO-NE, a substantial share of DR, roughly 30–40%, is delivered via backup generation and not delivered through load reductions.

DR programs have been exhaustively marketed to large C&I customers. Every large customer at PG&E, SCE, and SDG&E has been offered several types of DR options and has made a decision about whether or not to participate.[52] As a result, approximately 35% and 70% of large non-residential customers and loads, respectively, are enrolled in some type of DR program. On the other hand, mass market programs for residential customers and small and medium businesses have relied on highly targeted efforts due to the substantial differences in climate and end-use saturation across California.

The optimal approach for estimating enrollment levels is to rely on choice models that quantify three main components: which customers are more predisposed to enroll, how the offer/program characteristics influence enrollment rates (e.g., number of events, penalties, incentive levels, need to install devices, etc.), and how specific marketing tactics such marketing approach (i.e., direct mail, phone, or door-to-door), number of times a customer is contacted and other marketing factors influence participation rates. The approach employed to estimate participation rates involved five general steps, the details of which are explained in the following sections;

1. Estimate an econometric choice model based on who has and has not enrolled in DR programs. The goal of this model is to estimate the pre-disposition or propensity of customers to participate in DR based on their characteristics.

2. Incorporate information about how different offer characteristics influence enrollment likelihood. What is the incremental effect of incentives? How do requirements for on-site installation affect enrollment rates? The two questions above have been analyzed using

[52] In response to the California energy crisis, several specific policies were implemented to attain high saturation levels of DR among large commercial and industrial customers. In 2003, all large commercial and industrial customers above 200 kW were placed on mandatory TOU rates with peak demand charges. This was followed by in person outreach by utility account representatives to each customer with maximum demands above 500 kW in order to offer and explain DR opportunities. Shortly after, utilities entered into contracts with aggregators to help recruit additional DR resources. Aggregators targeted the next tier of non-residential customers (200-500 kW). In 2008–2010, the major California utilities implemented default critical peak pricing for all customers above 200 kW that had not yet enrolled in DR programs.

California specific data for residential customers. In each case, regression coefficients describe the incremental effect of each of the above factors on participation rates.

3. Incorporate information about how marketing tactics and intensity of marketing influence participation rates. What is the effect of incremental acquisition attempts? Is there a bump in enrollment rates when phone and/or door-to-door recruitment is added to direct mail recruitment?

4. Calibrate the models to reflect actual enrollment rates attained with mature programs. To calibrate the models the constant is adjusted so that the model produces exactly the enrollment rates observed by mature programs used for benchmarking.

5. Predict participation rates using specific tactics and incentive levels for programs with and without installation requirements. The enrollment estimates were produced for low, medium, and high marketing levels, where specific marketing tactics are specified for each scenario. All estimates reflect enrollment rates for eligible customers. For example, if 25% of eligible customers can be enrolled but only 40% have central air conditioners, the attainable penetration rate for AC load control is 10% (25% x 40%). The assumptions about marketing tactics underlying the enrollment projections are not prescriptive. Utilities can attain the enrollment levels in a number of ways.

Section F-4 provides a conceptual overview of probit models and background to understand how coefficients can be extracted from aggregate level tests.

F-3. Key Assumptions and Data Sources

Error! Reference source not found.1 summarizes the data sources employed for each step of he estimation and model calibration. The data used to estimate enrollment predisposition and to calibrate results reflect a compromise between incomplete data and the need to produce the results given those constraints. While data including participation and acquisition marketing was provided for various DR programs, this list was not complete and only included marketing touches for one to two years. Any effect of acquisition marketing must then be interpreted only as the incremental effect of marketing; in all likelihood most customers had already been receiving marketing materials prior to what was delivered.

Table F-2: Data sources and calculations employed

Step		Residential	Small and medium businesses	Large C&I
1	Econometric choice model to establish pre-disposition or propensity to participate	▪ SCE and PG&E air conditioner load control program and opt-in Peak Time Rebate data were used to estimate base propensity to enroll. ▪ Adjusted for eligibility by including air conditioner likelihood variable in econometric model and estimating propensity only for customers who were marketed to, then predicted for the full population.	▪ The pre-disposition of specific industries/building types to participate was estimated using customers with less than 400 kW in annual max demand. ▪ The propensity of customers to enroll in DR were estimated using customers who were marketed to, then predicted for the full population	▪ Large customer participation data at PG&E, SCE, and SDG&E. ▪ Enrollments from default CPP were screened out since the focus was on program enrollment. ▪ Assumes all large customers have been offered DR options by account representatives or aggregators
2	Effect of offer characteristics	▪ Effect of incentive level is based on PG&E publicly available choice analysis of various incentive levels.[53]	▪ Incentive level coefficient from residential model used and adjusted downward by 25%	▪ Effect of incentives and average number of events derived by comparing customers with enough load to be eligible for BIP on

[53] George, Bode, Perry, and Goett (2010). 2009 Load Impact Evaluation for Pacific Gas and Electric Company's Residential SmartRate, Peak Day Pricing, TOU Tariffs, and SmartAC Programs: Volume II. PG&E implemented a number of marketing tests. The analysis and results are detailed in Section 4.1 of Volume II.

Step		Residential	Small and medium businesses	Large C&I
		▪ Effect of installation requirements on enrollment assessed by comparing SmartAC and SmartRate enrollment after controlling for customer characteristics, incentive levels and marketing offers.	▪ The effect of the installation requirement was doubled. This was a judgmental adjustment based on experience with field recruitment.	their own (>100 kW on a 24/7 basis) versus incentives and participation by customers too small to participate on BID on their own.
3	Influence of marketing tactics and intensity of marketing	▪ Decreasing effect of incremental touches is derived from publicly available choice analysis. ▪ Effects of phone, and door-to-door marketing were derived from field experience from PG&E's ancillary service pilot.[54]	▪ Incentive level coefficient from residential model used and adjusted downward by 40%	▪ No known variation in marketing techniques. Assumes phone calls plus in-person follow up by account representatives or aggregators.
4	Calibration and benchmarking	▪ Models were calibration to participation levels attained by mature DLC programs, after controlling for AC saturation.	▪ Calibrated to SDG&E Summer Saver non-residential program. It is one of the SMB programs with the highest penetration in the U.S.	▪ No calibration used. This approach assumes that additional reductions and grid applications will come from increasing reductions

[54] Sullivan, Bode, and Mangasarian (2009). 2009 Pacific Gas and Electric Company SmartAC Ancillary Services Pilot. See section 4.4 Enrollment/Recruitment.

Step	Residential	Small and medium businesses	Large C&I
			and/or DR automation from existing participants.

For residential customers, the propensity to participate in demand response programs were developed using SCE and PG&E participation for air conditioning load control and PTR programs. Propensities were estimated using customers who had been marketed to in either 2014 or 2015; therefore the propensity to enroll implicitly assumed customers were eligible for the program. This estimation was done across groupings of customer characteristics, including geography, customer size, and low income status as identified by participation in CARE.

The propensity scores were estimated using a probit model that took in to account both the likelihood of owning air conditioning and an indicator variable that identified if a customer was in a grouping of customers within a particular climate zone, decile of annual usage, and whether they were enrolled in CARE. The estimated constant and coefficient from the customer grouping can be interpreted as the propensity of that group to enroll in a DR program, adjusted for eligibility. The models were subsequently calibrated to data regarding penetration as a percentage of eligible sites based on a survey of large mature load control programs.

Enrollment rates for SMB customers (<200 kW) were the most challenging. Until recently, most SMB customers were not eligible for most DR programs, with the exception of AC load control, because they lacked smart meters. Both SDG&E and SCE have marketed load control to SMB customers with package air conditioning units for multiple years, but the granular data for those programs and acquisition marketing campaigns was not available. As a result, the pre-disposition of customers to participate was estimated using customers with annual max demand below 400 kW as a proxy. We then incorporated coefficients quantifying the influence of marketing tactics from residential studies, and calibrated the models based on SDG&E SMB load control penetration. SDG&E has enrolled roughly 4,800 customers and over 11,000 package air conditioning units. In total, we estimate that 6% of SMB eligible customers have enrolled. Historically, enrollment rates for SMB customers have been lower than in any other segment for DR and energy efficiency programs.

Large customer enrollment rates were estimated based on actual participation data. As noted earlier, every large customer at PG&E, SCE, and SDG&E has been offered several types of DR options and has made a decision about whether or not to participate. This approach assumes that additional reductions and grid applications will come from improving or increasing DR automation from existing participants rather than adding a large number of new participants. Enrollments from default CPP were screened out when possible, since the main topic of interest was program enrollment. To assess how the number of expected dispatch hours affects enrollment levels, we incorporated information from the 2012 FERC DR survey, which canvassed utilities that make up over 90% of loads in the U.S.

Error! Reference source not found. summarizes key assumptions about marketing tactics ssociated with different marketing levels. Different marketing levels – low, medium, and high – were constructed to allow customization of marketing tactics and intensity for specific customer types. This allows for value-based targeting approach were segments with a high expected benefits may receive more extensive marketing. The specific tactics included in the low, medium, and high marketing scenarios are not prescriptive but are instead designed to provide concrete details about the assumptions used. There is a wide range of strategies and tactics that can attain the same enrollment levels and utilities should be encourages to develop, test, and optimize their own marketing strategy. In each instance enrollment rates were modeled under a wide range of incentive amounts to allow the potential model to quantify achievable potential with different incentive levels. Marketing levels vary in their cost for outreach, with direct mailers costing $1.50 per mail and $8.50 for each phone outreach.

Table F-3: Summary of Marketing Tactics Underlying Enrollment Rate Projections

Sector	Marketing Component	Marketing Level		
		Low	Medium	High
Residential	Incentive	0-$200 per customer per year	0-$200 per customer per year	0-$200 per customer per year
	Number of marketing attempts	3	5	5
	Outreach mode	Direct Mail	Direct Mail	DM + Phone
	Years to Reach Achievable Potential	3	5	5
	Cost over Campaign per Customer Receiving Marketing	$4.50	$7.50	$14.50 (4*1.5 + 8.5)
SMB	Incentive	0-$200 per control device	0-$200 per control device	0-$200 per control device
	Number of marketing attempts	5	5	8
	Outreach mode	Direct Mail	DM + Phone	DM + Phone
	Years to Reach Achievable Potential	5	5	8
	Cost over Campaign per Customer	$7.50	$14.50 (4*1.5 + 8.5)	$17.50 (6*1.5 + 2*8.5)
Large C&I	Incentive	0-$200 per kW-year	0-$200 per kW-year	0-$200 per kW-year
	Number of marketing attempts	8		
	Outreach mode	In-person account reps or vendors		

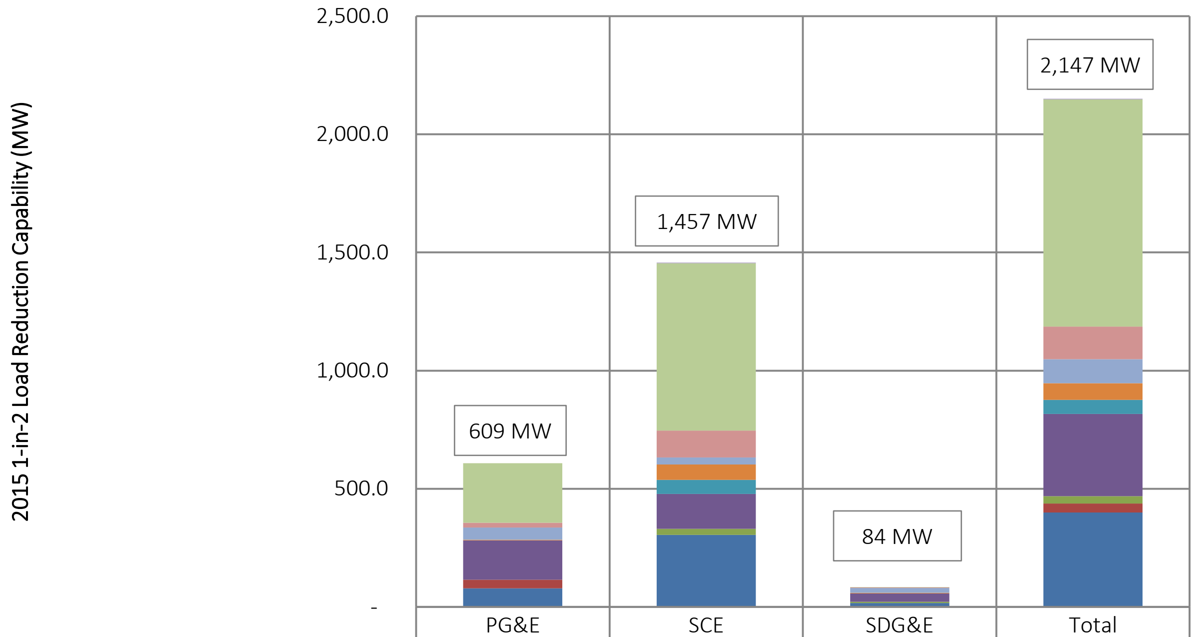
	Years to Reach Achievable Potential	7

Current Participation Rates and Benchmarking

California has several unique aspects that affect DR penetration – a very diverse climate, limited humidity during heat waves, limits on the use of back-up generators for demand response, and TOU rates with large on-peak price signals (for large C&I). For the purpose of this study, it is useful to assess the level of penetration of DR in California, benchmark it with other programs in the U.S. and identify key differences.

Error! Reference source not found. summarizes the demand reduction capability in August 015 under 1-in-2 weather year conditions. For some programs, such as air conditioner load control, the resources available are substantially larger under extreme conditions when they are needed most. Across the three major investor owned utilities, 2,147 MW of load reduction capability was available in 2015. This represents 4.6% of the 1-in-2 weather peak loads in CAISO (47,188).[55]

[55] CAISO. *2015 Summer Loads and Resources Assessment.* Available at: www.caiso.com/Documents/2015SummerAssessment.pdf



	PG&E	SCE	SDG&E	Total
Non-Res - Real time pricing		2.5		2.5
Non-Res - Interruptible rates	252.1	707.8	1.0	961.0
Non-Res - Demand bidding	21.0	114.5	2.6	138.1
Non-Res - Critical peak pricing	51.5	29.8	20.9	102.2
Non-Res - Air conditioner load control	2.7	64.3	3.1	70.1
Non-Res - Agricultural pump control		59.4		59.4
Non-Res - Aggregator programs	165.7	147.2	34.7	347.6
Residential - Peak time rebates		27.0	5.3	32.3
Residential - Critical peak pricing	36.9			36.9
Residential - Air conditioner load control	78.9	304.5	17.0	400.3

Figure F-4: Existing Demand Reduction Capability at California Investor Owner Utilities

Source: Utility Monthly reports on interruptible load and demand response programs. Filed with the CPUC (A.11-03-001).

As part of its annual *Assessment of Demand Response and Advanced Metering*, FERC compares the potential peak reductions in organized markets in the U.S. **Error! Reference source not ound.** shows this summary for 2014. In comparison to the reminder of the U.S., participation in California is lower than what has been achieved elsewhere. However, the comparisons should not be made directly because of differences in what gets classified as Demand Resources (versus Demand Response). Two of the markets with the highest penetration – the ISO-NE and PJM – both include a substantial amount of behind-the-meter generation and energy efficiency. In MISO, over 4,200 MW or roughly 40% of resources are behind the meter generation. Once these adjustments are incorporated, the overall penetration at ISO-NE, MISO, and PJM are 2.5%, 5.3%, and 4.1%, respectively, and are comparable or lower than penetration in California. With the exception of ERCOT, participation of DR is mainly as capacity resources. ERCO is unique in that it relies on DR primarily to deliver synchronized contingency reserves.

Table F-4: Potential Peak Reduction from U.S. Independent System Operators

	2014 Potential Peak Reduction (MW) [1]	% Peak Demand [1]	Includes behind-the-meter generation?	Includes energy efficiency?
California ISO (CAISO)	2,316	5.1%	No	No
Electric Reliability Council of Texas (ERCOT)	2,100	3.2%	Yes, but the amount is not publicly posted	No
ISO New England (ISO-NE)	2,487	10.2%	Yes, approximately 300 MW [2]	Yes, approximately 1600 MW [2, 3]
Midcontinent Independent System Operator (MISO)	10,356	9.0%	Yes, 4,200 MW [4]	No
New York Independent System Operator (NYISO)	1,211	4.1%	Yes, but the amount is not publicly posted	No
PJM Interconnections, LLC (PJM)	10,416	7.4%	Yes, approximately 2,700 MW [5]	Yes, approximately 1100 MW [6]
Southwest Power Pool, Inc. (SPP)	48	0.1%		
Total ISO/RTO	**28,934**	**6.2%**	Over 7,200 MW	Approximatey 2700 MW

[1] FERC (2015). *Assessment of Demand Response and Advanced Metering* . Page 12. Available at: http://www.ferc.gov/legal/staff-reports/2015/demand-response.pdf

[2] ISO-NE Demand Resource Enrollment Statistics as of February 24, 2016. http://iso-ne.com/static-assets/documents/2016/02/a01_intro_drwg_mtg_02_24_2016.pptx

[3] ISO Key Grid and Market Stats. http://www.iso-ne.com/about/what-we-do/key-stats

[4] https://www.misoenergy.org/Library/Repository/Market%20Reports/Demand_Response_Participation.pdf . Publish date 2/02/2016.

[5] PJM 2015 Load Response Activity Report , February 2016. https://www.pjm.com/~/media/markets-ops/dsr/2015-demand-response-activity-report.ashx

[6] Neme, C., Energy Futures Group, and Cowart, R., Regulatory Assistance Project. (2014) *Energy Efficiency Participation in Electricity Capacity Markets – The U.S. Experience.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7303

Comparisons of aggregate resources across utilities are also challenging. We caution against drawing strong conclusions from aggregate program results. Programs are not always marketed to all customers and strategies and incentives to recruitment customers vary substantially. But perhaps most importantly, the share of customers with specific end-uses, such as air conditioners, and the magnitude of those loads can vary substantially. Nowhere is this more evident than for residential air conditioner load control programs.

F-4. Achievable Participation Rates

Error! Reference source not found. summarizes achievable enrollment rates for residential ustomers as a function of incentive levels and marketing intensity. Attainable participation rates range between 20% and 30% for eligible customers, with higher levels of marketing intensity. The participation estimates are linked the eligibility, which is often related to whether a customers have a specific end use. In a territory like SDG&E's, where approximately 50% of customers have central air conditioners, the achievable penetration as a percentage of the population would be half as large as shown in the figure because only half of the customer meet pre-requisite criteria. The participation rates increase with higher incentives, but higher incentives have diminishing returns. Overall enrollment rates reflect the cumulative effect of repeated attempts to enroll customers.

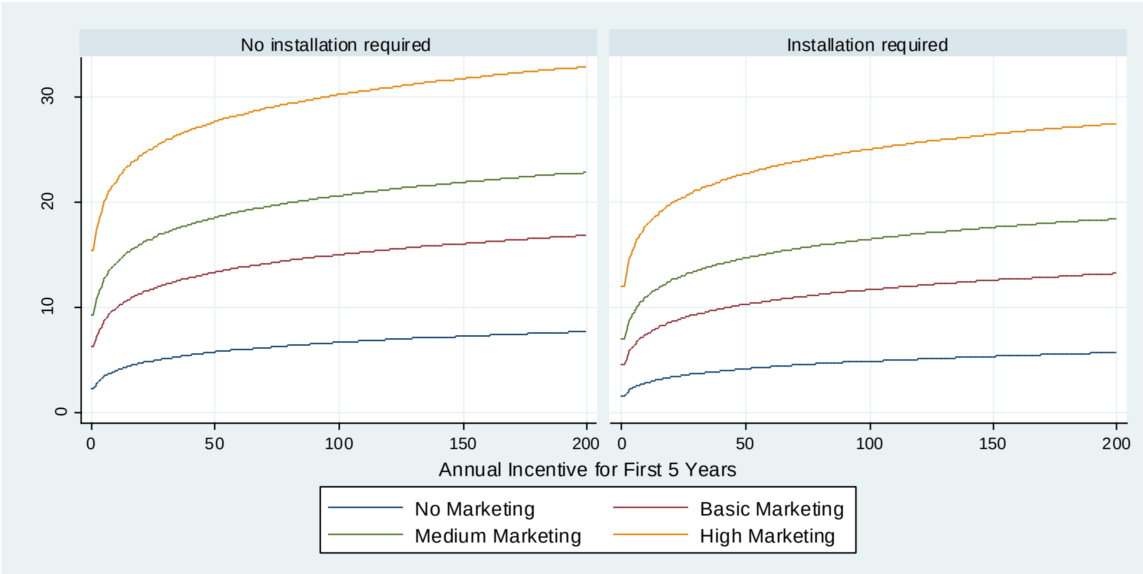


Figure F-5: Achievable Residential Participation Rates by Incentive and Marketing Level

Error! Reference source not found. also summarizes achievable enrollment rates for small and edium customers as a function of incentive levels and marketing intensity. At the highest, the projections for SMB customers are roughly half of residential achievable participation rates. They are substantially lower when installations are considered. Historically, small and medium businesses have been difficult to enroll in demand response, energy efficiency, or pricing programs. They tend to lack dedicated energy managers, often are busy and thus difficult to engage, and prefer to avoid interruptions to their businesses.

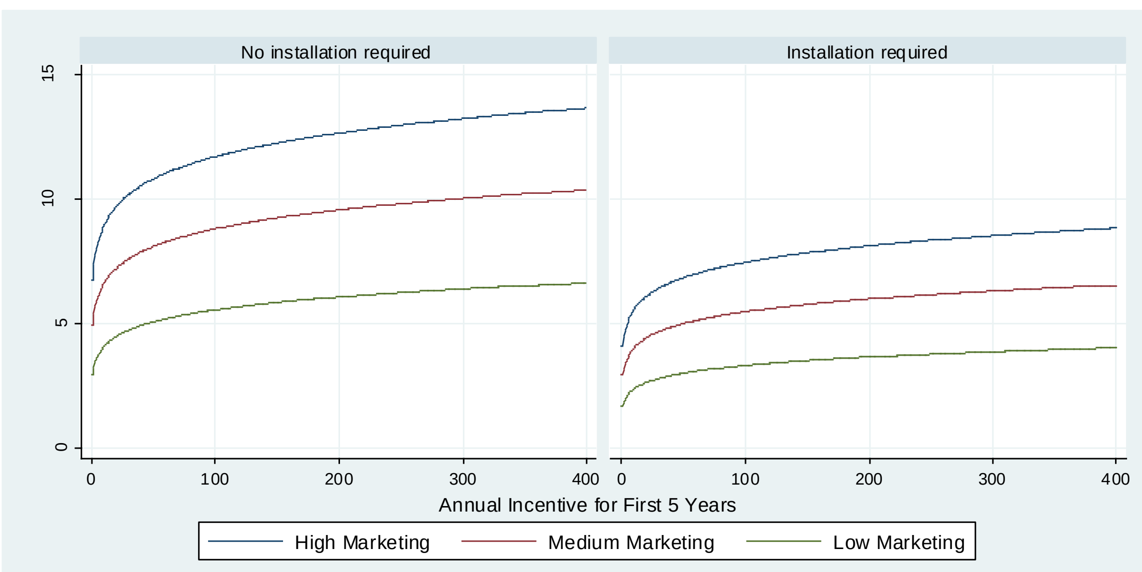


Figure F-6: Achievable Small and Medium Business Participation Rates by Incentive and Marketing Level

Error! Reference source not found. shows how the projected achievable enrollment rates vary y building type, assuming high marketing efforts, and incentives of $50 and $100 per device. Projected participation rates are highest for water pumps, sprinklers, and waste water facilities.

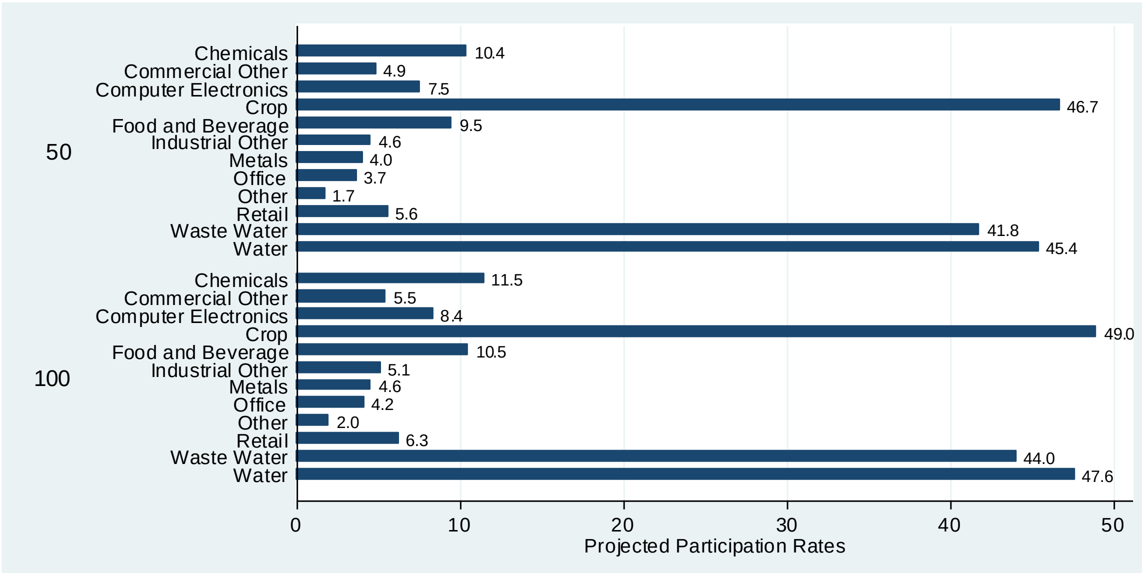


Figure F-7: Comparison of Participation Rates by Industry (High Marketing Scenario)

For large C&I customers (>200 kW), the achievable participation rates vary based on a number of factors: industry, customers' size, incentive levels, and the expected number dispatch hours (which is different than a cap on annual dispatch hours). **Error! Reference source not found.** ummarizes overall enrollment rates a functions of incentives, in $kW-year, and different expected number of dispatch hours. The projected participation rates do not reflect policies such as default critical peak pricing and simply reflect opt-in participations rates into programs. Enrollment levels are lower when large customers are dispatched more frequently but are paid the same incentive.

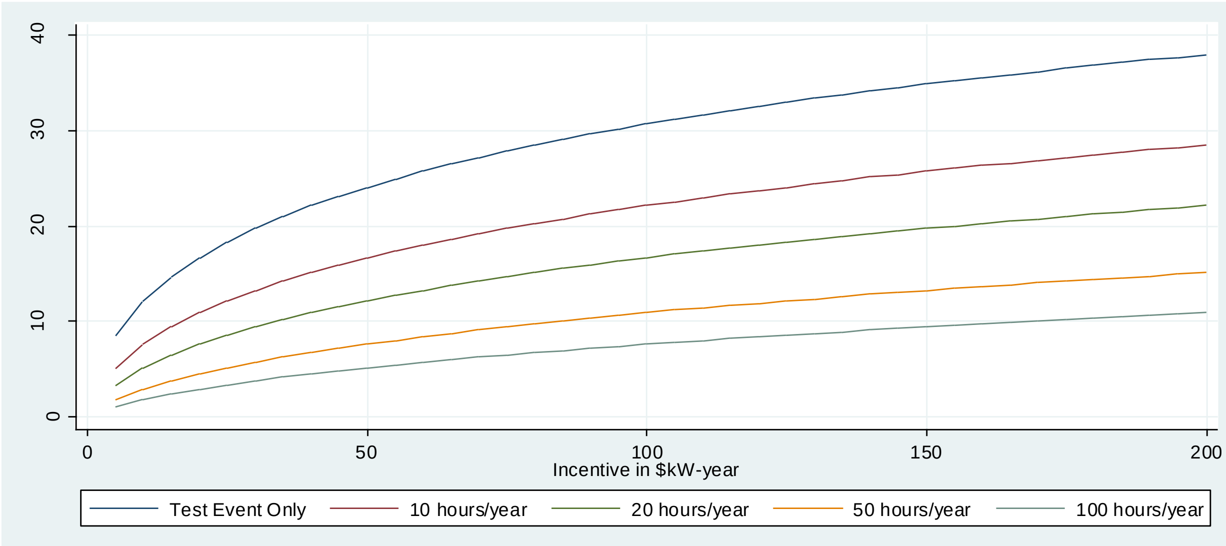


Figure F-8: Achievable Large C&I Participation Rates by Incentive and Average Annual Dispatch Hours

Error! Reference source not found. provides a different perspective and reflects that articipation rates decrease when customers are called more often (holding all other factors constant). A key question is how to better integrate DR into markets without exhausting it prematurely. HVAC end uses typically have low or no start-up costs and can deliver demand reductions for a short time period at little or no cost because of inherent storage in the form of heating, cooling or production stock. However, the more often and the longer DR is dispatched, the more expensive it becomes for businesses to sustain the reduction. Customers do not necessarily forego production when they reduce demand; more often than not, they either reduce a nonessential end-use load or are able to shift production to a different time period or day. Frequent or prolonged dispatch can inhibit the ability to shift or make up production for consumers who rely on this means to provide demand response.

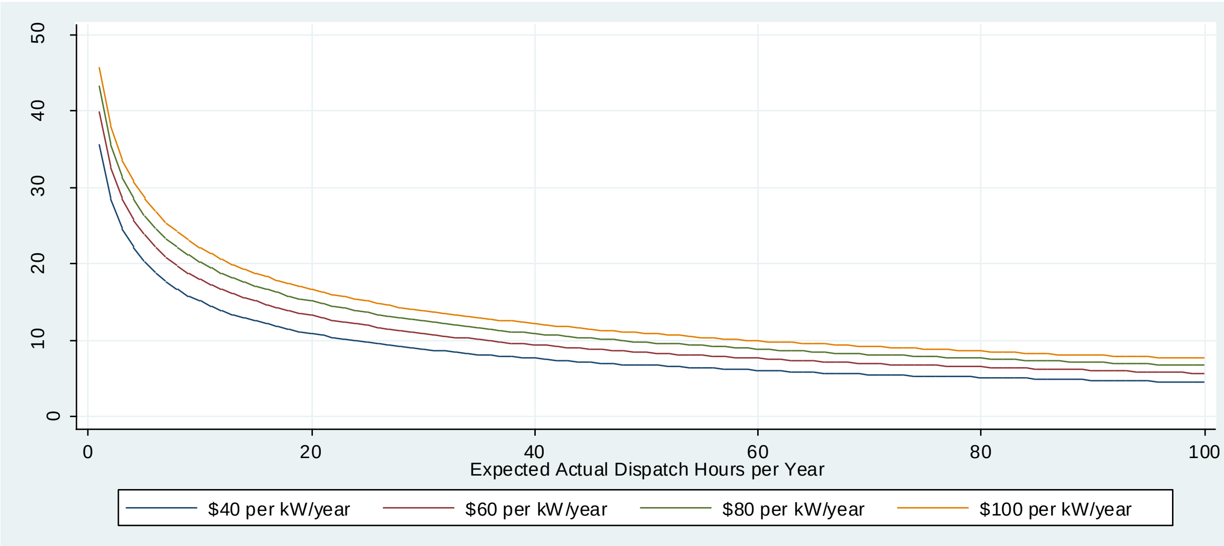


Figure F-9: Large C&I Effect of More Frequent Dispatch on Achievable Participation

Error! Reference source not found.F-4 summarizes achievable participation rates by industry nd size if resources are dispatched on a limited basis, when the system is strained and capacity is needed or as contingency reserves. **Error! Reference source not found.**F-5 shows achievable participation rates with more frequent use, averaging 40 dispatch hours per year. In general industrial facilities are more likely to participate while offices are month the least likely to do so.

Table F-5: Achievable Participation Rates by Industry and Customer Size (%)

(Limited use scenario - $80/kW-year)

Building Type or Industry	Less than 250 MWh	250-500 MWh	500-1,000 MWh	1-2 GWh	2-4 GWh	Over 4 GWh	All
Chemical	14.5	27.8	13.7	12.7	15.6	32.4	27.1
Commercial Other	21.2	36.0	15.6	13.5	19.7	31.8	23.9
Computer Electronics	16.4	29.8	13.2	11.6	15.2	32.6	27.7
Crop	36.2	57.4	38.4	29.8	40.9	43.9	38.0
Data Center			4.7	4.6	6.4	19.8	19.2
Food and Beverage	83.8	39.9	18.0	17.2	24.1	40.2	35.8
Industrial Gas			31.2	35.1	37.8	69.6	69.0
Industrial Other	18.8	33.7	17.4	16.2	22.5	41.0	36.0
Metals	16.2	30.3	16.4	15.5	22.2	39.3	30.7
Offices	10.8	21.7	7.2	6.7	10.3	18.0	13.0
Other	14.0	29.8	14.2	14.1	19.7	14.3	13.2
Petrol	13.2	25.4	10.9	8.7	18.1	53.9	51.3
Plastics and Rubber	35.1	54.6	35.7	31.3	41.7	56.2	51.9
Refrigerated Warehouses	42.8	67.0	34.9	31.0	38.0	48.1	43.5
Retail	32.0	51.2	25.7	27.1	34.4	45.5	32.4
Water	42.7	63.1	34.4	35.7	38.3	35.2	36.7
Waste Water Facilities	28.7	59.4	24.9	24.3	24.8	41.8	37.5

Table F-6: Achievable Participation Rates by Industry and Customer Size (%)

(Frequent use scenario – Avg. 40 hours per year at $80/kW-year)

Building Type or Industry	Less than 250 MWh	250-500 MWh	500-1,000 MWh	1-2 GWh	2-4 GWh	Over 4 GWh	All
Chemical	3.5	9.0	3.3	3.0	4.1	12.1	9.7
Commercial Other	6.1	13.5	4.1	3.3	5.7	11.5	7.9
Computer Electronics	4.1	9.9	3.2	2.7	3.9	12.2	10.0
Crop	13.3	28.8	15.0	10.4	16.8	18.8	15.2
Data Center			0.8	0.8	1.2	5.6	5.4
Food and Beverage	33.7	16.2	5.0	4.7	7.6	16.3	14.0
Industrial Gas			10.8	12.7	15.0	41.0	40.6
Industrial Other	5.1	12.3	4.9	4.5	6.9	17.5	14.8
Metals	4.1	10.2	4.3	4.0	6.6	16.0	11.5
Offices	2.4	6.3	1.4	1.3	2.3	5.1	3.4
Other	3.3	10.2	3.5	3.5	5.6	4.5	3.8
Petrol	3.0	7.9	2.5	1.8	4.9	27.4	25.8
Plastics and Rubber	12.7	26.2	13.3	11.0	17.2	28.1	25.0
Refrigerated Warehouses	18.2	38.8	14.2	11.7	15.5	21.9	19.2
Retail	11.0	23.6	8.2	8.9	12.8	20.3	12.0
Water	17.4	34.0	13.8	14.0	15.7	13.4	14.7
Waste Water Facilities	9.9	30.9	8.8	8.5	8.4	17.6	15.3

F-5. Conceptual Overview of Probit Models

Probit models are non-linear choice models used to estimate the propensity or likelihood of participation. The basis of a probit model is a standardized cumulative normal distribution as shown in Figure F-10. The enrollment likelihood is non-linear and bound between 0% and 100% likelihood.

The coefficients reflect the change in standard deviations due to the explanatory variable. The model is non-linear and, as a result, the effect of specific external interventions, such as incentive level, depends on each customer's starting point. Customers who are highly predisposed against or for participation are less influenced by external factors than customer without strong pre-dispositions. The non-linearity is illustrated in **Error! Reference source not ound.**10. The same change in the standard deviation (equal to a coefficient of 0.5) leads to a different change in enrollment depending on the customers starting point or pre-disposition. For the customer with a strong predisposition against enrollment, the effect of the intervention is to increase the enrollment likelihood from 2.3% to 6.7%. For the customer who is not highly pre-disposed against participation, the same intervention boosts the enrollment probability from 30.8% to 50%.

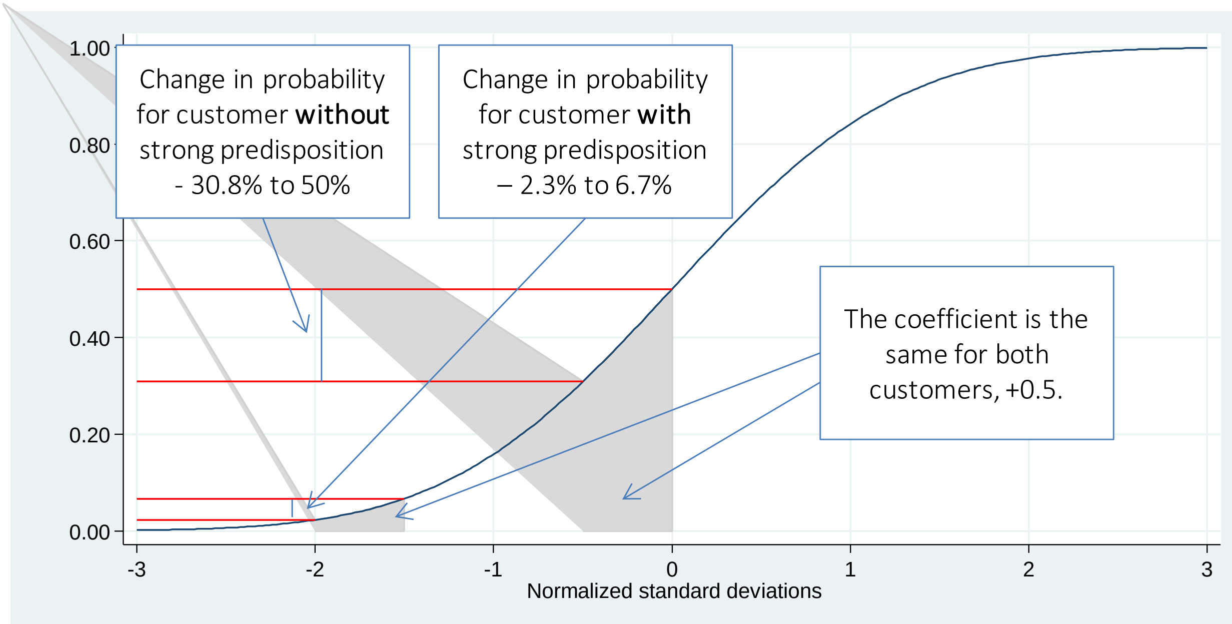


Figure F-10: : Illustration of Non-Linear Pattern of Probit Choice Models.

Appendix G: DR-PATH

This appendix describes the framework of the DR-PATH Model, and explains the inputs to the model. The inputs and underlying assumptions to the DR-PATH Model are contained in a spreadsheet, referred to as the DRPATH-INPUT.

The DR-PATH model estimates the potential to provide grid service with demand response (DR) across a range of technology and market pathways (hence, “DR-PATH”).

The input to the model includes end-use load baseline forecasts (from the LBNL-Load module), a database of assumptions about the cost and performance of DR technology, attributes of the market and value frameworks, and supporting datasets. Using a set of algorithms, the model calculates the expected cost and quantity of DR available for each end-use in each cluster included in the baseline load. For each LBNL-Load scenario (combination of year, weather, and demand level), the DR-PATH module creates multiple DR-level scenarios experiencing varying technology costs, technology capabilities, and customer propensities to enroll. DR-PATH has four broad steps to develop estimates for the cost and quantity of DR available:

1) Compare the dispatch, telemetry, and load control performance attributes of each potential DR technology (in the context of the possible sites) with the requirements for DR products.
2) For DR technology system - product matches, estimate the flexibility potential for qualified loads and develop an estimate of DR capacity or service quantity value for sites that participate through that combined technology and market pathway, adjusted based on assumptions for performance increases if appropriate.
3) Define a set of possible incentives pathways, and compute an estimated enrollment probability (“propensity score”) for the customer based on the offer and their demographic profile (site type, energy use profile, etc.)
4) Estimate the full cost of DR technology from the perspective of an aggregator who pays for technology at the sites, including initial and operating hardware and labor costs, financing premiums, administrative and marketing costs, and incentive payments.

G-1. DR Enabling Technologies

In Phase 1, we developed a framework for characterizing the cost, performance and availability of dispatchable DR technology options as well as load reductions from time-of-use pricing. The end-uses and dispatchable enabling technology included in the model for this report are listed in Table G-1 below.

Table G-1: Summary of enabling technology options included in Phase 2 results.

Sector	End-Use	Enabling Technology Summary
All	Battery-electric & plug-in hybrid vehicles	Level 1 & Level 2 charging interruption
	Behind-the-meter batteries	Automated DR (Auto-DR).
Residential	Air Conditioning	Direct load control (DLC), programmable communicating thermostats (PCT).
	Pool Pumps	DLC
Commercial	HVAC	Depending on site size, energy management system Auto-DR, DLC, and/or PCT.
	Lighting	A range of luminaire, zonal & standard control options.
	Refrigerated warehouses	Auto-DR
Industrial	Processes & large facilities	Automated and manual load shedding & process interruption.
	Agricultural & municipal pumping	Manual, DLC & Auto-DR
	Data centers	Manual DR
	Wastewater treatment	Automated & manual DR

For Phase II, additional DR enabling technologies with faster communication and load data acquisition capabilities were added to the DR-PATH data set. These added “Fast DR” technologies qualify or are expected to qualify for ancillary services and other market products which require faster response to a dispatch signal, with the fastest requirement of 4 seconds for regulation up or regulation down market participation.

As part of the process of determining which end-uses are currently or likely future Fast DR participants, LBNL surveyed a number of DR industry stakeholders (including aggregators, scheduling coordinators, ESCOs, and contractors). Through written surveys responses and interviews with these stakeholders, LBNL obtained data on the configuration and the costs of hardware and installation to enable Fast DR. LBNL also referenced some literature and whitepapers focused on telemetry and communication requirements for Fast DR.

The end-uses eligible for Fast DR LBNL has included in DR-PATH are:

- Agricultural Pumping
- Commercial HVAC (with EMS)
- Commercial Battery
- Commercial BEV and PHEV (fleet and public)
- Commercial Lighting (luminaire and zonal)
- Commercial Refrigerated Warehouses
- Industrial Battery
- Residential Battery
- Residential BEV and PHEV
- Wastewater Process and Pumping

LBNL populated the variable “Site-level communication and control cost” to reflect the added communication and telemetry costs to enable fast DR, additional costs above what would be required for Slow DR. This added cost is assumed to for the entire DR enabled site, rather than by end-use. To account for this in the DR-PATH data set, which is by end-use and not by site, LBNL added a second variable representing the portion of the site-wide cost to allocate to that particular end-use to avoid double counting (assuming the same communication and telemetry infrastructure is used for the whole site across multiple DR-enabled end-uses).

- For commercial sites: LBNL assumes that on average, the end-uses that would be enabled for Fast DR are HVAC, lighting, and storage. For each of these end-uses ⅓ of the site-wide cost is allocated.
- For residential sites: LBNL assumes that AC is the primary Fast DR enabled end-use. Therefore 100% of the site-wide cost is allocated to AC.
- For industrial sites: 100% of the site-wide cost is allocated to storage.
- For BEVs or PHEV, both commercial and residential, both public and fleet, Level 2 charging: 100% of the site-wide cost is allocated.
- For wastewater treatment and pumping sites: 100% of the site-wide cost is allocated.
- For commercial warehouse sites: 100% of the site-wide cost is allocated.
- For agricultural pumping sites: 100% of the site-wide cost is allocated.

G-2. Typical Fast DR Telemetry and Dispatch Architecture

The typical telemetry architecture starts with the 1) data source (an instrument to measure load), 2) connected to a resource interface, 3) connected to an Intra-Protocol to communicate between the resource and a Remote Intelligent Gateway (RIG) which collects and aggregates many individual data streams, and finally a connection to the CAISO Energy Management

System.

LBNL assumes that for end-uses that can deliver Fast DR services, the same local control technology would be used as their "slow DR" equivalents, and that the only differences between Fast and Slow DR technologies are in the telemetry and dispatch configurations. Therefore, the hardware and installation costs for Fast DR control technology are the same, and any additional costs are for the telemetry and communication system upgrades, which could be for metering, a resource interface, a gateway or another component.

The structure of the DR-PATH model is based on estimating a wide range of possible pathways that each end-use can take for providing DR—a "tree of possible outcomes". This is illustrated in Figure G-1 below. For each scenario/year/weather case we estimate the available DR along each possible pathway, including the expected quantity and unit cost of providing DR along the range of possible pathway options. The end-uses defined by LBNL-LOAD with baseline load profiles are fixed in the model, and there are many combinations of technology, markets, and incentive pathways defined for each.

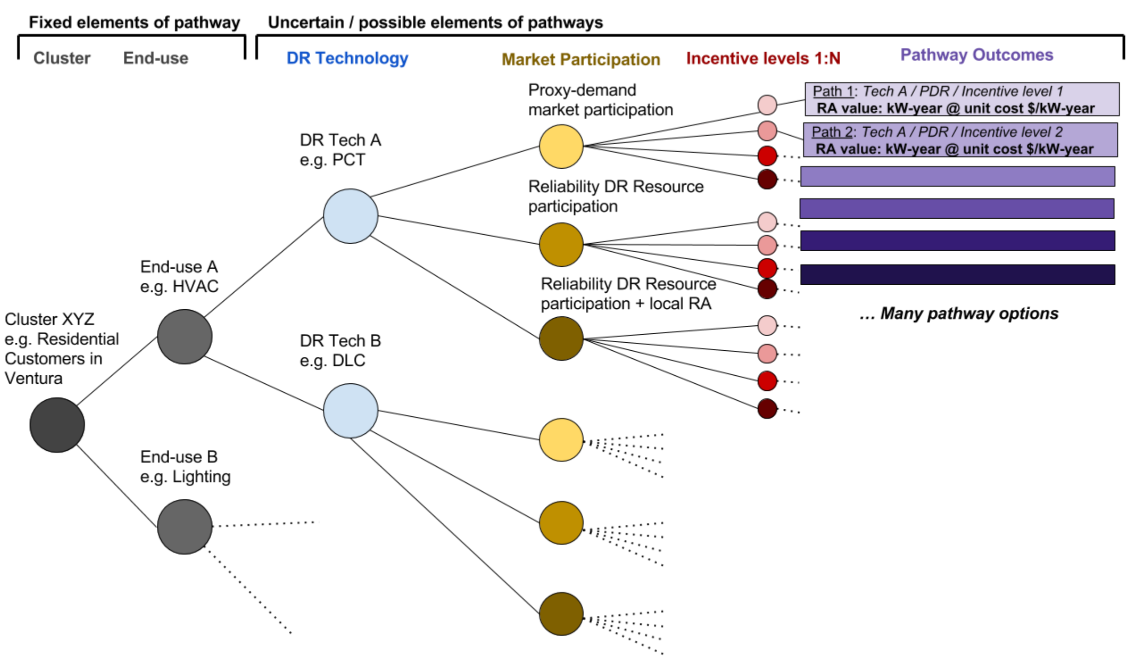


Figure G-1: DR-PATH model structure, demonstrating the possible pathways for cluster-end-use pairings to take, depending on available DR technologies, markets, and incentives.

G-3. Propensity Scores

A propensity scoring approach is used to estimate DR enablement and enrollment rates in DR-PATH. In this framework we assume that the parameters used in recruiting customers include the number of events called, incentive levels, targeted end-uses, and marketing.

All estimates reflect enrollment rates for eligible customers. For example, if 25% of eligible customers can be enrolled but only 40% have central air conditioners, the attainable penetration rate for AC load control is 10% (25% x 40%). The assumptions about marketing tactics underlying the enrollment projections are not prescriptive. Utilities or aggregators can attain the enrollment levels in a number of ways. Appendix F provides a conceptual overview of the probit models that underlie the approach taken here and background to understand how coefficients can be extracted from aggregate level tests.

The propensity score estimates are combined with baseline "non-parametric" estimates of adoption rate based on the actual fraction of customers in each cluster that participate in DR programs currently. For Industrial and Residential customers, we use the non-parametric baseline as a starting point for estimates, and adjust it based on the propensity score model results.

G-4. Technology Inputs to DR-PATH Model

In the following sections, we describe the framework for defining DR enabling technology performance and cost, and document how these inputs are used to estimate the resource magnitude and unit costs associated with enabling end use equipment to provide grid services. This framework covers only the cost of the DR enabling technology and its performance, not program administration and other costs.

The inputs to the model are organized in a spreadsheet titled "DRPATH-INPUT"; the spreadsheet includes various tabs that define different types of inputs to the DR-PATH Model that are used to calculate the cost, performance and capabilities of specific enabling technologies.

Tabs in the DRPATH-INPUT workbook are structured as follows:

1. Product requirements: the set of grid products we examine and requirements for participation
2. Technology list: the list of technologies examined in the DR-PATH model defining a potential pathway; each technology includes specifications for each of the following:
    a. Local control: building-level load controllability
    b. Dispatch: communication for receiving DR signals

    c. Telemetry: data acquisition and communication for operations and settlement
3. Scenarios: a set of assumptions defining the future trajectories of DR technology and markets.
4. Metadata options: a set of variable options used to populate the fields in the database

G-4.1. Defining Enabling Technology

Demand response enabling technology is the mix of load control and communications hardware and software that make it possible to change the energy consumption patterns of end uses. The enabling technologies examined in the current study are defined in terms conducive to estimating the expected costs and performance in future scenarios. For example, we define cost and performance inputs specific to distinct technologies, as well as distinct customer/building types (e.g., residential or large retail). We make these distinctions because similar technologies may perform differently in different types of buildings. We draw on a mix of past experience, current trends, and future projections to identify the various types and quantify the cost, performance and response characteristics of DR enabling technologies.

In the context of this study, we define each enabling technology in terms of three key attributes: Local Control, Dispatch, and Telemetry. Figure G-2 describes the role each of these attributes plays in facilitating communication between a DR technology system, a building system, and the grid. A single instance (or "pathway") of an enabling technology will consist of one "option" from each of these areas. These options specify the response characteristics of a building system under control of a DR technology system. We compare the capabilities of each DR technology system to the needs and requirements of specific grid services (e.g., participation as a proxy demand resource in the energy market). Thus we determine whether each technology system meets the response characteristics necessary to provide each candidate grid service.

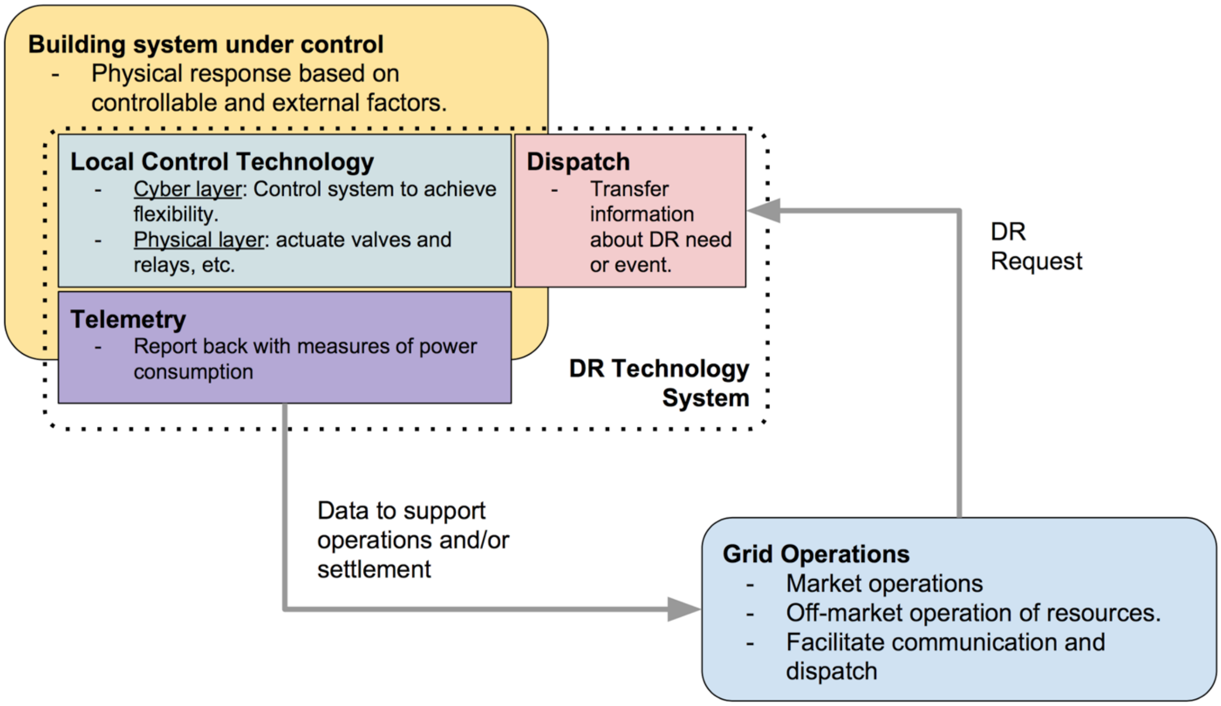


Figure G-2: Interactions between the DR technology system, grid operations, and the building systems under control. The dotted area represents the behaviors considered in DR-PATH.

G-4.1.2. Local Control Technology

The local control technology describes the capabilities to manage and/or change the demand characteristics of a particular end-use load or group of end-use loads together. Table G-2 lists input data fields related to local control technologies.

Table G-2: Local control technology input data field names, description and specification.

Data Field Name	Data Field Description	Notes
`lc_id`	Unique local control technology identifier	Used to uniquely identify local control technology.
`lc_name`	Human readable name of local control technology	
`dr_type`	Supply or Load-Modifying DR	Both types can be specified in the framework, with some difference

Data Field Name	Data Field Description	Notes
		in the way the calculations are applied as appropriate.
sector	Applicable sector (res/com/ind)	These are specified for each local control technology since there are often significant differences in technology that may operate on similar principles in difference sectors.
sub_sector	Applicable building type within sector (or all of above)	
site_size_cat	Customer size category (e.g., all, large, medium or small)	
install_type	For all buildings: category for technology installation effort	Owner effort required, passive install, etc
end_use	The type or set of end-uses that are controlled by the particular instance of local control.	Each technology must apply to a specific end_use type.
flex_cat		
t_delay_local	The delay between receiving of a control signal and the start of a control action at the site.	Timing features are added to the round trip communications latency to estimate the total system latency when combined with dispatch and telemetry signals as appropriate.
t_ramp	The time from the start of the control action to the full response from the end-use.	
t_resolution_ … local_control	The shortest time-step between two different control signals.	
shed_peak	The peak level of load shed possible with the technology for short (~10 minute) amounts of time. If Load Modifying DR, this field can indicate the expected reduction in use during peak times for "direct input" option of specifying lmdr.	Sheds beyond peak shed for supply resources typically have diminishing availability fractions to account for needs to cycle load and manage rebound.

Data Field Name	Data Field Description	Notes
shed_1_hour	1-hour Shed: The shed level over a continuous one-hour period	
shed_2_hour	...over 2 hours	
shed_4_hour	..over 4 hours	
window	The maximum time over which the shift must occur (first shed or take start until the end of the last take or shed)	
shift_shed_4_hour_window	The amount of shed that can occur within a 4-hour shift window	
shift_shed_8_hour_window	The amount of shed that can occur within a 8-hour shift window	
shift_shed_24_hour_window	The amount of shed that can occur within a 24-hour shift window	
hours_avail_annual	Maximum number of hours allowed for dispatch per year. NOTE: data need to be updated. NA values are treated as 8760	
lmdr_input_… option	“direct” or “file”	For LMDR, if “direct” input option only the shed_peak will be used, taken to define the expected shed fraction during system peak times. If “file” input option the fraction of shed during the full year is specified based on a file at the filename in lmdr_file.
lmdr_file	A filename for load impact from LMDR	in 'flex_market_econ/… input/lmdr_shapes'
Added in Phase 2: Take capabilities, regulation capabilities, shift capabilities.		

G-4.1.3. Dispatch Technology

The dispatch technology defines the performance of communications for DR dispatch methods used to send and receive control or other signals from a central or decentralized authority. Table G-3 lists input data fields related to dispatch technologies.

Table G-3: Dispatch technology input data field names, description and specification.

Data Field Name	Data Field Description	Notes
sig_id	Dispatch signal type ID	Used to uniquely identify dispatch technology
sig_name		
t_delay_ … dispatch	The delay from identification of dispatch need to signal receipt at premises.	The timing is added to the round trip communications latency to estimate the total system latency for comparing to DR product requirements.
t_resolution_ … dispatch	The shortest time-step between two different DR signals.	The resolution is compared to requirements for DR products.
reliability	The fraction of times dispatch is successfully communicated to the site.	Used to derate available capacity.
regOK_dispatch	T/F for continuous signaling capability	Used to indicate if participation in regulation market is possible
spatial_dispatch	finest-grain spatial resolution of dispatch signal targeting	
Added in Phase 2: Spatial resolution of dispatch (e.g., IOU territory, SubLAP, Feeder, Device), regulation capabilities		

G-4.1.4. Telemetry

Telemetry defines the visibility provided to system operators for feedback during operations and settling markets after DR resources respond to provide a grid service. Table G-4 lists input data fields related to dispatch technologies.

Table G-4: Telemetry input data field names, description and specification.

Data Field Name	Data Field Description	Notes
`telem_id`	Telemetry type ID	Used to uniquely identify telemetry technology
`t_delay_telem`	The delay from measured control actions to receipt of verification at DR settlement entity (normally CAISO).	The timing and resolution characteristics are compared to requirements for particular DR products.
`t_resolution_…telem`	The shortest time-step between two DR measurements returned by telemetry.	
`regOK_telem`	T/F for continuous response capability	
`telem_comm`	telemetry communication type	e.g. AMI, dedicated WAN
`telem_data`	telemetry data type	e.g. AMI, sub-metered
To be added in Phase 2: regulation capabilities.		

G-4.1.5. Integrated DR Technology

Each DR enabling technology set includes an element of local control, dispatch, and telemetry and inherits all of the attributes from each of those elements, as specified in Tables G-2 to G-4. Each row in the Technology List is defined by an enabling technology system, applied to specific end uses in particular sectors and/or building types. Data fields specified for each unique technology possibility are listed in Table G-5.

Table G-5: Integrated DR Technology List input data field names, description and specification.

Data Field Name	Data Field Description	Notes
`tech_name`	DR technology name	A string describing the technology name in "plain English".
`source`	The data source of the inputs.	Usually "LBNL Synthesis" if based on synthesis of LBNL institutional knowledge as well as

Data Field Name	Data Field Description	Notes
		best available external data.
scenario	A label to define if the technology is included in the base scenario or only in development (not used in model runs unless explicitly called).	The timing and resolution characteristics are compared to requirements for particular DR products.
tech_id	DR technology ID (automatically generated as the combination of lc_id, sig_id, and telem_id that are specified)	Used to uniquely identify DR technology. The technology inherits all attributes that are defined for each of the constituent elements.
adopt_drtech_2015	The fraction of eligible sites in 2015 that adopt the local control technology (i.e., have a controllable site / end-use) for non-DR reasons.	Used to define the threshold in a random draw to determine if certain cost components are zeroed out in the analysis. This value is related to the Integrated Demand Side Management (IDSM) and qualitative benefits of controllability.
adopt_drtech_2025	Same as above, for 2025.	This allows for an expansion in expected non-DR adoption over time if appropriate.
adopt_stock_2015	The fraction of eligible sites that have DR enabling technology installed in 2015.	Used to trace implied trajectory in technology adoption rate. Values that are “NA” are replaced by the benchmark propensity score.
ratio_ps_2015	The expected ratio of the propensity to adopt for this particular DR technology in 2015 to the	Propensity is higher for technology with qualitative

Data Field Name	Data Field Description	Notes
	benchmark propensity score.	improvements in site-level service or marketing effectiveness compared to the technology and marketing combinations that were available during periods when data were captured to train benchmark propensity score model.
`ratio_ps_2025`	Same as above, for 2025	Propensity ratio can improve over time if qualitative technology or marketing attributes are expected to shift.
`ratio_cost_2025`	The expected ratio of 2025:2015 technology cost	Typically <= 1 for improvement.
`ratio_perf_2025`	The expected ratio of 2025:2015 technology performance	Typically <= 1 for improvement.
`crf`		
`levelized_tot_cost`		
`levelized_upfront_cost`		
`levelized_op_cost`		
`cost_unit_var`	This defines the units for calculating variable cost components.	Typically either not used, or based on $/kW under control.
`cost_site_enab`		
`Site-level comm and control cost`	This defines the known separate fixed $ 2015 cost for site-level DR comms (e.g., for building gateway necessary for DR)	Typically 0. This applies to site-level DR-specific communications equipment cost.

Data Field Name	Data Field Description	Notes
`cost_fix_init`	The **fixed initial costs** for achieving controllability “per site” for the given end-use.	To pay for hardware and soft costs of installation per site. *If there is non-DR adoption at a site these costs are zeroed out.*
`cost_var_init`	The **variable initial costs** for achieving controllability “per unit” of the variable portion.	To pay for hardware and soft costs of installation. *If there is non-DR adoption at a site these costs are zeroed out.*
`cost_fix_opco`	The **fixed annual operating costs** for maintaining controllability and/or paying communication fees “per unit” of the fixed portion.	To cover technology-related (not administrative etc.) annual operating costs.
`cost_var_opco`	The **variable annual operating costs** for maintaining controllability and/or paying communication fees “per unit” of the variable portion.	To cover technology-related (not administrative etc.) annual operating costs.
`cost_fix_ …` `co_benefit`	The **expected fixed level of co-benefit buy-in** per end use for enabling costs (i.e., expected monetary contributions to initial costs by site operators where there has been non-DR related adoption of the technology, represented as a levelized benefit over the lifetime).	Often set to zero. Only set to non-zero number when there is strong evidence or expectation that site owners will buy-in to share initial costs of DR based on qualitative improvements in building performance or other benefits related to fixed portion.
`cost_var_ …` `co_benefit`	The **expected variable level of co-benefit buy-in** per end use for enabling costs (i.e., expected monetary contributions to initial costs per variable unit).	Used primarily to account to demand charge reduction for commercial and industrial customers.
`cost_margin_ …` `dispatch_day`	The marginal additional cost per day of dispatch.	Used to account for scheduling coordinator fees, additional administrative costs, etc. related

Data Field Name	Data Field Description	Notes
		to actual dispatch of DR events.
`tech_lifetime`	The lifetime of the DR technology	Used to amortize initial costs over the lifetime to get a levelized annual average.
Added in Phase 2: Cost data for advanced / fast DR		

G-4.2. Eligibility for Grid Product Services

Within the framework of the DR-PATH model, each end-use/technology combination has a set of characteristics (i.e. telemetry, signal, local control) that define the ability for the end-use to respond to a DR dispatch signal, as defined in section 6.4.1.2. We define a set of filters, described in Table G-6, that we use to determine whether a particular end-use/technology pair matches the response characteristics required to provide a specific grid service. For example, Table G-7 describes the filters and requirements for providing PDR and RDRR products in the DR-PATH model.

Table G-6: Description of filters used to determine which enabling technologies meet the response characteristics required to provide specific grid services.

Filter	Units	Description
Regulation-quality telemetry and dispatch required	Boolean (True or False)	Does the product categorically require dispatch and telemetry technology performance on the order of seconds (4-sec)?
Expected dispatches per year	Number of days	This filter can disqualify technologies that are extremely dispatch-limited (only a small number have this constraint)
Maximum dispatch delay allowed	Seconds	Maximum time between when a dispatch request is made (black diamond in figure

		below) and the start of local response (the delay to start of local response).
Maximum ramp allowed	Seconds	Maximum additional time allowed for ramping. The total response delay including the ramp should be less than the sum of the maximum dispatch delay and ramp allowed.
Maximum resolution for control signal	Time, as specified (e.g., minutes or s)	The maximum time between control signal steps (the "local control resolution"). For example, a load that can change its operation every 10 minutes has a "10 minute" local control resolution.
Minimum bid duration		The minimum continuous time that a load must be able to participate when dispatched.
Maximum telemetry delay		The maximum delay between DR response and telemetry signals back to the system operator (or if there is no active telemetry, the settlement signal).
Maximum telemetry resolution		The maximum time step resolution on telemetry.

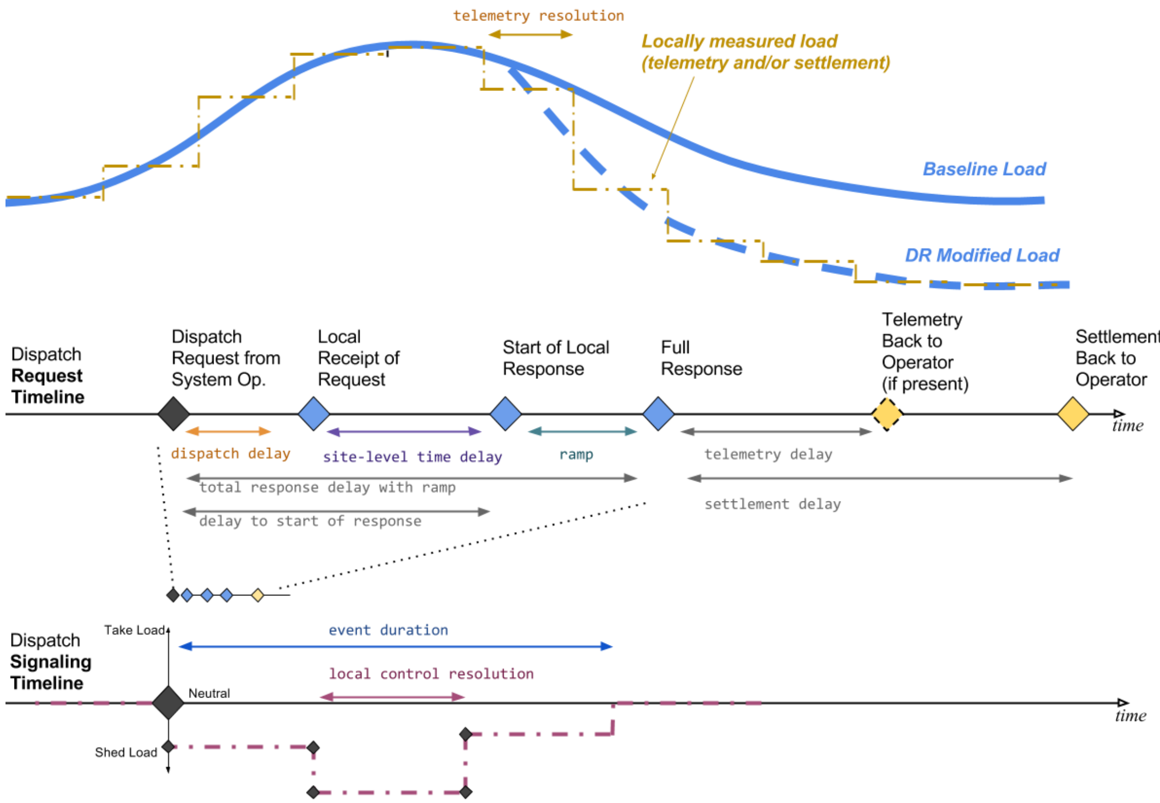


Figure G-3: Illustration of DR Technology system dispatch, local control, and telemetry timing characteristics that determine qualification for product service provision.

Table G-7: Comparison of filter requirements for Local Capacity DR, Energy Market participation via RDRR, and Energy market participation via PDR.

	DR Products			Units
	local capacity DR	Energy market via RDRR	Energy market via PDR	
Product category	energy	energy	energy	
Demand Response type allowed	supply	supply	supply	
Scenario Name	base	base	base	
Expected number of dispatches / year	50	2	50	Days per year
Unique ID for DR enabling technology	energy_pdr_local	energy_rdrr	energy_pdr	
Requires regulation quality dispatch and telem?	False	False	False	True or False
Maximum time delay for dispatch	1200	64801	64801	Seconds
Maximum ramping time	0	500	500	Seconds
Maximum tenable resolution for control signal	3601	86401	3601	Seconds
Minimum continuous bid duration	4	4	4	Hours
Maximum delay in telemetry signal	2592000	2592000	2592000	Seconds
Maximum resolution of telemetry signal	3600	3600	3600	Seconds

G-4.3. DR Product Service Qualification: Step 1

The dispatch, telemetry and control characteristics for each end-use/technology are compared to the requirements of the DR Product to determine if the combination can provide the DR service. The model tags each one of the requirements as a True or False for each end-use, and only those end-uses that pass the qualification test are passed to step 2 of the qualification process.

G-4.4. DR Product Service Qualification: Step 2

For those end-uses that pass the product screening, the model then determines how much DR is available from that end-use. The available DR is defined as the baseline end-use in each hour times a fraction of sheddability available over a continuous a DR event window that lasts as long as the minimum bid duration, which is indicated in the Table G-7 above. For each end-use/enabling technology combination, we specify shed capabilities for 1, 2 and 4-hour DR event windows. In the cases of PDR and RDRR, we examine only 4-hour event windows. For other DR products, we select event windows based on specific grid needs over the course of the year; our approach for determining these needs is detailed in Appendix D.

G-4.5. Capabilities Model for DR Technology - Quantity of RA Credit

The capacity credit for each DR enabling technology is based on the weighted sum of the available shed capabilities, which we calculate in Step 2 above. For load modifying DR, the magnitude of RA credit ($m_{RA,LMDR}$) is defined as the sum of the difference between the baseline and modified baseline load times a capacity weighting vector for each hour, as shown in Equation G-1.

$$m_{RA,LMDR} = \sum_{hour=1}^{8760} \{ (\underline{b_{tot}} - \underline{b_{tot,mod}}) \odot \underline{c_{RA}} \} \quad (1)$$

$$m_{RA,supply} = d_{rel} * \sum_{hour=1}^{8760} \{(S_X \circ \underline{b_{eu,mod}}) \odot \underline{c_{RA}} \} \quad (2)$$

Note on notation in equations above:

- *In both equations the circle with dot is an element-wise product of the remaining two vectors after the first operation is complete.*
- *Subtraction of vectors is element-wise in the load modifying equation.*
- *In the equation describing supply-side DR, the empty circle denotes an element-wise product of the scalar S_X (the available load reduction fraction) and $\underline{b_{eu,mod}}$ (the modified baseline load shape).*

For the PDR and RDRR DR Products, we calculate the quantity of RA credit (in kW/yr) for each end use by multiplying the fraction of load an end use is capable of shedding for a 4-hour event window, by the 8760 hourly load profile for that end use. We weight the hourly sheddable load based on the relative capacity needs in the 250 hours of the year with the highest net system load; this process uses a conventional RA calculation. These hourly values are summed and (as described below) adjusted for dispatch reliability, operating reserves, T&D, improvements in performance within the scenarios (BAU, medium, and high), and for changes in the year-to-year trajectory, (i.e. 2020 - 2025). As DR capacity is sourced from the end-user, the RA credit is adjusted for T&D and operating reserves to be consistent with capacity from conventional generation.

G-4.6. Adjustments to performance

- Cost-Effectiveness Protocols: The protocols include performance adjustments for Operating Reserves and T&D to capture the benefits of DR in the supply market. For example, this adjustment captures the fact that a MW of DR is not equal to a MW from a generator, because the MW from a generator will lose energy/capacity over transmission and distribution lines. These protocols are described in detail in Appendix K.
- Adjustments for scenarios: The performance ratios within the BAU, Medium and High scenarios include technology performance improvements for forecasting DR Potential in 2020 and 2025. The performance improvements are captured as increases in the shed factors for each technology.
- Adjustments for year-to-year trajectory: From 2015-2025, in many cases technology performance is expected to improve beyond 2015 levels. We account for these improvements through a performance adjustment independent of the scenario adjustments.

Table G-8: DR performance variables from input and calculated as intermediate values in the model and their mathematical symbols for use in equations below.

Input File Field or Model Variable	Symbol in equations below	Example / Notes
baseline (calculated)	$\underline{b_{tot}}$	The total baseline load, a vector of 1:8760 values, one for each hour of the year, in kW/site. (e.g., {4, 4.5, 5.5 … 2.4, 2.3, … N})
baseline (calculated)	$\underline{b_{eu}}$	The end use baseline load, a vector of 1:8760 values, one for each hour of the year, in kW/site. (e.g., {4, 4.5, 5.5 … 2.4, 2.3, … N})
baseline_mod (calculated)	$\underline{b_{tot,mod}}$	The modified total baseline load (after load modifying DR), a vector of 1:8760 values, one for each hour of the year, in kW/site. (e.g., {4, 4.2, 5.1 … 2.1, 2.0, … N})
baseline_mod (calculated)	$\underline{b_{eu,mod}}$	The modified end use baseline load (after load modifying DR), a vector of 1:8760 values, one for each hour of the year, in kW/site. (e.g., {4, 4.2, 5.1 … 2.1, 2.0, … N})
shed_***X***_hour	s_X	The fraction of load that can be shed over ***X*** hours of continuous time, where the continuous period is defined in the product requirements., (e.g., 0.4)
cap_ra_weight (calculated)	$\bar{c}_{RA}$	The relative value of capacity value in each hour of the year, a vector of 1:8760 values that sum to one, one for each hour of the year, unitless. This is calculated dynamically based on the top 250 hours of system net load. (e.g., {0, 0, 0, 0.1, 0, … , N}}
reliability	d_{rel}	Dispatch reliability fraction derates capacity.

G-5. Cost Model for DR Sites

The sections above describe how we derive the quantity (in kW) of DR eligible to provide each grid product. The current section describes how the model estimates the annual costs of installing and maintaining each DR enabling technology at a particular site. We assign these costs at the cluster level, as described in Appendix C. These average annual costs are analogous to the "levelized" cost of DR service -- the equivalent annual cost of having a resource installed, enrolled, and working. Levelized costs have a long history of use for considering alternative investments in generation assets and we use them here to facilitate comparisons between using conventional generators and DR resources for meeting peak capacity needs on the grid.

For residential and small/medium commercial customers, costs are estimated by end use. Our approach uses the perspective of estimating the total costs to enable a site with a specific end-use/enabling tech combination. For large and industrial customers, a premise-wide, rather than end-use, approach is taken to evaluate DR technologies and enablement (e.g. $200/kW installed). We define the average annual costs as the sum of all the costs over the lifetime of the technology divided by the useful life of the measure.

For each of the end uses, we estimate the initial fixed, variable and operating costs for a customer site, based on customer sector and size[56]. A description of each are as follows:

- Initial Costs:
    - The fixed initial costs for achieving controllability "per site" for the given end-use, e.g., paying for communication and control gateways.
    - The variable initial costs for achieving controllability "per kW", e.g., scaling costs appropriately for large facilities.
    - The initial costs are increased using a factor to account for the expected cost of financing
    - The initial costs are levelized over the lifetime of the technology
- Operating Costs:
    - The fixed annual operating costs for maintaining controllability, e.g., paying communication or license fees
    - The variable annual operating costs for maintaining controllability, e.g., control system maintenance.
- Administrative and marketing costs are assigned "per site" on an annual basis

Note: "per kWh" used as variable cost unit for batteries.

The DR-PATH model also utilizes a propensity to adopt DR (Pscore) which is based on customer characteristics and historical precedence for customer participation and adoption of

[56] The details and assumptions are provided in later chapters of this Appendix C, categorized by customer end use and sector.

DR programs and technologies[57].

The equations below describe how we estimate enablement costs for each end use in each cluster.

G-5.1. Cost Model Step 1: Estimate unit cost by category

Each of these costs is calculated in units of "$/kW-year" for consistency with the expected RA credit described in Equations G-1 and G-2. Some of the factors are modified by a cost adjustment factor ($A_{C,scen-y}$) specific to each scenario and year. Each of these is estimated in terms of "$/kW-year" based on the expected RA credit, which was calculated in the *Capabilities Model for DR Technology - Quantity of RA credit* section above. Some of the factors are adjusted by a scenario-year specific cost adjustment factor ($A_{C,scen-y}$).

Initial cost:

$$c_{init} = A_{C,scen-y} * (C_{site,enab} + C_{fix,init} + M_{var} c_{var,init}) \ / \ t_{lifetime} \ / \ RA_{site} \quad \text{(G-3)}$$

Financing cost:

$$c_{finance} = (1 - F_{t,r}) * C_{init} \quad \text{(G-4)}$$

Operating cost:

$$c_{opco} = A_{C,scen-y} * (C_{fix,opco} + M_{var} c_{var,opco}) \ / \ RA_{site} \quad \text{(G-5)}$$

Administrative cost:

$$c_{admin} = A_{C,scen-y} * C_{admin} \ / \ RA_{site} \quad \text{(G-6)}$$

Marketing cost (note adjustment for expected propensity to adopt DR):

$$c_{market} = A_{C,scen-y} * C_{market} \ / \ RA_{site} \ / \ P_{cluster} \quad \text{(G-7)}$$

Incentive cost:

$$c_{incentive} = C_{incentive} \ / \ RA_{site} \quad \text{(G-8)}$$

Buy-down value (results in a negative number):

$$c_{buydown} = -((C_{fix,coben} + M_{var} c_{var,coben}) \ / \ t_{lifetime} + C_{coben,other}) \ / \ RA_{site} \quad \text{(G-9)}$$

[57] The propensity score (Pscore) is discussed in detail in Appendix E.

G-5.2. Cost Model Step 2: Aggregate to expected unit cost total

This is an estimate of the effective levelized unit cost of DR at the site, in $/kW-year.

$$c_{cluster} = (1 - A_{ndr,Y}) * (c_{init} + c_{finance}) + c_{opco} + c_{admin} + c_{market} + c_{incentive} + c_{buydown} \tag{G-10}$$

The total cost of DR for the cluster can be estimated by multiplying the unit cost by the expected quantity of RA, etc.

Table G-9: Cost variables from input and calculated as intermediate values in the model and their mathematical symbols for use in equations above and below.

Input File Field or Model Variable	Symbol in equations below	Example / Notes
`cost_unit_fix`	--	This defines the units for M_{fix}
`unit_fix_prem`	M_{fix}	Magnitude of fixed portion (e.g., 1 premise)
`cost_unit_var`	--	This defines the units for M_{var} (e.g. kW-peak or kWh-battery)
`mag_var_prem` *(calculated)*	M_{var}	Magnitude of variable cost portion, not defined in input file but dynamically calculated for each cluster at the site level. (e.g., 100 kW under control)
`cost_site_enab`	C_{enab}	Site-level commissioning and control costs, e.g., $1,000 / site
`cost_fix_init`	$C_{fix,init}$	Hardware, installation and software cost per premise e.g., $10,000 / site If there is non-DR adoption at the site these costs are zeroed out.
`cost_var_init`	$C_{var,init}$	Hardware, installation and software cost per variable unit, e.g., $200 / kW under control If there is non-DR adoption at the site these costs are zeroed out.

Input File Field or Model Variable	Symbol in equations below	Example / Notes
`cost_fix_opco`	$C_{fix,opco}$	Annual operating costs per site including software licensing, testing/certification, e.g., $100 / premise-year
`cost_var_opco`	$C_{var,opco}$	Annual operating costs per variable unit including software licensing, testing/certification per variable unit, e.g., $2 / kW under control / year
cost_fix_co_benefit	$C_{fix,coben}$	e.g., $100 / year from expectation in improved system performance.
cost_var_co_benefit	$C_{var,coben}$	e.g., $3 / kW under control / year in expected demand charge reduction from day-to-day controllability.
other co-benefits (calculated)	$C_{coben,other}$	Other co-benefit value streams (e.g., expected energy market gains).
`tech_lifetime`	$t_{lifetime}$	e.g. 15 years
`cluster_p_score` (calculated)	$P_{cluster}$	Benchmark propensity to adopt DR, adjusted based on the year and scenario.
`cost_marketing` (calculated based on cluster characteristics)	C_{market}	Cost of marketing to the cluster for the particular end-use type.
`cost_admin` (calculated based on cluster characteristics)	C_{admin}	Administrative costs are assigned per site on an annual basis
Incentive	$C_{incentive}$	Incentive level per site
`adopt_nondr_`***YYYY***	$A_{ndr,Y}$	non-DR adoption rate in year **YYYY,** estimated with straight line assumption from 2015 to 2025.

Input File Field or Model Variable	Symbol in equations below	Example / Notes
financing premium adjustment factor (calculated)	$F_{t,r}$	Financing premium for a project of lifetime t with discount rate (i.e. weighted average cost of capital) r. Equal to: $F_{t,r} = \frac{t_{lifetime}}{A_{t,r}}$ where $A_{t,r}$ is an equivalent annuity lifetime factor defined by: $A_{t,r} = \frac{1-\frac{1}{(1+r)^t}}{r}$
Resource adequacy credit	RA_{site}	Capacity credit per site that adopts (kW-year)

G-5.3. Identifying Unit Costs of Demand Response and Expected Quantity

The expected quantity of DR involves derating the magnitude of RA from enabled sites by their propensity to adopt, as given Equation G-11.

$$m_{RA,expected} = P_{cluster} * m_{RA} \qquad \text{(G-11)}$$

Where the propensity to adopt depends on the benchmark propensity score adjustment factor for supply DR, and is assigned based on the year and approach for each type of load modifying or supply DR.

G-5.4. Customer Incentives

The cost of customer incentives for DR is not included in the DRPATH-INPUT database framework, but are captured in the propensity to adopt model framework, detailed in Appendix F. The propensity score model outputs provide lookup tables with values for adoption that vary depending on marketing and incentive levels, and influence the expected likelihood of customer adoption for each technology. The propensity scores are used in the DR-PATH cost model to predict cluster level DR technology costs, while the incentive levels are used to help determine the quantity of DR available at various levels of incentive payments.

G-5.5. Marketing and Administrative Costs

The marketing and administrative costs are included in the model as fixed values for each customer site.

The annual marketing costs are estimated as follows:

- $5 / site /year for residential
- $10 / site / year commercial
- $20 /site / year industrial

The initial administrative costs are defined as:

- Residential and small commercial: $50/ customer
- Large Commercial/ Industrial: $350/customer (range of $200- $400)

Recurring administrative costs are set to $10/ customer for all customers.

G-5.6. Co-benefits

Some DR enabling technologies may have other co-benefits for the building occupant or owner in addition to providing DR. For example, DR-enabled lighting can also be more efficient and advanced than standard lighting, and batteries can provide backup power and earn revenue from streams unrelated to DR. For the technologies with known co-benefits that are readily quantifiable, we attribute only a portion of site-level enablement costs to DR, subtracting out the value derived from other streams. Appendix K provides specific details on the co-benefits considered in this study.

G-5.7. Dispatch costs

In addition to the cost of enabling a DR technology, for some technologies there may be a nominal cost associated with dispatching a device or interrupting a load during a DR event. Where this is the case, we estimate the dispatch costs and factor them into the levelized cost calculations.

G-5.8. Site-level commissioning and control cost

Site-level commissioning and control costs for fast telemetry and control are often required above and beyond typical control investment costs. We utilize this variable to account for the associated **additional site-level commission and control costs** above and beyond the enabling technology costs for conventional DR, (i.e. Shed).

G-6. Capturing Uncertainty in Model Inputs with Monte Carlo Simulation

We use Monte Carlo simulation to obtain results for a range of assumptions regarding price, performance, and lifetime of DR-enabling technologies. We define a “base” scenario with price and performance assumptions founded in results from the literature, 1,000 stochastic scenarios generated by populating input values with numbers sampled randomly from a prescribed distribution. The stochastic scenarios are designed to capture cost and performance for a range of possible realizations of the future cost and performance of DR-enabling technologies.

We can then compute the levelized cost per MW of DR enabling technologies in each of the 1,000 scenarios. Due to stochastic variation in the cost, performance and lifetime of the enabling technologies, the optimal (i.e., least costly) enabling technology for a particular end use may differ from one scenario to another. These differences inform which enabling technology is selected for deployment in the DR-PATH model. Thus each of the 1,000 scenarios yields a different enablement cost (and perhaps a different enabling technology), resulting in a distribution of levelized costs for each end use across the 1,000 scenarios stochastic.

We identify two sources of uncertainty in estimating the cost of DR enabling technologies:

1. Uncertainty in expected cost/performance of emerging DR-enabling technologies;
2. Uncertainty in site-specific performance and enablement costs.

The first arises from lack of information about current and future costs and performance of DR enabling technologies, while the second arises from site-to-site variability in cost and performance. The Monte Carlo simulation allows us to quantify how these uncertainties affect our results by providing a range of stochastically sampled values for the expected and site-specific cost and performance parameters. We employ a two stage Monte Carlo simulation to generate these values, where the expected values sampled in the first stage inform the distributions we use to sample site-level cost and performance parameters in the second stage

Both stages of the Monte Carlo simulation use triangular distributions to stochastically populate cost/performance parameters for each cluster and DR-enabling technology. Triangular distributions are described parametrically by a central value and upper/lower bounds, as illustrated in Figure C-3. The enabling technologies database described in Appendix C defines these parameters using central values based in the literature, and upper/lower bounds defined relative to these central values. For example, the database may define upper and lower bounds as being +/- 30% of the central value in the first stage, and +/- 20% of the central value in the second stage. The first stage of the Monte Carlo simulation gives expected values for cost and performance values for a particular enabling technology; within a single realization, we apply the same central value across all clusters. The expected values sampled in the stage 1 are taken to be the central values in stage 2 of the Monte Carlo, which assigns cost and performance values to each individual cluster.

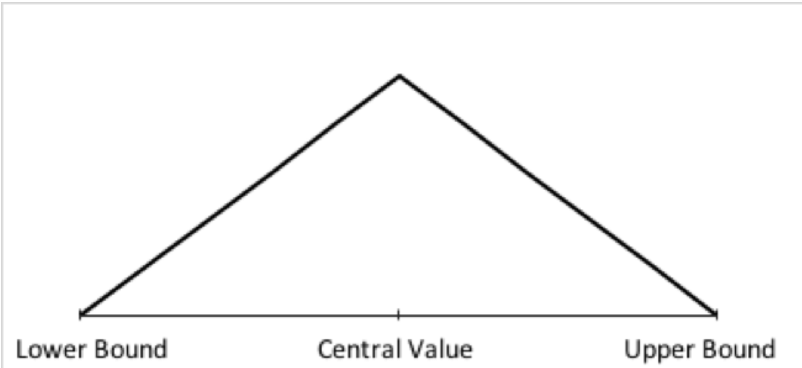


Figure G-4: Probability density function for triangular distribution denoting descriptive parameters including the central value and upper/lower bounds.

In select cases, we limit the Monte Carlo simulation to only one stage or the other. For data fields that are not expected to vary from site-to-site (e.g., improvements in technology performance), we use only the first stage Monte Carlo and assign the same values to all relevant clusters. For data fields that vary from site-to-site but with well understood central values, we perform only the second stage of the Monte Carlo using a prescribed central value for all simulations. A schematic diagram illustrating the two stage Monte Carlo simulation process is provided in Figure G-5.

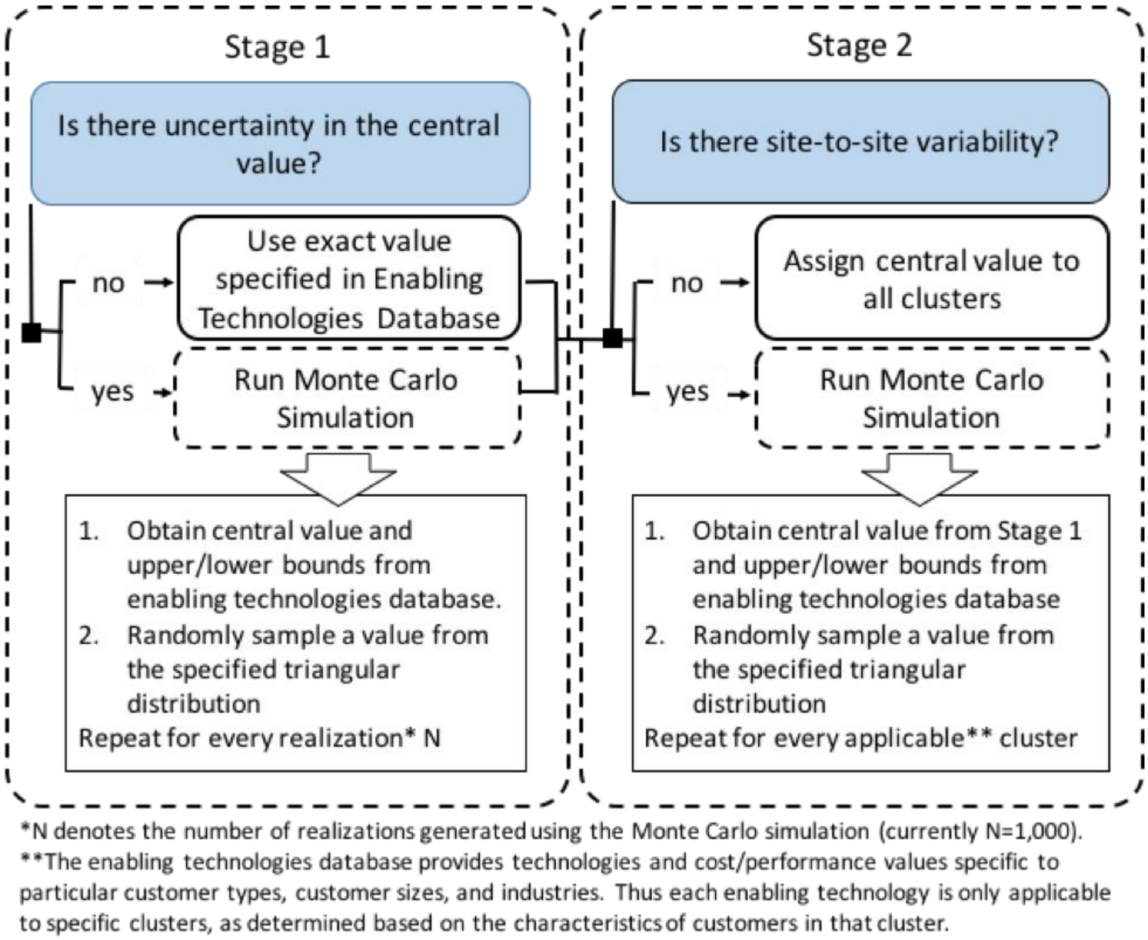


Figure G-5: Schematic diagram of Monte Carlo simulation.

Figure G-6 shows the distribution of sampled values across 100 realizations of the Monte Carlo simulations of marketing costs (left) and technology lifetime (right) for residential DLC switches. Marketing costs are defined relative to a prescribed central value ($5 for residential customers), and thus are stochastically varied only in stage 2 of the Monte Carlo simulation.

Technology lifetime, on the other hand, includes both stages of the Monte Carlo simulation. The marketing costs follow a triangular distribution, as all realizations are sampled from identical triangular distributions. Technology lifetimes, on the other hand, follow an approximately normal distribution because they are sampled from several triangular distributions with different central values defined for each realization of the Stage 1 simulation.[58]

[58] According to the Central Limit Theorem, the sum of a large number of non-identical distributions begins to

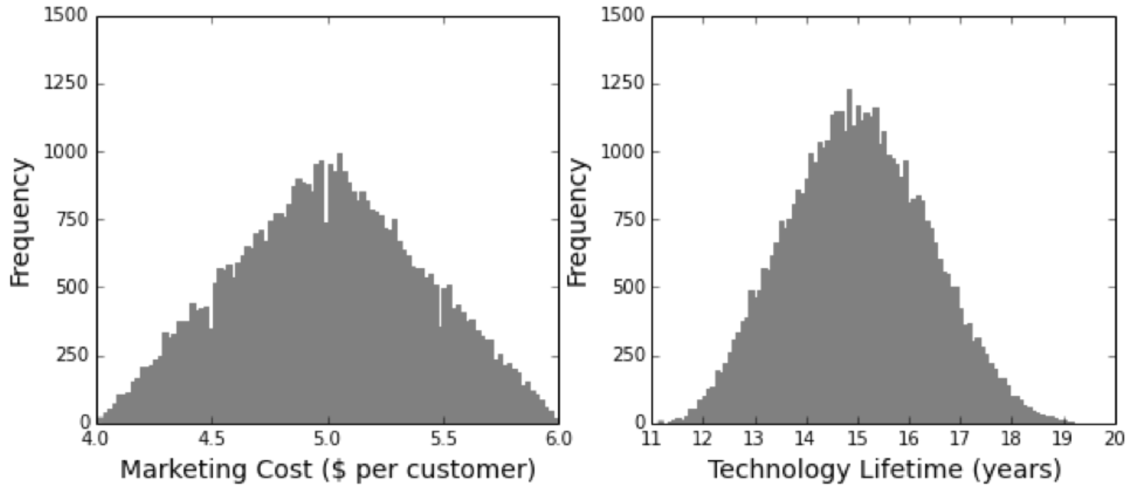


Figure G-6: Distribution of marketing costs and technology lifetime for residential DLC switches observed in 100 realizations of the Monte Carlo simulation.

G-7. DR-PATH Model "Tree" Structure

The structure of the DR-PATH model is based on estimating a wide range of possible pathways that each end-use can take for providing DR—a "tree of possible outcomes", as illustrated in Figure G-7. For each scenario/year/weather case we estimate the available DR along each possible pathway.

follow an approximately normal distribution regardless of the shape of the underlying distributions themselves.

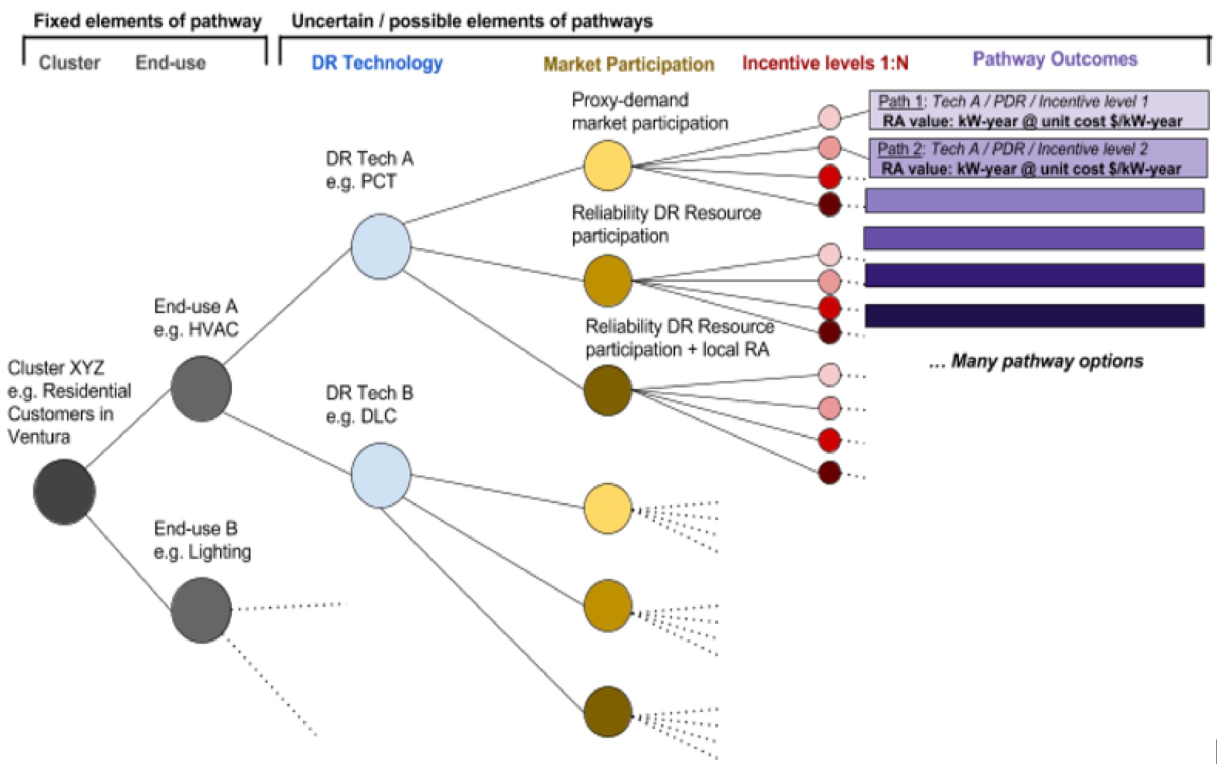


Figure G-7: DR-PATH schematic of the tree of possible pathway outcomes

G-8. Scenarios

The base case costs and performance inputs we collect for each technology reflect 2016 levels. To capture expected performance improvements between today and 2020/2025, we multiply the shed factors by 110% for the Business as Usual (BAU) scenario. To test for possible decreases in costs and further performance improvements, we have Medium and High scenarios where costs are 90% and 70% of base case costs, respectively, and shed factors are 120% and 140% of base case performance, respectively. The BAU, Medium and High scenarios also adjust for non-DR related adoption of DR technologies, and the propensity scores.

Table G-10: Summary of parameter adjustments of each scenario in DR-PATH model.

	Scenarios			
Parameters	**Base**	**Business as Usual**	**Medium**	**High**
Cost	100%	100%	90%	70%
Performance	100%	110%	120%	140%
Non-DR adoption	100%	110%	140%	150%
Propensity Score	100%	110%	130%	150%

G-9. DR Enabling Technology Costs and Performance Data

Cost and performance data on the DR enabling technologies modeled in DR-PATH for each pathway option illustrated above from come from a variety of sources, including other DR potential study reports, LBNL studies and institutional experience, academic literature, industry and stakeholder surveys and feedback, and market data. We document the sources and specific data inputs by end-use and sector below.

G-9.1. Data Sources

G-9.1.1. LBNL data

LBNL has many years of experience researching demand response technologies. We refer to several LBNL reports focused on DR technologies in specific sectors (industrial, commercial, agricultural) for data on the cost of DR enablement and typical load shed capabilities of specific end uses and enabling technologies by sector and building type. Where cost and/or performance data were limited, we also consulted with subject matter experts at LBNL to determine appropriate cost and performance inputs.

G-9.1.2. Industry and Market Data

LBNL submitted a formal data request to obtain information from the IOUs about current and planned DR investments and costs for those investments by end use and DR enabling technology. We use the costs supplied by the utilities wherever they are applicable. We also use IOU load impact evaluations that include program and technology costs to calibrate our estimates. For sectors with limited publicly available cost data (e.g., commercial, industrial) we consulted industry experts, including DR providers, to obtain estimates of DR technology costs and performance. For the residential sector, we also referenced current retail prices for DR technologies that are currently on the market, for example through retailers such as

Amazon.

G-9.1.3. Navigant data

We derive a portion of the cost data for the DR enabling technologies from a report prepared by Navigant Consulting for the Northwest Power and Conservation Council's Seventh Power Plan (Navigant Consulting, 2015). The Navigant study estimates costs for some residential, commercial, agricultural and industrial DR technologies, and provides costs for basic and automated DR enabling devices. The study estimates overall "Enablement Costs" that include technology costs, installation costs, and customer incentives. We draw from Navigant's estimates of technology and installation costs, but do not include any of their incentive costs. These technology and installation costs are either provided as an aggregate cost for enabling an entire site (in $/customer), or calculated by multiplying enablement costs per unit load (in $/kW) by the magnitude of load enabled to provide DR (in kW). Whenever possible we isolate the $/kW costs as initial variable costs and use our own assumptions regarding load impacts. The Navigant report also includes an "Implementation cost" to account for program administration, DR program management systems, and evaluation studies. In the current work we exclude these costs because they are not considered to be part of the actual enabling technology costs. Tables G-11 and G-12 contain Navigant's cost estimates for DR technologies; technologies are categorized as either "Capacity DR - Base" (Table G-11) or "Capacity DR - Smart" (Table G-12). Smart DR technologies are those that provide automated DR. Examples include PCTs that provide automated control of heating and cooling systems in residential and small commercial buildings, and energy management and control systems in medium and large commercial buildings.

Table G-11: Navigant cost assumptions for capacity DR - Base

DR Type	DR Component	DR Technology	Technology Cost ($/customer)	Installation Cost ($/kW)
Residential DR	Space Heating - DLC	Switch	$60	$80
	Water Heating - DLC	Switch	$60	$80
	Space Cooling - CAC DLC	Switch	$60	$80
	Space Cooling - RAC DLC	Switch	$40	$80
Commercial DR	Space Cooling, Small - CAC DLC	Switch	$100	$60
	Space Cooling, Medium - CAC DLC	Switch	$100	$60
	Lighting Controls	N/A	N/A	N/A
Agricultural / Industrial DR	Irrigation Pumping - DLC	Switch	$100	$40
	Curtailable/Interruptible Tariffs	-	$ -	$ -
	Load Aggregator	N/A	N/A	N/A
	Refrigerated Warehouses	N/A	N/A	N/A

Table G-12: Navigant cost assumptions for capacity DR - Smart

DR Type	DR Component	DR Technology	Technology Cost (Note: inconsistent units)	Installation Cost (Note: inconsistent units)
Residential DR	Space Heating - DLC	DLC	$400/kW	$114.90/kW
	Water Heating - DLC	DLC	$400/kW	$114.90/kW
	Space Cooling - CAC DLC	DLC	$400/kW	$114.90/kW
	Space Cooling - RAC DLC	DLC	$400/kW	$114.90/kW
Commercial DR	Space Cooling, Small - CAC DLC	DLC	$285.17/kW	$82.07/kW
	Space Cooling, Medium - CAC DLC	AutoDR	$138.50/kW	$96.00/kW
	Lighting Controls	AutoDR	$138.50/kW	$96.00/kW
Agricultural / Industrial DR	Irrigation Pumping - DLC	AutoDR	$138.50/kW	$96.00/kW
	Curtailable/Interruptible Tariffs	AutoDR	$2,500/customer	$1,250/customer
	Load Aggregator	AutoDR	$2,500/customer	$1,250.00/customer
	Refrigerated Warehouses	Refrigerated Warehouse Controls	$5000/customer	$2,500/customer

G-9.2. Commercial sector

Commercial customers are categorized as small, medium or large customers if their peak demand is less than 50 kW, between 50 and 200 kW, or greater than 200 kW, respectively. Customer size thresholds are shown in Table G-13. These thresholds are commonly used, and are consistent with the Navigant study.

Table G-13: Peak demand thresholds for categorizing small, medium and large commercial customers.

	Small Commercial	Medium Commercial	Large Commercial
Peak demand threshold [kW]	<50	50 - 200	>200

G-9.2.2. Commercial HVAC

Tables G-14 to G-21 below provide the key cost and performance assumptions for HVAC DR enabling technologies, for the base case, Business as Usual, Medium and High scenarios. The LBNL synthesis values for the base case scenario are presented in greater detail in Tables G-14 through G-21.

The following sections describe the four local control technologies we consider for commercial HVAC. These include: Direct load control (DLC) switches (Section G-6.9.2.2), Programmable communicating thermostats (PCTs) (Section G-6.9.2.3), Automated demand response (AutoDR) (Section G-6.9.2.4) and Manual demand response (Section G-6.9.2.5).

Table G-14: Summary Table: Commercial HVAC Enabling Technology Costs - Base Case.

			Initial costs		Operating costs	
End Use	**Commercial Class/Sector**	**Enabling Technology Component**	**Equipment & Installation Costs ($/Site)**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
HVAC	Small	Direct load control switches (DLC)	$100	$60	$0	$0
		Programmable communicating thermostats (PCT)	$0	$368	$0	$0
	Medium	Direct load control switches (DLC)	$100	$60	$0	$0
		Manual demand response	$800	$20	$0	$0

		Automated demand response (ADR)	$0	$235	$0	$0
	Large	Manual demand response	$0	$0	$0	$0
		Automated demand response (ADR)	$0	$235	$0	$0

Table G-15: Summary Table: Commercial HVAC End-Use Shed Filters - Base Case.

End Use	Commercial Class/Sector	Enabling Technology Component	Peak Shed	Average 1-Hour Shed [Fraction]	Average 2-Hour Shed [Fraction]	Average 4-Hour Shed [Fraction]
HVAC	Small	Direct load control switches (DLC)	0.5	0.4	0.4	0.35
		Programmable communicating thermostats (PCT)	0.8	0.7	0.7	0.6
	Medium	Direct load control switches (DLC)	0.5	0.4	0.4	0.35
		Manual demand response	0.6	0.5	0.45	0.35
		Automated demand response (ADR)	0.8	0.7	0.7	0.6
	Large	Manual demand response	0.6	0.5	0.45	0.35
		Automated demand response (ADR)	0.8	0.7	0.7	0.6

Table G-16: Summary Table: Commercial HVAC Enabling Technology Costs - BAU Case.

			Initial costs		Operating costs	
End Use	Commercial Class/Sector	Enabling Technology Component	Equipment & Installation Costs ($/Site)	Variable Initial costs ($/kW)	Fixed Operating Costs ($/yr)	Variable Operating Costs ($/kW/yr)
HVAC	Small	Direct load control switches (DLC)	$100	$60	$0	$0

		Programmable communicating thermostats (PCT)	$0	$368	$0	$0
	Medium	Direct load control switches (DLC)	$100	$60	$0	$0
		Manual demand response	$800	$20	$0	$0
		Automated demand response (ADR)	$0	$235	$0	$0
	Large	Manual demand response	$0	$0	$0	$0
		Automated demand response (ADR)	$0	$235	$0	$0

Table G-17: Summary Table: Commercial HVAC End-Use Shed Filters - BAU Case.

End Use	Commercial Class/Sector	Enabling Technology Component	Peak Shed	Average 1-Hour Shed [Fraction]	Average 2-Hour Shed [Fraction]	Average 4-Hour Shed [Fraction]
HVAC	Small	Direct load control switches (DLC)	0.55	0.44	0.44	0.39
		Programmable communicating thermostats (PCT)	0.88	0.77	0.77	0.66
	Medium	Direct load control switches (DLC)	0.55	0.44	0.44	0.39
		Manual demand response	0.66	0.55	0.50	0.39
		Automated demand response (ADR)	0.88	0.77	0.77	0.66
	Large	Manual demand response	0.66	0.55	0.50	0.39
		Automated demand response (ADR)	0.88	0.77	0.77	0.66

Table G-18: Summary Table: Commercial HVAC Enabling Technology Costs - Medium Case.

			Initial costs		Operating costs	
End Use	**Commercial Class/Sector**	**Enabling Technology Component**	**Equipment & Installation Costs ($/Site)**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
HVAC	Small	Direct load control switches (DLC)	$90	$54	$0	$0
		Programmable communicating thermostats (PCT)	$0	$331	$0	$0
	Medium	Direct load control switches (DLC)	$90	$54	$0	$0
		Manual demand response	$720	$18	$0	$0
		Automated demand response (ADR)	$0	$211	$0	$0
	Large	Manual demand response	$0	$0	$0	$0
		Automated demand response (ADR)	$0	$211	$0	$0

Table G-19: Summary Table: Commercial HVAC End-Use Shed Filters - Medium Case.

End Use	**Commercial Class/Sector**	**Enabling Technology Component**	**Peak Shed**	**Average 1-Hour Shed [Fraction]**	**Average 2-Hour Shed [Fraction]**	**Average 4-Hour Shed [Fraction]**
HVAC	Small	Direct load control switches (DLC)	0.60	0.48	0.48	0.42
		Programmable communicating thermostats (PCT)	0.96	0.84	0.84	0.72
	Medium	Direct load control switches (DLC)	0.60	0.48	0.48	0.42
		Manual demand response	0.72	0.60	0.54	0.42
		Automated demand response (ADR)	0.96	0.84	0.84	0.72

	Large	Manual demand response	0.72	0.60	0.54	0.42
		Automated demand response (ADR)	0.96	0.84	0.84	0.72

Table G-20: Summary Table: Commercial HVAC Enabling Technology Costs – High Case.

			Initial costs		Operating costs	
End Use	**Commercial Class/Sector**	**Enabling Technology Component**	**Equipment & Installation Costs ($/Site)**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
HVAC	Small	Direct load control switches (DLC)	$70	$42	$0	$0
		Programmable communicating thermostats (PCT)	$0	$257	$0	$0
	Medium	Direct load control switches (DLC)	$70	$42	$0	$0
		Manual demand response	$560	$14	$0	$0
		Automated demand response (ADR)	$0	$164	$0	$0
	Large	Manual demand response	$0	$0	$0	$0
		Automated demand response (ADR)	$0	$164	$0	$0

Table G-21: Summary Table: Commercial HVAC End-Use Shed Filters - High Case.

End Use	Commercial Class/Sector	Enabling Technology Component	Peak Shed	Average 1-Hour Shed [Fraction]	Average 2-Hour Shed [Fraction]	Average 4-Hour Shed [Fraction]
HVAC	Small	Direct load control switches (DLC)	0.70	0.56	0.56	0.49
		Programmable communicating thermostats (PCT)	1.12	0.98	0.98	0.84

	Medium	Direct load control switches (DLC)	0.70	0.56	0.56	0.49
		Manual demand response	0.84	0.70	0.63	0.49
		Automated demand response (ADR)	1.12	0.98	0.98	0.84
	Large	Manual demand response	0.84	0.70	0.63	0.49
		Automated demand response (ADR)	1.12	0.98	0.98	0.84

G-9.2.3. Direct load control (DLC) switches

Traditional switch-based Direct Load Control (DLC) technology is the most common means of enabling DR in commercial HVAC systems. DLC switches are typically installed on the central air conditioner (or heat pump), and function by cycling the units on and off during a DR event. This technology is most common in small to medium commercial buildings, rather than in large commercial buildings. DLC programs typically offer customers the option of two tiers of cycling on the HVAC unit- 50%, which means the HVAC unit is cycled 30 minutes out of every hour, or 100%, in which the HVAC unit is cycled for a full hour. We refer to this as 50% control and 100% control below, and the shed performance is impacted by the percentage control m where 100% provide the most shed, and 50% is half of that.

A commercial DLC switch costs $100, based on an analysis conducted for Tucson Electric Power's mass market DLC program (Navigant Consulting, 2015). This cost does not include costs associated with installation and grid integration. The variable cost for Commercial DLC switches is $60/kW (Navigant Consulting, 2015). DR-PATH inputs relating to cost and performance of DLC switches in commercial HVAC systems are listed in Table G-22.

Table G-22: HVAC cost and performance assumptions: Direct load control switches (DLC), small and medium commercial, 50% control

Input field	LBNL Synthesis Value Small commercial		Other Estimates/ Bounds on Assumption		Notes
Building size	**Small**	**Medium**	**Small**	**Medium**	
Cost Assumptions					
`cost_unit_var`	kW-peak	kW-peak			
`cost_site_enab`	$0	$0			Default assumption
`cost_fix_init`	$100	$100	Navigant Technology cost: $100/customer	Navigant Technology cost: $100/customer	Navigant assumptions (from Excel spreadsheet and the Key Assumptions tab)
`cost_var_init`	$60/kW	$60/kW	Navigant Installation cost: $60/kW Navigant assumes a 2.8 kW/customer for small commercial, which would come to $168/customer	Navigant Installation cost: $60/kW Navigant assumes a 15kW/customer for small commercial, which would come to $900/customer	
`cost_fix_opco`	0	0			Default Assumption
`cost_var_opco`	0	0	Navigant Implementation cost:$10/kW/yr	Navigant Implementation cost:$10/kW/yr	The Navigant implementation cost is not used in our study since it is not considered an enablement cost

Input field	LBNL Synthesis Value Small commercial		Other Estimates/ Bounds on Assumption		Notes
Building size	Small	Medium	Small	Medium	
cost_fix_ … co_benefit	0	0			Default Assumption
cost_var_ … co_benefit	0	0			Default Assumption
cost_margin_ … dispatch_day	$0.5/day	$0.5/day			LBNL estimate
tech_lifetime	15 years	15 years			LBNL estimate
Performance Assumptions					
T_delay_local (seconds)	1	1			LBNL estimate
T_ramp (seconds)	10	10			LBNL estimate
t_resolution_ … local_control (seconds)	3600	3600			LBNL estimate
Shed_peak (Fraction of end use sheddability)	0.5	0.5			LBNL estimate
Shed_1_hour (Fraction of end use	0.4	0.4			LBNL estimate

Input field	LBNL Synthesis Value Small commercial		Other Estimates/ Bounds on Assumption		Notes
Building size	Small	Medium	Small	Medium	
sheddability)					
Shed_2_hour (Fraction of end use sheddability)	0.4	0.4			LBNL estimate
Shed_4_hour (Fraction of end use sheddability)	0.35	0.35			LBNL estimate

G-9.2.4. Programmable communicating thermostats (PCTs)

A commercial PCT costs $285.71/kW (Navigant Consulting, 2014). The Installation Cost for Commercial PCT is $82.07/kW (Navigant Consulting, 2015). We use the sum of these two $/kW costs as the variable initial cost of the technology. DR-PATH inputs relating to cost and performance of PCTs in commercial HVAC systems are listed in Table G-23.

Table G-23: HVAC cost and performance assumptions: Programmable communicating thermostats (PCT), small commercial, 50% control

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
cost_unit_var	kW-peak		
cost_site_enab	0		Default assumption
cost_fix_init	0		Default assumption

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
`cost_var_init`	$367.78/kW	From Navigant: $285.71/kW (Technology cost) + $82.07/kW (Installation cost)= $367.78/kW On a $/customer value from Navigant: Technology cost: $798.48/customer Installation cost: $229.8/customer	We use the $/kW value from Navigant instead of $/customer
`cost_fix_opco`	0		Default assumption
`cost_var_opco`	0	Navigant Implementation cost: $20/kW/yr	The Navigant implementation cost is not used in our study since it is not considered an enablement cost
`cost_fix_ … co_benefit`	0		Default assumption
`cost_var_ … co_benefit`	0		Default assumption
`cost_margin_ … dispatch_day`	0		LBNL estimate
`tech_lifetime`	12 years		LBNL estimate
Performance Assumptions			
`T_delay_local (seconds)`	1		LBNL estimate
`T_ramp (seconds)`	10		LBNL estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
t_resolution_ … local_control (seconds)	15		LBNL estimate
Shed_peak (Fraction of end use sheddability)	0.8		LBNL estimate
Shed_1_hour (Fraction of end use sheddability)	0.7		LBNL estimate
Shed_2_hour (Fraction of end use sheddability)	0.7		LBNL estimate
Shed_4_hour (Fraction of end use sheddability)	0.6		LBNL estimate

G-9.2.5. Automated demand response

According to Piette et al. (2015), the median cost of an automated DR system is about $200/kW based on cost data from 56 customers. The difference between minimum and maximum cost is more than a factor of ten, based on the wide range of "system age, size of load reduction, sophistication, and type of equipment included in cost analysis." However, "the cost to automate DR in new buildings that comply with the 2013 building code are expected to be less than the costs of retrofitting an existing building's DR system to automate it" (Piette et al., 2015).

According to Navigant Auto DR + Energy Management System costs $138.50/kW * the load impact, based on its analysis conducted for a BPA smart grid investment case in 2014 (Navigant Consulting, 2015). DR-PATH inputs relating to cost and performance of AutoDR systems in commercial HVAC systems are listed in Table G-24. AutoDR systems are typically only installed in medium and large commercial buildings, thus these inputs do not apply to small commercial customers.

Table G-24: HVAC cost and performance assumptions: Automated demand response, medium and large commercial

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
`cost_unit_var`	kW-peak		
`cost_site_enab`	0		Default assumption
`cost_fix_init`	0		Default assumption
`cost_var_init`	$234.5/kW	Navigant: $138.5/kW (Technology cost) + $96/kW (Installation cost) 138.5 = $234.5/kW On a $/customer value from Navigant: Technology cost: $2077.5/kW Installation cost: $1440.00/customer	The initial variable cost is now based on Navigant's assumptions. An alternative is to use $200/kW, based on typical commercial DR from Piette et al. (2015)
`cost_fix_opco`	0		Default assumption
`cost_var_opco`	0	$20/kW/yr	The Navigant implementation cost is not used in our study since it is not considered a enablement cost
`cost_fix_ … co_benefit`	0		Default assumption

cost_var_ … co_benefit	0		Default assumption
cost_margin_ … dispatch_day	$2/day		LBNL estimate
tech_lifetime	12 years		LBNL estimate
Performance Assumptions			
T_delay_local (seconds)	1		LBNL estimate
T_ramp (seconds)	120		LBNL estimate
t_resolution_ … local_control (seconds)	15		LBNL estimate
Shed_peak (Fraction of end use sheddability)	0.8		LBNL estimate
Shed_1_hour (Fraction of end use sheddability)	0.7		LBNL estimate
Shed_2_hour (Fraction of end use sheddability)	0.7		LBNL estimate
Shed_4_hour (Fraction of end use sheddability)	0.6		LBNL estimate

G-9.2.6. Manual demand response

We estimate the cost of enabling manual DR by examining the cost of purchasing appropriate enabling technologies from online retailers. For example, Figure G-8 shows a thermostat from

Ecobee available for purchase online at a cost of $383. The Ecobee and similar products can be used for manual DR. The LBNL synthesis estimates a technology cost of $400 and an additional installation cost of $400 for manual DR.

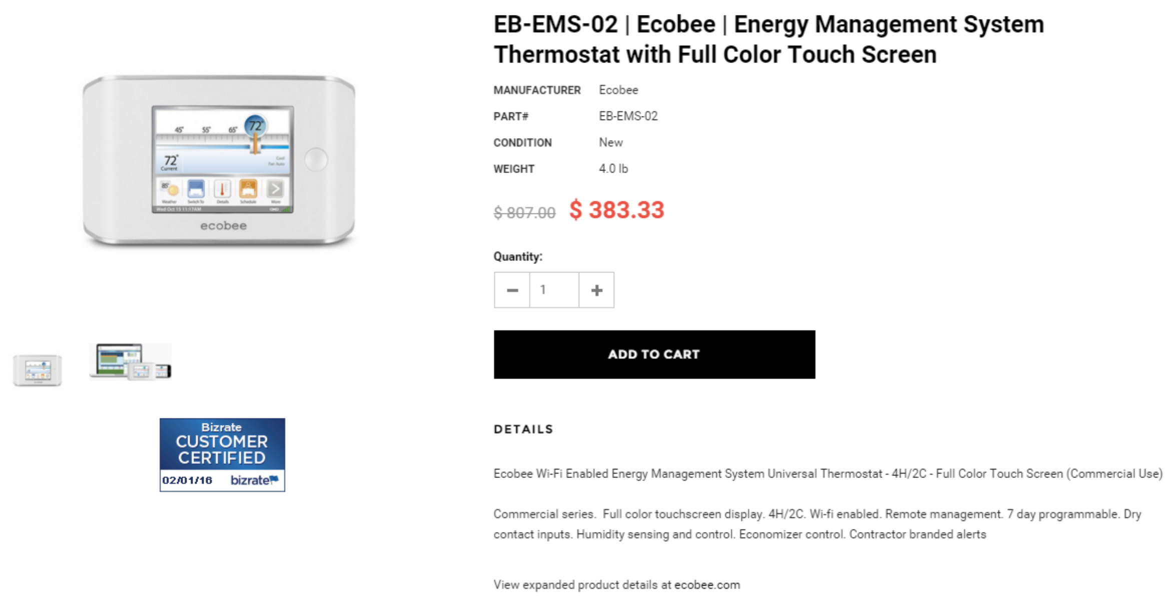


Figure G-8: Example of cost and specifications for an Ecobee thermostat capable of enabling manual DR in commercial HVAC systems.

Table G-25: HVAC cost and performance assumptions: Manual DR with EMS, medium and large commercial

Input field	LBNL Synthesis Value		Other Estimates/ Bounds on Assumption	Notes
Building size	Large	Medium	Medium and large	
Cost Assumptions				
cost_unit_var	kW-peak	kW-peak		
cost_site_enab	$0	$0		Default assumption
cost_fix_init	$0	$800	Ecobee: $800	Ecobee, hardware $400 and installation $400

Input field	LBNL Synthesis Value		Other Estimates/ Bounds on Assumption	Notes
Building size	Large	Medium	Medium and large	
cost_var_init	0	$20/kW		LBNL estimate
cost_fix_opco	0	0		Default assumption
cost_var_opco	0	0		Default assumption
cost_fix_ … co_benefit	0	0		Default assumption
cost_var_ … co_benefit	0	0		Default assumption
cost_margin_ … dispatch_day	0	$2/day		LBNL estimate
tech_lifetime	5 years	15 years		LBNL estimate
Performance Assumptions				
T_delay_local (seconds)	86400	3600		LBNL estimate
T_ramp (seconds)	300	300		LBNL estimate
t_resolution_ … local_control (seconds)	3600	1800		LBNL estimate
Shed_peak (Fraction of end use	0.5	0.6		LBNL estimate

Input field	LBNL Synthesis Value		Other Estimates/ Bounds on Assumption	Notes
Building size	Large	Medium	Medium and large	
sheddability)				
Shed_1_hour (Fraction of end use sheddability)	0.4	0.5		LBNL estimate
Shed_2_hour (Fraction of end use sheddability)	0.4	0.45		LBNL estimate
Shed_4_hour (Fraction of end use sheddability)	0.3	0.35		LBNL estimate

G-9.2.7. Commercial lighting

We draw information regarding advanced lighting control systems for enabling DR in commercial (office and retail) buildings from multiple sources. We examine numerous factors including system functionality, DR savings potential (maximum, expected and value based on costs), and system costs. A key challenge with estimating the costs enabling advanced lighting control systems for DR is that they are typically installed for purposes other than DR. Rather, these systems are typically installed either for non-energy benefits, such as occupant comfort, or for their energy-efficiency benefits. As such, neither the enabling costs nor the associated benefits can be attributed exclusively to DR. If we were to attribute the cost of an advanced lighting system exclusively to DR, enabling costs would be on the order of $20,000/kW. At such high costs, the technology would never be installed. However, installation of advanced lighting control system is accelerating due to their non-DR benefits.

To better capture the costs of lighting controls for DR, we need to attribute some portion of the enabling costs to DR, and some portion to EE. Sections G-6.9.2.7 and G-6.9.2.8 describe our assumptions and calculations, respectively, for allocating these costs in small, medium and large, commercial office and retail buildings. We consider three DR-enabling technology cases; (1) highly granular control including digitally addressable, individual luminaires (fixtures); (2) zonally controlled luminaires; and (3) existing standard practice lighting system consistent with meeting CA Title 24 Energy Code baseline.

The Tables G-26 to G-33 describe the cost and shed DR-PATH inputs for the lighting technologies for the base, BAU, Medium and High scenarios.

Table G-26: Summary Table: Commercial lighting Enabling Technology Costs - Base Case.

			Initial costs		Operating costs	
End Use	**Commercial Class/Sector**	**Enabling Technology Component**	**Equipment & Installation Costs ($/Site)**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
Lighting	Small	Office Luminaire	$0	$337	$0	$0
		Office Zonal	$0	$250	$0	$0
		Office Std.	$0	$438	$0	$0
		Retail Luminaire	$0	$316	$0	$0
		Retail Zonal	$0	$235	$0	$0
		Retail Std.	$0	$410	$0	$0
	Medium	Office Luminaire	$0	$953	$0	$0
		Office Zonal	$0	$708	$0	$0
		Office Std.	$0	$1,239	$0	$0
		Retail Luminaire	$0	$311	$0	$0
		Retail Zonal	$0	$232	$0	$0
		Retail Std.	$0	$405	$0	$0
	Large	Office Luminaire	$0	$531	$0	$0
		Office Zonal	$0	$394	$0	$0
		Office Std.	$0	$690	$0	$0
		Retail Luminaire	$0	$416	$0	$0
		Retail Zonal	$0	$309	$0	$0
		Retail Std.	$0	$541	$0	$0

Table G-27: Summary Table: Commercial lighting End-Use Shed Filters - Base Case.

End Use	Commercial Class/Sector	Enabling Technology Component	Peak Shed	Average 1-Hour Shed [Fraction]	Average 2-Hour Shed [Fraction]	Average 4-Hour Shed [Fraction]
Lighting	Small	Office Luminaire	0.35	0.35	0.35	0.35
		Office Zonal	0.3	0.3	0.3	0.3
		Office Std.	0.2	0.2	0.2	0.2
		Retail Luminaire	0.35	0.35	0.35	0.35
		Retail Zonal	0.3	0.3	0.3	0.3
		Retail Std.	0.2	0.2	0.2	0.2
	Medium	Office Luminaire	0.65	0.65	0.65	0.65
		Office Zonal	0.35	0.35	0.35	0.35
		Office Std.	0.25	0.25	0.25	0.25
		Retail Luminaire	0.5	0.5	0.5	0.5
		Retail Zonal	0.3	0.3	0.3	0.3
		Retail Std.	0.2	0.2	0.2	0.2
	Large	Office Luminaire	0.65	0.65	0.65	0.65
		Office Zonal	0.35	0.35	0.35	0.35
		Office Std.	0.65	0.65	0.65	0.65
		Retail Luminaire	0.5	0.5	0.5	0.5
		Retail Zonal	0.3	0.3	0.3	0.3
		Retail Std.	0.2	0.2	0.2	0.2

Table G-28: Summary Table: Commercial lighting Enabling Technology Costs –BAU.

			Initial costs		Operating costs	
End Use	Commercial Class/Sector	Enabling Technology Component	Equipment & Installation Costs ($/Site)	Variable Initial costs ($/kW)	Fixed Operating Costs ($/yr)	Variable Operating Costs ($/kW/yr)
Lighting	Small	Office Luminaire	$0	$337	$0	$0
		Office Zonal	$0	$250	$0	$0
		Office Std.	$0	$438	$0	$0
		Retail Luminaire	$0	$316	$0	$0
		Retail Zonal	$0	$235	$0	$0
		Retail Std.	$0	$410	$0	$0
	Medium	Office Luminaire	$0	$953	$0	$0
		Office Zonal	$0	$708	$0	$0
		Office Std.	$0	$1,239	$0	$0
		Retail Luminaire	$0	$311	$0	$0
		Retail Zonal	$0	$232	$0	$0
		Retail Std.	$0	$405	$0	$0
	Large	Office Luminaire	$0	$531	$0	$0
		Office Zonal	$0	$394	$0	$0
		Office Std.	$0	$690	$0	$0
		Retail Luminaire	$0	$416	$0	$0
		Retail Zonal	$0	$309	$0	$0
		Retail Std.	$0	$541	$0	$0

Table G-29: Summary Table: Commercial lighting End-Use Shed Filters - BAU Case.

End Use	Commercial Class/Sector	Enabling Technology Component	Peak Shed	Average 1-Hour Shed [Fraction]	Average 2-Hour Shed [Fraction]	Average 4-Hour Shed [Fraction]
Lighting	Small	Office Luminaire	0.39	0.39	0.39	0.39
		Office Zonal	0.33	0.33	0.33	0.33
		Office Std.	0.22	0.22	0.22	0.22
		Retail Luminaire	0.39	0.39	0.39	0.39
		Retail Zonal	0.33	0.33	0.33	0.33
		Retail Std.	0.22	0.22	0.22	0.22
	Medium	Office Luminaire	0.72	0.72	0.72	0.72
		Office Zonal	0.39	0.39	0.39	0.39
		Office Std.	0.28	0.28	0.28	0.28
		Retail Luminaire	0.55	0.55	0.55	0.55
		Retail Zonal	0.33	0.33	0.33	0.33
		Retail Std.	0.22	0.22	0.22	0.22
	Large	Office Luminaire	0.72	0.72	0.72	0.72
		Office Zonal	0.39	0.39	0.39	0.39
		Office Std.	0.72	0.72	0.72	0.72
		Retail Luminaire	0.55	0.55	0.55	0.55
		Retail Zonal	0.33	0.33	0.33	0.33
		Retail Std.	0.22	0.22	0.22	0.22

Table G-30: Summary Table: Commercial lighting Enabling Technology Costs - Medium Case.

			Initial costs		Operating costs	
End Use	**Commercial Class/Sector**	**Enabling Technology Component**	**Equipment & Installation Costs ($/Site)**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
Lighting	Small	Office Luminaire	$0	$303	$0	$0
		Office Zonal	$0	$225	$0	$0
		Office Std.	$0	$394	$0	$0
		Retail Luminaire	$0	$284	$0	$0
		Retail Zonal	$0	$212	$0	$0
		Retail Std.	$0	$369	$0	$0
	Medium	Office Luminaire	$0	$858	$0	$0
		Office Zonal	$0	$637	$0	$0
		Office Std.	$0	$1,115	$0	$0
		Retail Luminaire	$0	$280	$0	$0
		Retail Zonal	$0	$209	$0	$0
		Retail Std.	$0	$365	$0	$0
	Large	Office Luminaire	$0	$478	$0	$0
		Office Zonal	$0	$355	$0	$0
		Office Std.	$0	$621	$0	$0
		Retail Luminaire	$0	$374	$0	$0
		Retail Zonal	$0	$278	$0	$0
		Retail Std.	$0	$487	$0	$0

Table G-31: Summary Table: Commercial lighting End-Use Shed Filters - Medium Case.

End Use	Commercial Class/Sector	Enabling Technology Component	Peak Shed	Average 1-Hour Shed [Fraction]	Average 2-Hour Shed [Fraction]	Average 4-Hour Shed [Fraction]
Lighting	Small	Office Luminaire	0.42	0.42	0.42	0.42
		Office Zonal	0.36	0.36	0.36	0.36
		Office Std.	0.24	0.24	0.24	0.24
		Retail Luminaire	0.42	0.42	0.42	0.42
		Retail Zonal	0.36	0.36	0.36	0.36
		Retail Std.	0.24	0.24	0.24	0.24
	Medium	Office Luminaire	0.78	0.78	0.78	0.78
		Office Zonal	0.42	0.42	0.42	0.42
		Office Std.	0.30	0.30	0.30	0.30
		Retail Luminaire	0.60	0.60	0.60	0.60
		Retail Zonal	0.36	0.36	0.36	0.36
		Retail Std.	0.24	0.24	0.24	0.24
	Large	Office Luminaire	0.78	0.78	0.78	0.78
		Office Zonal	0.42	0.42	0.42	0.42
		Office Std.	0.78	0.78	0.78	0.78
		Retail Luminaire	0.60	0.60	0.60	0.60
		Retail Zonal	0.36	0.36	0.36	0.36
		Retail Std.	0.24	0.24	0.24	0.24

Table G-32: Summary Table: Commercial lighting Enabling Technology Costs - High Case.

			Initial costs		Operating costs	
End Use	**Commercial Class/Sector**	**Enabling Technology Component**	**Equipment & Installation Costs ($/Site)**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
Lighting	Small	Office Luminaire	$0	$236	$0	$0
		Office Zonal	$0	$175	$0	$0
		Office Std.	$0	$307	$0	$0
		Retail Luminaire	$0	$221	$0	$0
		Retail Zonal	$0	$165	$0	$0
		Retail Std.	$0	$287	$0	$0
	Medium	Office Luminaire	$0	$667	$0	$0
		Office Zonal	$0	$496	$0	$0
		Office Std.	$0	$867	$0	$0
		Retail Luminaire	$0	$218	$0	$0
		Retail Zonal	$0	$162	$0	$0
		Retail Std.	$0	$284	$0	$0
	Large	Office Luminaire	$0	$372	$0	$0
		Office Zonal	$0	$276	$0	$0
		Office Std.	$0	$483	$0	$0
		Retail Luminaire	$0	$291	$0	$0
		Retail Zonal	$0	$216	$0	$0
		Retail Std.	$0	$379	$0	$0

Table G-33: Summary Table: Commercial lighting End-Use Shed Filters - High Case.

End Use	Commercial Class/Sector	Enabling Technology Component	Peak Shed	Average 1-Hour Shed [Fraction]	Average 2-Hour Shed [Fraction]	Average 4-Hour Shed [Fraction]
Lighting	Small	Office Luminaire	0.49	0.49	0.49	0.49
		Office Zonal	0.42	0.42	0.42	0.42
		Office Std.	0.28	0.28	0.28	0.28
		Retail Luminaire	0.49	0.49	0.49	0.49
		Retail Zonal	0.42	0.42	0.42	0.42
		Retail Std.	0.28	0.28	0.28	0.28
	Medium	Office Luminaire	0.91	0.91	0.91	0.91
		Office Zonal	0.49	0.49	0.49	0.49
		Office Std.	0.35	0.35	0.35	0.35
		Retail Luminaire	0.70	0.70	0.70	0.70
		Retail Zonal	0.42	0.42	0.42	0.42
		Retail Std.	0.28	0.28	0.28	0.28
	Large	Office Luminaire	0.91	0.91	0.91	0.91
		Office Zonal	0.49	0.49	0.49	0.49
		Office Std.	0.91	0.91	0.91	0.91
		Retail Luminaire	0.70	0.70	0.70	0.70
		Retail Zonal	0.42	0.42	0.42	0.42
		Retail Std.	0.28	0.28	0.28	0.28

We base our cost assumptions for ‘activating’ advanced lighting controls in commercial buildings to enable DR on a ‘frozen efficiency’ regime for consistency with prior studies. However, we highlight that commercial lighting is becoming increasingly efficient as LED light sources have improved in performance and decreased in cost.

Our approach for modeling DR includes three key steps:

1. Estimate baseline lighting system load for each cluster (described in Appendix D) based on current lighting technologies.
2. For each future technology pathway, estimate the new lighting system efficacy for a controllable lighting system and scale the baseline load accordingly.
3. For each pathway, estimate the DR potential as a function of the adjusted baseline load.

The cost of installing lighting controls range between $0.10/ft^2 - $0.38/ft^2 . We assume a cost of $0.24/ft^2. The cost for sensors, switches and other miscellaneous system components is assumed to be $0,52/ft^2 Thus the total variable initial cost is $0.76/ft^2 The fixed initial cost is assumed to be $0/ft^2 since lighting is highly dependent on floor area, and because available cost data is expressed in terms of cost per unit floor area.

G-9.2.8. Cost Allocation of Advanced Lighting Systems

We base our cost analysis on the 2011 California Building Energy Efficiency Standards, Measure Information Template (California Building Energy Efficiency Standards, 2011).

These standards include two advanced lighting systems, including a digitally addressable lighting system and a zone-based digital lighting system. The addressable lighting system is similar in design to that of a centralized control panel, but with more granular control capabilities. In the zonal control system, a centralized control panel is controls each channel (or circuit) in unison. Enabling DR digitally addressable systems a fixed cost, versus a variable cost on zone based systems.

Existing requirements in Title 24, including Section 131(d) automatic shutoff control, are assumed to require a centralized network connection to a time-clock or a control panel with built in time-clock functionality. There are some exceptions to this assumption, for example in scenarios when each space is connected to occupancy sensors, which meets the requirements for automatic shutoff control without the need for a time-clock. These exceptions are most similar to the zone based lighting system, as both systems use network adapters to enable each room to be monitored and controlled for demand response.

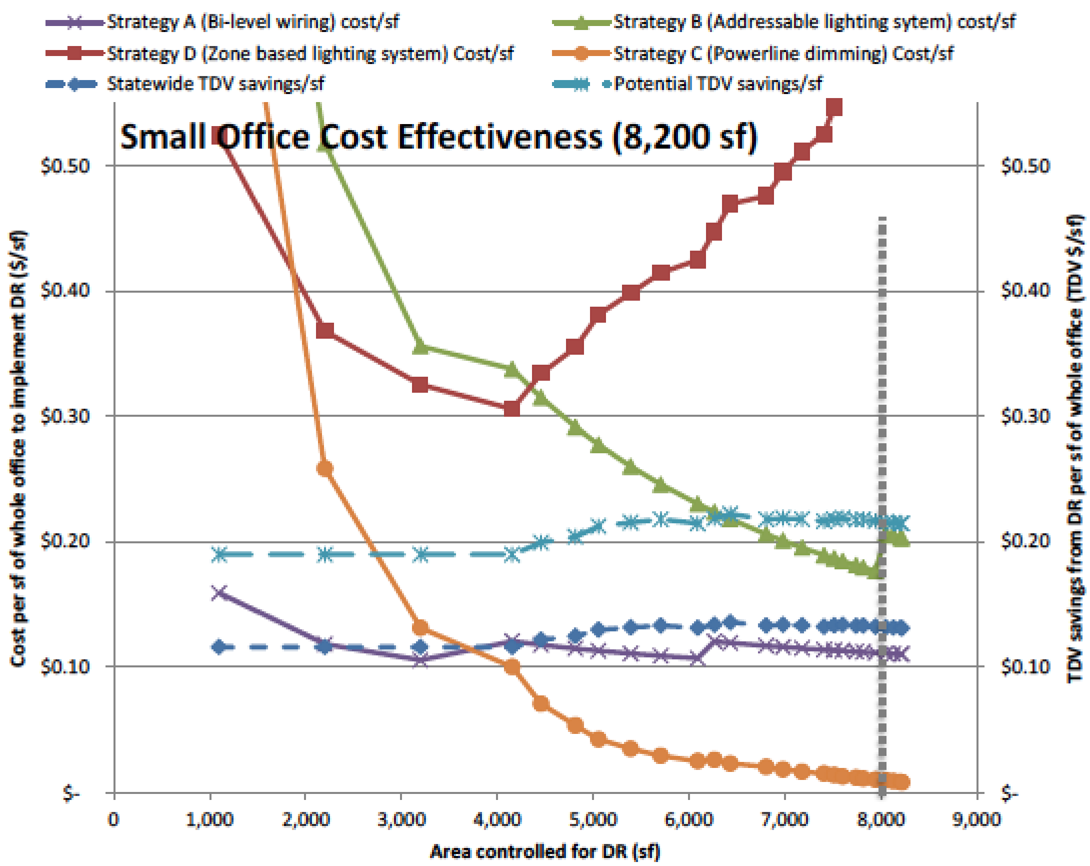


Figure G-9: Cost effectiveness of DR in small office prototype.

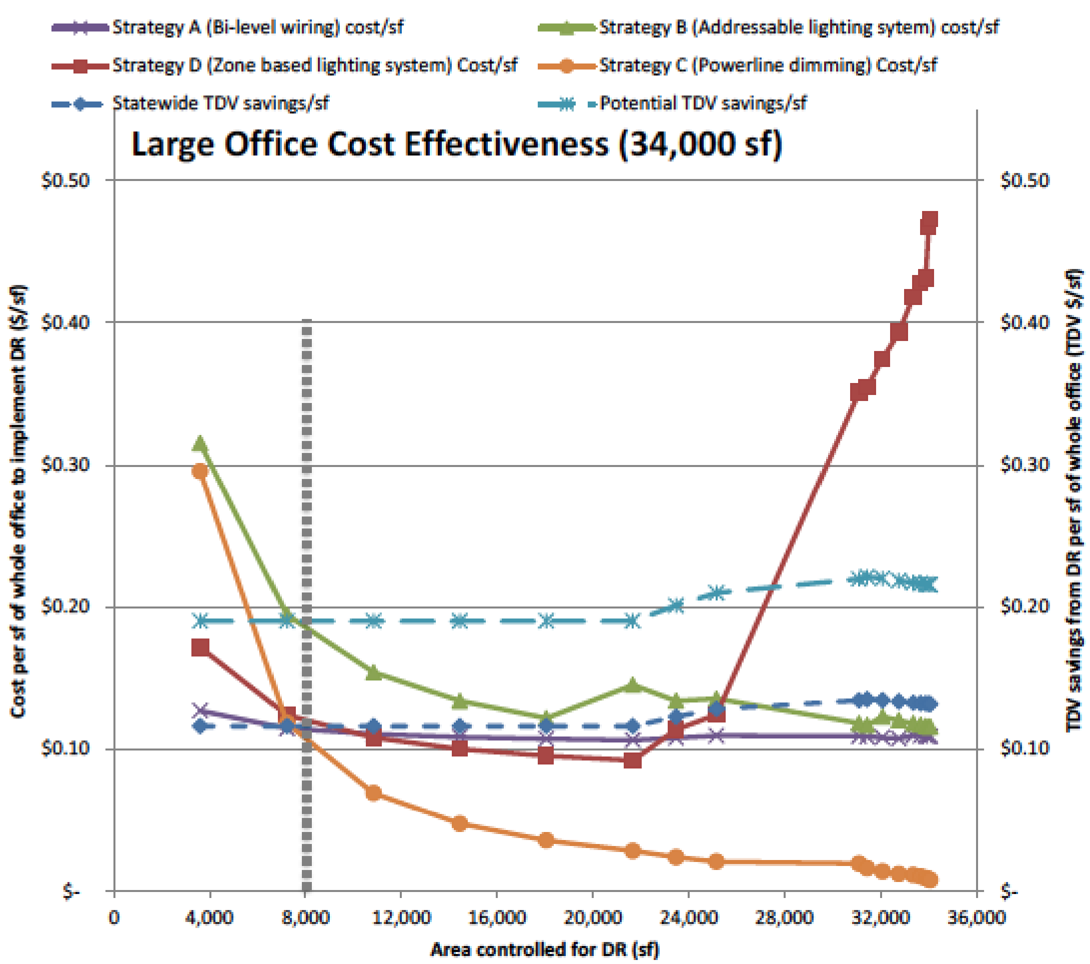


Figure G-10: Cost effectiveness of DR in large office prototype.

Figure G-9 and Figure G-10 depict enabling-DR technology cost-effectiveness for small and large office prototypes respectively. The blue dashed lines indicate the DR responsive lighting controls' savings per square foot of DR-controlled area within a building. The light blue dashed lines displays the energy savings (in dollars) assuming 20% of lighting load can be shed in the controlled area 87 hours per year over a 15-year life cycle. This value is the weighted average TDV value for the top 1% of hours, approximately $16/kWh. The lower, dark blue line reflects the adjusted load shed potential based upon a 70% enrollment rate, 97% signal reception, and 90% participation rate.

We choose average building sizes to represent the cost and value for small and large offices as exhibited in the spreadsheet excerpts below. The current analysis aims to derive the average cost per kW ($/kW); results are shown for each type of lighting system in Table G-37 (Columns 25, 26 and 27). We highlight that in Table G-34, the 'bare' costs per kW ($/kW) of enabling lighting for DR is extremely high (Columns 18, 19 and 20). These costs reflect the full technology cost burden before allocating some of that burden to EE. For that reason, we use the 2013 CASE report (California Building Energy Efficiency Standards, 2011) which delineates the lighting controls systems' installed cost relative to the DR enablement only.

To compute the average enablement costs per kW (Table G-35, Columns 25, 26 and 27), we make the following intermediary calculations:

1. First, we compute the average cost per premise ($) (Table G-32, Columns 9-11) by multiplying the average premise size (ft^2) (Table G-32 Column 4) by the average cost per square foot ($/ft^2) (Table G-32 Columns 6-8) in each scenario.
2. Next, we derive the average load shed per cite (Table G-33 Columns 13-15) by multiplying CEUS estimates of non-coincident peak lighting load (Table G-33 Column 12) by the average premise size (ft^2), and the percent load shed for the each DR-enabling technology. These are: 20% for digitally addressable systems, 35% for zonally controlled systems, and 65% for existing systems consistent with meeting CA Title 24 Energy Code baseline.
3. Finally, we divide the overall DR-enabling technology cost per square foot ($/ft^2) (Table D-34 Column 21) by the Average Load Shed per Square Foot (kW/ft^2) (Table D-34 Columns 22-24) to determine the DR-enabling technology Cost per kW of load shed per technology case ($/kW) (Table G-34 Columns 25-27).

Table G-34: Lighting cost and performance calculations and inputs (CEC, 2003) Table A

Occupancy Type	Premises	Est. Average Annual Electricity Consumption (kWh/yr)	Ave. Premise Size (ft²)	Total Electric Energy Intensity (kWh/ft²-yr)	Low (BAU) Scenario-Ave. Cost/SF ($/ft²)	Medium Scenario-Ave. Cost/SF ($/ft²)	High Scenario-Ave. Cost/SF ($/ft²)	BAU Ave. Cost/Premises ($)	Medium Scenario Ave. Cost/Premises ($)	High Scenario Ave. Cost/Premises ($)
1	2	3	4	5	6	7	8	9	10	11
		Est.	=3/5	CEUS Database	Est.	Est.	Est.	=4x6	=4x7	=4x8
Large Office	Large	10,000,000	564,972	17.70	$ 1.00	$ 3.50	$ 6.00	$ 564,972	$ 1,977,401	$3,389,831
	Medium	3,500,000	217,662	16.08	$ 1.00	$ 3.50	$ 6.00	$ 217,662	$ 761,816	$1,305,970
	Small	1,500,000	114,504	13.10	$ 1.00	$ 3.50	$ 6.00	$ 114,504	$ 400,763	$ 687,023
Small Office	Large	1,000,000	56,497	17.70	$ 1.50	$ 4.50	$ 6.00	$ 84,746	$ 254,237	$ 338,983
	Medium	75,000	4,664	16.08	$ 1.50	$ 4.50	$ 7.50	$ 6,996	$ 20,989	$ 34,981
	Small	15,000	1,145	13.10	$ 2.00	$ 5.00	$ 10.00	$ 2,290	$ 5,725	$ 11,450
Retail	Large	1,500,000	106,686	14.06	$ 1.00	$ 3.50	$ 6.00	$ 106,686	$ 373,400	$ 640,114
	Medium	650,000	46,230	14.06	$ 1.00	$ 3.50	$ 6.00	$ 46,230	$ 161,807	$ 277,383
	Small	75,000	5,334	14.06	$ 2.00	$ 4.50	$ 7.50	$ 10,669	$ 24,004	$ 40,007

Table G-35: Lighting cost and performance calculations and inputs (CEC, 2003) Table B

Occupancy Type	Premises	Lighting Electric Demand Intensity (W/ft^2)	Code Standard Ave. Load Shed (kW/Site)	Zone Level Ave. Load Shed (kW/Site)	Luminaire Level Ave.Load Shed (kW/Site)	Lighting Electric Demand/ Site (kW/Site)	Luminaire Level (New LED Lighting System Baseline) Lighting Electric Demand Intensity (W/ft^2)	Std. Ave. Cost/kW ($/kW)	Zone Level Ave. Cost/kW ($/kW)	Luminaire Level Ave. Cost/kW ($/kW)
Percent Load Shed			20%	35%	65%					
1	2	12	13	14	15	16	17	18	19	20
		CEUS: Interior Lighting Non-coincident Peak Load ($Watts/ft^2$)	=12x4x20% /1000	=12x4x35% /1000	=12x4x65% /1000	=4x12/1000	=12x0.40	=9/13	=10/14	=11/15
Large Office	Large	0.87	98.2	171.9	127.7	491.1	0.35	$ 5,752	$ 11,505	$ 26,550
	Medium	0.87	37.9	66.3	49.2	189.4	0.35	$ 5,747	$ 11,494	$ 26,525
	Small	0.87	19.9	34.9	25.9	99.6	0.35	$ 5,747	$ 11,494	$ 26,525
Small Office	Large	1.09	12.3	21.6	16.0	61.6	0.44	$ 6,881	$ 11,796	$ 21,171
	Medium	1.09	1.0	1.8	1.3	5.1	0.44	$ 6,881	$ 11,796	$ 26,464
	Small	1.37	0.3	0.5	0.4	1.6	0.55	$ 7,299	$ 10,428	$ 28,074
Retail	Large	1.11	23.7	41.4	30.8	118.4	0.44	$ 4,505	$ 9,009	$ 20,790
	Medium	1.11	10.3	18.0	13.3	51.3	0.44	$ 4,505	$ 9,009	$ 20,790
	Small	1.34	1.4	2.5	1.9	7.1	0.54	$ 7,463	$ 9,595	$ 21,527

Table G-36: Lighting cost and performance calculations and inputs (CEC, 2003) Table C

Occupancy Type	Premises	Cost ($/SF)	Code Standard Ave. Load Shed per SF (kW/ft^2)	Zone Level Ave. Load Shed per SF (kW/ft^2)	Luminaire Level Ave. Load Shed per SF (kW/ft^2)	Std. Ave. Cost/kW ($/kW)	Zone Level Ave. Cost/kW ($/kW)	Luminaire Level Ave. Cost/kW ($/kW)
1	2	21	22	23	24	25	26	27
			=13/4	=14/4	=15/4	=21/22	=21/23	=21/24
Large Office	Large	0.12	0.000174	0.000304	0.000226	$ 690	$ 394	$ 531
	Medium	0.09	0.000174	0.000305	0.000226	$ 517	$ 296	$ 398
	Small	0.11	0.000174	0.000305	0.000226	$ 632	$ 361	$ 486
Small Office	Large	0.27	0.000218	0.000382	0.000283	$ 1,239	$ 708	$ 953
	Medium	0.35	0.000218	0.000382	0.000283	$ 1,606	$ 917	$ 1,235
	Small	0.12	0.000274	0.000480	0.000356	$ 438	$ 250	$ 337
Retail	Large	0.12	0.000222	0.000389	0.000289	$ 541	$ 309	$ 416
	Medium	0.09	0.000222	0.000389	0.000289	$ 405	$ 232	$ 312
	Small	0.11	0.000268	0.000469	0.000348	$ 410	$ 235	$ 316

Table G-37: Annual electric summary statistics for large office buildings (CEC, 2003)

Annual Electric Summary Statistics CA_LOFF - Large Office (>=50k ft2)								
End Use	EUFS End-use Floor Stock (kSqFt)	EUI Energy-use Indices (kWh/EUFS/Year)	End-use Floor Stock Distribution (%)	EI Energy Intensity (kWh/Segment FS/Year)	End-use Energy Distribution (%)	Non-coincident Peak Load (watts/SF)	Connected Load (watts/SF)	Annual Energy Usage (GWh)
		(a)	(b)	(a*b)				
Heating	509,049	0.63	77.1%	0.49	2.8%	0.18	618.46 SF/kB	322
Cooling	608,796	3.87	92.2%	3.57	20.2%	1.67	360.25 SF/ton	2,358
Ventilation	623,559	3.24	94.4%	3.06	17.3%	0.59	1.10	2,019
Water Heating	339,024	0.24	51.3%	0.12	0.7%	0.02	0.17	80
Cooking	647,306	0.12	98.0%	0.12	0.7%	0.04	0.37	77
Refrigeration	648,945	0.41	98.3%	0.41	2.3%	0.05	0.24	268
Exterior Lighting	634,106	0.51	96.0%	0.49	2.8%	0.11	0.11	324
Interior Lighting	660,429	4.46	100.0%	4.46	25.2%	0.87	0.99	2,945
Office Equipment	660,429	3.58	100.0%	3.58	20.2%	0.60	1.73	2,365
Miscellaneous	593,264	0.65	89.8%	0.58	3.3%	0.10	0.47	383
Process	11,292	1.60	1.7%	0.03	0.2%	0.00	0.01	18
Motors	591,579	0.80	89.6%	0.72	4.1%	0.18	0.80	474
Air Compressors	402,211	0.15	60.9%	0.09	0.5%	0.02	0.05	60
Segment Total	660,429	--	--	17.70	100.0%	4.09	--	11,691

Table G-38: Annual electric summary statistics for small office buildings (CEC, 2003)

Annual Electric Summary Statistics CA_SOFF - Small Office (<50k ft2)								
End Use	EUFS End-use Floor Stock (kSqFt)	EUI Energy-use Indices (kWh/EUFS/Year)	End-use Floor Stock Distribution (%)	EI Energy Intensity (kWh/Segment FS/Year)	End-use Energy Distribution (%)	Non-coincident Peak Load (watts/SF)	Connected Load (watts/SF)	Annual Energy Usage (GWh)
		(a)	(b)	(a*b)				
Heating	164,537	0.44	45.5%	0.20	1.5%	0.42	159.44 SF/kB	72
Cooling	325,672	2.90	90.1%	2.61	19.9%	2.26	342.69 SF/ton	943
Ventilation	330,459	1.41	91.4%	1.29	9.8%	0.37	0.57	467
Water Heating	218,530	0.41	60.4%	0.25	1.9%	0.05	0.49	90
Cooking	336,712	0.11	93.1%	0.10	0.8%	0.04	0.69	38
Refrigeration	339,105	0.61	93.8%	0.58	4.4%	0.07	0.40	208
Exterior Lighting	266,643	1.28	73.7%	0.95	7.2%	0.23	0.26	343
Interior Lighting	361,584	3.83	100.0%	3.83	29.3%	1.09	1.39	1,386
Office Equipment	359,449	2.21	99.4%	2.19	16.7%	0.52	2.21	793
Miscellaneous	285,767	0.99	79.0%	0.78	6.0%	0.20	1.55	283
Process	1,497	0.76	0.4%	0.00	0.0%	0.00	0.00	1
Motors	79,443	0.99	22.0%	0.22	1.7%	0.05	0.23	79
Air Compressors	61,734	0.58	17.1%	0.10	0.8%	0.03	0.13	36
Segment Total	361,584	--	--	13.10	100.0%	4.51	--	4,738

Table G-39: Annual electric summary statistics for retail buildings (CEC, 2003).

Annual Electric Summary Statistics CA_RETL - Retail									
End Use	EUFS End-use Floor Stock (kSqFt)	EUI Energy-use Indices (kWh/EUFS/Year)	End-use Floor Stock Distribution (%)	EI Energy Intensity (kWh/Segment FS/Year)	End-use Energy Distribution (%)	Non-coincident Peak Load (watts/SF)	Connected Load (watts/SF)	Annual Energy Usage (GWh)
		(a)	(b)	(a*b)				
Heating	154,345	0.36	22.0%	0.08	0.6%	0.11	495 SF/kB	55
Cooling	511,774	3.03	72.9%	2.21	15.7%	1.40	504.59 SF/ton	1,553
Ventilation	539,874	2.35	76.9%	1.81	12.8%	0.34	0.51	1,267
Water Heating	389,564	0.25	55.5%	0.14	1.0%	0.03	0.19	96
Cooking	613,138	0.26	87.3%	0.22	1.6%	0.05	0.32	157
Refrigeration	631,176	1.15	89.9%	1.03	7.4%	0.14	1.26	726
Exterior Lighting	579,626	1.11	82.6%	0.92	6.5%	0.25	0.28	644
Interior Lighting	702,053	6.05	100.0%	6.05	43.0%	1.11	1.34	4,246
Office Equipment	701,522	0.49	99.9%	0.49	3.5%	0.10	0.49	343
Miscellaneous	603,181	0.80	85.9%	0.69	4.9%	0.13	0.82	483
Process	11,105	3.30	1.6%	0.05	0.4%	0.01	0.03	37
Motors	282,040	0.71	40.2%	0.29	2.0%	0.06	0.28	200
Air Compressors	162,774	0.39	23.2%	0.09	0.6%	0.02	0.10	64
Segment Total	702,053	--	--	14.06	100.0%	3.37	--	9,871

G-9.2.9. Refrigerated Warehouses

Table G-40 through G-46 detail enabling cost and performance assumptions for refrigerated warehouses in various scenarios.

Table G-40: Summary of commercial refrigerated warehouses enabling technology costs (base case).

			Initial costs		Operating costs	
End Use	Commercial Class/ Sector	Enabling Technology Component	Equipment & Installation Costs ($/Site)	Variable Initial costs ($/kW)	Fixed Operating Costs ($/yr)	Variable Operating Costs ($/kW/yr)
Refrigerated warehouses	All Commercial	Automated demand response (ADR)	$0	$280	$20	$0

Table G-41: Summary of shed filter values for commercial refrigerated warehouses (base case).

End Use	Commercial Class/Sector	Enabling Technology Component	Peak Shed	Average 1-Hour Shed [Fraction]	Average 2-Hour Shed [Fraction]	Average 4-Hour Shed [Fraction]
Refrigerated warehouses	All Commercial	Automated demand response (ADR)	0.65	0.65	0.65	0.5

Table G-42: Summary of commercial refrigerated warehouses enabling technology costs (BAU case).

			Initial costs		Operating costs	
End Use	Commercial Class/ Sector	Enabling Technology Component	Equipment & Installation Costs ($/Site)	Variable Initial costs ($/kW)	Fixed Operating Costs ($/yr)	Variable Operating Costs ($/kW/yr)
Refrigerated warehouses	All Commercial	Automated demand response (ADR)	$0	$280	$20	$0

Table G-43: Summary of shed filter values for commercial refrigerated warehouses (BAU case).

End Use	Commercial Class/Sector	Enabling Technology Component	Peak Shed	Average 1-Hour Shed [Fraction]	Average 2-Hour Shed [Fraction]	Average 4-Hour Shed [Fraction]
Refrigerated warehouses	All Commercial	Automated demand response (ADR)	0.72	0.72	0.72	0.55

Table G-44: Summary of commercial refrigerated warehouses enabling technology costs (medium case).

			Initial costs		Operating costs	
End Use	Commercial Class/ Sector	Enabling Technology Component	Equipment & Installation Costs ($/Site)	Variable Initial costs ($/kW)	Fixed Operating Costs ($/yr)	Variable Operating Costs ($/kW/yr)
Refrigerated warehouses	All Commercial	Automated demand response (ADR)	$0	$252	$18	$0

Table G-45: Summary of shed filter values for commercial refrigerated warehouses (medium case).

End Use	Commercial Class/Sector	Enabling Technology Component	Peak Shed	Average 1-Hour Shed [Fraction]	Average 2-Hour Shed [Fraction]	Average 4-Hour Shed [Fraction]
Refrigerated warehouses	All Commercial	Automated demand response (ADR)	0.78	0.78	0.78	0.60

Table G-46: Summary of commercial refrigerated warehouses enabling technology costs (high case).

			Initial costs		Operating costs	
End Use	Commercial Class/ Sector	Enabling Technology Component	Equipment & Installation Costs ($/Site)	Variable Initial costs ($/kW)	Fixed Operating Costs ($/yr)	Variable Operating Costs ($/kW/yr)
Refrigerated warehouses	All Commercial	Automated demand response (ADR)	$0	$196	$14	$0

Table G-47: Summary of shed filter values for commercial refrigerated warehouses (high case).

End Use	Commercial Class/Sector	Enabling Technology Component	Peak Shed	Average 1-Hour Shed [Fraction]	Average 2-Hour Shed [Fraction]	Average 4-Hour Shed [Fraction]
Refrigerated warehouses	All Commercial	Automated demand response (ADR)	0.91	0.91	0.91	0.70

Several studies have estimated the cost of controls technology in refrigerated warehouses. LBNL uses results from Lekov et al. (2009) who compiled enablement cost data from numerous sources, and find an average cost of $280/kW. Navigant (2015) estimates the technology cost of refrigerated warehouse controls to be $5000, based on their assumption that the controls comprised half the cost of BPA's pilot hardware cost of $10000. They estimate installation costs to be $7500 (Navigant Consulting, 2015). Several of the utilities, including PG&E, offer incentives up to $400/kW for ADR in various sectors, including refrigerated warehouses. Table G-48 lists DR-PATH input fields and values pertaining to AutoDR in refrigerated warehouses.

Table G-48: DR-PATH input data fields and values for AutoDR in refrigerated warehouses.

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
cost_unit_var	kW-peak		Navigant report listed all variable cost as per kW-year. We assume this is same as kW-peak
cost_site_enab	0		Default Assumption
cost_fix_init	0	$7500 estimated by Navigant report as sum of the technology cost and installation costs per customer.	Navigant report. (Sum of technology and installation costs per customer)
cost_var_init	$280/kW		DOE and IEEE report
cost_fix_opco	$20/site/year	Costs for communication ADR	IOU data request data
cost_var_opco	0		Default Assumption
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	$0.5/day		Estimate based on marginal dispatch cost of other ADR enabling technology
tech_lifetime	15 years		Estimate based on lifetime of other ADR enabling technology

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Performance Assumptions			
T_delay_local (seconds)	0.1		LBNL Estimate
T_ramp (seconds)	120		LBNL Estimate
t_resolution_ … local_control (seconds)	15		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.65		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	0.65		LBNL Estimate
Shed_2_hour (Fraction of end use sheddability)	0.65		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.5		LBNL Estimate

G-9.3. Residential sector

Residential sector demand response programs have historically focused on controlling residential central air conditioning units with a DLC switch. Recent programs have begun to include programmable communicating technologies such as thermostats. Over the next decade, we expect to see the number of residential end-uses available for DR enablement increase as a result of emerging technology in the residential sector. These include battery storage and battery/plug-in electric vehicles, which are entering the marketplace now, but should have a strong presence in the residential sector over the next decade.

The current study focuses on five residential end uses, as outlined in the table below. For central AC, we have identified three technology pathways, including DLC, programmable communicating thermostats (PCTs), and Manual DR. For the remaining end uses, we focus on a single technology pathway. In the following sections, we document our assumptions regarding the costs and shed capabilities for residential end uses and enabling technology options used in the DR-PATH model.

Below, Tables G-49 to G-56 provide an overview of the costs and shed filters that serve as inputs in the DR-PATH model. Following the tables, we take a deeper dive into the specifics with references for each end-use subsection.

Table G-49: Summary of residential enabling technology costs by end use (base case).

		Initial costs		Operating costs	
End Use	**Enabling Technology Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
HVAC	Direct load control switches (DLC) (100% cycle)	$160	$0	$6	$0
	Programmable communicating thermostats (PCT) (100% cycle)	$309	$0	$20	$0
	Direct load control switches (DLC) (50% cycle)	$160	$0	$6	$0
	Programmable communicating thermostats (PCT) (50% cycle)	$309	$0	$20	$0
Pool Pumps	Direct load control switches (DLC, FM telem)	$141	$0	$4	$0
	Direct load control switches (DLC, Wifi telem)	$141	$0	$4	$0
Battery Storage	Automated demand response (ADR) * Note that the fixed and variable initial cost for battery storage are expressed in a different unit, $/kWh	$550/kWh*	$324/kWh*	$34	$0
Battery Electric Vehicles	Automated demand response (Level 2 Chargers)	$2,200	$0	$20	$0
	Level 1 Chargers IoT Automated	$0	$0	$20	$0
	Level 1 Chargers, Manual	$0	$0	$20	$0
Plug in Hybrid EV	Automated demand response (Level 2 Chargers)	$2,200	$0	$20	$0
	Level 1 Chargers, IoT Automated	$0	$0	$20	$0
	Level 1 Chargers, Manual	$0	$0	$20	$0

Table G-50: Summary of residential shed filter values by end use (base case).

End Use	Enabling Technology Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
HVAC	Direct load control switches (DLC)	0.85	0.7	0.7	0.65
	Programmable communicating thermostats (PCT)	0.85	0.85	0.75	0.65
	Direct load control switches (DLC) (50% cycle)	0.6	0.4	0.4	0.35
	Programmable communicating thermostats (PCT) (50% cycle)	0.42	0.42	0.42	0.37
Pool Pumps	Direct load control switches (DLC, FM telem)	0.79	0.7	0.7	0.7
	Direct load control switches (DLC, Wifi telem)	0.79	0.7	0.7	0.7
Battery Storage	Automated demand response (ADR)	1	1	0.5	0.25
Battery Electric Vehicles	Automated demand response (Level 2 Chargers)	0.9	0.9	0.9	0.9
	Level 1 Chargers IoT Automated	0.8	0.8	0.8	0.8
	Level 1 Chargers, Manual	0.8	0.8	0.8	0.8
Plug in Hybrid EV	Automated demand response (Level 2 Chargers)	0.86	0.86	0.86	0.86
	Level 1 Chargers, IoT Automated	0.8	0.8	0.8	0.8
	Level 1 Chargers, Manual	0.8	0.8	0.8	0.8

Table G-51: Summary of residential enabling technology costs by end use (BAU case).

		Initial costs		Operating costs	
End Use	**Enabling Technology Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
HVAC	Direct load control switches (DLC) (100% cycle)	$160	$0	$6	$0
	Programmable communicating thermostats (PCT) (100% cycle)	$309	$0	$15	$0
	Direct load control switches (DLC) (50% cycle)	$160	$0	$6	$0
	Programmable communicating thermostats (PCT) (50% cycle)	$309	$0	$15	$0
Pool Pumps	Direct load control switches (DLC, FM telem)	$141	$0	$4	$0
	Direct load control switches (DLC, Wifi telem)	$141	$0	$4	$0
Battery Storage	Automated demand response (ADR) * Note that the fixed and variable initial cost for battery storage are expressed in a different unit, $/kWh	$550*	$324*	$34	$0
Battery Electric Vehicles	Automated demand response (Level 2 Chargers)	$2,200	$0	$20	$0
	Level 1 Chargers IoT Automated	$0	$0	$20	$0
	Level 1 Chargers, Manual	$0	$0	$20	$0
Plug in Hybrid EV	Automated demand response (Level 2 Chargers)	$2,200	$0	$20	$0
	Level 1 Chargers, IoT Automated	$0	$0	$20	$0
	Level 1 Chargers, Manual	$0	$0	$20	$0

* Note that the fixed and variable initial cost for battery storage are expressed in a different unit, $/kWh

Table G-52: Summary of residential shed filter values by end use (BAU case).

End Use	Enabling Technology Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
HVAC	Direct load control switches (DLC)	0.94	0.77	0.77	0.72
	Programmable communicating thermostats (PCT)	0.94	0.94	0.83	0.72
	Direct load control switches (DLC) (50% cycle)	0.66	0.44	0.44	0.39
	Programmable communicating thermostats (PCT) (50% cycle)	0.46	0.46	0.46	0.41
Pool Pumps	Direct load control switches (DLC, FM telem)	0.87	0.77	0.77	0.77
	Direct load control switches (DLC, Wifi telem)	0.87	0.77	0.77	0.77
Battery Storage	Automated demand response (ADR)	1.10	1.10	0.55	0.28
Battery Electric Vehicles	Automated demand response (Level 2 Chargers)	0.99	0.99	0.99	0.99
	Level 1 Chargers IoT Automated	0.88	0.88	0.88	0.88
	Level 1 Chargers, Manual	0.88	0.88	0.88	0.88
Plug in Hybrid EV	Automated demand response (Level 2 Chargers)	0.95	0.95	0.95	0.95
	Level 1 Chargers, IoT Automated	0.88	0.88	0.88	0.88
	Level 1 Chargers, Manual	0.88	0.88	0.88	0.88

Table G-53: Summary of residential enabling technology costs by end use (medium case).

		Initial costs		Operating costs	
End Use	Enabling Technology Component	Equipment and Installation Costs	Variable Initial costs ($/kW)	Fixed Operating Costs ($/yr)	Variable Operating Costs ($/kW/yr)
HVAC	Direct load control switches (DLC) (100% cycle)	$144	$0	$5	$0
	Programmable communicating thermostats (PCT) (100% cycle)	$278	$0	$14	$0
	Direct load control switches (DLC) (50% cycle)	$144	$0	$5	$0
	Programmable communicating thermostats (PCT) (50% cycle)	$278	$0	$14	$0
Pool Pumps	Direct load control switches (DLC, FM telem)	$127	$0	$4	$0
	Direct load control switches (DLC, Wifi telem)	$127	$0	$4	$0
Battery Storage	Automated demand response (ADR) * Note that the fixed and variable initial cost for battery storage are expressed in a different unit, $/kWh	$495*	$292*	$31	$0
Battery Electric Vehicles	Automated demand response (Level 2 Chargers)	$1,980	$0	$18	$0
	Level 1 Chargers IoT Automated	$0	$0	$18	$0
	Level 1 Chargers, Manual	$0	$0	$18	$0
Plug in Hybrid EV	Automated demand response (Level 2 Chargers)	$1,980	$0	$18	$0
	Level 1 Chargers, IoT Automated	$0	$0	$18	$0
	Automated demand response (Level 2 Chargers)	$0	$0	$18	$0

Table G-54: Summary of residential shed filter values by end use (medium case).

End Use	Enabling Technology Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
HVAC	Direct load control switches (DLC)	1.02	0.84	0.84	0.78
	Programmable communicating thermostats (PCT)	1.02	1.02	0.90	0.78
	Direct load control switches (DLC) (50% cycle)	0.72	0.48	0.48	0.42
	Programmable communicating thermostats (PCT) (50% cycle)	0.50	0.50	0.50	0.44
Pool Pumps	Direct load control switches (DLC, FM telem)	0.95	0.84	0.84	0.84
	Direct load control switches (DLC, Wifi telem)	0.95	0.84	0.84	0.84
Battery Storage	Automated demand response (ADR)	1.20	1.20	0.60	0.30
Battery Electric Vehicles	Automated demand response (Level 2 Chargers)	1.08	1.08	1.08	1.08
	Level 1 Chargers IoT Automated	0.96	0.96	0.96	0.96
	Level 1 Chargers, Manual	0.96	0.96	0.96	0.96
Plug in Hybrid EV	Automated demand response (Level 2 Chargers)	1.03	1.03	1.03	1.03
	Level 1 Chargers, IoT Automated	0.96	0.96	0.96	0.96
	Automated demand response (Level 2 Chargers)	0.96	0.96	0.96	0.96

Table G-55: Summary of residential enabling technology costs by end use (medium case).

		Initial costs		Operating costs	
End Use	**Enabling Technology Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
HVAC	Direct load control switches (DLC) (100% cycle)	$112	$0	$4	$0
	Programmable communicating thermostats (PCT) (100% cycle)	$216	$0	$11	$0
	Direct load control switches (DLC) (50% cycle)	$112	$0	$4	$0
	Programmable communicating thermostats (PCT) (50% cycle)	$216	$0	$11	$0
Pool Pumps	Direct load control switches (DLC, FM telem)	$99	$0	$3	$0
	Direct load control switches (DLC, Wifi telem)	$99	$0	$3	$0
Battery Storage	Automated demand response (ADR) * Note that the fixed and variable initial cost for battery storage are expressed in a different unit, $/kWh	$550*	$324*	$24	$0
Battery Electric Vehicles	Automated demand response (Level 2 Chargers)	$1,540	$0	$14	$0
	Level 1 Chargers IoT Automated	$0	$0	$14	$0
	Level 1 Chargers, Manual	$0	$0	$14	$0
Plug in Hybrid EV	Automated demand response (Level 2 Chargers)	$1,540	$0	$14	$0
	Level 1 Chargers, IoT Automated	$0	$0	$14	$0
	Automated demand response (Level 2 Chargers)	$0	$0	$14	$0

Table G-56: Summary of residential shed filter values by end use (high case).

End Use	Enabling Technology Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
HVAC	Direct load control switches (DLC)	1.19	0.98	0.98	0.91
	Programmable communicating thermostats (PCT)	1.19	1.19	1.05	0.91
	Direct load control switches (DLC) (50% cycle)	0.84	0.56	0.56	0.49
	Programmable communicating thermostats (PCT) (50% cycle)	0.588	0.588	0.588	0.518
Pool Pumps	Direct load control switches (DLC, FM telem)	1.106	0.98	0.98	0.98
	Direct load control switches (DLC, Wifi telem)	1.106	0.98	0.98	0.98
Battery Storage	Automated demand response (ADR)	1.4	1.4	0.7	0.35
Battery Electric Vehicles	Automated demand response (Level 2 Chargers)	1.26	1.26	1.26	1.26
	Level 1 Chargers IoT Automated	1.12	1.12	1.12	1.12
	Level 1 Chargers, Manual	1.12	1.12	1.12	1.12
Plug in Hybrid EV	Automated demand response (Level 2 Chargers)	1.20	1.20	1.20	1.20
	Level 1 Chargers, IoT Automated	1.12	1.12	1.12	1.12
	Automated demand response (Level 2 Chargers)	1.12	1.12	1.12	1.12

G-9.3.2. Residential Air Conditioning

Residential central air conditioning (AC) generally consists of a supply fan and a compressor unit. While there are other technologies for space cooling (e.g., evaporative swamp coolers) these technologies are not widely used in California, so we exclude them from the current study. For DR applications, a residential central air conditioning unit can be controlled either by a DLC switch, which turns off the compressor for a selected period of time, or by adjusting the setpoint temperature of a PCT, which controls the compressor and the fan of the entire central AC unit. Table D-55 lists DR-PATH inputs relating to DLC enablement of residential AC.

G-9.3.3. Load Control Tech 1: DLC Switches

DLC switches typically interrupt the operation of loads using a relay. In residential air conditioning units, the relay is installed on the condensing fan unit (typically outdoors). The switch can interrupt operation (or prevent operation when the next cooling cycle begins). DLC switches on AC units are appropriate for fast operation and meet technical response capabilities required to provide regulation and fast, energy-neutral DR products. DLC switches are not currently utilized for fast DR (Sullivan et al., 2013), but rather for peak shaving and multi-hour net load reshaping.

G-9.3.4. Legacy programs and emerging technology

DLC switches have a long history in utility program offerings, with FM radio communication serving as the primary channel for signaling curtailment. More recently, two way FM communication technologies have come to market, allowing the administrator to monitor the response rates of DLC switches in the the field. This functionality can lend Load Serving Entities (LSEs) and aggregators transparency in monitoring these devices, and facilitates the process of determining if/when load reductions observed in AMI data are attributable to the DLC switch or to other factors. While these technologies have not yet been implemented in large scale, several of the IOUs are planning on implementing these two way communicating DLC switches in the coming years.

G-9.3.5. Shed assumptions justification

During normal operation the condensing unit represents approximately 70% of the load. The condensing unit is the controllable portion of load with a DLC switch. This DR technology allows for the fan to continue operating while the condensing unit is controlled, and 30% of the AC load continues to draw power. The shed rates used in the model reflect a 70% shed reduction from the condensing unit but also reflects some operational limitations to shed rates. Most DR administrators elect to offer program participant varying degrees of AC cycling within their programs, such as 50% cycling which equates to 30 minutes of cycling each hour. Our model accounts for 50% cycling and 100% cycling of the condensing unit, reflected in the shed rates listed in Table G-58.

G-9.3.6. Cost justification

Several data sources were used to estimate costs for the DLC switches and installation. Data was gathered from the IOUs regarding the costs of existing and planned programs, and the corresponding technologies. The data provided by the IOUs varies in price depending on the technology vendors and on the IOU. We use the average of all the prices reported by the utilities. The initial costs include device and installation costs and are about $160. Navigant reports a costs of $108 dollars for the device and installation (Navigant Consulting, 2015). We do not use this value as it is substantially lower than values reported by the California utilities.

Table G-57: Residential AC, DLC (50% and 100% cycling respectively)

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
`cost_fix_init`	$160	Average Device Cost - $70 Average Install Cost - $90	IOU data request #3 report on enabling technology. Navigant report is $108. (Sum of technology and installation costs per customer)
`cost_var_init`	0		Default Assumption
`cost_fix_opco`	$6		IOU data request #3 report on enabling technology.
`cost_var_opco`	0		Default Assumption
`cost_fix_ … co_benefit`	0		Default Assumption
`cost_var_ … co_benefit`	0		Default Assumption
`cost_margin_ … dispatch_day`	$0.5/day		Estimated from NegaWatt study on DLC switches in pool pumps
`tech_lifetime`	15 years		IOU data request #3 with assumptions on lifetime

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Performance Assumptions - 50% Cycling			
T_delay_local (seconds)	1		LBNL Estimate
T_ramp (seconds)	10		LBNL Estimate
t_resolution_ … local_control (seconds)	3600		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.6		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	0.4		LBNL Estimate
Shed_2_hour (Fraction of end use sheddability)	0.4		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.35		LBNL Estimate
Performance Assumptions - 100% Cycling			
T_delay_local (seconds)	1		LBNL Estimate
T_ramp (seconds)	10		LBNL Estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
t_resolution_ … local_control (seconds)	3600		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.85		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	0.70		LBNL Estimate
Shed_2_hour (Fraction of end use sheddability)	0.70		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.65		LBNL Estimate

G-9.3.7. Load Control Tech 2: Programmable Communicating Thermostat + Wifi (100% shed and 50% shed)

The 2010 Statewide RASS survey conducted by Gilmore Research group reports that 46% of customers in the collective IOU territories have a programmable thermostat, while an estimated 26% have a programmable communicating thermostats (PCT) (2010 Statewide Residential Appliance Saturation Study (RASS)). PCTs are expected to continue to grow in popularity. We anticipate that adoption PCTs for non-DR purposes (and for DR specifically) will promote greater participation in DR programs. PCTs are equipped with capabilities to communicate with a smart meter. They are a two-way communication device that can receive signals from the utility, the internet, or a mobile phone. PCTs allow for the consumer (or a DR program administer) to control an AC unit, either by changing a setpoint, or by turning the AC off. PCT devices do not require constant programming input by the consumer.

G-9.3.8. Shed assumptions justification

Unlike DLC switches, PCTs can turn off an entire AC unit by adjusting the setpoint or signaling both the fan and the compressor unit to turn off, allowing for greater shed in a DR event. Most DR administrators elect to offer program participants varying degrees of AC cycling within their programs, such as 50% cycling which equates to 30 minutes of cycling each hour. For the purpose of PCTs, we can think of this as a 2, 4, or 6 degree increase in indoor temperature achieved by adjusting the setpoint temperature on the PCT. For example, if a consumer had set their PCT to 75 degrees and the DR event signals the thermostat to adjust by 4 degrees, the new setpoint would be 79 degrees. The AC unit would not resume operation until the indoor air temperature reaches the new setpoint. For simplicity, we reflect these setpoint adjustments in terms of cycling levels, and our model accounts for 50% cycling and 100% cycling of the AC unit; these are reflected in the shed rates below.

G-9.3.9. Cost justification

Several data sources were used to technology and installation costs of PCTs. Data was gathered from the IOUs regarding the costs of existing and planned programs and corresponding technologies; these costs varied depending on the technology vendors and on the IOU. We use the average of all prices the utilities reported. The initial costs include device and installation costs and are $309. This cost is consistent with results in Navigant Consulting (2015).

Table G-58: Residential AC, PCT (50% and 100% cycling respectively)

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
`cost_unit_var`	0		Default Assumption
`cost_site_enab`	0		Default Assumption
`cost_fix_init`	$309	$120- $130 for installation, and average tech costs of $160- $200	Navigant report. (Sum of technology and installation costs per customer). Utility data request #3- average cost for installation and technology

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
cost_var_init	0		Default Assumption
cost_fix_opco	$20	range from $6/pct/yr to $38/pct/yr	Utility data request #3- average annual cost for communications for each device
cost_var_opco	0		Default Assumption
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	$0.5/day		Estimated from NegaWatt study on DLC switches in pool pumps (*Demand Response Enabled Pool Pump Analysis, 2013*), (*Information & Energy Services, Inc. Multi-Family Residential Variable Speed Swimming Pool/Spa Pump Retrofit., 2012*)
tech_lifetime	12 years		LBNL Estimate
Performance Assumptions - 100% Cycling			
T_delay_local (seconds)	1		LBNL Estimate
T_ramp (seconds)	10		LBNL Estimate
t_resolution_ … local_control (seconds)	15		LBNL Estimate
Shed_peak (Fraction of end	0.85		LBNL Estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
use sheddability)			
Shed_1_hour (Fraction of end use sheddability)	0.85		LBNL Estimate
Shed_2_hour (Fraction of end use sheddability)	0.75		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.65		LBNL Estimate
Performance Assumptions - 50% Cycling			
T_delay_local (seconds)	1		LBNL Estimate
T_ramp (seconds)	10		LBNL Estimate
t_resolution_ … local_control (seconds)	15		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.42		LBNL Estimate
Shed_1_hour	0.42		LBNL Estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
(Fraction of end use sheddability)			
Shed_2_hour (Fraction of end use sheddability)	0.42		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.37		LBNL Estimate

G-9.3.10. Pool Pumps

DLC switches on pool pumps have a limited role in current utility program offerings. Today, FM radio communication serves as the primary channel for signaling curtailment, but WiFi connected pool pump DLC switches have recently entered the market and may take a limited market share in the future. For the purpose of our analysis, we address only the radio DLC switches for pool pumps, albeit with two-way communication. Below we provide details from a recent NegaWatt study commissioned by SDG&E (Demand Response Enabled Pool Pump Analysis, 2013).

G-9.3.11. Cost justification

In a pilot conducted by SDG&E for a ETCC effort on emerging technologies, costs for DR enabled pool pump switches were reported to be $141 for a retrofit installation DLC switch on residential pool pumps (Demand Response Enabled Pool Pump Analysis, 2013).]

G-9.3.12. Shed justification

LBNL estimates that a pool pump could shed up to 70% of load. This estimate has been based on the expected availability of the device and the amount of load available from the pumping duty.

Table G-59: Residential Pool pump, DCL, FM and Wifi Telemetry

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
cost_unit_var	End-use		Default Assumption
cost_site_enab	0		Default Assumption
cost_fix_init	$141		Average cost for installed retrofit DLC switch from NegaWatt study.
cost_var_init	0		Default Assumption
cost_fix_opco	$4		NegaWatt study average annual operating costs.
cost_var_opco	0		Default Assumption
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	$0.5/day	$1/day for FM Telemetry, and $0.50/day for Wifi	NegaWatt study and LBNL Synthesis
tech_lifetime	10 years		NegaWatt study
Performance Assumptions			
T_delay_local (seconds)	0.1		LBNL Estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
T_ramp (seconds)	0.1		LBNL Estimate
t_resolution_ … local_control (seconds)	600		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.79		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	0.7		LBNL Estimate
Shed_2_hour (Fraction of end use sheddability)	0.7		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.7		LBNL Estimate

G-9.3.13. Electric Vehicles

Electric Vehicles (EVs) can provide a range of DR opportunities which include both shedding and taking load from the grid. Although many of these innovative DR load modifications are still in experimental and pilot stages, a significant opportunity exists to couple new installations of residential EV charging stations with DR enablement as EV ownership continues to grow. Many factors will influence the willingness of consumers to participate in DR programs for EVs, including pricing incentives and tariffs, program incentives, improvements in two way communications technologies within EVs and charging stations, and decreasing costs for Level 2 charging stations.

G-9.3.14. Cost justifications

We derive cost estimates from several recent pilots conducted by California Utilities: SMUD and SDG&E (Final Evaluation for San Diego Gas & Electric's Plug- in Electric Vehicle TOU Pricing and Technology Study, 2014). In both pilots, utilities report combined technology and installation costs at around $2,200 for technologies enabling two-way communication with the EV; this cost is consistent with results from their 2012 and 2013 pilots. The costs included dedicated circuit and meter socket box, a smart charging station with Level 2 power at 240 Volts, and a DC fast charge port on the vehicle. SMUD also included an AMI TOU sub-meter with the installations. The breakdown of costs is provided in Table G-61.

G-9.3.15. Shed Filter assumptions

We derived the shed filters for both Battery Electric Vehicles (BEV) and Plug-in Hybrid Electric Vehicles (PHEV) from modeling done with V2G Sim model developed at LBNL. The estimates for shed range are estimated at 94% for PHEV and 95% for BEV.

Table G-60: Battery Electric Vehicle, ADR Level 2 Chargers, Commercial (public and fleet) and Residential Cost and Performance

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
cost_unit_var			Default Assumption
cost_site_enab			Default Assumption
cost_fix_init	$3,400	Installation of Dedicated Circuit, Meter Socket Box, and smart charging station ~$1500, $1,300 for installation, and ~$600 for charging socket on EV	Average costs reported from SDG&E PHEV tech study and the DOE SGIG EV charging study
cost_var_init	0		Default Assumption
cost_fix_opco	0	$20/yr for residential, $0/yr for commercial	LBNL Estimate
cost_var_opco	0		Default Assumption

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	$0.50		LBNL Estimate
tech_lifetime	10 years		SDG&E PHEV tech study assumption
Performance Assumptions - Commercial Sector (public and fleet)			
T_delay_local (seconds)	1		LBNL Estimate
T_ramp (seconds)	10		LBNL Estimate
t_resolution_ … local_control (seconds)	15		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.95		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	0.95		LBNL Estimate
Shed_2_hour (Fraction of end	0.95		LBNL Estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
use sheddability)			
Shed_4_hour (Fraction of end use sheddability)	0.95		LBNL Estimate
Performance Assumptions - Residential Sector			
T_delay_local (seconds)	1		LBNL Estimate
T_ramp (seconds)	10		LBNL Estimate
t_resolution_ … local_control (seconds)	15		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.90		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	0.90		LBNL Estimate
Shed_2_hour (Fraction of end use sheddability)	0.90		LBNL Estimate
Shed_4_hour	0.90		LBNL Estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
(Fraction of end use sheddability)			

Table G-61: Residential Battery Electric Vehicle, Level 1 Internet of Things (IoT) Auto Charging

Iput field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
cost_unit_var			Default Assumption
cost_site_enab			Default Assumption
cost_fix_init	0		LBNL Estimate
cost_var_init	0		LBNL Estimate
cost_fix_opco	$20/year		LBNL Estimate
cost_var_opco	0		Default Assumption
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	0		Default Assumption

Iput field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
tech_lifetime	15 years		LBNL Estimate
Performance Assumptions			
T_delay_local (seconds)	3600		LBNL Estimate
T_ramp (seconds)	300		LBNL Estimate
t_resolution_ … local_control (seconds)	600		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.8		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	0.8		LBNL Estimate
Shed_2_hour (Fraction of end use sheddability)	0.8		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.8		LBNL Estimate

Table G-62: Residential Battery Electric Vehicle, Residential Level 1 Manual Charging

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
cost_unit_var			Default Assumption
cost_site_enab			Default Assumption
cost_fix_init	0		LBNL Estimate
cost_var_init	0		LBNL Estimate
cost_fix_opco	$20/year		LBNL Estimate
cost_var_opco	0		Default Assumption
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	$2/day		LBNL Estimate
tech_lifetime	10 years		LBNL Estimate
Performance Assumptions			
T_delay_local (seconds)	3600		LBNL Estimate
T_ramp (seconds)	300		LBNL Estimate
t_resolution_ … local_control (seconds)	7200		LBNL Estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Shed_peak (Fraction of end use sheddability)	0.8		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	0.8		LBNL Estimate
Shed_2_hour (Fraction of end use sheddability)	0.8		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.8		LBNL Estimate

G-9.3.16. Plug-in Hybrid Electric Vehicles

Table G-63: Plug-in Electric Vehicle, ADR Level 2 Chargers, Commercial (public and fleet) and Residential Cost and Performance

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
cost_unit_var			Default Assumption
cost_site_enab			Default Assumption
cost_fix_init	$3,400	Installation of Dedicated Circuit, Meter Socket Box, and smart charging station ~$1500, $1,300 for installation, and ~$600 for charging socket on EV	Average costs reported from SDG&E PHEV tech study and the DOE SGIG EV charging study
cost_var_init	0		Default Assumption
cost_fix_opco	$20/yr	$20/yr for residential and for commercial	LBNL Estimate
cost_var_opco	0		Default Assumption
cost_fix_ … co benefit	0		Default Assumption
cost_var_ … co benefit	0		Default Assumption
cost_margin_ … dispatch day	$0.5		Default Assumption
tech_lifetime	10 years		SDG&E PHEV tech study assumption
Performance Assumptions - Commercial Sector (public and fleet)			
T_delay_local (seconds)	1		LBNL Estimate
T_ramp (seconds)	10		LBNL Estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
t_resolution_ … local_control	15		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.94		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	0.94		LBNL Estimate
Shed_2_hour (Fraction of end use sheddability)	0.94		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.94		LBNL Estimate
Performance Assumptions - Residential Sector			
T_delay_local (seconds)	1		LBNL Estimate
T_ramp (seconds)	10		LBNL Estimate
t_resolution_ … local_control (seconds)	15		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.86		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	0.86		LBNL Estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Shed_2_hour (Fraction of end use sheddability)	0.86		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.86		LBNL Estimate

Table G-64: Residential Plug-In Electric Vehicle, Level 1 Internet of Things (IoT) Auto Charging

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
cost_unit_var			Default Assumption
cost_site_enab			Default Assumption
cost_fix_init	0		LBNL Estimate
cost_var_init	0		LBNL Estimate
cost_fix_opco	$20/year		LBNL Estimate
cost_var_opco	0		Default Assumption
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
cost_margin_ … dispatch_day	0		Default Assumption
tech_lifetime	15 years		LBNL Estimate
Performance Assumptions			
T_delay_local (seconds)	3600		LBNL Estimate
T_ramp (seconds)	300		LBNL Estimate
t_resolution_ … local_control (seconds)	600		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.8		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	0.8		LBNL Estimate
Shed_2_hour (Fraction of end use sheddability)	0.8		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.8		LBNL Estimate

Table G-65: Residential Plug-In Electric Vehicle, Level 1 Manual Charging

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
cost_unit_var			Default Assumption
cost_site_enab			Default Assumption
cost_fix_init	0		LBNL Estimate
cost_var_init	0		LBNL Estimate
cost_fix_opco	$20/year		LBNL Estimate
cost_var_opco	0		Default Assumption
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	$2/day		Default Assumption
tech_lifetime	10 years		LBNL Estimate
Performance Assumptions			
T_delay_local (seconds)	3600		LBNL Estimate
T_ramp (seconds)	300		LBNL Estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
`t_resolution_ … local_control (seconds)`	7200		LBNL Estimate
`Shed_peak (Fraction of end use sheddability)`	0.8		LBNL Estimate
`Shed_1_hour (Fraction of end use sheddability)`	0.8		LBNL Estimate
`Shed_2_hour (Fraction of end use sheddability)`	0.8		LBNL Estimate
`Shed_4_hour (Fraction of end use sheddability)`	0.8		LBNL Estimate

G-9.4. Industrial Sector

Within the industrial sector we focused on DR enabling technologies at large production facilities and for agricultural water pumping.

G-9.4.1. Industrial Processes

Table G-66: Summary Table: Industrial Enabling Technology Costs by End-Use - Base Case.

			Initial costs		Operating costs	
End Use	**Building Class**	**Enabling Technology Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
Process	**Industrial**	Manual Process Interrupt	$3,000	$0	$0	$0
		Semi-Automated	$0	$200	$0	$0

		Process Interrupt				
		Automated demand response (ADR)	$0	$250	$0	$0

Table G-67: Summary Table: Industrial End-Use Shed Filters - Base Case.

End Use	Building Class	Enabling Technology Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
Process	**Industrial**	Manual Process Interrupt	0.5	0.5	0.5	0.5
		Semi-Automated Process Interrupt	0.55	0.55	0.55	0.55
		Automated demand response (ADR)	0.6	0.6	0.6	0.6

Table G-68: Summary Table: Industrial Enabling Technology Costs by End-Use - BAU Case.

			Initial costs		Operating costs	
End Use	**Building Class**	**Enabling Technology Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
Process	**Industrial**	Manual Process Interrupt	$3,000	$0	$0	$0
		Semi-Automated Process Interrupt	$0	$200	$0	$0
		Automated demand response (ADR)	$0	$250	$0	$0

Table G-69: Summary Table: Industrial End-Use Shed Filters - BAU Case

End Use	Building Class	Enabling Technology Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
Process	Industrial	Manual Process Interrupt	0.55	0.55	0.55	0.55
		Semi-Automated Process Interrupt	0.605	0.605	0.605	0.605
		Automated demand response (ADR)	0.66	0.66	0.66	0.66

Table G-70: Summary Table: Industrial Enabling Technology Costs by End-Use - Medium Case.

			Initial costs		Operating costs	
End Use	Building Class	Enabling Technology Component	Equipment and Installation Costs	Variable Initial costs ($/kW)	Fixed Operating Costs ($/yr)	Variable Operating Costs ($/kW/yr)
Process	Industrial	Manual Process Interrupt	$2,700	$0	$0	$0
		Semi-Automated Process Interrupt	$0	$180	$0	$0
		Automated demand response (ADR)	$0	$225	$0	$0

Table G-71: Summary Table: Industrial End-Use Shed Filters - Medium Case.

End Use	Building Class	Enabling Technology Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
Process	Industrial	Manual Process Interrupt	0.6	0.6	0.6	0.6
		Semi-Automated Process Interrupt	0.66	0.66	0.66	0.66

		Automated demand response (ADR)	0.72	0.72	0.72	0.72

Table G-72: Summary Table: Industrial Enabling Technology Costs by End-Use - High Case.

			Initial costs		Operating costs	
End Use	**Building Class**	**Enabling Technology Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
Process	**Industrial**	Manual Process Interrupt	$2,100	$0	$0	$0
		Semi-Automated Process Interrupt	$0	$140	$0	$0
		Automated demand response (ADR)	$0	$175	$0	$0

Table G-73: Summary Table: Industrial End-Use Shed Filters - High Case.

End Use	Building Class	Enabling Technology Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
Process	**Industrial**	Manual Process Interrupt	0.7	0.7	0.7	0.7
		Semi-Automated Process Interrupt	0.77	0.77	0.77	0.77
		Automated demand response (ADR)	0.84	0.84	0.84	0.84

For customers at large production facilities—such as factories, food processing plants or metal product manufacturing sites—utilities pay an incentive to interrupt a process and either partially or completely shut down load during a contingency event. Utilities notify these industrial customers either with a phone call, typically providing 30 minutes advanced notice, or through an AutoDR system. Once notified, customers either manually shut down their facility processes or automatically shed load through an AutoDR signal. There are also facilities with semi-automated controls, where some elements of the industrial process still need to be switched off manually during a DR event (Ghatikar et. al, 2012).

Navigant studied the curtailable industrial programs at Idaho Power, PG&E, and SMUD, among those of other utilities. If the notification to customers is by phone and the load shed is fully manual, we assume no DR enabling device need be installed but that there are still upfront enabling costs. If the customer participates in the Curtailable/Interruptible program with an AutoDR system, Navigant estimates the upfront installation ($1250) and technology ($2500) cost together to be approximately $3750 per customer, which is about $7.5/kW using their 500 kW load shed assumption (Navigant Consulting, 2015). We find this estimate to be low compared to a study (Piette et. al, 2015) of 56 installed AutoDR systems which approximated the median technology enabling cost to be $200/kW. Cost data from a study of 23 industrial sites in PG&E's 2007 industrial DR program ranged from $9/kW to $236/kW (Piette et. al, 2015). Cost estimates in Piette et. al. include technical coordination and installation. We use the median $200/kW cost for both AutoDR and semi-automated DR as we think of this as a more realistic value than the Navigant estimate.

Tables G-74 through G-76 detail DR-PATH inputs for industrial DR including for AutoDR (Table G-74), manual DR (Table G-75) and semi-automated DR (Table G-76).

Table G-74: AutoDR Industrial Process Interrupt

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
`cost_unit_var`	kW-peak		LBNL report listed cost as per kW value. We assume this is same as kW-peak
`cost_site_enab`	0		Default Assumption
`cost_fix_init`	0	Navigant assumes this cost (sum of technology and installation cost) as $3750 per customer with a 500 kW load shed.	LBNL report estimates all upfront costs as $/kW
`cost_var_init`	$250/kW		LBNL report median AutoDR cost

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
cost_fix_opco	0		Default Assumption
cost_var_opco	0		Default Assumption
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	$1/day		Estimate to account for communication fees
tech_lifetime	10 years		Estimate based on the lifetimes of other ADR enabling technologies
Performance Assumptions			
T_delay_local (seconds)	0.1		LBNL estimate
T_ramp (seconds)	120		LBNL estimate
t_resolution_ … local_control (seconds)	600		LBNL estimate
Shed_peak (Fraction of end use sheddability)	0.6		LBNL estimate
Shed_1_hour (Fraction of end use sheddability)	0.6		LBNL estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Shed_2_hour (Fraction of end use sheddability)	0.6		LBNL estimate
Shed_4_hour (Fraction of end use sheddability)	0.6		LBNL estimate

Table G-75: Industrial Manual Process Interrupt, normal and deep cuts.

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
cost_unit_var	kW-peak		Navigant report listed all variable cost as per kW-year. We assume this is same as kW-peak
cost_site_enab	0		Default Assumption
cost_fix_init	$3000		Navigant report estimates AutoDR fixed initial costs to be $3750, and we assume the Manual fixed initial costs are lower than for AutoDR. Assumed that no equipment needs to be installed for manual load shed and telephone notification but there are other upfront costs.
cost_var_init	0		Default Assumption
cost_fix_opco	0		Default Assumption
cost_var_opco	0		Default Assumption

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	$1/day		Estimate to account for marginal dispatch costs
tech_lifetime	10 years		Based on estimate of average contract term and possible renewal terms
Performance Assumptions (normal cut)			
T_delay_local (seconds)	1800		LBNL estimate
T_ramp (seconds)	300		LBNL estimate
t_resolution_ … local_control (seconds)	3600		LBNL estimate
Shed_peak (Fraction of end use sheddability)	0.5		LBNL estimate
Shed_1_hour (Fraction of end use sheddability)	0.5		LBNL estimate
Shed_2_hour (Fraction of end use sheddability)	0.5		LBNL estimate

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Shed_4_hour (Fraction of end use sheddability)	0.5		LBNL estimate
Performance Assumptions (deep cuts)			
T_delay_local (seconds)	7200		LBNL estimate
T_ramp (seconds)	3600		LBNL estimate
t_resolution_ … local_control (seconds)	28800		LBNL estimate
Shed_peak (Fraction of end use sheddability)	0.95		LBNL estimate
Shed_1_hour (Fraction of end use sheddability)	0.95		LBNL estimate
Shed_2_hour (Fraction of end use sheddability)	0.95		LBNL estimate
Shed_4_hour (Fraction of end use sheddability)	0.95		LBNL estimate

Table G-76: Semi-Automated Industrial Process Interrupt

Input field	LBNL Synthesis	Other Estimates/ Bounds on	Notes

	Value	Assumption	
Cost Assumptions			
cost_unit_var	kW-peak		LBNL report listed cost as per kW value. We assume this is same as kW-peak
cost_site_enab	0		Default Assumption
cost_fix_init	0		LBNL report estimates all upfront costs as $/kW
cost_var_init	$200/kW		LBNL report median AutoDR cost. Semi-automated DR assumed to be similar cost.
cost_fix_opco	0		Default Assumption
cost_var_opco	0		Default Assumption
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	$1/day		Estimate to account for communication fees
tech_lifetime	10 years		Estimate based on the lifetimes of other ADR enabling technologies
Performance Assumptions			
T_delay_local (seconds)	1800		Estimated to be same as manual
T_ramp (seconds)	180		Estimated to be between automated and manual

t_resolution_ … local_control (seconds)	600		LBNL estimate
Shed_peak (Fraction of end use sheddability)	0.55		LBNL estimate
Shed_1_hour (Fraction of end use sheddability)	0.55		LBNL estimate
Shed_2_hour (Fraction of end use sheddability)	0.55		LBNL estimate
Shed_4_hour (Fraction of end use sheddability)	0.55		LBNL estimate

G-9.4.2. Agricultural Pumping

Table G-77: Summary Table: Agricultural Pumping Enabling Technology Costs by End-Use - Base Case.

			Initial costs		Operating costs	
End Use	**Building Class**	**Enabling Technology Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
Irrigation Pumping	**Agricultural**	Direct load control switch (DLC)	$100	$60	$0	$0
		Automated demand response (ADR)	$0	$235	$0	$0

Table G-78: Summary Table: Agricultural Pumping End-Use Shed Filters - Base Case.

End Use	Building Class	Enabling Technology Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
Irrigation	**Agricultural**	Direct load control	0.7	0.7	0.7	0.7

Pumping		switch (DLC)				
		Automated demand response (ADR)	0.8	0.8	0.8	0.8

Table G-79: Summary Table: Agricultural Pumping Enabling Technology Costs by End-Use - BAU Case.

			Initial costs		**Operating costs**	
End Use	**Building Class**	**Enabling Technology Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
Irrigation Pumping	**Agricultural**	Direct load control switch (DLC)	$100	$40	$0	$0
		Automated demand response (ADR)	$0	$235	$0	$0

Table G-80: Summary Table: Agricultural Pumping End-Use Shed Filters - BAU Case.

End Use	**Building Class**	**Enabling Technology Component**	**Peak shed**	**Average 1-hour shed [Fraction]**	**Average 2-hour shed [Fraction]**	**Average 4-hour shed [Fraction]**
Irrigation Pumping	**Agricultural**	Direct load control switch (DLC)	0.77	0.77	0.77	0.77
		Automated demand response	0.88	0.88	0.88	0.88

Table G-81: Summary Table: Agricultural Pumping Enabling Technology Costs by End-Use - Medium Case.

			Initial costs		Operating costs	
End Use	**Building Class**	**Enabling Technology Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
Irrigation Pumping	**Agricultural**	Direct load control switch (DLC)	$90	$36	$0	$0
		Automated demand response (ADR)	$0	$211	$0	$0

Table G-82: Summary Table: Agricultural Pumping End-Use Shed Filters - Medium Case.

End Use	Building Class	Enabling Technology Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
Irrigation Pumping	**Agricultural**	Direct load control switch (DLC)	0.84	0.84	0.84	0.84
		Automated demand response (ADR)	0.96	0.96	0.96	0.96

Table G-83: Summary Table: Agricultural Pumping Enabling Technology Costs by End-Use - High Case.

			Initial costs		Operating costs	
End Use	**Building Class**	**Enabling Technology Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
Irrigation Pumping	**Agricultural**	Direct load control switch (DLC)	$70	$28	$0	$0
		Automated demand response (ADR)	$0	$164	$0	$0

Table G-84: Summary Table: Agricultural Pumping End-Use Shed Filters - High Case.

End Use	Building Class	Enabling Technology Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
Irrigation Pumping	Agricultural	Direct load control switch (DLC)	0.98	0.98	0.98	0.98
		Automated demand response (ADR)	1.12	1.12	1.12	1.12

DR can be enabled for agricultural loads for the irrigation season by either a basic DLC switch or with an AutoDR system on the water pumps and other irrigation devices. Based on sampling Idaho Power and PacifiCorp and Bonneville Power's irrigation pumping DR programs, Navigant estimated the fixed initial installation cost to be $100 and technology cost to be $60/kW for a basic DLC system. We use installation cost as a fixed upfront cost and the technology cost as a variable upfront cost. For an AutoDR system Navigant estimated the variable installation and technology costs to be approximately $235/kW (when accounting for their kW of load shed assumed), and we use these costs as the variable upfront cost for the study (Navigant Consulting, 2015). An LBNL report on AutoDR potential in California's irrigation sector (Olsen et. al, 2015) noted that shed rates around 80% were common.

Table G-85: Agricultural pumping, basic DLC switch.

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
`cost_unit_var`	kW-peak		Navigant report listed all variable cost as per kW-year. We assume this is same as kW-peak
`cost_site_enab`	0		Default Assumption
`cost_fix_init`	$100		Navigant report. (Technology cost)
`cost_var_init`	$40		Navigant report (installation cost divided by kW of load shed to get

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
			$/kW value)
cost_fix_opco	0		Default Assumption
cost_var_opco	0		Default Assumption
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	0		Default Assumption
tech_lifetime	15 years		Estimate based on lifetime of other DLC enabling technology
Performance Assumptions			
T_delay_local (seconds)	0.1		LBNL Estimate
T_ramp (seconds)	0.1		LBNL Estimate
t_resolution_ … local_control (seconds)	600		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	0.7		Based on LBNL report (Olsen 2015) and average shed factors
Shed_1_hour (Fraction of end	0.7		Based on LBNL report (Olsen 2015) and average shed factors

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
use sheddability)			
Shed_2_hour (Fraction of end use sheddability)	0.7		Based on LBNL report (Olsen 2015) and average shed factors
Shed_4_hour (Fraction of end use sheddability)	0.7		Based on LBNL report (Olsen 2015) and average shed factors

Table G-86: Agricultural pumping, ADR.

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
cost_unit_var	kW-peak		Navigant report listed all variable cost as per kW-year. We assume this is same as kW-peak
cost_site_enab	0		Default Assumption
cost_fix_init	0		Navigant report has costs in $/kW
cost_var_init	$235		Navigant report (sum of technology and installation cost divided by kW of load shed to get $/kW value)
cost_fix_opco	0		Default Assumption
cost_var_opco	0		Default Assumption

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
cost_fix_ … co_benefit	0		Default Assumption
cost_var_ … co_benefit	0		Default Assumption
cost_margin_ … dispatch_day	$0.5/day		Estimate based on marginal dispatch cost of other ADR enabling technology
tech_lifetime	15 years		Estimate based on lifetime of other ADR enabling technology
Performance Assumptions			
T_delay_local (seconds)	0.1		LBNL estimate
T_ramp (seconds)	0.1		LBNL estimate
t_resolution_ … local_control (seconds)	600		LBNL estimate
Shed_peak (Fraction of end use sheddability)	0.8		Based on LBNL report (Olsen 2015) and average shed factors
Shed_1_hour (Fraction of end use sheddability)	0.8		Based on LBNL report (Olsen 2015) and average shed factors
Shed_2_hour (Fraction of end use sheddability)	0.8		Based on LBNL report (Olsen 2015) and average shed factors

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
`Shed_4_hour` `(Fraction of end use sheddability)`	0.8		Based on LBNL report (Olsen 2015) and average shed factors

G-9.4.3. Wastewater Treatment and Pumping

Our assumptions for DR opportunities with wastewater treatment and pumping facilities are based on previous research conducted by LBNL on Wastewater treatment plant DR opportunities (Thompson et al.) (Olsen et al.). Our study includes two types of enabling technologies, manual DR and ADR. Manual DR is much more commonplace today, however, ADR installations in Wastewater treatment facilities are expected to gain traction in the market over the coming decade.

For manual process interruption, we assume the costs would be an upfront initial cost of $3000 for an audit of the site by the LSE or aggregator. We base this assumption on information provided by one of the IOUs in the study. For ADR installations, we used data collected by LBNL from a variety of pilot efforts that implemented ADR in commercial buildings, and took the average of the installations, approximately $258/kW. The kW reductions came from LBNL research that determined facility load reduction of 26% could be achieved through automation or manual process interrupt (Thompson et al., 2009) (Olsen et al., 2012).

Table G-87: Summary Table: Wastewater Enabling Technology - Base Case.

		Initial costs		Operating costs	
Building Class	**Enabling Tech Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
WW Pumping	Manual Process Interrupt	$3,000	$0	$0	$0
	Automated demand response (ADR)	$0	$262	$50	$0
WW Treatment	Manual Process Interrupt	$3,000	$0	$0	$0
	Automated demand response (ADR)	$0	$258	$50	$0

Table G-88: Summary Table: Wastewater Shed Filters - Base Case.

Building Class	Enabling Tech Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
WW Pumping	Manual Process Interrupt	0.76	0.7	0.6	0.6
	Automated demand response (ADR)	0.76	0.7	0.6	0.6
WW Treatment	Manual Process Interrupt	0.26	0.26	0.2	0.15
	Automated demand response (ADR)	0.26	0.26	0.2	0.15

Table G-89: Summary Table: Wastewater Enabling Technology - BAU Case.

		Initial costs		Operating costs	
Building Class	Enabling Tech Component	Equipment and Installation Costs	Variable Initial costs ($/kW)	Fixed Operating Costs ($/yr)	Variable Operating Costs ($/kW/yr)
WW. Pumping	Manual Process Interrupt	$3,000	$0	$0	$0
	Automated demand response (ADR)	$0	$262	$50	$0
WW Treatment	Manual Process Interrupt	$3,000	$0	$0	$0
	Automated demand response (ADR)	$0	$258	$50	$0

Table G-90: Wastewater Enabling Shed Filters - BAU Case.

Building Class	Enabling Tech Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
WW. Pumping	Manual Process Interrupt	0.84	0.77	0.66	0.66
	Automated demand response (ADR)	0.84	0.77	0.66	0.66
WW Treatment	Manual Process Interrupt	0.29	0.29	0.22	0.17
	Automated demand	0.29	0.29	0.22	0.17

	response (ADR)				

Table G-91: Summary Table: Wastewater Enabling Technology Costs - Medium Case.

		Initial costs		Operating costs	
Building Class	**Enabling Tech Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
WW. Pumping	Manual Process Interrupt	$2,700	$0	$0	$0
	Automated demand response (ADR)	$0	$236	$45	$0
WW Treatment	Manual Process Interrupt	$2,700	$0	$0	$0
	Automated demand response (ADR)	$0	$232	$45	$0

Table G-92: Summary Table: Wastewater Shed Filters - Medium Case.

Building Class	Enabling Tech Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
WW Pumping	Manual Process Interrupt	0.91	0.84	0.72	0.72
	Automated demand response (ADR)	0.91	0.84	0.72	0.72
WW Treatment	Manual Process Interrupt	0.31	0.31	0.24	0.18
	Automated demand response (ADR)	0.31	0.31	0.24	0.18

Table G-93: Summary Table: Wastewater Enabling Technology Costs - High Case.

		Initial costs		Operating costs	
Building Class	**Enabling Tech Component**	**Equipment and Installation Costs**	**Variable Initial costs ($/kW)**	**Fixed Operating Costs ($/yr)**	**Variable Operating Costs ($/kW/yr)**
WW. Pumping	Manual Process Interrupt	$2,100	$0	$0	$0
	Automated demand response (ADR)	$0	$183	$35	$0
WW Treatment	Manual Process Interrupt	$2,100	$0	$0	$0
	Automated demand response (ADR)	$0	$181	$35	$0

Table G-94: Summary Table: Wastewater Shed Filters - High Case.

Building Class	Enabling Tech Component	Peak shed	Average 1-hour shed [Fraction]	Average 2-hour shed [Fraction]	Average 4-hour shed [Fraction]
WW. Pumping	Manual Process Interrupt	1.06	0.98	0.84	0.84
	Automated demand response (ADR)	1.06	0.98	0.84	0.84
WW Treatment	Manual Process Interrupt	0.36	0.36	0.28	0.21
	Automated demand response (ADR)	0.36	0.36	0.28	0.21

G-9.4.4. Data Centers

Data centers have two main energy consuming loads, IT servers and HVAC. The Demand response strategies in data centers have opportunities to reduce demand by employing the following strategies:

- Load migration (moving the IT load to another data center)
- Job delay (queuing the IT jobs to be done at a later time)
- Shutting off the HVAC system and letting the temperature drift

Since the complexity and dynamism of managing data centers does not lend itself easily to automation, there are only a few data center DR participants in the market today; those that participate, do so on manual response platforms. In data centers, it is particularly difficult estimate the cost and performance of specific end uses or enabling technologies due to the lack of relevant literature. Therefore, we examine DR load reduction at the site level rather than focusing on specific end-uses, and we assume that manual intervention will be used to respond to a DR event. Based on previous research conducted by LBNL on DR in Data Centers, we assumed a whole facility load reduction of 17%, with an facility audit of $3000 to confirm that load could be reduced at the site (Ghatikar, Ganti, et al., 2012). Tables G-95 to G-98 summarize cost and performance assumptions for data centers in various scenarios.

Table G-95: Summary Table: Data Center Technology Costs and Shed Filters - Base Case.

		Initial costs		Operating costs					
Building Class	**Enabling Tech Component**	**Equipment and Install Costs**	**Variable Initial costs ($/kW)**	**Fixed Op. Costs ($/yr)**	**Var. Op. Costs ($/kW/yr)**	**Peak shed**	**Average 1-hour shed**	**Average 2-hour shed**	**Average 4-hour shed**
Data Centers	Manual DR	$3,000	$0	$0	$0	0.15	0.15	0.15	0.15

Table G-96: Summary Table: Data Center Technology Costs and Shed Filters - BAU Case.

		Initial costs		Operating costs					
Building Class	**Enabling Tech Component**	**Equipment and Install Costs**	**Variable Initial costs ($/kW)**	**Fixed Op. Costs ($/yr)**	**Var. Op. Costs ($/kW/yr)**	**Peak shed**	**Average 1-hour shed**	**Average 2-hour shed**	**Average 4-hour shed**
Data Centers	Manual DR	$3,000	$0	$0	$0	0.17	0.17	0.17	0.17

Table G-97: Summary Table: Data Center Technology Costs and Shed Filters - Medium Case.

		Initial costs		Operating costs					
Building Class	**Enabling Tech Component**	**Equipment and Install Costs**	**Variable Initial costs ($/kW)**	**Fixed Op. Costs ($/yr)**	**Var. Op. Costs ($/kW/yr)**	**Peak shed**	**Average 1-hour shed**	**Average 2-hour shed**	**Average 4-hour shed**
Data Centers	Manual DR	$2,700	$0	$0	$0	0.18	0.18	0.18	0.18

Table G-98: Summary Table: Data Center Technology Costs and Shed Filters - High Case.

		Initial costs		Operating costs					
Building Class	**Enabling Tech Component**	**Equipment and Install Costs**	**Variable Initial costs ($/kW)**	**Fixed Op. Costs ($/yr)**	**Var. Op. Costs ($/kW/yr)**	**Peak shed**	**Average 1-hour shed**	**Average 2-hour shed**	**Average 4-hour shed**
Data Centers	Manual DR	$2,100	$0	$0	$0	0.21	0.21	0.21	0.21

G-9.5. Energy Storage- Batteries

Tables G-99 to G-102 summarize cost and performance inputs for commercial and industrial battery storage technology.

Table G-99: Summary Table: Commercial & Industrial Storage Technology Costs & Shed Filters - Base Case.

		Initial costs		Operating costs					
Building Class	**Enabling Tech Component**	**Equipment and Install Costs**	**Variable Initial costs ($/kW)**	**Fixed Op. Costs ($/yr)**	**Var. Op. Costs ($/kW/yr)**	**Peak shed**	**Average 1-hour shed**	**Average 2-hour shed**	**Average 4-hour shed**
Com. Storage	ADR	$550/kWh	$324/ kWh	$34	$0	1	1	0.5	0.25
Industrial Storage	ADR	$550	$324/ kWh	$34	$0	1	1	0.5	0.25

Table G-100: Summary Table: Commercial Storage Technology Costs and Shed Filters - BAU Case.

		Initial costs		Operating costs					
Building Class	Enabling Tech Component	Equipment and Install Costs	Variable Initial costs ($/kW)	Fixed Op. Costs ($/yr)	Var. Op. Costs ($/kW/yr)	Peak shed	Average 1-hour shed	Average 2-hour shed	Average 4-hour shed
Com. Storage	ADR	$550/kWh	$324/kWh	$34	$0	1.10	1.10	0.55	0.28
Industrial Storage	ADR	$550/kWh	$324/kWh	$34	$0	1.10	1.10	0.55	0.28

Table G-101: Summary Table: Commercial Storage Technology Costs and Shed Filters - Medium Case.

		Initial costs		Operating costs					
Building Class	Enabling Tech Component	Equipment and Install Costs	Variable Initial costs ($/kW)	Fixed Op. Costs ($/yr)	Var. Op. Costs ($/kW/yr)	Peak shed	Average 1-hour shed	Average 2-hour shed	Average 4-hour shed
Com. Storage	ADR	$495/kWh	$292/kWh	$31	$0	1.2	1.2	0.6	0.3
Industrial Storage	ADR	$495/kWh	$292/kWh	$31	$0	1.2	1.2	0.6	0.3

Table G-102: Summary Table: Commercial Storage Technology Costs and Shed Filters - High Case.

		Initial costs		Operating costs					
Building Class	**Enabling Tech Component**	**Equipment and Install Costs**	**Variable Initial costs ($/kW)**	**Fixed Op. Costs ($/yr)**	**Var. Op. Costs ($/kW/yr)**	**Peak shed**	**Average 1-hour shed**	**Average 2-hour shed**	**Average 4-hour shed**
Com. Storage	ADR	$385/kWh	$227/ kWh	$24	$0	1.4	1.4	0.7	0.35
Industrial Storage	ADR	$385/kWh	$227/ kWh	$24	$0	1.4	1.4	0.7	0.35

Locally-sited, "behind the meter" energy storage can make any load appear flexible to grid operators. Batteries that are equipped with the right telemetry, control, and intelligence can provide a wide range of services to both local load (increased reliability, power quality correction, reduction in demand charges, etc.) and the grid (through demand response and other grid services).

The cost of energy storage is changing rapidly from economies of scale in manufacturing for batteries (lithium in particular) and innovation on soft costs of installation and operation.

G-9.5.2. Battery storage benefits streams from non-DR sources

Many consumers adopt and install various end uses and technologies for cost saving reasons other than DR. For battery storage, we expect that adoption among consumers will be largely driven by non-DR benefit streams, most of which involve managing energy costs and improving service at the premise. However, some storage benefit streams come from engaging in the supply market to provide grid services such as regulation and spinning/non-spinning reserves. These benefits typically apply only to customers with large battery stacks, such as large C&I or utilities.

Table G-103 summarizes results from a study conducted by the Rocky Mountain Institute in 2015 titled "The Economics of Battery Energy Storage" (Fitzgerald et al., 2015). The study captures various value streams from BTM battery storage and compares those benefits to the total costs of installation for residential, commercial and utility scale battery systems. Our study includes total costs, including Balance of System (BOS) and battery storage cells/racks, along with benefit streams from DR and non-DR economic transactions, as detailed in Sections G-9.5.1 through G-9.5.3.

Table G-103: Battery Energy Storage Value Streams

SERVICE	Value [$/kW/yr]	CAISO Ranges
ARBITRAGE & LOAD FOLLOWING	$3-$97	34-47
REGUL.ATION	$28- $204	$7.8- $10.36
SPIN/ NONSPIN	$1-$65	
RA (Includes Forward Capacity)	$65-$155	
VOLTAGE SUPPORT	$56	
TRANS & DISTR. UPGRADE DEFERRAL	$51-$900	$67-$128
TRANS CONGEST RELIEF	$10-$12	
TOU	$23- $230	
kW CHARGE	$58- $269	
BLACK START	$6	
SELF CONSUMPTION OPTIMIZATION (with PV)	$10-$51	

***Values from Rocky Mountain Institute Report The Economics of Battery Storage, Appendix A, 2015**

Customers with larger battery storage systems can participate in the energy markets and benefit financially from these interactions. For example, battery storage systems can be used for regulation capacity or spinning and non-spinning reserves in the same manner as a conventional generator. In residential or small commercial applications, battery systems can be utilized for self-consumption optimization. For example, for sites with PV installations, excess solar generation can be stored for later use rather than selling over generation back to the grid. As another example, battery systems can be used to manage peak load for demand charge minimization.

G-9.5.3. Battery Storage Costs

Battery storage is a rapidly evolving technology that promises to become much more cost competitive over the next decade. For our analysis, we sought the expertise of E3, a subcontractor on this research study. They assisted with providing references and a recommended approach for appropriately costing battery systems. These costs are independent of the storage capacity of the system, allowing us to examine several scenarios regarding storage capacity. The DR-PATH analysis incorporates cost data from E3's research efforts, which rely heavily on "Electrical energy storage systems: A comparative life cycle cost analysis" (Zakeri and Syri, 2015), along with the DOE 2013 Energy Storage Handbook (Akhil et al.).

G-9.5.4. Balance of System (BOS)

Energy storage systems require equipment such as permitting and interconnection, inverters/converters, and specific power electronics. Theses equipment are commonly referred to as 'balance of system'" (BOS). These costs are often not reported by manufacturers, or it is unclear what costs are included. We consider the kW costs as fixed initial costs, and the variable costs of a battery system to include the kWh costs for the battery stack.

Storage systems present a unique challenge when categorizing costs because unlike power plants, which are valued at their max capacity value, battery storage has both a maximum power output and a maximum energy output. These are respectively characterized as the capacity (kW), and the energy (kWh) or duration (hours). The energy output (kWh) from a battery can vary considerably because of the duration of discharge, even for units with similar capacity. Thus E3 recommended a unique approach for overcoming the challenges of determining standardized costs for battery storage systems with different kWh durations. Following that approach, we breakdown the costs as follows: storage costs in $/kWh (the actual battery stacks in case of a battery system), and BOS costs in $/kW (inverter, utility interconnection, BMS, and installation). Table G-106 lists DR-PATH input fields and assumptions regarding commercial and industrial battery storage cost and performance.

Table G-104: Commercial and Industrial Battery Storage Cost and Performance

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
Cost Assumptions			
cost_unit_var			
cost_site_enab			
cost_fix_init	$550/kW installed	2015 cost estimates	2015 costs, average of BOS costs from Zakeri and Syri (2014) report
cost_var_init	$324/kWh	2015 cost estimates	Average battery cell price per kWh from DOE handbook and E3 calculations
cost_fix_opco	$34/kW	2015 cost estimates	E3 estimates based on Zakeri and Syri

Input field	LBNL Synthesis Value	Other Estimates/ Bounds on Assumption	Notes
cost_var_opco	0		Default Assumption
cost_fix …	0		Default Assumption
cost_var …	0		Default Assumption
cost_margin …	0		Default Assumption
tech_lifetime	5 years		LBNL Estimate
Performance Assumptions			
T_delay_local	1		LBNL Estimate
T_ramp (seconds)	120		LBNL Estimate
t_resolution_ … local_control	15		LBNL Estimate
Shed_peak (Fraction of end use sheddability)	1		LBNL Estimate
Shed_1_hour (Fraction of end use sheddability)	1		LBNL Estimate
Shed_2_hour (Fraction of end use sheddability)	0.5		LBNL Estimate
Shed_4_hour (Fraction of end use sheddability)	0.25		LBNL Estimate

G-10. Fast DR Enabling Technologies: Telemetry Costs and Performance

In Phase II, we consider additional DR enabling technologies with faster communication and load data acquisition capabilities than we examined in Phase I. These "Fast DR" technologies qualify or are expected to qualify for ancillary services and other market products which require faster response to a dispatch signal, with the fastest requirement of 4 seconds for regulation up or regulation down market participation.

To identify the end-uses capable of providing Fast DR today and in the future, LBNL performed a thorough review of the literature on telemetry and communication requirements for Fast DR. As many of these technologies are not widely examined in the literature, we also surveyed a number of DR industry stakeholders (including aggregators, scheduling coordinators, ESCOs, and contractors). Through written surveys responses and interviews with these stakeholders, LBNL obtained data on the configuration and costs of hardware and installation to enable Fast DR.

The end-uses eligible for Fast DR we examine in DR-PATH include:

- Agricultural Pumping
- Commercial HVAC (with EMS)
- Commercial Battery
- Commercial BEV and PHEV (fleet and public)
- Commercial Lighting (luminaire and zonal)
- Commercial Refrigerated Warehouses
- Industrial Battery
- Residential Battery
- Residential BEV and PHEV
- Wastewater Process and Pumping

LBNL populated the variable "Site-level communication and control cost" to reflect the added communication and telemetry costs to enable fast DR, above what would be required for Slow DR. Unlike costs considered in Phase I, this new cost applies to the entire DR enabled site rather than to any specific end-use. Because DR-PATH examines costs at the end-use level, we distribute the site-level costs among all DR-enabled end-uses present at that site using the following guidelines:

- **For commercial sites:** LBNL assumes that on average, the end-uses that would be enabled for Fast DR are HVAC, lighting, and storage. For each of these end-uses ⅓ of the site-wide cost is allocated.
- **For residential sites:** LBNL assumes that AC is the primary Fast DR enabled end-use. Therefore 100% of the site-wide cost is allocated to AC.
- **For industrial sites:** 100% of the site-wide cost is allocated to storage.
- **For BEVs or PHEV, both commercial and residential, both public and fleet, Level 2 charging:** 100% of the site-wide cost is allocated to BEV/PHEVs.
- **For wastewater treatment and pumping sites:** 100% of the site-wide cost is allocated to process and pumping end uses.
- **For commercial refrigerated warehouse sites:** 100% of the site-wide cost is allocated to refrigeration.

G-10.1. Typical Fast DR Telemetry and Dispatch Architecture

The typical telemetry architecture includes several components. At the site-level, a data collection mechanism measures end-use load, and connects to a resource interface which encrypts the data using Intra-Protocol, (which is an encryption protocol that enhances cyber security). The Intra-Protocol encryption enables the resource to communicate with a Remote Intelligent Gateway (RIG). The RIG aggregates individual data streams from many sites, and communicates the aggregate signal to the CAISO Energy Management System.

It is important to note that CAISO's requirement for telemetry is tied to the size of the resource (anything greater than 10MW) as well as the product type and associated response times. In our model, we capture the costs of enablement for DR resources with a RIG communication and advanced telemetry platforms, and we apply those cost to resources that are participating in conventional DR (peak shed DR). We outline those costs below, specific to those resources that have RIG communication enablement. In other words, the costs of DR enablement that meets the CAISO's requirement for resources greater than 10 MW is captured by specifying the costs for RIG and telemetry enablement at the customer premise for both fast DR and conventional DR.

For end-uses that can deliver Fast DR services, we assume the the same local control technology is used for both Fast and slow DR, (e.g. Auto DR, energy management systems, and end use local controls). Thus the only differences between Fast and Slow DR technologies are the telemetry and dispatch configurations. Therefore, the hardware and installation costs for Fast and Slow DR control technologies are the same, and any additional costs incurred in enabling a site to provide Fast DR are telemetry and communication system upgrades which could include metering, a resource interface, a gateway or another component.

G-10.2. Telemetry: Energy Measurement and Resource Interface

Based findings from the literature and survey responses, we identify several candidate technologies to measure energy usage and to interface with CAISO. These are detailed below.

G-10.2.1. Energy Measurement Technologies

According to a recent PG&E whitepaper on Fast DR telemetry, three possible options for energy measurement include:

1. Reprogrammed High Resolution AMI: an existing SmartMeter reprogrammed to record data at more frequent intervals
2. CAISO Revenue Quality Meter: an AMI specifically designed to meet CAISO telemetry requirements; these collect high-resolution data and use cellular communications technology

3. Power quality meter.

A $3000 power quality meter (Option 3) was considered to be too expensive to be a viable option. Thus we limit our analysis to options 1 and 2.

G-10.2.2. Reprogrammed High Resolution AMI

Option 1 with an existing SmartMeter has no additional cost. Based on results from the 2009 pilot, the meters can meet telemetry requirements for non-spinning reserves. According to manufacturer specifications, SmartMeters can also meet the spinning reserves requirements. Further study is needed to determine whether a reprogrammed SmartMeter can also continue to support data collection for billing purposes.

G-10.2.3. CAISO Revenue Quality Meter

According to the white paper, in 2009, PG&E conducted a commercial pilot with dedicated Landis + Gyr S4e AMI meters (PG&E, 2009).

Option 2's dedicated cellular AMI meters have the advantage of supporting sub-minute intervals and not interfering with any other traffic or data collection for billing purposes. The meters have built in cellular modems that transmit telemetry data to a server where data are aggregated and transmitted to CAISO. These meters are able to respond to CAISO dispatches within 10 minutes for non-spinning reserves, and can measure load in intervals of 10 seconds or less. Based on the literature, these dedicated meters cost about $1000 each with an estimated $150 installation cost. A survey response reports a total cost of $1350. The current study uses the average of these two costs ($1250).

G-10.2.4. Resource Interface

In order to provide Fast DR services, a building must be able to communicate energy measurements to a gateway connected to CAISO. PG&E (2009) suggests that interface options include:

1. KYZ Modules
2. ZigBee radio
3. Network Interface Card (NIC)

Although there is no additional hardware cost associated with a NIC (as they are already installed in SmartMeters), the NIC is not considered viable option due to limitations in the bandwidth of the AMI platform.

G-10.2.5. KYZ Modules

The KYZ module is an add-on that plugs into an existing SmartMeter meter and submits energy use data from the meter to some other piece of remote equipment (Solid State

Instruments, 2011). The KYZ board can support the CAISO response times, transmitting 57,600 pulses a second with transmission latency of 200 miliseconds. However, KYZ modules are really only best suited for large commercial, industrial and agricultural loads because they can only detect high load drops (6 kW) at sampling intervals of 1 minute. The KYZ modules costs on the order of $100 with an installation cost of $150. Since they would be installed on existing meters, the $250 for the KYZ module is assumed to be the only additional site enablement cost for this option.

G-10.2.6. ZigBee Radio

The ZigBee radio is a potential resource interface for residential and small and medium commercial customers because it is already included (but not enabled) in SmartMeters. It can be enabled for residential customers who install a Home Area Network (HAN) device.

G-10.3. Dispatch from CAISO

In order to participate in Fast DR, the technologies need to receive dispatch messages from the CAISO. The building uses a gateway to receive these messages and translate them into control logic that is sent to end-use loads (Piette et al. 2015). There is a range of gateway options, which must be configured to communicate with the control logic of the building as well as the DR program manager' automation server. Some end uses have local relays or PCTs that do not require additional gateways because the devices can receive DR signals directly through Wifi or other interfaces such as wireless sensor networks or those mentioned above. A building with an internet connection using an internet-based telemetry and controls system such as OpenADR can communicate with CAISO at no additional cost (Piette et al 2015). Alternatively a cellular network , either proprietary or through a mobile carrier, can be used for communication with the CAISO, although this may be very data intensive for the purposes of providing ancillary service signals. LBNL has included internet and cellular based connections to the CAISO as a dispatch option.

For SmartMeters, the ZigBee radio transmits data to an external Smart Energy Gateway (SEG) device which sends information to the CAISO with broadband. One example gateway is from Rainforest, which has a "several second" measurement resolution, and can be remotely programmed. **The gateway for the ZigBee costs about $100**. The downside is the accuracy of the radio signal through concrete and steel depends on where the SmartMeter is located. As the ZigBee resource interface is already installed in a typical SmartMeter, it is assumed that the only additional cost for this option is $100 for the gateway.

G-10.4. Overall Telemetry and Dispatch Combinations and Costs

Given the survey responses and literature, LBNL considered the possible configurations of telemetry and communications/dispatch options below in its DR-PATH model. Some configurations are only appropriate for certain sectors. **Additionally, some configurations relied on existing infrastructure (such as SmartMeters) and the costs listed are only for additional components to upgrade existing hardware for Fast DR services. The telemetry and communication configurations discussed below meet the CAISO requirements for market participation based on the Business Practice Manual for Direct Telemetry and Metering[59].**

Table G-105: Fast DR telemetry and communication component costs by sector

Sector	Telemetry and Communication Configuration	Site Enabling Cost	Telemetry and Dispatch Name in DR-PATH db	Notes
Small and Med. Com.	Existing SmartMeter + 6LoWPAN wireless sensor network and 802.15.4e to OpenADR	Cost: $0.20/sq. foot	AMI High Res, SEG - internet	Cost is for communication hardware and installation, which includes gateway. Only for small and medium commercial. Square footage data is from the CEUS survey for small and medium commercial and retail offices. Source: Industry survey responses
Small, mediu m Com.	Power meter -> mobile broadband router gateway -> internet to OpenADR	Cost: $2000	CAISO Rev Meter, SEG-cell	Cost for hardware including(metering electronics, mobile broadband router, gateway, embedded computer, cellular modem) and installation. Source: Sila Kiliccote, Steven Lanzisera, Anna Liao, Oren Schetrit, Mary Ann Piette. *Fast DR: Controlling Small Loads over the Internet*. Lawrence

[59] See Business Practice Manual for Direct Telemetry and Metering at https://www.caiso.com/market/Pages/MeteringTelemetry/Default.aspx

Sector	Telemetry and Communication Configuration	Site Enabling Cost	Telemetry and Dispatch Name in DR-PATH db	Notes
				Berkeley National Laboratory. 2014 ACEEE Summer Study on Energy Efficiency in Buildings. http://aceee.org/files/proceedings/2014/data/papers/11-183.pdf
Large Com. and Ind.	Dedicated AMI meter, data transmitted via cellular network -> Server -> RIG	Cost: $1250	CAISO Rev Meter, CASIO RIG - cell	Cost is for dedicated meter hardware and installation (meter already has cellular modem to transmit telemetry data to server) Source: PG&E Telemetry Whitepaper, Survey Responses
Large Com. and Ind.	Existing SmartMeter + KYZ module -> SCADA system or other CAISO monitoring system	Cost: $250	KYZ, CAISO RIG - internet; KYZ, CAISO RIG - cell	Cost is for KYZ module and installation. KYZ module plugs into existing meter. Only an option for large commercial or industrial loads Source: PG&E Telemetry Whitepaper
Large Com. and Ind.	Meter and submeter + BAS -> wired internet -> RIG	Cost: $2200	CAISO RIG internet, CAISO Rev Meter; CAISO RIG internet, AMI-High Res CASIO RIG cell, AMI High Res;	Building automation system controls setpoints, and other building systems controlled through sMAP. Cost is for internet used to bring dispatch signals to and within building. This cost is used for all the large commercial and industrial buildings using AMI high res or CAISO Rev Meter. Source: Sila Kiliccote, Steven Lanzisera, Anna Liao, Oren Schetrit, Mary Ann Piette. *Fast DR: Controlling Small Loads*

Sector	Telemetry and Communication Configuration	Site Enabling Cost	Telemetry and Dispatch Name in DR-PATH db	Notes
				over the Internet. Lawrence Berkeley National Laboratory. 2014 ACEEE Summer Study on Energy Efficiency in Buildings. http://aceee.org/files/proceedings/2014/data/papers/11-183.pdf
Res	Existing SmartMeter, data transmitted via ZigBee resource interface -> home gateway -> data transmitted via broadband -> RIG	Cost: $100	net-HEMS, AMI High Res	For home gateway (SmartMeter already installed, ZigBee already installed but needs activation). Only an option for residential customers with HAN Source: PG&E Telemetry Whitepaper, Sila Kiliccote, Steven Lanzisera, Anna Liao, Oren Schetrit, Mary Ann Piette. *Fast DR: Controlling Small Loads over the Internet*. Lawrence Berkeley National Laboratory. 2014 ACEEE Summer Study on Energy Efficiency in Buildings. http://aceee.org/files/proceedings/2014/data/papers/11-183.pdf

Table G-106: Telemetry and Dispatch Combinations by Sector:

	Dispatch	Telemetry	Upfront Hardware + Installation Cost	Source
Small Commercial Office	seg-cell	CAISO-rev-meter	$2,000.00	Kiliccote et. al
	seg-internet	AMI-highres	$0.2/sq. ft x	Survey Responses;

	Dispatch	Telemetry	Upfront Hardware + Installation Cost	Source
			1,145 sq. ft. = $229.00	CEUS square footage
Small Commercial Retail	seg-cell	CAISO-rev-meter	$2,000.00	Kiliccote et. al
	seg-internet	AMI-highres	$0.2/sq. ft x 5,334 sq. ft. = $1,066.80	Survey Responses; CEUS square footage
Medium Commercial Office	seg-cell	CAISO-rev-meter	$2,000.00	Kiliccote et. al
	seg-internet	AMI-highres	$0.2/sq. ft x 56,497 sq. ft. = $11,299.40	Survey Responses; CEUS square footage
Medium Commercial Retail	seg-cell	CAISO-rev-meter	$2,000.00	Kiliccote et. al
	seg-internet	AMI-highres	$0.2/sq. ft x 46,230 = $9,246.00	Survey Responses; CEUS square footage
Large Commercial Office	caiso-rig-internet	AMI-highres	$2000.00	Kiliccote et. al
	caiso-rig-internet	KYZ	$250.00	PG&E Telem
	caiso-rig-internet	CAISO-rev-meter	$1250.00	Survey Responses, PG&E Telem
	caiso-rig-cell	AMI-highres	$2000.00	Kiliccote et. al
	caiso-rig-cell	KYZ	$250.00	PG&E Telem
	caiso-rig-cell	CAISO-rev-meter	$1250.00	Survey Responses, PG&E Telem
Large Commercial Retail	caiso-rig-internet	AMI-highres	$2000.00	Kiliccote et. al
	caiso-rig-internet	KYZ	$250.00	PG&E Telem

	Dispatch	Telemetry	Upfront Hardware + Installation Cost	Source
	caiso-rig-internet	CAISO-rev-meter	$1250.00	Survey Responses, PG&E Telem
	caiso-rig-cell	AMI-highres	$2000.00	Kiliccote et. al
	caiso-rig-cell	KYZ	$250.00	PG&E Telem
	caiso-rig-cell	CAISO-rev-meter	$1250.00	Survey Responses, PG&E Telem
	caiso-rig-internet	AMI-highres	$2000.00	Kiliccote et. al
	caiso-rig-internet	KYZ	$250.00	PG&E Telem
	caiso-rig-internet	CAISO-rev-meter	$1250.00	Survey Responses, PG&E Telem
	caiso-rig-cell	AMI-highres	$2000.00	Kiliccote et. al
	caiso-rig-cell	KYZ	$250.00	PG&E Telem
Industrial	caiso-rig-cell	CAISO-rev-meter	$1250.00	Survey Responses, PG&E Telem
Residential	net-HEMS	AMI-highres	$100.00	PG&E Telem, Kiliccote

Note: For Commercial BEVs and PHEVs, the site enablement cost for medium commercial office space was used.

G-10.4.2. Fast enabling technologies

Kiliccote et al. 2014 estimated that current enablement cost per site for regulation services can be assumed to be between $50k and $80k. Real-time control and monitoring of loads over the internet have been demonstrated with sufficient reliability at a cost under $100. The demonstration involved installation of fast DR systems for lighting, motor, and thermostat control along with power metering at 6 commercial and 4 residential buildings. The testing showed that fast DR is capable of control to respond in 4 seconds and loads were transitioned in seconds to less than a minute, depending on load type. The demonstration successfully met specifications for ancillary services across the US. Telemetry via the 4G cellular network had a 94.5% success rate and residential internet had a 98% success rate.

G-11. DR Service Type Performance Filters

The performance filters that were considered for the Shift and Shimmy service types differ from the Shed filter introduced and detailed in the previous sections. The ability for a DR technology and end use to respond to a dispatch signal for fast and flexible DR service types, such as Shift and Shimmy, distinguishes it from the Shed service type. For both the Shift and Shimmy service types, the performance of the DR will be shallower than the shed response, and will occur on a daily basis if needed. The performance for these service types is intended to be non-invasive on the DR participant, in other words, the participant should not have any disruption as a result of the DR events. That is because the Shift and Shimmy response is shallow and handled mainly by technologies such as lighting and variable frequency pumps and drives, which ramp down slightly in response to a dispatch and/or a signal, and are generally automated.

Below we provide the details for the performance filters for the Shift and Shimmy service types, beginning with Shift.

G-12. Modeling the Performance of the DR Service Types in DR PATH

G-12.1. Shift Service Type

A shift includes both a load shed and a load take, based on a daily dispatch signal (mainly to prevent overgeneration in the middle of the day, and the evening ramp of the "neck" of the duck curve**)**. Examples of possible end uses that can shift are: thermal storage/pre-cooling batch process delay and acceleration; and energy storage.

The shift is energy neutral over the course of the day, meaning that the amount of energy shed has to equal the amount of energy taken over the 24-hour period. The shift is intended to be a regular occurrence, and not just for emergency times. These shift parameters are for supply-side DR, although TOU would also be considered a shift in load from high price times to low price times.

To determine the shift potential an envelope is created around the baseline that establishes the available maximum shed and maximum take throughout the day.

The RESOLVE model will provide outputs on when there is a need to dispatch the shift based on the 37 days matched for RESOLVE and DR PATH. For the hours when there is a need for shift, the DR PATH model will map how much energy the end-use can provide in order to meet that dispatch signal.

Our model handle the shift factor differently between the thermal loads and other loads. For thermal loads, i.e. HVAC, refrigeration, we assume that the ability to shed is declining over time. For batch processes and storage the shed factor is assumed to be constant.

Parameters:

1) **Energy budget:** The portion of energy you can shift over the course of the day, of the total daily energy (baseline) per end use.

$$min\left\{w * \frac{f_{shed,w}}{48} * \int_1^{24} E_{Baseline,i},\ w * \frac{f_{take,w}}{48} * \int_1^{24} E_{Baseline,i}\right\}$$

W = window length (i.e. 4 hours)

$E_{Baseline,i}$ = Baseline energy of end use per hour (i)

F_{shed} = Shed factor (i.e. 50%)

F_{take} = Take factor (i.e. 115%)

The energy budget is defined as the minimum of

a) window length/2 x shed factor/24hours x integral of the baseline, and

b) window length/2 x shed factor/24hours x integral of the baseline

The window is divided by 2 to account for 50% of the time of shed and take, the shed or take factors are divided by 24 to account for the portion of the day that comprises the window. The budget is the minimum of a) and b) because either the shed or the take quantities could be the binding constraint on the total quantity of energy that can be shifted over the course of the day.

Thermal loads:

i) The shed factors decrease as the window increases (deeper sheds can only be sustained for shorter periods of time). This is because larger deviations from acceptable operating temperature boundaries cannot be sustained for long periods of time. (see NREL O'Connell, 2015)

ii) Three different shed factors are defined for 4, 8 and 24 hour shift windows respectively.
   (1) $F_{shed,4h} = F_{shed,2h,Phase1}$ (The 4 hour shift uses the 2 hour shed factor from Phase 1)
   (2) $F_{shed,8h} = F_{shed,4h,Phase1}$
   (3) $F_{shed,24h} = 0.5F_{shed,4h,Phase1}$

The shed factors corresponding to a 4 hour window use the 2 hour shed factor from Phase 1 because it is assumed that the shed will only "take" half the time of the whole window time period (the remaining time is used to "shed" load).

Batch Processes:

i) With batch processes, the shed and take factors do not change with the length of the window (as they would with thermal loads described above).

2) **Time window:** This is the window of time over which the shift occurs. The shed and take times do not have to be symmetrical or right after one another, but must occur within this time frame. The total time window cannot be shorter than the sum of the shed and take periods; in other words, the total time window is greater than or equal to the sum of the shed and take periods.
   a) From the start of the first energy take/shed to the end of the last take/shed event
   b) There is no constraint on when this window starts
      i) Need to figure out if we can roll over the midnight HE 24 minus "duration"
      ii) Q: End use specific constraints on when load is available to shift?

3) **Maximum shed:** for each hour of shed, this is the quantity that can be reduced of the baseline load. This quantity is calculated from the shed percentage (from Phase I) in that hour times the baseline load of that hour.

4) **Maximum take:** for each hour of take, this is the quantity that can be increased of the baseline load. This take quantity is bounded by the maximum baseline energy use of the year, which serves as a proxy for the maximum physical capability of the enabling technology.

AMAX = maximum baseline kW use over the year (or alternative maximum acceptable energy use)

Maximum take = (AMAX - Baseline)

Algorithm to map RESOLVE dispatch to DR enabling tech value and supply

1) For each cluster, identify the baseline end use load on a particular day from the 37 representative days in RESOLVE
2) Inspect dispatch schedule from RESOLVE output from that day to identify window of operation needed
3) If window is binding, identify de-rate factor to be applied to eventual resource (e.g., if 75% of shift energy happens within possible window, integral of absolute value of dispatch signal)
4) Identify maximum shift resource based on shed/take constraints, bounded by the resource time window.

Notes on Energy Shift

- Time window for shift: For non-thermal resources (ie. batteries, EVs) the default time window is 24 hours. For thermal resources (ie. HVAC, refrigeration) the time window can be significantly narrower because pre-cooling or other take actions cannot be conducted with so much delay between a shed. The default time window for thermal resources is assumed to be 8 hours.

G-12.1.1. Shift Service Type Performance Filters

The Shift DR technologies are defined in terms of bandwidth (how much capacity is available to take and shed as a fraction of the baseline). The load following and regulation capacity performance filters are shown as decimals (equal to percentages) of each end use baseline load that can be controlled and respond to daily dispatch signals from the CAISO. These are described in the tables below.

Table G-107: Residential Shift Filters (Take and Shed)

	Shift (shed or take)					
Enabling Technology Component	**Shift percentage, given window**	**Shift percentage, in 4-Hour Window for Shiftable Techs**	**Window**	**Shift (shed or take) within 4-Hour Window [Fraction]**	**Shift (shed or take) within 8-Hour Window [Fraction]**	**Shift (shed or take) within 24-Hour Window [Fraction]**
Programmable communicating thermostats (PCT)	0.75	0.75	4	0.75	0.65	0.325
Direct load control switches (DLC) (50% cycle)	0.4	0.4	4	0.4	0.35	0.175
Programmable communicating thermostats (PCT) (50% cycle)	0.42	0.42	4	0.42	0.37	0.185
Direct load control switches (DLC, FM telem	0.35	0.7	24	0.7	0.7	0.35
Direct load control switches (DLC, Internet telem)	0.35	0.7	24	0.7	0.7	0.35
Automated demand response (ADR)	0.125	0.5	24	0.5	0.25	0.125
Automated demand response (Level 2 Chargers)	0.45	0.9	24	0.9	0.9	0.45
Level 1 Chargers IoT Automated	0.4	0.8	24	0.8	0.8	0.4
Level 1 Chargers, Manual	0.4	0.8	24	0.8	0.8	0.4
Automated demand response (Level 2 Chargers)	0.43	0.86	24	0.86	0.86	0.43
Level 1 Chargers, IoT Automated	0.4	0.8	24	0.8	0.8	0.4
Level 1 Chargers, Manual	0.4	0.8	24	0.8	0.8	0.4

Table G-108: Commercial Shift Filters

DR Technology and End Use	Shift percentage , given window	Shift percentage, in 4-Hour Window for	Window	Shift (shed or take) within 4-Hour	Shift (shed or take) within 8-Hour	Shift (shed or take) within 24-Hour
Com. AC (PCT, 50% control)-sm	0.7	0.7	4	0.7	0.6	0.3
Com. AC (DLC, 50% control)-med	0	0	0	0.4	0.35	0.175
Com. HVAC (med. EMS & Manual)	0.35	0.45	8	0.45	0.35	0.175
Com. HVAC (med. EMS & ADR)	0.6	0.7	8	0.7	0.6	0.3
Com. HVAC (Lrg. EMS & Manual)	0.35	0.45	8	0.45	0.35	0.175
Com. HVAC (lrg. EMS & ADR)	0.6	0.7	8	0.7	0.6	0.3
Com. Lighting (luminare)- sm	0	0.35	0	0.35	0.35	0.175
Com. Lighting (zone)-sm	0	0.3	0	0.3	0.3	0.15
Com. Lighting (standard)-sm	0	0.2	0	0.2	0.2	0.1
Com. Lighting (luminare)- sm	0	0.35	0	0.35	0.35	0.175
Com. Lighting (zone)-sm	0	0.3	0	0.3	0.3	0.15
Com. Lighting (standard)-sm	0	0.2	0	0.2	0.2	0.1
Com. Lighting (luminare)- med	0	0.65	0	0.65	0.65	0.325
Com. Lighting (zone) -med	0	0.35	0	0.35	0.35	0.175
Com. Lighting (standard) -med	0	0.25	0	0.25	0.25	0.125
Com. Lighting (luminare)- med	0	0.5	0	0.5	0.5	0.25
Com. Lighting (zone) -med	0	0.3	0	0.3	0.3	0.15
Com. Lighting (standard) -med	0	0.2	0	0.2	0.2	0.1
Com. Lighting (luminare) -lrg	0	0.65	0	0.65	0.65	0.325
Com. Lighting (zone)-lrg	0	0.35	0	0.35	0.35	0.175
Com. Lighting (standard)-lrg	0	0.65	0	0.65	0.65	0.325
Com. Lighting (luminare) -lrg	0	0.5	0	0.5	0.5	0.25
Com. Lighting (zone)-lrg	0	0.3	0	0.3	0.3	0.15
Com. Lighting (standard)-lrg	0	0.2	0	0.2	0.2	0.1
Com. Ref. Warehouse ADR	0.65	0.65	4	0.65	0.5	0.25
Com. Battery (ADR)	0.125	0.5	24	0.5	0.25	0.125
Com. BEV (Level 2 Automated - Public)	0.9	0.95	8	0.95	0.9	0.45
Com. BEV (Level 2 Automated - Fleet)	0.9	0.95	8	0.95	0.9	0.45
Com. PHEV (Level 2 Automated - Public)	0.47	0.94	24	0.94	0.94	0.47
Com. PHEV (Level 2 Automated - Fleet)	0.47	0.94	24	0.94	0.94	0.47

Table G-109: Industrial Shift Filters

	Shift (shed or take)					
Enabling Technology Component	Shift percentage, given window	Shift percentage, in 4-Hour Window for Shiftable Techs	Window	Shift (shed or take) within 4-Hour Window [Fraction]	Shift (shed or take) within 8-Hour Window [Fraction]	Shift (shed or take) within 24-Hour Window [Fraction]
Direct load control switch (DLC)	0.35	0.7	24	0.7	0.7	0.35
Automated demand response (ADR)	0.4	0.8	24	0.8	0.8	0.4
AutoDR VFD Irrigation/water pump control	0.4	0.8	24	0.8	0.8	0.4
Manual Process Interrupt	0.6	0.6	8	0.6	0.6	0.3
Automated demand response (ADR)	0.3	0.6	24	0.6	0.6	0.3
AutoDR VFD Waste water pump control	0.3	0.6	24	0.6	0.6	0.3
Manual Process Interrupt	0.25	0.5	24	0.5	0.5	0.25
Semi-Automated Process Interrupt	0.55	0.55	8	0.55	0.55	0.275
Automated demand response (ADR)	0.6	0.6	8	0.6	0.6	0.3
Manual Process Interrupt (day-ahead, deep cut)	0.95	0.95	8	0.95	0.95	0.475
Ind. Battery (ADR)	0.125	0.5	24	0.5	0.25	0.125
Manual demand response	0.15	0.15	8	0.15	0.15	0.075
Manual Process Interrupt	0.15	0.2	8	0.2	0.15	0.075
Automated demand response (ADR)	0.15	0.2	8	0.2	0.15	0.075
AutoDR -VFD- Waste water treatment	0.15	0.2	8	0.2	0.15	0.075

G-12.2. Shimmy Service Type Performance Filters

The Shimmy service type DR technology resources can increase or curtail load intra-hour in response to a CAISO 5 minute (load-following) or 4 second (regulation) signal. Load following capabilities (5 minute dispatch) enable load to be in the real-time energy market and spin. Regulating reserves (4 second dispatch) enable load to participate in regulation markets.

Both Shimmy services are defined in terms of bandwidth (how much capacity to go up or down, a fraction of the baseline). The load following and regulation capacity performance filters are shown in percentages of each end use load that can be controlled and respond to a 4 second and 5 minutes dispatch signal from the CAISO. These are described in the tables below.

Table G-110: Residential Shimmy Service Type Filters

	Shimmy	
Enabling Technology Component	Shimmy within 4 sec [Fraction]	Shimmy within 5 min [Fraction]
Programmable communicating thermostats (PCT) (50% cycle)	0.4	0.4
Programmable communicating thermostats (PCT)	0.5	0.5
Automated demand response (ADR)	0.94	0.94
Automated demand response (Level 2 Chargers)	0.94	0.94
Automated demand response (Level 2 Chargers)	0.94	0.94

Table G-111: Commercial Shimmy Service Type Performance Filters

DR Technology and End Use	Shimmy within 4 sec [Fraction]	Shimmy within 5 min [Fraction]
Com. Lighting (zone)-sm	0.3	0.3
Com. Lighting (zone)-sm	0.3	0.3
Com. Lighting (zone) -med	0.3	0.3
Com. Lighting (zone)-lrg	0.3	0.3
Com. Lighting (luminare)- sm	0.35	0.35
Com. Lighting (luminare)- sm	0.35	0.35
Com. Lighting (zone) -med	0.35	0.35
Com. Lighting (zone)-lrg	0.35	0.35
Com. AC (PCT, 50% control)-sm	0.4	0.4
Com. HVAC (med. EMS & ADR)	0.5	0.5
Com. HVAC (lrg. EMS & ADR)	0.5	0.5
Com. Lighting (luminare)- med	0.5	0.5
Com. Lighting (luminare) -lrg	0.5	0.5
Com. Ref. Warehouse ADR	0.6	0.6
Com. Lighting (luminare)- med	0.65	0.65
Com. Lighting (luminare) -lrg	0.65	0.65
Com. Battery (ADR)	0.94	0.94
Com. BEV (Level 2 Automated - Public)	0.94	0.94
Com. BEV (Level 2 Automated - Fleet)	0.94	0.94
Com. PHEV (Level 2 Automated - Public)	0.94	0.94
Com. PHEV (Level 2 Automated - Fleet)	0.94	0.94

Table G-112: Industrial Shimmy Service Type Performance Filters

	Shimmy	
Enabling Technology Component	Shimmy within 4 sec [Fraction]	Shimmy within 5 min [Fraction]
AutoDR VFD Waste water pump control	0.6	0.45
Automated demand response (ADR)	0.6	0.3
AutoDR -VFD- Waste water treatment	0.6	0.3
AutoDR VFD Irrigation/water pump control	0.8	0.6
Ind. Battery (ADR)	0.94	0.94

G-13. Other Cost Assumptions

G-13.1. Scheduling Coordinator Cost for participating in CAISO Wholesale Markets

According to the CAISO Business Practice Manual (https://bpmcm.caiso.com/BPM%20Document%20Library/Scheduling%20Coordinator%20Certification%20and%20Termination/SC_Certification_and_Termination_v7_EIM%20redline.pdf) a load serving entity or scheduling coordinator bidding in Fast DR resources would need to pay an upfront application fee, and must post security and have minimum assets to be able to participate in the markets. Additionally there are grid management charges, which will be at least $1000 per month for the scheduling coordinator, and go to the CAISO to recover their costs. Additional costs for markets (such as for ancillary services) requiring telemetry may be incurred as well. LBNL has not attributed any of these costs to the enabling technologies as it is assumed to be part of the cost of doing business.

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Appendix H: RESOLVE Model Description

H-1. Introduction

E3's Renewable Energy Solutions ("RESOLVE") Model is a power system operations and dispatch model that minimizes operational and investment costs over a defined time period. RESOLVE selects an optimal portfolio of renewable resources such as wind, solar or geothermal; conventional resources such as combined-cycle or simple-cycle natural gas generators; demand-side resource such as energy efficiency or demand response; and renewable integration "solutions" such as natural gas plant retrofits, flexible loads or energy storage. RESOLVE minimizes the sum of operating costs (fuel, O&M costs, and emissions), investment costs (the cost of developing new generation along with any associated transmission), and transmission wheeling costs over time. RESOLVE incorporates conventional power system constraints such as total delivered energy and generation resource adequacy, policy constraints such as renewables portfolio standards and greenhouse gas targets, scenario-specific constraints on the availability of specific resources, and operational constraints that are based on a linearized version of the classic zonal unit commitment problem.

RESOLVE has a particular strength in evaluating flexibility costs. Flexibility costs are driven by the increase in renewable resources and the policy directives for renewable energy targets. In a flexibility-constrained system, the consequence of insufficient operational flexibility is curtailment of renewable energy production during time periods in which the system becomes constrained[60]. In a jurisdiction with a binding renewable energy target, however, this curtailment may jeopardize the utility's ability to comply with the renewable energy target. In such a system, a utility may need to procure enough renewables to produce in excess of their energy target in anticipation of curtailment events, in order to ensure compliance with the RPS. This "renewable overbuild" carries with it additional costs to the system. In these systems, the value of an integration solution such as energy storage can be conceptualized as the renewable overbuild cost that can be avoided by using the solution to deliver a larger share of available renewable energy. Cost effectiveness for an integration solution under these conditions may be established when the avoided renewable overbuild cost exceeds the cost of the integration solution.

A number of geographic and temporal simplifications are made in order to achieve a

[60] Olson, A., R. Jones, E. Hart and J. Hargreaves, "Renewable Curtailment as a Power System Flexibility Resource," The Electricity Journal, Volume 27, Issue 9, November 2014, pages 49-61

reasonable model runtime while maintaining focus on key cost considerations:

+ Investment decisions and operational dispatch are made in multi-year time increments: 2016, 2020, 2025, 2030

+ 37 representative days are modeled in RESOLVE in each year. These 37 days with appropriate weights to be equivalent to full year are chosen to best represent a typical full year's load, renewables, hydro, net load conditions, as well as the annual monthly distribution of days.

+ Investment decisions are made for the Balancing Authority Area operated by the California Independent System Operator ("CAISO"). Since Given the CAISO is interconnected with other balancing areas, RESOLVE incorporates a geographically coarse representation of neighboring regions in the West (the Northwest, Southwest, and Los Angeles Department of Water and Power (LADWP)) in order to characterize and constrain flows into and out of the CAISO.

E3 developed RESOLVE cases for the CAISO area as part of the CAISO's studies of a regional market directed by Senate Bill 350 (SB 350).[61] E3 adapted these cases for this project by incorporating additional functionality to model flexible loads. Some key assumptions from these cases, such as carbon price forecasts and gas price forecasts, were developed for SB 350 work and remain in the model. These assumptions are explained in detail in the Appendix.

H-2. Methodology

The RESOLVE model co-optimizes investment and operational decisions over several years in order to identify least-cost portfolios for meeting renewable energy targets. This section describes the RESOLVE model in terms of its temporal and geographical resolution, characterization of system operations, and investment decisions. Particular attention is placed on topics that are unique to an investment model that seeks to examine renewable integration challenges, including: renewables selection; reserve requirements; energy storage; flexible

[61] For more on SB-350, see https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

loads; and day selection and weighting for operational modeling.

Flexibility costs are driven by the increase in renewable resources and the policy directives for renewable energy targets. In a flexibility-constrained system, the default consequence of failing to secure enough operational flexibility to deliver all of the available renewable energy is to curtail some amount of production in the time periods in which the system becomes constrained. In a jurisdiction with a binding renewable energy target, however, this curtailment may jeopardize the utility's ability to comply with the renewable energy target. In such a system a utility may need to procure enough renewables to produce in excess of the energy target in anticipation of curtailment events to ensure compliance with the Renewable Portfolio Standard ("RPS"). This "renewable overbuild" carries with it additional costs to the system. In these systems, the value of an integration solution, like energy storage, can be conceptualized as the renewable overbuild cost that can be avoided by using the solution to deliver a larger share of the available renewable energy. Cost effectiveness for an integration solution under these conditions may be established when the avoided renewable overbuild cost exceeds the cost of the integration solution.

During this project, RESOLVE was augmented to model a variety of DR services defined by LBNL and E3. RESOLVE optimizes investment and dispatch of these services to reduce portfolio costs for meeting future renewable energy targets.

To quantify the value of DR to the CAISO system, E3 began with a Base Case that contained no DR, and allowed RESOLVE to minimize system costs over the 2016 – 2030 investment period.[62] Then, DR was added to the system in increasing increments, and costs minimized over the same period. Any decrease in system costs was attributed to the added DR resource.

E3 and LBNL defined three DR services that are modeled in RESOLVE:

- **Shift:** Flexible load that can be moved from one hour to another, subject to a daily energy neutrality constraint and other constraints described below
- **Shimmy:** Fast-response DR that provides load following and regulation reserves, reducing the need for conventional resources to provide these services

[62] 2016 - 2030 was selected as a long-term planning horizon, and corresponds with an assumption of 50% RPS in 2030.

- **Shed:** "Conventional" DR that decreases load during system peaks, subject to a capacity (MW) cap and annual MWh cap

The modeling of DR impacts in RESOLVE is also summarized in **Error! Reference source ot found.**

Table H-1: Modeling of DR Strategies in RESOLVE

DR Strategy	RESOLVE Modeling
Shed	DR is dispatched to maximize benefits, subject to limits on 1) annual kWh that can be shed, and 2) maximum amount of shed in any hour.
Shift	DR is dispatched to maximize the net benefit of dispatch and make-up power. The amount of load reduction is limited by four constraints: 1. Cannot exceed an input percentage of the static (pre-dispatch) hourly load 2. Total reduction for the day cannot exceed an input percentage of the daily energy that can be shifted 3. All load reductions must be "made up" by increased usage in other hours 4. The amount of make-up power in any hour is limited to the gap between the maximum static load for the day minus the static load for the hour.
Shimmy	DR is modeled as pre-defined reductions in load following and regulation requirements.

An illustrative example of each DR function is provided below. It should be noted that E3 modeled each of the above advanced DR technologies at zero implementation cost. Thus, the economic results discussed in this report reflect merely the economic *benefits*.

H-2.1. Temporal Scope and Resolution

In this analysis, investment decisions are made with roughly 5-year resolution in the years 2016, 2020, 2025, and 2030. Operational decisions are made with hourly resolution on a subset of independent days modeled within each investment year. Modeled days are selected to best reflect the long run distributions of key variables like load, wind, solar, and hydro availability. The day selection and weighting methodology is described in more detail below.

For each year, the user defines the portfolio of resources (including conventional, renewable, and storage) that are available to the system without incurring additional fixed costs – these include existing resources, resources that have already been approved, and contracted resources, net of planned retirements. In addition to these resources, the model may be given the option to select additional resources or retrofit existing resources in each year in order to meet an RPS requirement, fulfill a resource adequacy need, or to reduce the total cost. Fixed costs for selected resources are annualized using technology-specific financing assumptions and costs are incurred for new investments over the remaining duration of the simulation. The objective function reflects the net present value of all fixed and operating costs over the simulation horizon, plus an additional N years, where the N years following the last year in the simulation are assumed to have the same annual costs as the last simulated year, T. When the investment decision resolution is coarser than one year, the weights applied to each modeled year in the objective function are determined by approximating the fixed and operating costs in un-modeled years using linear interpolations of the costs in the surrounding modeled years.

H-2.2. Operating Day Selection and Weighting

To reduce the problem size, it is necessary to select a subset of days for which operations can be modeled. In order to accurately characterize economic relationships between operational and investment decisions, the selected days and the weights applied to their cost terms in the objective function must reflect the distributions of key variables. In the analysis described here, distributions of the following parameters were specifically of interest: hourly load, hourly wind production, hourly solar production, hourly net load, and daily hydropower availability. In addition, the selection of the modeled days sought to accurately characterize: the number of days per month, average monthly hydropower availability, and site-specific annual capacity factors for key renewable resources.

To select and weight the days according to these criteria or target parameters, an optimization problem was constructed. To construct the problem, a vector, b, was created that contained all of the target parameter values and described each target parameter distribution with a set of elements, each of which represents the probability that the parameter falls within a discrete bin. The target values can be constructed from the full set of days that the problem may select or from an even longer historical record if data is available.

For each of the days that can be selected, a vector, a, is produced to represent the contribution of the conditions on that day to each of the target parameters. For example, if b_i represents the number of hours in a year in which the load is anticipated to fall within a specified range, a_{ij} will represent the number of hours in day j that the load falls within that range. The target parameters vector, b, may therefore be represented by a linear combination of the day-specific vectors, a_j, and the day weights can be determined with an optimization problem that minimizes the sum of the square errors of this linear combination. An additional term is included in the objective function to reduce the number of days selected with very small weights and a coefficient, c, was applied to this term to tune the number of days for which the selected weight exceeded a threshold. The optimization problem was formulated as follows:

$$\begin{aligned} &\mathit{minimize} && \sum_i \left[\left(\sum_j a_{ij} w_j \right) - b_i \right]^2 - c \sum_j w_j^2 \\ &\mathit{subject\ to} && \sum_j w_j = 365 \end{aligned}$$

The resulting weights can then be filtered based on the chosen threshold to yield a representative subset of days. This method can be modified based on the specific needs of the problem. For example, in this analysis, while the hourly net load distribution was included in the target parameter vector, cross-correlations between variables were not explicitly treated.

H-2.3. Geographic Scope and Resolution

While RESOLVE selects investment decisions only for the region of interest, in this case the ISO, operations in a highly interconnected region are influenced by circumstances outside the region. For example, the conditions in the Northwest, Southwest, and Los Angeles Department of Water and Power ("LADWP") regions influence the ISO dispatch via economic imports and exports. To capture these effects, RESOLVE includes a zonal dispatch topology with interactions between the zones characterized by a linear transport model. Both the magnitudes of the flows and the ramps in flows over various durations can be constrained based on the scenario. Hurdle rates can also be applied to represent friction between balancing areas. Simultaneous flow constraints can also be applied over collections of interties to constrain interactions with neighboring regions.

The zonal topology for the analysis is shown in Figure H-1 – the ISO footprint is the primary zone and the Northwest and Southwest regions and LADWP balancing area are the secondary zones. The Northwest region includes the region encompassed by the U.S. portion of the Northwest Power Pool, plus the Balancing Area of the Northern California. The Southwest region includes New Mexico, Arizona, Southern Nevada, and the Imperial Irrigation District. The flow constraints applied in this analysis are summarized in Table H-1. Negative numbers in the table represent exports from California, while positive values represent imports.

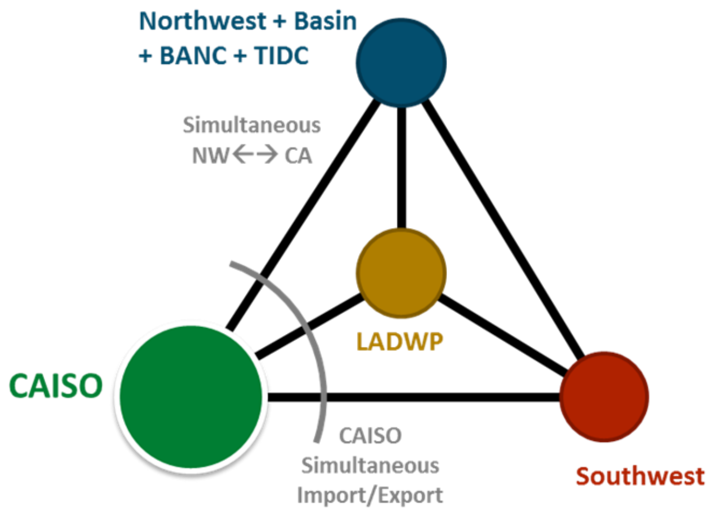

Figure H-1: Zonal topology.

Table H-1: Flow constraints between zones and simultaneous flow constraints (negative numbers reflect flows in opposite direction)

Path	Minimum Flow (MW)	Maximum Flow (MW)
SW → ISO	-7,250	6,785
NW → ISO	-5,171	6,364
LADWP → ISO	-2,045	4,186
LADWP → NW	-,2826	2,963
SW → LADWP	-3,373	3,373
NW → SW	-1,480	1,465
Simultaneous NW →	-7,934	9,390
ISO Simultaneous	-8,000 to -2,000	10,068

H-2.4. Investment Decisions

H-2.4.1. Renewable Resources

The RESOLVE model was designed primarily to investigate investment driven by a renewable energy target. This constraint, which is applied based on the policy goal each year, ensures that the procured renewable energy from RPS resources net of any renewable energy from RPS resources curtailed in operations exceeds a MWh target based on the load or retail sales in that year. RESOLVE allows the user to specify a set of resources that must be built in each modeled year as well as additional renewable resources that may be selected by the optimization. These options allow for the design of portfolios that take into consideration factors such as environmental or institutional barriers to development.

While a traditional capacity-expansion model might take into consideration the technology cost, transmission cost, capacity factor of candidate renewable resources, RESOLVE also considers the energy value through avoided operational costs, capacity value through avoided resource adequacy build, and the integration value through avoided renewable resource overbuild. These three factors depend on the timing and variability of the renewable resource availability as well as the operational capabilities of the rest of the system. To account for all of these factors, each candidate resource is characterized by its hourly capacity factor over the subset of modeled days, installed cost on a per kW basis, location within a set of transmission development zones, and maximum resource potential, in MW.

Transmission development zones are characterized by a threshold total RPS renewable build, above which a $/MW-yr cost is applied to incremental renewable build to reflect the annualized cost of additional transmission build to support interconnecting renewables onto the high-voltage transmission system. Multiple renewable resources may be assigned to the same transmission development zone (for example some zones may have both solar and wind resources that can be developed) and the selection of resources within each zone will depend on their relative net cost and the combined impact of resource build on incurred transmission development costs.

H-2.4.2. Integration Solutions

RESOLVE is also given the option to invest in various renewables integration solutions such as different types of energy storage or gas resources. Renewable curtailment occurs when the system is not capable of accommodating all of the procured renewable energy in hourly operations. While there is no explicit cost penalty applied to the curtailment observed in the system dispatch, the implicit cost is the cost of overbuilding renewable resources to replace the curtailed energy and ensure compliance with the renewable energy target. This renewable overbuild cost is the primary renewable integration cost experienced by the system and may be reduced by investment in integration solutions.

H-2.4.3. Resource Portfolios in Secondary Zones

RESOLVE selects investment decisions only for the primary zone, in this case the ISO. The resource portfolios for the secondary zones, in this case the Northwest, Southwest and LADWP, must be designed to ensure resource adequacy and renewable policy compliance, and selected as a RESOLVE input. These decisions, which are exogenous from the planner's perspective in the primary (ISO) zone are also exogenous to the model. For each year of the simulation, each secondary zone is characterized by the hourly load, hourly renewable availability, hydro availability, and conventional resource stack. Because the model only selects investment decisions for the primary zone, the resource portfolios for the secondary zones must be designed to ensure resource adequacy and renewable policy compliance outside of RESOLVE. These decisions, which are exogenous from the planner's perspective in the primary zone are also exogenous to the model.

H-2.5. System Operational Constraints

H-2.5.1. General

RESOLVE requires that sufficient generation is dispatched to meet load in each hour in each modeled zone. In addition, dispatch in each zone is subject to a number of constraints related to the technical capabilities of the fleets of generators within the zone, which are described in detail below. In general, dispatch in each zone must satisfy

$$\sum_{i \in I_z} x_h^{it} + w_h^{zt} + \sum_{\omega \in Z} \sum_{j \in J_{z\omega}} (R_{jt}^{tot} r_h^j - q_h^{jt}) + \sum_{k \in K_z^{in}} f_h^{kt} - \sum_{k \in K_z^{out}} f_h^{kt}$$
$$+ x_h^{dzt} - x_h^{czt} + u_h^{zt} - o_h^{zt} = l_h^{zt}$$

where l_h^{zt} is the load in zone z, year t, and hour h; x_h^{it} is the generation from thermal resource i; I_z is the set of all thermal resources in zone z; R_{jt}^{tot} is the total installed capacity of RPS resource j; q_h^{jt} is the curtailment of RPS resource j; $J_{z\omega}$ is the set of all RPS resources located in zone z and contracted to zone ω; w_h^{zt} is large-scale hydro generation in zone z; x_h^{dzt} and x_h^{czt} are the energy discharged from energy storage and energy extracted from the grid to charge energy storage respectively; u_h^{zt} is the undergeneration and o_h^{zt} is other overgeneration in zone z; f_h^{kt} is the flow over line k, K_z^{in} and K_z^{out} are the sets of all transmission lines flowing into and out of zone z, respectively.

H-2.5.2. Reserve Requirements and Provision

RESOLVE requires upward and downward load following reserves to be held in each hour in order to ensure that the system has adequate flexibility to meet sub-hourly fluctuations and to accommodate forecast errors. In real systems, reserve requirements depend non-linearly on the composition of the renewable portfolio and the renewable output in each hour. To avoid additional computational complexity, RESOLVE requires the user to specify the hourly reserve requirements for each scenario. In the ISO example, the methodology described in

NREL the Eastern Wind Integration and Transmission Study ("EWITS")[63] was used to derive hourly reserve requirements associated with today's renewable portfolio, a 33% RPS portfolio in 2020, and two potential 50% RPS portfolios in 2030 – one dominated by solar resources and one with a more diverse mix of solar, wind, and geothermal resources. For each scenario, the user selects which set of reserve requirements to use for 2020 and 2030 and the reserve requirements in each year are approximated via linear interpolation.

The user specifies whether each technology is capable of providing flexibility reserves, and the reserve provisions available from each technology are described above. Upward flexibility reserve violations are penalized at a very high cost to ensure adequate commitment of resources to meet upward flexibility challenges within the hour. However, downward reserve shortages are not penalized as operating violations. RESOLVE assumes that a portion of downward reserve needs – 50% in the cases analyzed for this study – can be managed via real-time curtailment of renewable resources. This behavior is approximated in RESOLVE through a parameterization of the sub-hourly imbalances similar to that implemented in E3's REFLEX model.[64] Sub-hourly curtailment in RESOLVE is a function of the reserve provisions held, as described in Hargreaves et al (2014). If the entire downward reserve requirement is held, then it is anticipated that the system will experience no additional curtailment of RPS resources in real-time to manage sub-hourly imbalances. If the downward reserve requirement cannot be met, then the expected real-time curtailment can be approximated.

This formulation allows the dispatch model to directly trade-off the cost of holding additional reserves (including the cost of committing additional units and operating these units at less efficient set points) against the cost of experiencing some amount of expected sub-hourly renewable curtailment by shorting the downward reserve provision. Just as with curtailment experienced on the hourly level, expected sub-hourly curtailment is not directly penalized in the objective function, but does result in additional cost to the system by requiring additional renewable overbuild for policy compliance.

In addition, RESOLVE allows the user to constrain the absolute amount of observed sub-hourly curtailment in each hour to reflect potential limits in the participation of renewable resources in real-time markets or real-time dispatch decisions. These limits are typically set as

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[63] National Renewable Energy Laboratory, "Eastern Wind Integration and Transmission Study," Revised February 2011. Available at: http://www.nrel.gov/docs/fy11osti/47078.pdf

[64] Hargreaves, J., E. Hart, R. Jones, A. Olson, "REFLEX: An Adapted Production Simulation Methodology for Flexible Capacity Planning," IEEE Transactions of Power Systems, Volume:PP, Issue: 99, September 2014, pp 1 – 10.

a fixed fraction of the available energy from curtailable renewable resources in each hour.

Finally, RESOLVE allows the user to apply a minimum constraint on the fraction of the downward reserve requirement held with conventional units. Specifying a limit on the ability of renewables to provide the necessary downward reserves ensures that that the model will carry a portion of the needed reserves on conventional resources such as hydro or thermal resources, or on energy storage resources. While full participation of renewable resources in real-time markets may be the lowest cost approach to managing downward flexibility challenges, a system operator may seek to keep some downward flexibility across the conventional fleet as a backstop in case the full response from renewable resources does not materialize in real-time.

H-2.5.3. Other requirements

Additional operational constraints are imposed based on specific system needs. For example, for this SB 350 project, additional constraints were designed for consistency with modeling efforts by the ISO for the California Long-Term Procurement Plan (“LTPP”). These include: a frequency response requirement of 775 MW in each hour, which can be met with dispatchable units on the system including renewables and energy storage resources.

H-2.5.4. Resource Adequacy

In addition to hourly operational constraints, RESOLVE enforces an annual resource adequacy constraint based on a parameterization of resource adequacy needs to maintain reliability. The parameterization was developed based on simulations of loss of load probability (“LOLP”) in the ISO system under high-solar and diverse renewable portfolio scenarios and takes into account the expected load-carrying capability (“ELCC”) of the renewable portfolio. The constraint requires that sufficient conventional capacity is available to meet net load plus a certain percentage above net load. In this study, the capacity adequacy constraint is not binding and does not cause procurement of conventional capacity.

H-2.6. Operational Constraints

H-2.6.1. Thermal Resources

For large systems such as the ISO’s, in RESOLVE thermal resources are aggregated into homogenous fleet of units that share a common unit size, heat rate curve, minimum stable operating level, minimum up and down time, maximum ramp rate, and ability to provide reserves. In each hour, dispatch decisions are made for both the number of committed units and the aggregate set point of the committed units in the fleet. For sufficiently large systems, such as the ISO, commitment decisions are represented as continuous variables. For smaller systems, specific units may be modeled with integer commitment variables. For the continuous commitment problem, reserve requirements ensure differentiation between the committed capacity of each fleet and its aggregated set point. The ability of each fleet to provide upward reserves, $\overline{x}_h^{it}$, is:

$$x_h^{it} + \overline{x}_h^{it} \leq n_h^{it} x_{max}^i \quad \forall i, t, h$$

where n_h^{it} is the number of committed units and x_{max}^i is the unit size. Downward reserve provision is limited by:

$$x_h^{it} - \underline{x}_h^{it} \geq n_h^{it} x_{min}^i \quad \forall i, t, h$$

where x_{min}^i is the minimum stable level of each unit.

Upward reserve requirements are imposed as firm constraints to maintain reliable operations, but downward reserve shortages may be experienced by the system with implications for renewable curtailment. The primary impact of holding generators at set points that accommodate reserve provisions is the increased fuel burn associated with operating at less efficient set points. This impact is approximated in RESOLVE through a linear fuel burn function that depends on both the number of committed units and the aggregate set point of the fleet:

$$g_h^{it} = e_i^1 x_h^{it} + e_i^0 n_h^{it}$$

where g_h^{it} is the fuel burn and e_i^1 and e_i^0 are technology-specific parameters.

Minimum up and down time constraints are approximated for fleets of resources in RESOLVE. In addition, startup and shutdown costs are incurred as the number of committed units change from hour to hour, and constraints to approximate minimum up and down times for thermal generator types are imposed.

Must-run resources are modeled with flat hourly output based on the installed capacity and a de-rate factor applied to each modeled day based on user-defined maintenance schedules. Maintenance schedules for must-run units are designed to overlap with periods of the highest anticipated oversupply conditions so that must run resources may avoid further exacerbating oversupply conditions in these times of year. Maintenance and forced outages may be treated for any fleet through the daily de-rate factor. However, in the analysis presented here, maintenance schedules for dispatchable resources were not explicitly modeled – it was instead assumed that maintenance on these systems could be scheduled around the utilization patterns identified by RESOLVE's dispatch solution.

H-2.6.2. Hydroelectric Resources

Hydroelectric resources are dispatched in the model at no variable cost, subject to: an equality constraint on the daily hydro energy; daily minimum and maximum outputs constraints; and multi-hour ramping constraints. These constraints are intended to reflect seasonal environmental and other constraints placed on the hydro system that are unrelated to power generation. The daily energy, minimum, and maximum constraints are derived from historical data from the specific modeled days. Ramping constraints, if imposed, can be derived based on a percentile of ramping events observed over a long historical record. Hydro resources may contribute to both upward and downward flexibility reserve requirements.

H-2.6.3. Energy Storage

Each storage technology is characterized by a round-trip efficiency, per unit discharging capacity cost ($/kW), per unit energy storage reservoir or maximum state of charge cost ($/kWh), and for some resources, maximum available capacity. Energy storage investment decisions are made separately for discharging capacity and reservoir capacity or maximum state of charge. Dispatch from each energy storage resource is modeled by explicitly tracking the hourly charging rate, discharging rate, and state-of-charge of energy storage systems based on technology-specific parameters and constraints. Reserves can be provided from storage devices over the full range of maximum charging to maximum discharging. This assumption is consistent with the capabilities of battery systems, but overstates the flexibility of pumped storage systems, which can only provide reserves in pumping mode if variable speed pumps are installed, typically pump storage units cannot switch between pumping and generating on the time scales required for reserve products, and are subject to minimum pumping and minimum generating constraints that effectively impose a deadband on the resource operational range.

An adjustment to the state of charge in RESOLVE is assumed that represents the cumulative impact of providing flexibility reserves with the device over the course of the hour. For example, if a storage device provides upward reserves throughout the hour, it is anticipated that over the course of the hour the storage device will be called upon to increase its discharge rate and/or decrease its charge rate to help balance the grid. These sub-hourly dispatch adjustments will decrease the state of charge at the end of the hour. Similarly, providing downward reserves will lead to an increase in the state of charge at the end of the hour. Little is known about how energy storage resources will be dispatched on sub-hourly timescales in highly renewable systems – this behavior will depend on storage device bidding strategies and technical considerations like degradation. Rather than model these factors explicitly, RESOLVE approximates the impact of sub-hourly dispatch with a tuning parameter, which represents the average deviation from hourly schedules experienced as a fraction of the energy storage reserve provision.

H-2.7. Demand Response

The RESOLVE model has been enhanced for this project to evaluate the DR strategies of Shape, Shed, and Shift. Each strategy is modeled in RESOLVE as described below

H-2.7.1. Shed

The Shed strategy requires RESOLVE to dispatch the DR as part of its cost minimization optimization. The ability to dispatch the DR is constrained by an annual limit on DR energy reductions, and a maximum hourly demand reduction limit. The Shed strategy does not have any associated increase in demand in non-dispatch hours to “make-up” for the shed energy.

Shed Constraints

$$\sum_{h \in H_p} Interrupt_h \times w_h \leq i\_ann \;\; \textit{for all } p$$

“max annual interruption of service”

$$Interrupt_h \leq i\_max$$

“max hourly interruption of service”

Where

h	=	hour index
d	=	day index
H_d	=	set of all hours on day d
w_h	=	RESOLVE day weight (indexed by hour for easier notation; all hours on the same day will have the same weight)
i_max	=	maximum power that can be shed in an hour
i_ann	=	total quantity of energy that can be shed in a year
$Interrupt_h$	=	interruption of service (not made up at another time)

H-2.7.2. Shift

The Shift strategy limits dispatched load reductions to no more than a fixed percentage of a static hourly load shape. In this way, the DR impacts could be linked to the reduction of specific end uses. For this high level DR analysis, the system load shape has been used for the static load shape.

The linking of the reductions to load shapes differs from the Shed strategy’s use of a fixed maximum reduction for any hour. The Shift strategy also differs from the Shed strategy in its requirement that any reduced energy be recovered via increased usage (up to a limit) in non-dispatch hours in that day.

Constraints

$\sum_{h \in H_d} (l_h + Take_h - Shed_h) = \sum_{h \in H_d} l_h \, for\ all\ d$
"energy neutral on each day"

$Shed_h \leq f_h \times l_h$
"stay inside shed boundary in each hour"

$Take_h \leq l_d^{max} - l_h$
" stay inside take boundary in each hour"

$\sum_{h \in H_d} (Shed_h) \leq \sum_{h \in H_d} f_d \times l_h \, for\ all\ d$
"maintain daily energy shed budget"

Where

h	=	hour index
d	=	day index
H_d	=	set of all hours on day d
l_h	=	hourly load from static load shape subject to shifting
d_d	=	daily total load subject to shifting (= $\sum_{h \in H_d} l_h$)
f_h	=	fraction of hourly load that can be shed (can vary by hour, but initial LBNL inputs will be the same for all hours)
$l^{max}{}_d$	=	the maximum load from the static load shape for each day
f_d	=	the maximum fraction of daily load that can shift
$Shed_h$	=	deviation from static hourly load in each hour in the downward direction (i.e. this defines the lower boundary of hourly load after shifting)
$Take_h$	=	deviation from static hourly load in each hour in the upward direction

H-2.7.3. Shimmy

The Shimmy strategy operates the DR to provide load following and regulation services to the system. The DR is assumed to operate within the hour to maintain energy neutrality in each hour.

Because the costs for DR are not being modeled in RESOLVE for this project, the load following and regulation provided by DR have been modeled as fixed reductions in the load following and regulation requirements for the system, subject to the limitation that the net requirements not go negative in any hour.

Constraints

$Provide_{LF_h} \leq lf_{cap}$

"load-following provision in each hour cannot exceed pre-specified capacity"

$Provide\_Reg_h \leq reg\_cap$

"regulation provision in each hour cannot exceed pre-specified capacity"

where

h	=	hour index
lf_cap	=	load-following capacity available
reg_cap	=	regulation capacity available
$Provide\_LF_h$	=	provision of load following by loads (symmetric up and down to ensure energy neutrality)
$Provide\_Reg_h$	=	provision of regulation by loads (symmetric up and down to ensure energy neutrality)

H-3. RESOLVE Modeling Assumptions

H-3.1. Scenario Definitions and Assumptions

The future trajectory of California's loads and generation mix is uncertain. E3 sought to capture the impacts of two aspects found in previous E3 work to be significant determinants of the value of new resources: the level of curtailment and load forecast.

To capture the impacts of curtailment on DR value, we selected two bounding 'Curtailment Futures': a High Curtailment Future and a Low Curtailment Future. To ensure consistency with current CPUC assumptions, these Futures are based on two scenarios from the 2016 – 2017 CAISO Transmission Planning Process.[65] H-2 lists the assumptions underlying each.

[65] For more information on CAISO's 2016-2017 TPP, see CPUC Rulemaking 13-12-010, available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11673

Table H-2: Curtailment 'Futures' modeled in RESOLVE

	High Curtailment Future (LTTP Scenario: 'High BTM PV')	Low Curtailment Future (LTTP Scenario: 'Out-of-state wind')
RPS	50% by 2030 (out-of-state resources permitted)	50% by 2030 (out-of-state resources permitted)
Export limit	2,000 MW	2,000 MW
Incremental Wind (beyond 33% RPS)	None	3,000 MW by 2025
Behind-the-meter (BTM) PV	26.9 GW of BTM PV in 2030	19.1 GW of BTM PV in 2030
Utility-Scale Solar PV	13.0 of utility-scale PV in 2030	12.4 GW of utility-scale PV in 2030

The CPUC's RPS Calculator Model[66] is used to output portfolios of renewable resources for each of these Curtailment Futures, consistent with the LTPP specifications. Renewable overbuild is modeled endogenously within RESOLVE.

Figure H-2 shows the resulting renewable generation portfolios in 2030, when the 50% RPS target is assumed to be met. The major difference between the two portfolios is the additional 8.4 GW of solar PV (both behind-the-meter and utility-scale) included in the High Curtailment Future. Solar PV systems have very similar, diurnal generating profiles due to daily timing of solar insolation across California. Therefore, the LTTP's High BTM Scenario, with its high PV penetration, acts as our High Curtailment Future.

[66] For more information, see http://www.cpuc.ca.gov/RPS_Calculator/

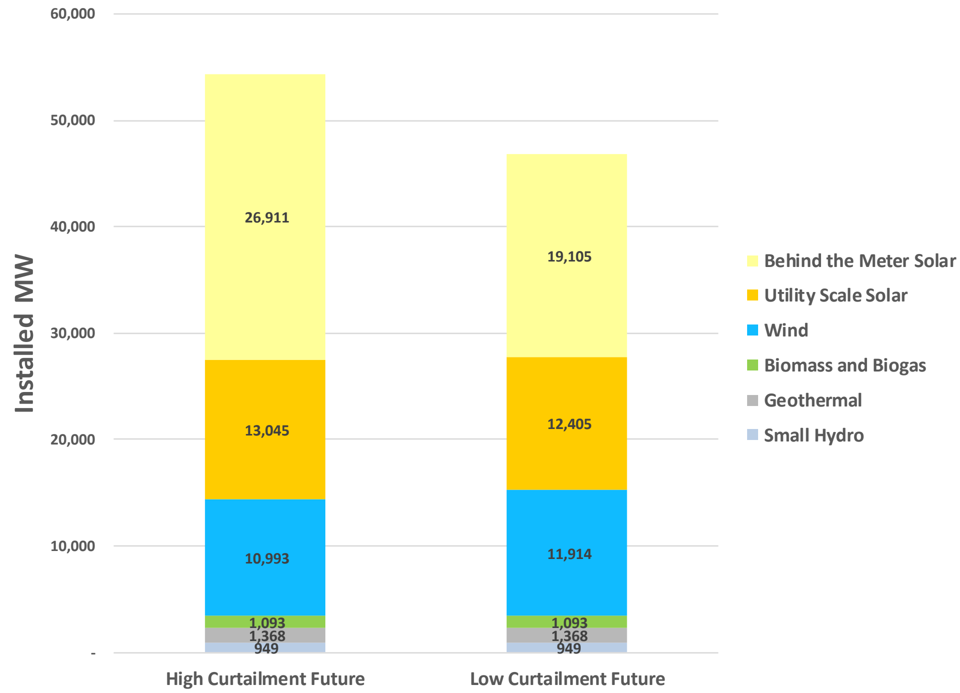

Figure H-2: 2030 Renewable generation portfolios, High and Low Curtailment Futures.

Figure H-4 shows curtailment, by year, under the Base Case (i.e., with no DR).

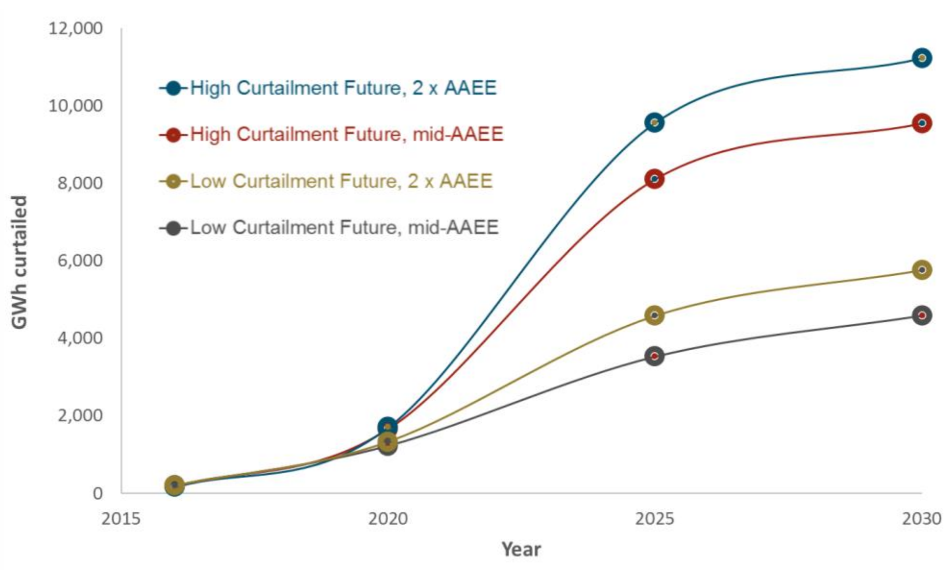

Figure H-3: Base Case curtailment, by year

The High Curtailment future has approximately 4,000-6,000 GWh (depending on load forecast assumption) more curtailment in 2025 and 2030 than the Low Curtailment Futures, due to their higher solar PV penetration. Doubling energy efficiency also increases curtailment by approximately 1,500-2,000 GWh. This is because lower loads in hours of high solar overgeneration increases curtailment, and this effect more than offsets any reduction in renewable energy procurement needed to meet the lower RPS requirement caused by lower load.

In RESOLVE, system costs are optimized over the entire 2016 – 2030 period. Since the major value driver for DR is curtailment, E3 used the curtailment shapes in Figure H-4 to convert the total savings from DR over this time period to annual snapshots for the intervening years: 2016, 2020, 2025 and 2030.

The value of DR can also be sensitive to the level of electric load growth. Faster growth results in more value for DR that can provide capacity to the system. The analysis was therefore run under two alternative load forecasts ('mid-achievable energy efficiency' and '2 x AAEE'), in addition to the two Electricity System Futures described above, creating four scenarios. Figure H-5 shows the two alternative load growth forecasts. Table H-3 provides a summary of the four scenarios modeled.

Table H-3: Scenarios run to assess DR value under varying grid conditions

	Electricity System Future		CAISO System Load Forecast	
Scenario Name	Low Curtailment	High Curtailment	Mid-AAEE	2 x AAEE
Low curtailment, mid-AAEE	X		X	
Low curtailment, 2 x AAEE	X			X
High curtailment, mid-AAEE		X	X	
High curtailment, 2 x AAEE		X		X

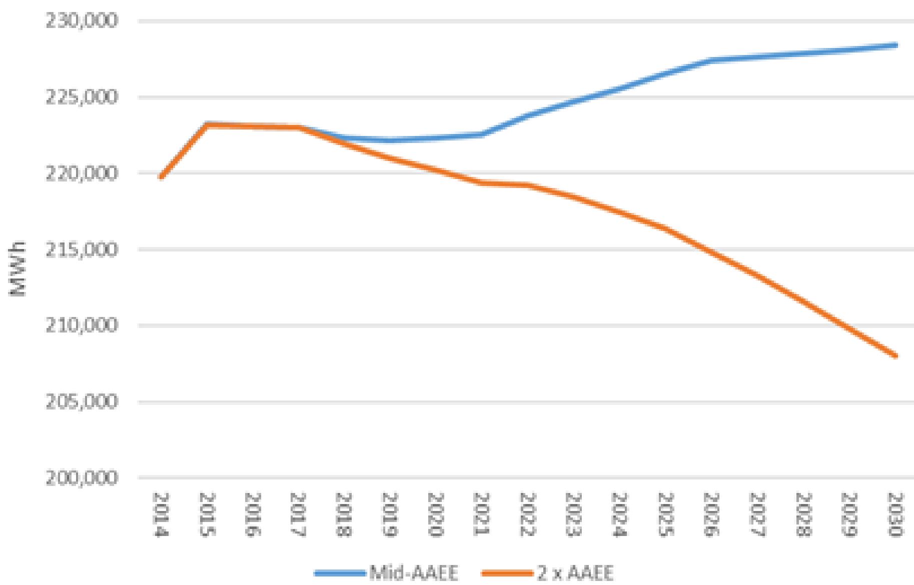

Figure H-4: CAISO system load forecasts

The Mid-AAEE load forecast is based on the 2015 IEPR Mid AAEE load forecast (January 2016 Update)[67]. 2026-2030 data (not in IEPR) is extrapolated using the 2024-2026 average annual growth rate. The IEPR forecast includes estimates for energy efficiency, electric vehicles, and behind-the-meter solar, among others (see Table H-4 below).

The '2 x AAEE' forecast follows the 2016 LTPP Assumptions' Default Scenario, which results in double the efficiency in the IEPR by 2030.

The ISO load forecast is based on the 2015 IEPR Mid AAEE load forecast (January 2016 Update)[3]. 2026-2030 data (not in IEPR) is extrapolated using the 2024-2026 average annual growth rate. The IEPR forecast includes estimates for energy efficiency, electric vehicles, and behind-the-meter solar, among others (see below).

[67] Available at:

https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03

Table H-4: 2015 IEPR Mid Baseline Mid AAEE Forecast for ISO.

Metric (all units in GWh/yr)	2015	2020	2025	2030
Mid Baseline Demand Before Any Modifiers	309,930	328,805	343,450	360,166
Demand Adders	481	2,344	6,299	12,280
Electric Vehicles	481	1,785	4,954	9,910
Other Electrification	-	311	849	1,553
Climate Change Impacts	-	248	497	818
Demand Reducers	92,511	118,954	140,076	170,485
Self-Generation Photovoltaic*	5,297	10,139	16,964	28,465
Self-Generation Other Private Generation	11,934	13,528	13,962	14,281
AAEE Savings	137	8,838	16,600	26,208
Committed EE Savings	75,143	86,449	92,550	101,530
2015 IEPR Managed Sales (retail)	217,900	212,195	209,673	201,961
2015 IEPR Managed Net Energy for Load**	235,011	228,748	225,877	217,302

* De-rated by 2% to account for losses incurred when exporting customer PV (different from IEPR forecast which assumes no losses). The equivalent installed capacity in 2030 is 16,649 MW (ac)

** Grossed up for losses at 7.33%.

H-3.1.2. Hourly Load Shapes

Load shapes for the ISO zone were built up from end use-specific hourly shapes. Hourly load shapes for non-transportation ISO loads are based on historical data. These non-transportation ISO loads are then adjusted to account for the impact of implementing mandatory residential time-of-use rates by 2020. Furthermore, the impact of smart charging and day-time charging availability of light-duty electric vehicles ("EV") is reflected in an EV load shape that is added onto the adjusted non-transportation load shape.

Load shapes in other zones, including non-ISO California entities, are based on the TEPPC 2024 Common Case, with fixed annual load growth rates extrapolated to 2030.

H-3.1.3. Time-of-use rates and flexible loads

The effect of time-of-use rates is implemented as a fixed 24-hour load shape adjustment for every month. The load shape adjustment for January is shown in Table H-5; other months show essentially the same load shape adjustment. By 2030, we assume there is up to about 1,000 MW of load shifting, from the evening hours into the early morning and midday hours. Aside from this time-of-use rate adjustment, demand response and other flexible loads are not explicitly modeled in this iteration of the analysis.

Table H-5: Hourly load shape adjustment (MW) due to time-of-use rates in ISO in the month of January for the years 2015, 2020, 2025 and 2030

Hour	2015	2020	2025	2030
1	0	319	321	264
2	0	319	321	264
3	0	319	321	264
4	0	319	321	264
5	0	319	321	264
6	0	319	321	264
7	0	319	321	264
8	0	418	435	410
9	0	517	549	556
10	0	616	663	701
11	0	715	777	847
12	0	813	891	992

Hour	2015	2020	2025	2030
13	0	715	777	992
14	0	616	663	847
15	0	287	305	437
16	0	-42	-53	27
17	0	-371	-412	-383
18	0	-601	-656	-793
19	0	-831	-900	-1057
20	0	-831	-900	-1057
21	0	-831	-900	-1057
22	0	-831	-900	-1057
23	0	-831	-900	-1057
24	0	-601	-656	-1057

H-3.1.4. Electric Vehicle Load Profiles

EV load profiles are created using an EV charging model developed by E3, which modify the base load profile assumptions. The charging model is based on the 2009 National Household Transportation Survey ("NHTS"), a dataset on personal travel behavior. The model translates travel behavior into aggregate EV load shapes by weekday/weekend-day, charging strategy, and charging location availability. The weekend/weekday shapes are aggregated and normalized into month hour shapes by charging location availability. A blend is created by assuming 20% of drivers have charging infrastructure only available at home, while 80% of drivers have charging infrastructure available both at home and at the workplace. Last, the evening peak of this blended shape is shifted partly to the early morning hours to reflect smart charging. To obtain the actual load profile, the normalized profile is multiplied with the annual EV load. The resulting ISO EV Load shape for January 2030 is shown in Figure H-5 below.

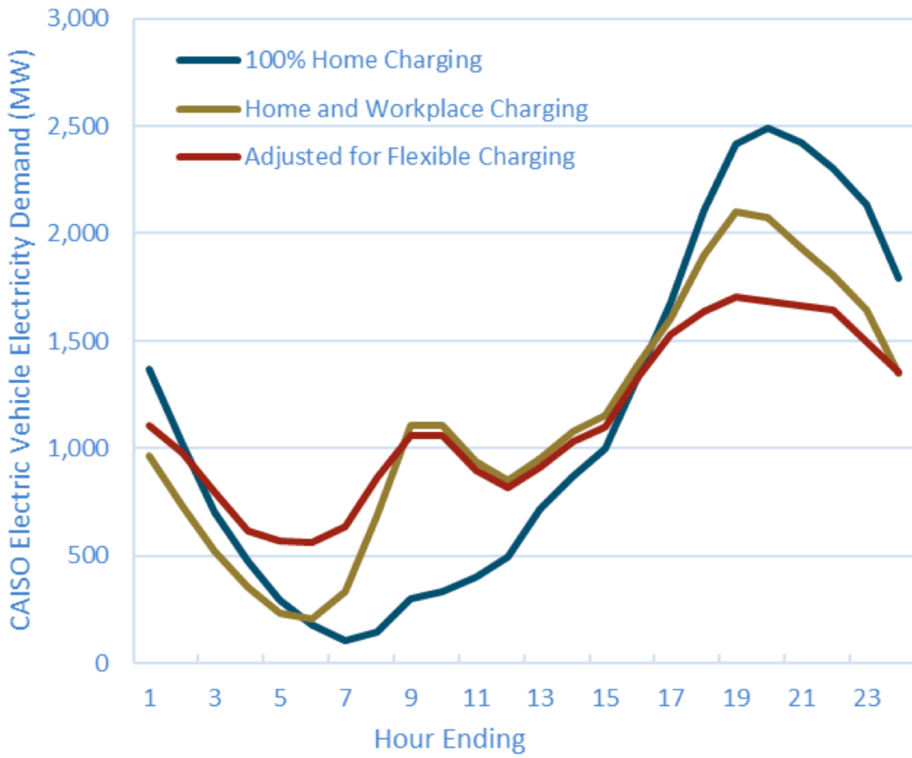

Figure H-5: ISO Electric Vehicle charging Profile (January 2030 example)

H-3.2. Carbon and Gas Price Forecasts

E3 developed gas and carbon price forecasts for use in the RESOLVE model in California during previous SB350 work. These assumptions are also used in this DR modeling work. The assumptions and their provenance are listed below:

Table H-6: Carbon Price Forecast.

	2015	2020	2025	2030
Carbon Price ($/metric ton)	12.10	15.44	19.71	25.16

The carbon prices in the above Table H-6 are based on the 2015 IEPR value with 5% annual inflation, similar to the method used by the CEC in IEPR. All cases use the “low” carbon price assumption from the table above, reflection expectation that carbon price allowances will stay at their floor price under cap and trade, as has historically been true.

Gas prices, shown below in H-7, are based on hub-level futures from NYMEX/CME group. Those hub forecasts are then aggregated into the three geographic zones of the Northwest (NW Sumas, NW Stanfield, OR), Southwest (SoCal Border), and California (SoCal Border, PG&E Gate). Prices include a delivery adder that varies by zones and 2% annual inflation. Futures only exist through 2027, so prices beyond 2027 are extrapolated based on the previous year's increase in Henry Hub futures.

Table H-7: Natural Gas Price Forecast

2015 $/MMBtu	2015	2020	2025	2030
CA Natural Gas Base	3.17	3.69	3.89	4.21
NW Natural Gas Base	2.65	2.84	3.12	3.44
SW Natural Gas Base	2.73	3.31	3.47	3.79

These annual price trends are then further converted to monthly prices based on percentages of the annual average provided in Table H-8. These numbers are based on historical gas prices.

Table H-8: Natural Gas Price Shaping

Planned Resources	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
CA Natural Gas	104%	103%	102%	96%	96%	97%	101%	101%	98%	97%	100%	105%
NW Natural Gas	112%	109%	105%	92%	90%	91%	94%	95%	95%	94%	105%	116%
SW Natural Gas	106%	105%	103%	93%	94%	95%	102%	102%	97%	95%	100%	106%

H-3.3. Renewable Generation Shapes

Hourly shapes for wind resources were obtained from NREL's Wind Integration National

Dataset ("WIND") Toolkit[4] and adjusted using a filter in order to match the site-specific capacity factors in the CPUC's RPS Calculator (version 6.1)[5]. Hourly solar shapes were obtained using NREL's Solar Prospector[6] and scaled/filtered to match capacity factors in the CPUC's RPS Calculator (version 6.1).

H-3.4. Thermal Resources

The thermal resource stack in the ISO footprint is characterized based on the 2014 Long Term Procurement Plan modeling undertaken by the ISO and adjusted to reflect retirements that are scheduled to occur between after 2015. Thermal resources are grouped by technology and performance characteristics (heat rate, minimum stable level, and ramp rate) into fleets of similarly behaving resources, which RESOLVE treats as homogenous. The resulting thermal fleets are summarized in Table H-9. Outside of ISO, thermal fleets are developed for each region based on the 2024 TEPPC Common Case. Coal retirements planned for between 2024 and 2030 are also reflected in each resource stack, assuming a one-for-one replacement with combined cycle gas units. A coarser aggregation approach is applied to non-ISO regions in order to reduce computational complexity. The conventional resource installed capacities by year are listed in Table H-10.

Table H-9: Performance characteristics for planned (i.e. exogenously selected) resources in each zone.

Planned Resources	Pmax (MW)	Pmin (MW)	Max Ramp (%Pmax/hr)	Min Up/ Down Tm (hrs)	Startup Cost ($/MW)	Fuel Burn Slope (MMBtu/MWh)	Fuel Burn Intercept (MMBtu/unit)
ISO Resources							
CHP	39.3	39.2	0%	24	0.0	6.845	0
Nuclear	572	572	0%	24	0.0	9.576	0
CCGT1	393	175	100%	6	50.9	6.268	288
CCGT2	410	118	100%	6	48.8	6.050	427
Gas Peaker1	64.4	28.0	100%	1	77.6	8.262	74
Gas Peaker2	44.9	16.3	100%	1	111.5	7.577	122
Steam Turbine	358	28.7	100%	6	10.0	9.302	212
Northwest Resources							
Nuclear	1,170	995	0%	24	-	10.907	-
Coal	344	137	100%	24	14.54	9.222	283
CCGT	337	166	100%	6	14.83	6.614	219
Gas Peaker	30	11	100%	1	662.71	9.381	39
Southwest Resources							
Nuclear	953	953	0%	24	-	10.544	-
Coal	427	171	100%	24	11.70	9.151	354
CCGT	391	199	100%	6	12.77	6.619	315
Gas Peaker	71	25	100%	1	279.97	8.795	141
LADWP Resources							
Nuclear	152	152	0%	24	-	10.544	-
Coal	820	328	100%	24	6.10	8.656	644
CCGT	230	123	100%	6	22	6.967	65
Gas Peaker	79.1	36	100%	1	253	8.857	88

Table H-10: Installed capacities of planned (i.e., exogenously selected) resources in each zone across all scenarios.

Resource	Planned Installed Capacity (MW)			
	2015	2020	2025	2030
ISO Resources				
CHP	4,006	4,006	4,006	4,006
Nuclear	2,862	2,862	1,742	622
CCGT1	10,705	9,307	10,207	10,207
CCGT2	5,328	5,328	5,328	5,328
Gas Peaker1	3,471	3,471	3,671	3,671
Gas Peaker2	3,200	3,046	2,916	2,916
Steam Turbine	10,388	6,314	0	0
Northwest Resources				
Nuclear	1,170	1,170	1,170	1,170
Coal	12,784	10,962	9,665	7,970
CCGT	12,034	14,296	15,593	17,288
Gas Peaker	4,193	4,135	4,135	4,050
Southwest Resources				
Nuclear	2,858	2,858	2,858	2,858
Coal	12,391	10,080	9,241	9,241
CCGT	21,130	23,445	24,169	24,169
Gas Peaker	8,885	11,329	12,903	12,528
LADWP Resources				
Nuclear	457	457	457	457
Coal	1,640	1,640	0	0
CCGT	2,069	2,069	3,709	3,709
Gas Peaker	2,742	2,769	2,531	2,531

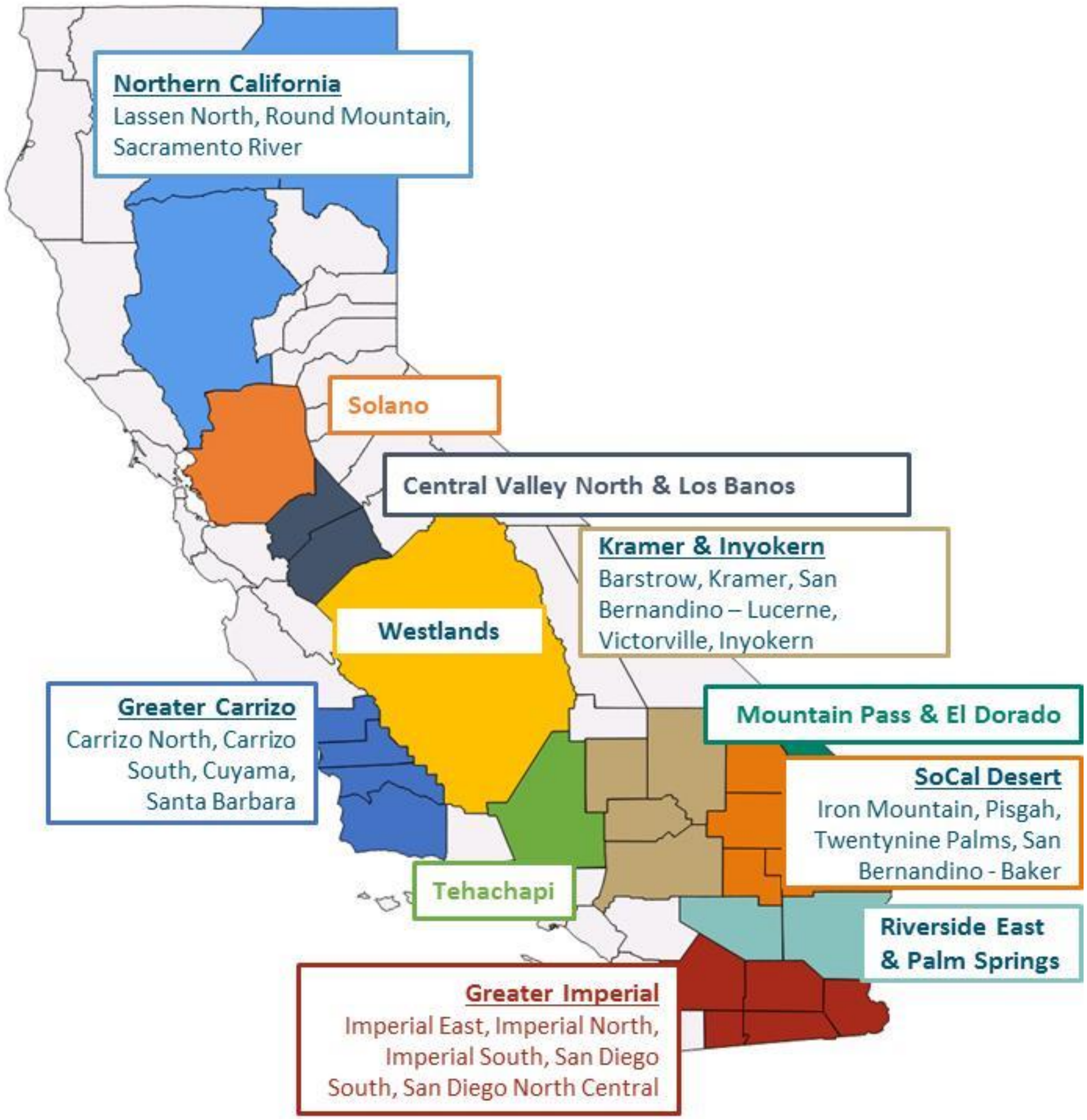

Figure H-6: California resource zones included in RESOLVE model

H-3.5. Out-of-State Renewable Potential

The renewable portfolios to meet California's RPS mandates are constrained to include only out-of-state resources that can be delivered on the existing system without requiring major new transmission; resources that would require major new interregional transmission projects are excluded. The transmission costs associated with each of these resources are discussed in Section H-3.7.

Table H-11: Out-of-state resource potential included in RESOLVE.

Resource		Description	Potential (MW)		
			Current Practice 1	Regional 2	Regional 3
Arizona Solar PV		High quality solar PV resource, available for delivery on existing transmission system	1,500	1,500	1,500
New Mexico Wind	**1**	Highest quality wind resource, requires new transmission investment	-	-	1,500
	2	Medium quality wind resource, requires new transmission investment	-	-	1,500
	3	Lowest quality wind resource, available for delivery on existing transmission system	1,000	1,000	1,000
Oregon Wind		Low quality wind resource, available for delivery on existing transmission system	2,000	2,000	2,000
Wyoming Wind	**1**	Highest quality wind resource, requires new transmission investment	-	-	1,500
	2	Medium quality wind resource, requires new transmission investment	-	-	1,500
	3	Lowest quality wind resource, available for delivery on existing transmission system	500	500	500
Total Out-of-State Resources Available			**5,000**	**5,000**	**11,000**

H-3.6. Renewable Cost & Performance

Renewable resource cost and performance for the resources identified in Sections 7.3.7 are derived from the CPUC's RPS Calculator (version 6.2), with adjustments made to solar and geothermal costs based on stakeholder feedback as part of the SB 350 study process. The RPS Calculator's assumptions regarding cost and performance for new renewables have been modified—in most cases, reduced—for this study based on stakeholder feedback and a review of current literature, including:

- *2014 Wind Technologies Market Report* (US DOE);[68]
- *Utility Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (LBNL);[69]
- WREZ Generation and Transmission model (version 2.5);[70] and

Email correspondence with the Geothermal Energy Association. The cost and performance of all candidate renewables for the portfolios—both in California and in the rest of the WECC—are summarized in Table 12. The federal renewable investment tax credit ("ITC") and production tax credit ("PTC") are both assumed to be reduced by 2030 according to current federal policy. The Federal PTC and ITC phase out by 2019 for wind and by 2021 for solar and geothermal. Solar PV and geothermal remain eligible for a 10% ITC after 2021.

Learning rates are assumed to reduce the capital cost of renewable technologies over time. However, the scheduled roll-offs of the federal PTC and ITC can result in a higher levelized cost of energy ("LCOE") in 2030 compared to today.

[68] Available at: http://energy.gov/sites/prod/files/2015/08/f25/2014-Wind-Technologies-Market-Report-8.7.pdf

[69] Available at: https://emp.lbl.gov/sites/all/files/lbnl-1000917.pdf

[70] Available at: http://www.westgov.org/component/docman/doc_download/1475-wrez-generation-and-transmission-model-

Table H-12: Renewable resource cost & performance assumptions in RESOLVE

Resource	Geography		Cap. Factor (%)	Capital Cost (2015 $/kW)		LCOE (2015 $/MWh)	
				2015	2030	2015	2030
California Geothermal	Imperial		88%	$ 5,142	$ 5,142	$ 76	$ 96
	Northern California		80%	$ 3,510	$ 3,510	$ 59	$ 81
California Solar PV	Central Valley & Los Banos		28%	$ 2,174	$ 1,826	$ 58	$ 76
	Greater Carrizo		30%	$ 2,174	$ 1,826	$ 53	$ 69
	Greater Imperial		30%	$ 2,174	$ 1,826	$ 56	$ 73
	Kramer & Inyokern		33%	$ 2,174	$ 1,826	$ 50	$ 66
	Mountain Pass & El Dorado		35%	$ 2,174	$ 1,826	$ 50	$ 65
	Northern California		29%	$ 2,174	$ 1,826	$ 59	$ 78
	Riverside East & Palm Springs		34%	$ 2,174	$ 1,826	$ 53	$ 70
	Solano		30%	$ 2,174	$ 1,826	$ 59	$ 78
	Southern California Desert		33%	$ 2,174	$ 1,826	$ 51	$ 67
	Tehachapi		34%	$ 2,174	$ 1,826	$ 52	$ 68
	Westlands		31%	$ 2,174	$ 1,826	$ 55	$ 72
OOS Solar PV	Arizona		31%	$ 2,001	$ 1,711	$ 45	$ 56
California Wind	Central Valley & Los Banos		30%	$ 2,069	$ 2,008	$ 51	$ 76
	Greater Carrizo		25%	$ 1,914	$ 1,857	$ 49	$ 74
	Greater Imperial		36%	$ 2,083	$ 2,022	$ 43	$ 68
	Riverside East & Palm Springs		35%	$ 2,047	$ 1,987	$ 57	$ 82
	Solano		29%	$ 1,992	$ 1,933	$ 58	$ 82
	Tehachapi		34%	$ 2,087	$ 2,025	$ 47	$ 72
OOS Wind	New Mexico	1	46%	$ 1,738	$ 1,687	$ 21	$ 46
		2	42%	$ 1,738	$ 1,687	$ 26	$ 51
		3	39%	$ 1,738	$ 1,687	$ 30	$ 55
	Oregon		32%	$ 1,943	$ 1,885	$ 49	$ 74
	Wyoming	1	46%	$ 1,738	$ 1,687	$ 21	$ 46
		2	42%	$ 1,738	$ 1,687	$ 26	$ 51
		3	39%	$ 1,738	$ 1,687	$ 30	$ 55

** OOS = out-of-state, LCOE = levelized cost of energy. Solar capital cost is expressed with respect to AC capacity with assumed inverter loading ratio of 1.3; i.e. the cost per kW-AC is 1.3 times higher than the cost per kW-DC.*

H-3.7. Transmission Availability & Cost

H-3.7.1. California Resources

For each resource zone in California, the ability to connect resources to the existing system is limited; assumptions are based on the rules of thumb developed by ISO for its 50 % Renewable Energy Special Study conducted as part of the 2015-2016 Transmission Planning process.[10] To the extent that the available resource potential in a zone exceeds the limits of the existing system, a transmission cost penalty is included for incremental additions beyond these limits; the assumed transmission cost is based on the assumptions of the RPS Calculator. This two-tiered approach for applying transmission costs to new resources is shown illustratively in Figure 6, where 'Available Capacity (a)' represents the limit of a system to accommodate new renewables at no cost; and 'Incremental Cost (b)' reflects the cost of new transmission upgrades once the available capacity has been exhausted. The assumptions for each of these parameters for each resource zone in California are summarized in Table H-13.

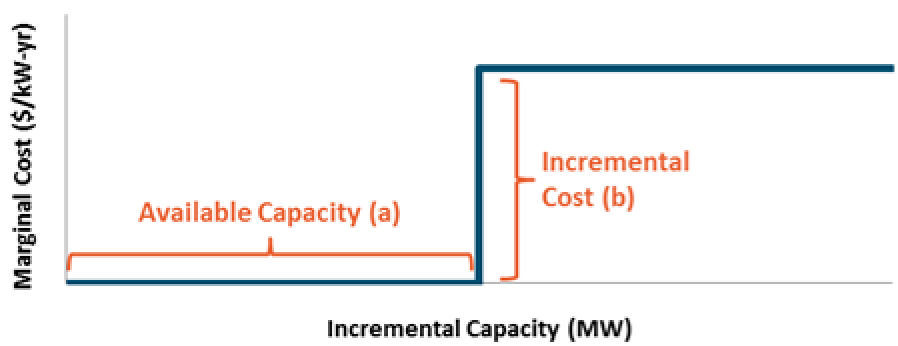

Figure H-7: Illustrative transmission costing for a California resource zone in RESOLVE

Table H-13: Availability of energy only capacity and cost of transmission upgrades in California zones

Zone	Capacity Available at no cost (MW)	Cost for Incremental Capacity ($/kW-yr.)
Central Valley & Los Banos	2,000	37
Greater Carrizo	2,982	84
Greater Imperial	1,140	147
Kramer & Inyokern	2,633	87
Mountain Pass & El Dorado	750	67
Northern California	0	82
Riverside East & Palm Springs	3,404	122
Solano	4,917	109
Southern California Desert	1,101	17
Tehachapi	5,000	27
Westlands	2,900	75

H-3.7.2. Out-of-State Resources

The transmission needs associated with out-of-state resources vary depending both on the resource and the scenario, but generally reflect one of two types of costs:

- Wheeling and pancake losses resulting from the need to purchase firm service on the existing transmission system from one or more neighboring balancing authorities; or
- Costs associated with major new projects to deliver a renewable resource to a sufficiently liquid trading hub.

The application of these costs to out-of-state resources varies by scenario:

- In Current Practice 1, only resources that can be delivered on the existing system are considered; the cost of wheeling through neighboring balancing areas is attributed to these resources. Current Practice 1 does not include resources that would require major new interregional transmission infrastructure to be constructed.
- Regional 2 considers the same set of resources as Current Practice 1; however, the shift towards a regional market results in no direct wheeling costs for the entities within the Regional ISO.
- Regional 3 considers both resources that can be delivered on the existing system as well as those that would require major new transmission. Resources that can be delivered on the existing system incur no transmission costs. Resources that require transmission upgrades are assumed to pay the annual revenue requirement associated those upgrades.

The differential treatment of transmission costs in each scenario—as well as the basis used to estimate each resource's associated transmission costs—are summarized in Table H-14.

Table H-14: Transmission cost assumptions for out-of-state resources

Resource		Quantity (MW)	Costs ($/kW-year)			Basis for Assumption
			CP 1	Reg. 2	Reg. 3	
Southwest Solar PV		1500	$39	$0	$0	Wheeling & losses on APS system
New Mexico Wind	1	1500	N/A	N/A	$50	Assumed project capital cost ($567 million for 1,500 MW of new transmission) based on RPS Calculator transmission costs, scaled for distance for delivery to Four Corners
	2	1500	N/A	N/A	$129	Sum of public information regarding SunZia costs ($2 billion for 3,000 MW) and assumed upgrade costs from Pinal Central to Palo Verde based on RPS Calculator
	3	1000	$72	$0	$0	Wheeling & losses on PNM & APS systems
Northwest Wind		2000	$34	$0	$0	Wheeling & losses on BPA system (system + southern intertie rates)
Wyoming Wind	1 & 2	3000	N/A	N/A	$88	Costs of Gateway project reported ($252 million per year for 2,875 MW) reported in *Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration* (Technical Appendix)
	3	500	$66	$0	$0	Wheeling & losses on PacifiCorp East & NV Energy systems

H-4. Storage Resources

Energy storage cost and performance inputs are based on a review of the literature and projections from manufacturers and developers, including:

- *Lazard's Levelized Cost of Storage Analysis – version 1.0 (*Lazard, 2015);[71]
- *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA* (Sandia National Laboratories, 2013);[72]

[71] Available at: https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf

[72] Available at: http://www.sandia.gov/ess/publications/SAND2013-5131.pdf

- *Electrical energy storage systems: A comparative life cycle cost analysis* (Zakery and Syri, Renewable and Sustainable Energy Reviews 2015);[73]
- *Rapidly falling costs of battery packs and electric vehicles* (Nykvist and Nilsson, Nature Climate Change 2015);[74]
- *2015 Greentechmedia.com coverage on emerging battery manufacturers*
- *Tesla Powerwall webpage (Last visited March 2016);*[75]
- *Capital Cost Review of Power Generation Technologies; Recommendations for WECC's 10- and 20-year studies (E3, 2014); only used for pumped hydro*[76]

Capital investment and O&M costs are annualized using E3's WECC Pro Forma tool. For lithium ion and flow batteries, a 15% adder is added on top of the capital costs shown in Table H-16 to take into account engineering, procurement and construction ("EPC"), and interconnection. E3 modeled replacement of the lithium ion battery pack in year 8 and replacement of the flow battery and lithium ion battery power conversion system in year 10. Replacement costs are assumed to be equal to the capital costs of the replacement item in the year of replacement (not including the 15% adder).

Cost and performance assumptions for energy storage technologies are summarized in Tables H-15 to H-17 below.

Table H-15: Energy storage performance and resource potential by technology.

Technology	Charging & Discharging Efficiency	Financing Lifetime (yr)	Replac-ement (yr)	Minimum duration (hrs)	Resource Potential (MW)
Lithium Ion Battery	92%	16	8	0	N/A
Flow Battery	84%	20	N/A	0	N/A
Pumped Hydro	87%	40	N/A	12	4,000

Note: For Lithium Ion Batteries and Flow Batteries we also assume inverter replacement at year 10.

[73] Available at: http://www.sciencedirect.com/science/article/pii/S1364032114008284

[74] Available at: http://www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html

[75] Available at: https://www.teslamotors.com/powerwall

[76] Available at: https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf

Table H-16: Energy storage cost assumptions by technology.

Type	Cost Metric	2015	2030
Lithium Ion Battery	Storage Cost ($/kWh)	$375	$183
	Power Conversion System Cost ($/kW)	$300	$204
	Fixed O&M Battery/Reservoir ($/kWh-yr)	$7.5	$3.7
	Fixed O&M PCS ($/kW-yr)	$6.0	$4.1
Flow Battery	Storage Cost ($/kWh)	$700	$315
	Power Conversion System Cost ($/kW)	$300	$204
	Fixed O&M Battery/Reservoir ($/kWh-yr)	$14.0	$6.3
	Fixed O&M PCS ($/kW-yr)	$6.0	$4.1
Pumped Hydro	Storage Cost ($/kWh)	$117	$117
	Power Conversion System Cost ($/kW)	$1,400	$1,400
	Fixed O&M Battery/Reservoir ($/kWh-yr)	-	-
	Fixed O&M PCS ($/kW-yr)	$15	$15

Table H-17: Energy storage cost estimates in 2015 and 2030 for each technology ($/kW-yr and $/KWh-yr).

Technology	2015 Annualized Cost Components ($/kW-yr; $/kWh-yr)	2030 Annualized Cost Components ($/kW-yr; $/kWh-yr)
Lithium Ion Battery	$69; $85	$46; $40
Flow Battery	$58; $118	$39; $53
Pumped Hydro	$146; $12	$146; $12

Note: The first number indicates the annualized cost of the power conversion system ($/kW-yr) of the device and the second number indicates the annualized cost of the energy storage capacity or reservoir size ($/kWh-yr). Both numbers are additive. This annualized cost is the full cost of owning and operating the system, including O&M and replacement costs.

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[1] National Renewable Energy Laboratory, "Eastern Wind Integration and Transmission Study," Revised February 2011. Available at: http://www.nrel.gov/docs/fy11osti/47078.pdf

[2] Hargreaves, J., E. Hart, R. Jones, A. Olson, "REFLEX: An Adapted Production Simulation Methodology for Flexible Capacity Planning," IEEE Transactions of Power Systems, Volume:PP, Issue: 99, September 2014, pp 1 – 10.

[3] Available at:

https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03

[4] The Wind Toolkit and associated materials can be obtained from NREL at:

http://www.nrel.gov/electricity/transmission/wind_toolkit.html

[5] The RPS Calculator and associated materials can be obtained from the CPUC at:

http://www.cpuc.ca.gov/RPS_Calculator/

[6] The Solar Prospector and associated materials can be obtained from NREL at:

http://maps.nrel.gov/node/10

[7] Available at: http://energy.gov/sites/prod/files/2015/08/f25/2014-Wind-Technologies-Market-Report-8.7.pdf

[8] Available at: https://emp.lbl.gov/sites/all/files/lbnl-1000917.pdf

[9] Available at: http://www.westgov.org/component/docman/doc_download/1475-wrez-generation-and-transmission-model-

[10] Available at:

https://www.ISO.com/Documents/Draft2015-2016TransmissionPlan.pdf

[11] Available at: https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf

[12] Available at: http://www.sandia.gov/ess/publications/SAND2013-5131.pdf

[13] Available at: http://www.sciencedirect.com/science/article/pii/S1364032114008284

[14] Available at: http://www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html

[15] Available at: https://www.teslamotors.com/powerwall

[16] Available at:
https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf

H-5. Modeling the Impact of the Storage Mandate

The California storage mandate[77] calls for 1,325 MW of storage to be installed by California's IOUs by 2025. This mandate is included in all RESOLVE scenarios as a block of four-hour duration batteries and was treated as exogenous to all DR service type modeling in the primary report findings. As part of our research scope the CPUC requested that E3 conduct a side analysis that examined the impact of the Storage Mandate on Shift type DR resources in the RESOLVE model. This analysis focused on understanding how the value of Shift might

[77] For more information on AB 2514 regarding energy storage systems, see
http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514

change when Storage Mandate resources are treated as Shift type DR[78].

E3 ran several shift cases with the Storage Mandate as Shift DR and compared it to the same Shift penetration cases with no Storage Mandate at all to estimate the value of Shift under the various storage scenarios. The absolute difference in the value varies by the amount of Shift penetration on the system. At its most significant, with 1% of Shift enabled, California's Storage Mandate reduces the value of Shift DR by 38%. In contrast, the least significant reduction at 5% Shift penetration, was 21%. On average across the different levels of Shift penetration examined, California's Storage Mandate reduces the associated value of DR by 27%. Figure XX presents the difference in system-level savings from Shift DR under varying levels of Shift penetration under the "With Storage Mandate" and "No Storage Mandate" model runs.

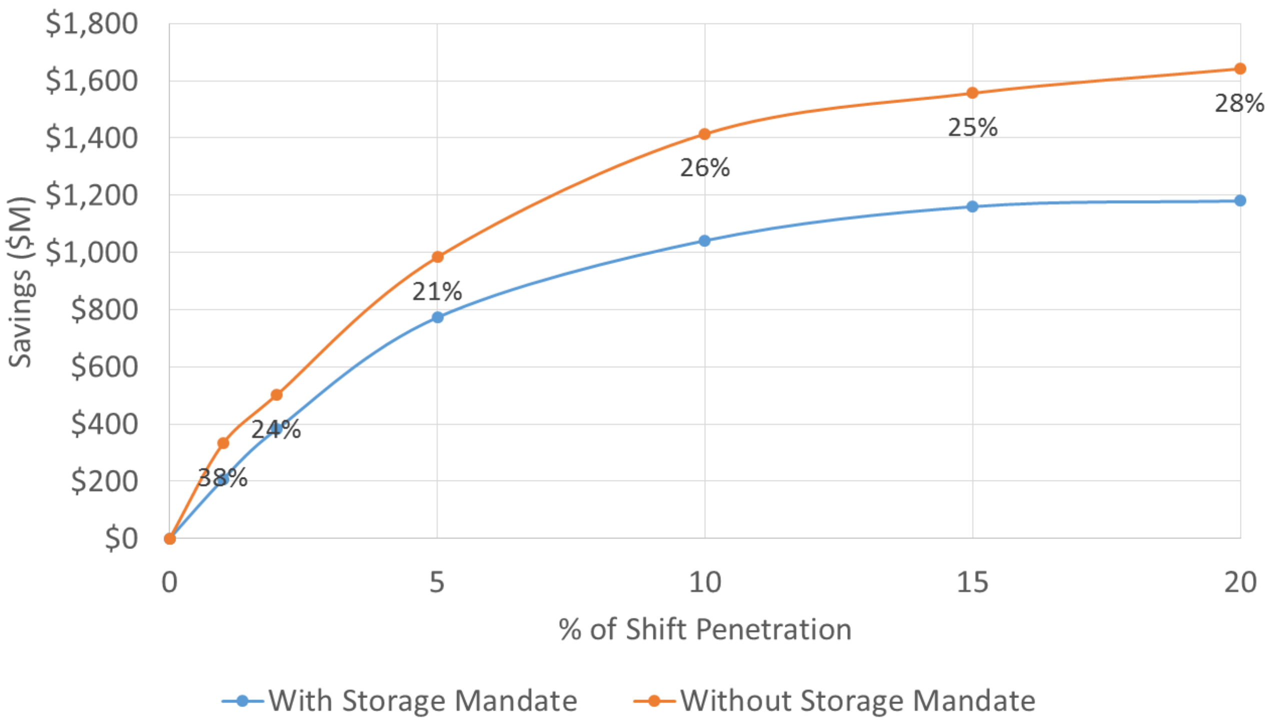

Figure H-8: Comparison of System-level savings from Shift DR under Storage Mandate Scenarios. Percentages reflect percent reduction from "Without Storage Mandate" compared to "With Storage Mandate"

Our findings indicate that 99% of the value of batteries comes from their ability to move load

[78] The model captures the Behind the Meter and Grid scale storage at penetration levels specified in the Storage Mandate.

around, while the other 1% comes from their ability to provide reserves. The relative values of shift (moving load) and shimmy (providing reserves) come from their ability to free up batteries to move load around. In short, any resource that can increase the flexibility of the grid's load will show significant value. We see that directly with shift and indirectly with shimmy (by way of newly-freed-up batteries).

In previous RESOLVE runs, the California Storage Mandate shifted about 1.2 TWh of load, which is approximately equivalent to 0.83% Shift penetration. If the California Storage Mandate were replaced with Shift DR, Shift's value (savings) would increase. The purpose of this analysis was to produce a quantitative estimate of the Storage Mandate's impact on Shift DR's value, however, these results cannot be used to definitively say whether traditional storage or Shift DR would provide a more economic long term solution. It is important to note that the implementation costs of Shift DR were not included in this sensitivity analysis.

Appendix I: Economic Valuation

Demand Response benefit value streams are conventionally identified through avoided generation capacity and energy needs in utility integrated resource and operational plans. In order to thoroughly assess the potential value of DR product participation in the market and the potential for avoided generation, transmission, and distribution capacity costs and avoided energy costs, they should be modeled within production cost and operational planning framework representing the full electricity system. However, such a modeling exercise is beyond the scope of our economic assessment. Our study employs two methods for determining the economic value of DR: (1) a price referent (used for Shed service only), determined by avoided cost of generation, transmission, and distribution as defined in the CPUC Cost Effectiveness Protocols and (2) system levelized values, calculated from E3's RESOLVE tool. These two approaches are introduced in Section 4.8 of the report and discussed in detail below.

The results of the economic assessments, when analyzed in conjunction with our DR supply curves, provide an indication of what quantity of DR is likely to be cost-effective given the calculated costs of the DR technologies. Additionally, this assessment allows us to examine opportunities for market transformation of DR technology adoption and participation on the supply side market.

I-1. Determining the Value of Demand Response

The value of demand response for offsetting transmission, distribution and generation capacity depends on how the DR resource lines up with times of system need on the grid. In DR-

PATH, the approach for defining these periods of need is based on predicted system net load peaks, which includes forecasted load and the renewable generation fleet.

Our estimates for the contributions of renewables in future years are based on current-day operations data for utility-scale solar and wind that are reported publicly on the CAISO OASIS service. These are paired with the coincident estimates for weather in two weather cases: a 1 in 2 weather year, which represents a typical or average weather year, or a 1 in 10 weather case, which depicts an extreme weather years, occurring once every 10 years. In the model, for each year and weather case, the generation from the statewide fleet of utility-scale solar and wind renewables estimated based on the expected growth in generation capacity for renewables.

We base the expected trajectory of renewable energy generation on the RPS requirements as interpreted by the CEC (listed below), which were most recently updated with SB350 and the 2016 IPER to put California on track for 50% renewable electricity in 2050.The current (circa 2015) baseline is around 20%, which is a mix of utility scale solar and wind, geothermal, biomass, and small hydroelectric power. About half of that is the utility-scale renewables in the CAISO data. To achieve a ~40% RPS by 2025, the fleet is grown by a factor of four.

The following are CEC defined trajectories for renewables in California[79].

- An average of 20 percent in 2011-2013
- 25 percent by the end of 2016
- 33 percent by the end of 2020
- 40 percent by the end of 2024
- 45 percent by the end of 2027
- 50 percent by the end of 2030
- No less than 50 percent in each multi-year compliance period thereafter

I-1.1. System Net Load Results

Figure I-1 shows four months from the system net load forecasts from the LBNL-LOAD model and renewable resource forecasts, where net load is equal to gross load forecasts minus wind and solar resources. For each of the four months shown in Figure I-1, each line represents a different scenario, with the values showing the average daily load over the entire month. The dashed versus solid lines show 1-in-2 and 1-in-10 weather years, respectively,

[79] http://www. energy. ca. gov/renewables/tracking_progress/documents/renewable. pdf

between which the difference is minimal. Blue-toned and red-toned lines show 2020 and 2025 scenarios, respectively, with the figure showing that 2025 has higher net load during morning and evening hours (due to higher gross load), but lower net load during afternoon hours (due to higher solar generation). This comparison shows that in later years there will be a progressive increase of dynamics known as the “duck curve” as discussed in Appendix D. Lastly, the lighter-toned lines represent no-AAEE scenarios, while the bolder/darker lines represent mid-AAEE. As expected, net load in no-AAEE scenarios is higher than the mid-AAEE scenarios, as gross demand is greater when there is less energy efficiency measures in place. Appendix XX shows and discusses more net load results, showing all months of the year as well as the difference between rate mix scenarios and the spread in net load over a given month (where we only have the average here).

The graphic below, Figure I-2, illustrates the monthly net load profiles from the DR PATH model used to estimate the top 250 peak hours, and used to calculate the value of DR Shed service. The black dots depict the top 250 hours for 2025, under a 1-in-2 weather year.

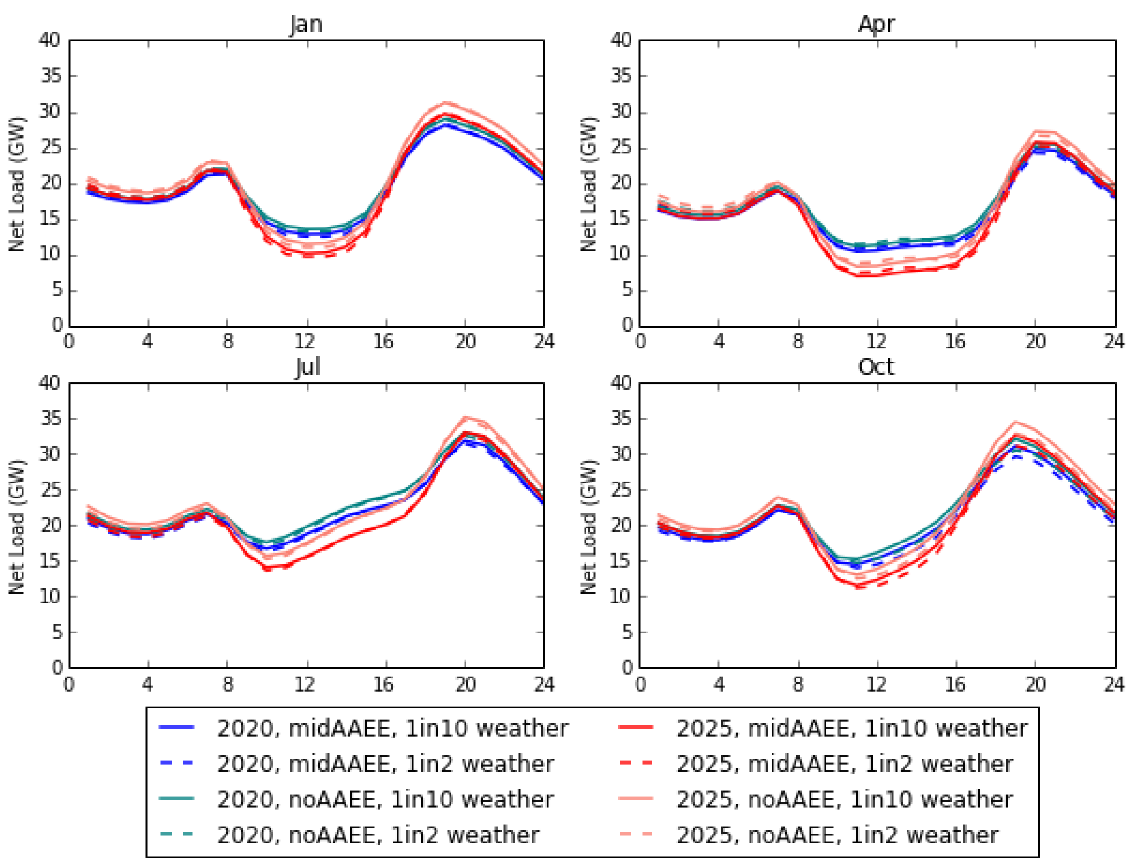

Figure I-1: Forecast Results - System Net Load (Gross Demand - Solar & Wind Generation) for eight scenarios over four illustrative months. Dashed vs. solid lines represent weather year; blue-toned lines are for 2020 while red-toned lines are for 2025; and dark lines are mid AAEE while lighter lines are no AAEE.

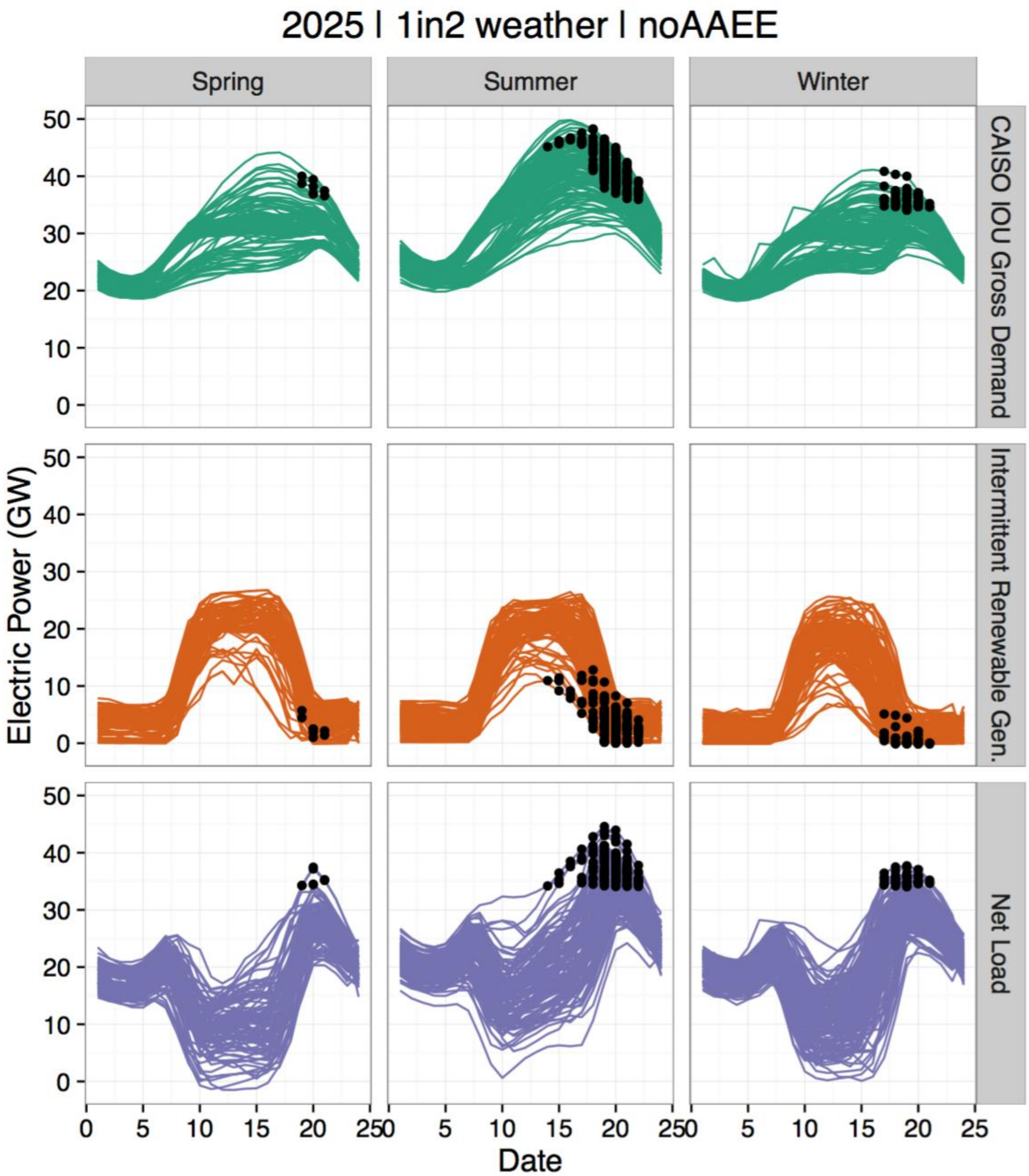

Figure I-2: Day-to-day variation in the load and renewable generation for one case: 2025, 1-in-2 weather, and the "No AAEE" efficiency case. The plot shows (top row) combined IOU demand, (middle row) intermittent renewables generation, and (bottom row) net load profiles broken out by season (Winter is October-February, Spring is March-May, Summer is June-September). Black dots indicate hours in the top 250 of net load, which are used to define the hours of need for valuing peak shed capacity.

In 1-in-10 weather years the top load hours remain concentrated in the summer months, while the 1-in-2 year includes some peak hours in the winter (a handful from November through February).This suggests that in the future there will be a year-round possibility of capacity needs, but that capacity shortages are still concentrated in the summer, coincident with high peak loads. For additional details as to the development of the Ex Ante Weather and Renewable Generation Forecasts, please see Appendix B.

The DR-PATH model estimates the RA value of DR using the top 250 hours in the net load for each run, using a weighted average value of DR capacity available for bid into supply markets (or expected load impacts for load modifying DR) during those hour. The weights are variable among the top hours depending on the relative net load magnitude, and the ratio in weight between the top hour and the 250th hour is approximately 4:1.

Using this approach is a simplified and useful approximation for the capacity value of DR that could be estimated through more complex models like "loss of load probability" or "estimated load carrying capability" approaches. Ultimately, the value of DR in the market (i. e., the quantity that is paid for) is determined through administrative processes that define how DR is measured and settled, which may or may not match exactly with model-based estimates. In section 8.1.2 below, we provide a heuristic comparison of our estimate of the top 250 hours to E3's RECAP Model, which captures capacity value through a loss of load probability estimate.

I-1.2. Heuristic comparison of DR PATH peak hours estimates to E3's RECAP Model for estimating system capacity constraints

E3's RECAP model uses 63 years of statistically-synthesized data to create distributions of net load and generation capacity in every hour of a year to calculate the probability that net load exceeds generation capacity, or the loss-of-load probability (LOLP), in each hour of the year. During the course of this analysis, LBNL expressed interest in exploring the potential for approximating RECAP's statistical calculation of LOLP) with a heuristic based solely on a year's distribution of net load. Two key questions needed answering to provide a sufficient answer to how one might use net load to approximate LOLP: over how many hours of net load might one expect a non-negligible LOLP and how is the LOLP distributed over those hours?

Examining the distributions of LOLP over each of the 63 years of results from RECAP, we find that nearly the entirety of a year's LOLP is contained in the top 100 net load hours of the year.[80] Figure I-3 illustrates the amount of LOLP in a given number of top net load hours over all 63 years.

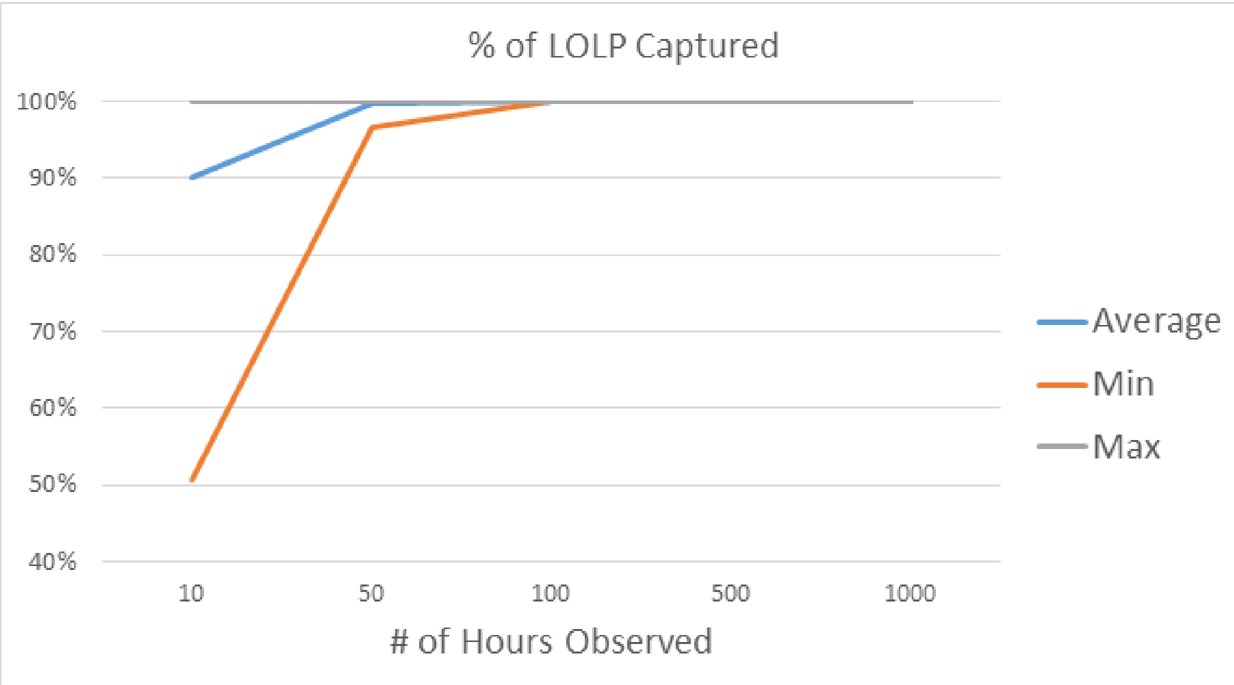

Figure I-3: Percentage of LOLP captured by the net load hours of a give year (number of hours on the x-axis)

After investigating how many hours the majority of LOLP is contained, we next investigated what distribution of LOLP, as a function of net load in the same hours, would best reflect the RECAP LOLP. Several weightings were considered, described below[81], assuming we are distributing LOLP over N hours of net load, where the net load in the highest net load hour is denoted by and the net load in the lowest, or Nth, net load hour is denoted by :

[80] Because RECAP accounts for even the very small (and thus improbable) amounts of LOLP in other hours, there is some amount of LOLP that is overlooked by only considering the top 100 hours.

[81] Note that each of these weightings is normalized to sum to 1.

- **Proportional in total:** the *n*th hour receives a weight of $\frac{NetLoad_n}{\sum_{i=0}^{N} NetLoad_i}$
  - Because the variance in net load across the top *N* hours is much smaller than the absolute magnitude of net load in each of these hours, this weighting ends up essentially looking uniformly distributed
- **Proportional compared to *N*th hour:** The *n*th hour receives a weight of $\frac{\boldsymbol{NetLoad_n} - \min(NetLoads)}{\sum_{i=1}^{N}(\boldsymbol{NetLoad_i} - \min(NetLoads))}$
  - Note that, in this weighting, the *N*th hour actually receives a weight of 0
- **Straight line from $\boldsymbol{NetLoad_1}$ to $\boldsymbol{NetLoad_N}$**
  - Here, also, the *N*th hour receives a weight of 0
- **Harmonic:** the *n*th hour receives a weight of $\frac{1}{\mathrm{n}}$
- **Gaussian:** the *n*th hour receives a weight of $e^{-(n^2)}$

Under each of these different weightings, E3 determined the mean-squared-error (MSE) between the heuristic approach and RECAP's actual distribution of LOLP over different numbers of hours. Figure I-4 and Table I-1 summarize the results.

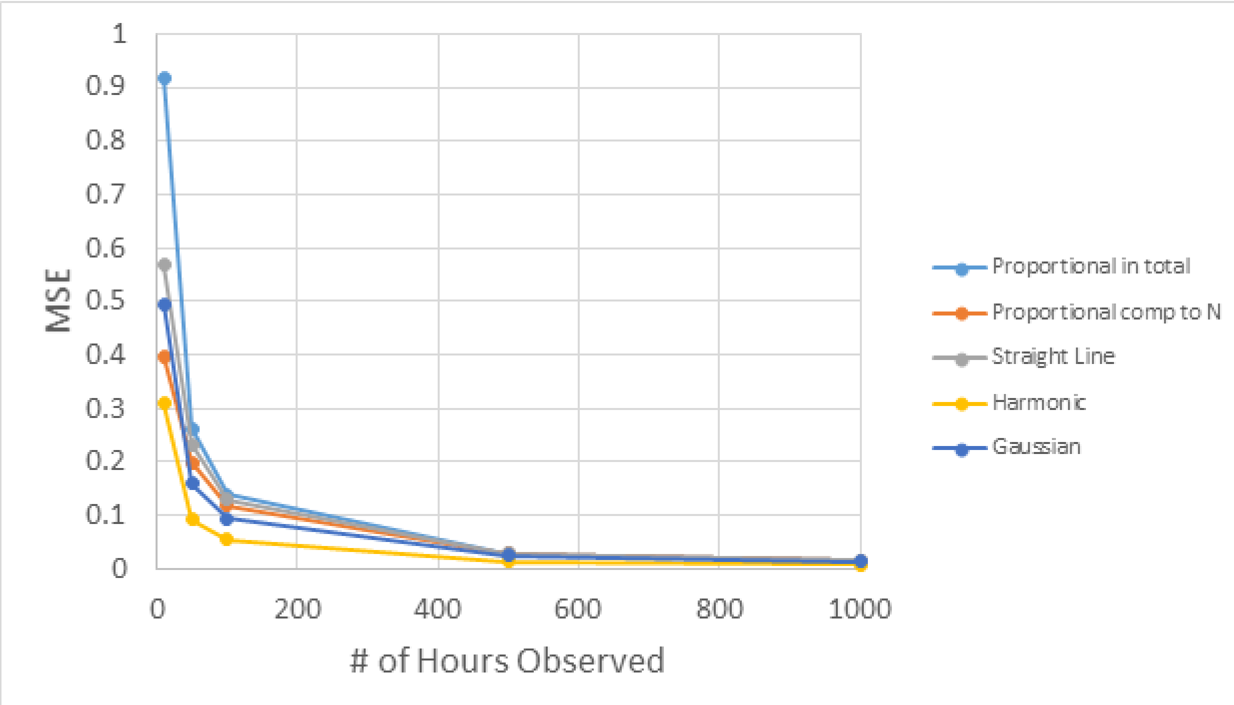

Figure I-4: Mean-squared error (MSE) between the heuristic approach and RECAP's actual distribution of LOLP over different numbers of hours.

Table I-1: The mean-squared-error (MSE) between the heuristic approach and RECAP's actual distribution of LOLP over different numbers of hours

	10	50	100	500	1000
Proportional in total	0.92	0.26	0.14	0.03	0.01
Proportional compared to N	0.40	0.20	0.12	0.03	0.01
Straight Line	0.57	0.23	0.13	0.03	0.01
Harmonic	0.31	0.09	0.05	0.01	0.01
Gaussian	0.49	0.16	0.09	0.02	0.01

In observing these results, it became clear that the best approximation for distribution of LOLP, regardless of how many hours of net load are under inspection, is the harmonic weighting.

I-2. Economic Valuation Inputs

Once we have identified the top 250 hours in the net load profile as described in the previous section, we assign weights to each of these hours for each year: 2014, 2020, and 2025.These hours are assigned resource adequacy capacity credit weights, or value, for which we assume represent the capacity needs for each year. For each of the DR Products, we match their hourly availability and load reduction capability, effectively determining the capacity for each to contribute to the grid needs. Once the DR products have this capacity value in kW, we are then able to determine what capacity benefits should be assigned, including avoided energy, adjustments for line losses, and T&D benefits.

For the PDR and RDRR DR Products, (i. e. Phase 1 supply DR), the quantity of RA credit (in kW/yr), is calculated by multiplying the 4-hour filter sheddable load fraction for each end-use 8760 hourly load profile. This vector of sheddable load values is multiplied by the vector of relative capacity weights, in this case the weighted top 250 hours (conventional RA calculation), which is based on net system load. These hourly values are summed and adjusted for dispatch reliability, operating reserves, T&D, improvements in performance within the scenarios (BAU, medium, and high), and for changes in the year to year trajectory, (i. e.2020 - 2025).As the source of DR capacity is at the end-user, the RA credit is adjusted for T&D and operating reserves to be consistent with capacity from conventional generation.

I-2.1. Adjustments to Performance and Allocation of Revenue Streams

- CE Protocols: The protocols include performance adjustments for Operating Reserves and T&D to capture the benefits of DR in the supply market. For example, this adjustment captures the fact that a MW of DR is not equal to a MW from a generator, because the MW from a generator will lose energy/capacity over transmission and distribution lines.
- Adjusted for scenarios: The performance ratios within the BAU, Medium and High scenarios include technology performance improvements for forecasting DR Potential in 2020 and 2025.The performance improvements are captured as increases in the shed factors for each technology.
- Adjustments for year-to-year trajectory: From 2015-2025, the performance of technology for some technologies is expected to improve beyond 2015 levels, which require additional adjustments outside of those performance adjustments made within the scenarios.

I-2.2. Assigning Economic Value to DR Performance

LBNL utilizes an interim economic analysis methodology that incorporates cost and benefit adjustments from the cost effectiveness protocols that are not already included in our model approach. This methodology provides economic potential values for demand response that meets flexible resource and ramping, contingency reserves, system and Local RA needs on the grid. The outputs of the analysis detail the influence of expected load-modifying demand response on RA and capacity needs and then determine what combinations of DR enabling technologies and targeted end uses can provide the Shift, Shape, Shed, and Shimmy service type DR as a cost effective supply side resource. The study adjusts the avoided costs in the model to account for external benefits as appropriate, based on the benefits and characteristics of each product and technology implementation.

The list below provides a high level overview of the economic potential analysis process, starting with the outputs of the supply curve analysis, which are summarized by an expected quantity of capacity credit (MW-year) available for each cluster at an expected cost level that includes the cost of administration, marketing, transactions, and site-level technology investment, and incentives as appropriate.

1. Identify cost and benefit categories that are external to the expected capacity value of DR, based on existing cost effectiveness protocols
2. Adjust the expected cost of each available DR resource at the cluster level, (e. g., avoided costs of energy, T&D avoided costs, etc.) for hour, month, and year per kW and MW (*Shed and Shimmy*), and MWh (*Shift*).
3. Adjust the expected cost for each DR resource (*Shape, Shift, Shed,* Shimmy) at the cluster level by the expected supply side market revenue streams, as described below in Table XX.
4. Adjust the expected quantity of DR available so capacity value is on the same basis as system-level generation (e. g., T&D losses, etc.)
5. Compare the resulting unit cost of DR ($/kW-year) to a price referent benchmark for long-run average capacity cost (e. g. , combustion turbine/capacity value).The DR that is available below this cost threshold is considered to be the "Economic Potential" DR for the given scenario.

Additional adjustments and valuation inputs for determining the benefits for each of the supply side markets products, (such as Ancillary Services, PDR, RDRR, flexible ramping), are required to appropriately estimate the value of DR in the sub-LAPs and IOU territories. The application, or exclusion, of the various cost-effectiveness protocols, (factors), and the values we used in the model are mapped in Table I-2 below. Appendix G provides details on the methodology of estimating the costs and value of DR within the DR-PATH model.

Table I-2: The 2015 C/E protocol factor mappings, explanations, and application of these factors for the valuation of DR supply curves and products.

Data used to estimate the Supply Curves & conduct Economic Valuation Analysis	Data Sources & Notes
Availability, dispatch trigger speed, and controllability of DR resource	These are implicitly calculated for each cluster & end-use in the model, based on a weighting function approach.
Avoided transmission capacity costs ($/kW-year)	2020 & 2025 values provided by NEM Public Tool. PG&E-$19. 39; SCE-$23. 34; SDG&E- $21. 34
Avoided distribution capacity costs ($/kW-year)	2020 & 2025 values from the NEM Public Tool. PG&E- $67. 70; SCE-$30. 10; SDG&E- $52. 24

Data used to estimate the Supply Curves & conduct Economic Valuation Analysis	Data Sources & Notes
T&D right time-right place adjustment [D Factor]	LBNL assumes that this factor is 100%, with no additional adder. LBNL does not have sufficient information about the needed investments in the IOUs service territories that would enable us to determine whether the locational DR sufficiently defers T&D investments.
Avoided energy and ancillary services' cost ($/kWh-year) by each Sub-LAP	Avoided energy & ancillary services costs based on expected hourly dispatch for DR. Hourly avoided costs are estimated based on results from a production cost model simulating the CAISO grid for Long-Term Procurement Planning[82].
Payments &/or avoided costs for flexible capacity & other advanced DR products.[F Factor & similar]	There is currently no market for the Shift service type resource, and due to uncertainty in the expected prices and markets it is not calculated in this study. For the Shimmy Service Type , we applied market revenues from participation in the Ancillary Services market.
Geographic adjustment of capacity value for Sub-LAPs in local capacity constrained areas [G Factor]	Based on CPUC-provided factors from cost effectiveness protocols, by local capacity area: SDG&E-110%; SCE-for Local dispatch in Big Creek-Ventura or the L. A. Basin, the G Factor will be 105%; PG&E- 100%
System-level avoided cost of peak capacity ($/kW-year)	Avoided capacity costs & capabilities to model alternative price referents for sensitivity analysis & to benchmark the model against other scenarios for future avoided cost.2025 capacity costs is modeled at $143 /kW-yr data, as reported in the 2015 CE Protocols.* The 2014 California Net Energy Metering Public Tool reports the "Net CONE of a marginal capacity resource" as $175 kW/yr
Operational Planning Reserve Margin	Assumed to be 0%. Load forecast planning applies the 15% reserve margin prior to incorporating available DR resources, thus, DR resources are accounted for after the reserve margin has been applied.

[82] California Independent System Operator, 2015. Planning Assumptions Update and Scenarios for use in the CPUC Rulemaking R.13-12-010 (The 2014 Long-Term Procurement Plan Proceeding), and the CAISO 2015-16 Transmission Planning Process. Available at: http://www.cpuc.ca.gov/General.aspx?id=6617.

Data used to estimate the Supply Curves & conduct Economic Valuation Analysis	Data Sources & Notes
Avoided GHG costs	GHG price based on the expected future price in California markets. Added to energy prices ~$13/MWh
Avoided Line Losses	Line losses are assumed to be approximately 10%

I-2.3. Demand Response Valuation Price Referent

The final step in our economic analysis in setting a price referent in the supply curves to estimate the quantity of demand response that is cost competitive. DR that falls beneath the price referent line is considered cost competitive, as it can clear in the market at prices less than the all-in costs of a new CT generator, plus the capacity values for T&D, specific to each utility. The price referent is set at a value of $200/kW within this model, and is comprised of capacity values that were developed in collaboration with the CPUC staff. These values are developed from the recent public tools, including the 2014 California Net Energy Metering Public Tool, E3's avoided costs calculator, and the 2015 C/E protocols.

The price referent is developed by summing the following values:

- **System-level avoided cost of peak capacity ($/kW-year):** The model incorporates the 2025 capacity costs of $143 /kW-yr, as reported in the 2015 CE Protocol
- **Avoided distribution capacity costs ($/kW-year):** 2020 & 2025 values from the NEM Public Tool. For PG&E = $67. 70; For SCE = $30. 10; For SDG&E = $52. 24
- **Avoided transmission capacity costs ($/kW-year):** 2020 & 2025 values provided by NEM Public Tool. For PG&E = $19. 39; For SCE = $23. 34; For SDG&E = $21. 34

I-2.4. Incorporating the Cost Effectiveness Protocols

LBNL utilized and interim economic analysis methodology for the Phase one deliverable. This methodology provides the CPUC with economic potential values for the PDR, System RA, and Local RA DR products. The outputs of the analysis detail what combinations of DR enabling technologies and targeted end uses for each DR product are cost effective and capable of meeting grid needs at the bulk power system.

The Phase 1 deliverable focuses on the Total Resource Costs Test which include:

- Administrative and capital costs incurred by the LSE
- Participant costs (capital costs to participant + value of service lost + transaction costs)

- Increased supply costs, if any

The economic potential analysis employs hourly energy and avoided cost data. The methodology retains the application of the existing protocols, including the Factors A,B, D, E, F, G, however the manner in which they are applied differs from the cost calculator that has historically be used in the DR cost effectiveness tests. The manner in which the protocols and factors are applied is described below.

The A Factor: The A factor is address in the LBNL model by capturing the DR resource availability by evaluating each hour (8760) for availability. The DR product supply curve method captures: (1) if the end use is in use and available to participate in a DR event, (2) if the technology is able to reduce load per the requirements of the DR product, and (3) how much of the load can be reduced. The available load that can be reduced for each DR product is summed up for each hour. It is then multiplied by the hourly avoided energy and capacity costs. This factor is accounted for in the following equation:

Sum of Load Impacts for each end use in each hour (reduced by DR event) x sum of hourly avoided costs= total benefits.

For phase 1, we applied the costs and benefits hourly to the top 250 hours for each utility, thus approximating the hourly System RA needs.

The B Factor: Our model captures the ability of a resource to respond based on the enabling technology and the end use, which is captured in each product's 8760-hour supply curve. The requirements for each product (e.g. response time, notification, etc.) are built into the assumptions around controllability and availability of the resource when developing the supply curves. This factor is applied during the development of the 8760 for each DR product, which are developed based on the requirements for that DR product to participate in the market.

The C Factor: This factor was removed during recent modifications to the C/E protocols.

The D Factor: Represented as a factor that is computed by comparing the non-coincident peak for each IOU service territory to the coincident system peak using CEC system load forecasts. For DR that can address both system and T&D peaks, and can avoid or defer T&D investments the D factor can be greater than 100%.In as much, the valuation of these DR supply curves should capture the right time and right place for each DR product and grid need combination. LBNL will assume that this factor is 100%, with no additional adder. LBNL does not have sufficient information about the needed investments in the IOUs service territories that would enable us to determine whether the locational DR sufficiently defers T&D investments.

The E Factor: The LBNL model incorporates hourly avoided energy price data provided by each utility. LBNL incorporates this as an hourly avoided energy calculation where hourly load impacts are multiplied by the hourly energy prices. It is treated as a benefit that offsets the costs of providing DR in the market.

The F Factor: The F factor intends to makes adjustments to DR Portfolios in the form of payments &/or avoided costs for flexible capacity & other advanced DR products. In our research, we found that there is currently no market for the Shift service type resource, and due to uncertainty in the expected prices and markets, revenues for Shift service type resources are not calculated in this study. For the Shimmy Service Type , we applied market revenues from participation in the Ancillary Services market.

The G Factor: The D Factor accounts for those DR resources that can be called locally in the resource constrained regions. For each IOU Sub-LAP, each supply curve evaluates DR at that level, and therefore, considers the available DR resource within that geographic area, and it does assume the ability to trigger the resource with geographic specificity. LBNL's model uses the G-factor adder for augmenting local capacity value in areas where DR provides additional local benefit as described in protocol update. The factors are applied as the adders defined below:

Table I-3: G Factor Adder from 2015 CE Protocols

Utility	G Factor Adder from 2015 CE Protocols
SDG&E	110%
SCE	0% for DR programs that can only be dispatched in the entire service territory. For Local dispatch in Big Creek- Ventura or the L. A. Basin, the G Factor will be 105%.
PG&E	For PG&E, there is no adder for the G Factor. Thus the G Factor is 100%

We evaluate the economic value of Shape, Shift, Shed, and Shimmy by creating supply curves (8760) for each service type. These supply curves incorporate the above C/E factors and avoided costs, as specified above. The methodology for determining the economic potential for each DR Service Type is done by applying the avoided costs and the adjustment factors from the C/E protocols to each of the supply curves as hourly benefits. We then determines how much DR is available given a range of dollar values.

I-3. Economic Valuation

I-3.1. Cost Calculation Framework

The cost of DR represented in the results of this study is from a hypothetical DR aggregator's perspective. This aggregator carries the cost of technology installation and operation, program coordination and marketing, and customer incentive payments, while potentially receiving revenue from energy and ancillary services markets. The cost of DR therefore represents the "missing money", or the amount of money another party (e.g. a utility or service operator) would need to pay the aggregator to make procurement of DR resources economically viable. Program and technology cost assumptions are described in Appendix G, while market pricing and revenue estimates are described below.

I-3.2. DR Sources of Revenue

DR services are able to receive revenue by participating in CAISO wholesale markets, as described in Table I-4. In this study, Shed services participate in the energy market and receive Resource Adequacy (RA) capacity payments, while Shimmy services participate in the ancillary services market. Participation in other markets (including markets that do not yet exist), is possible but not quantified in this study. Such markets could include Reverse DR, where payments are given for taking additional energy from the grid, and Flexible Ramping capacity payments. Hourly prices for the energy and ancillary services markets quantified in the this study are obtained from a PLEXOS simulation run by CAISO based on the 2014 LTPP scenario (CPUC, 2013). We also consider low and high scenarios that capture ranges of available DR resources at various prices. These scenarios are generated by increasing the amplitude of the price signal, multiplying the existing signal by a constant value (1.1 for the high value scenario, and 0.9 for the low value scenario). In all three scenarios, we maintain the upper and lower price caps specified in CAISO's modeling assumptions.

Table I-4: CAISO markets considered for three DR service types. Checkmarks represent market revenue calculated in this study, while asterisks represent future potential sources of market revenue.

Service Type	Ancillary Services Market	Energy Market	Capacity & RA Payments	Flexible (Ramping) Capacity	Reverse DR (future)
Shed		✓	✓		
Shift	*	*	*	*	*
Shimmy	✓				

Results for this study are aggregated to annual values, and therefore assumptions must be made for the dispatch frequency and timing of DR resources. Methods used to calculate annual revenue are directly tied to those used to aggregate hourly DR availability into annual values. Shimmy and Shift services are assumed to be needed during all hours of the year, and therefore annual revenue is the sum of hourly availability multiplied by the hourly market price.

I-3.3. Co-Benefits of DR Technologies

For certain end-uses, the same technologies or device upgrades that enable DR (e.g. smart thermostats, building energy management systems (EMS) or lighting controls) produce other cost benefits by allowing a building to operate more efficiently (Goldman et al. 2010). These economic benefits are referred to in this study as "co-benefits", and are modeled as a percentage of enabling technology costs by which the upfront cost attributed to DR would be reduced. In practice, co-benefits could be realized through customer bill savings that come from DR-device-induced efficiency or energy efficiency (EE) incentives paid by a third party that help buy down the upfront cost of DR. Co-benefits are included in our study for the following end-uses: lighting (luminaire-level, zone level) controls, refrigerated warehouses, residential AC (smart thermostat), commercial HVAC (EMS), EV chargers, and batteries.

A previous study (Starr et al. 2014) showed co-benefits of implementing EE and DR measures together in a refrigeration system in the range of 25 - 40%, primarily from jointly completing the design, installation, commissioning, and incentives at the same time. However, in our study to be more conservative, we have assumed 33% co-benefits (average of 25 and 40%) for the end-uses that are considered (residential AC Smart Thermostats, Commercial HVAC with EMS, and refrigerated warehouses). Based on storage value streams collected from the Rocky

Mountain Institute, we have assumed a co-benefit of 50% for batteries, which in addition to savings from TOU price arbitrage and improved reliability locally (ie. keeping critical loads working with backup power), can also provide co-benefits when linked with rooftop solar PV. We have assumed co-benefits of 75% for lighting (luminaire and zonal), which has controls typically installed to receive energy savings benefits. Lastly, we have assumed that the co-benefits of PHEV and BEV charging are 75%.

For added fast DR technologies such as variable frequency drive pumps or motors for agriculture, wastewater pumping and wastewater process, we have assumed a co-benefit of 75% from energy savings .

Table I-5: Summary of DR Technology Co-Benefits. Co-Benefits reduce the cost of the technology by a defined fraction of the initial cost.

End-Use & DR-Enabling Tech	Initial DR Technology Cost Reduction from Co-Benefit	Potential sources of Co-benefits
Commercial & Residential HVAC (EMS & Smart Thermostat)	30%	Energy efficiency & kW reduction
Refrigerated Warehouses	30%	Energy efficiency & kW reduction
Batteries	50%	Consumption optimization, kW reduction, backup energy supply
Agricultural Pumps	75%	Energy efficiency, kW reduction & controllability
Wastewater Process and Pumping technologies	75%	Energy efficiency, kW reduction & controllability
Commercial & Residential BEV & PHEV Level 1 & 2 charging (Fleet & Public)	75%	Fast Charging & controllability
Lighting (Luminaire-level & Zonal)	75%	Energy efficiency & kW reduction

I-3.4. Modeling Value to Grid with RESOLVE

E3's Renewable Energy Solutions ("RESOLVE") Model is a power system operations and dispatch model that minimizes operational and investment costs over a defined time period. RESOLVE selects an optimal portfolio of renewable resources such as wind, solar or geothermal; conventional resources such as combined-cycle or simple-cycle natural gas generators; demand-side resource such as energy efficiency or demand response; and renewable integration "solutions" such as natural gas plant retrofits, flexible loads or energy storage. RESOLVE minimizes the sum of operating costs (fuel, O&M costs, and emissions), investment costs (the cost of developing new generation along with any associated transmission), and transmission wheeling costs over time. RESOLVE incorporates conventional power system constraints such as total delivered energy and generation resource adequacy, policy constraints such as renewables portfolio standards and greenhouse gas targets, scenario-specific constraints on the availability of specific resources, and operational constraints that are based on a linearized version of the classic zonal unit commitment problem.

RESOLVE has a particular strength in evaluating flexibility costs. Flexibility costs are driven by the increase in renewable resources and the policy directives for renewable energy targets. In a flexibility-constrained system, the consequence of insufficient operational flexibility is curtailment of renewable energy production during time periods in which the system becomes constrained[83]. In a jurisdiction with a binding renewable energy target, however, this curtailment may jeopardize the utility's ability to comply with the renewable energy target. In such a system, a utility may need to procure enough renewables to produce in excess of their energy target in anticipation of curtailment events, in order to ensure compliance with the RPS. This "renewable overbuild" carries with it additional costs to the system. In these systems, the value of an integration solution such as energy storage can be conceptualized as the renewable overbuild cost that can be avoided by using the solution to deliver a larger share of available renewable energy. Cost effectiveness for an integration solution under these conditions may be established when the avoided renewable overbuild cost exceeds the cost of the integration solution.

A number of geographic and temporal simplifications are made in order to achieve a reasonable model runtime while maintaining focus on key cost considerations:

- Investment decisions and operational dispatch are made in multi-year time increments: 2016, 2020, 2025, 2030
- 37 representative days are modeled in RESOLVE in each year. These 37 days with appropriate weights to be equivalent to full year are chosen to best represent a typical full year's load, renewables, hydro, net load conditions, as well as the annual monthly distribution of days.
- Investment decisions are made for the Balancing Authority Area operated by the California Independent System Operator ("CAISO"). Since Given the CAISO is

83 Olson, A., R. Jones, E. Hart and J. Hargreaves, "Renewable Curtailment as a Power System Flexibility Resource," The Electricity Journal, Volume 27, Issue 9, November 2014, pages 49-61

interconnected with other balancing areas, RESOLVE incorporates a geographically coarse representation of neighboring regions in the West (the Northwest, Southwest, and Los Angeles Department of Water and Power (LADWP)) in order to characterize and constrain flows into and out of the CAISO.

E3 developed RESOLVE cases for the CAISO area as part of the CAISO's studies of a regional market directed by Senate Bill 350 (SB 350).[84] E3 adapted these cases for this project by incorporating additional functionality to model flexible loads. Some key assumptions from these cases, such as carbon price forecasts and gas price forecasts, were developed for SB 350 work and remain in the model.

During this project, RESOLVE was augmented to model a variety of DR services defined by LBNL and E3. RESOLVE optimizes investment and dispatch of these services to reduce portfolio costs for meeting future renewable energy targets.

To quantify the value of DR to the CAISO system, E3 began with a Base Case that contained no DR, and allowed RESOLVE to minimize system costs over the 2016 – 2030 investment period. Then, DR was added to the system in increasing increments, and costs minimized over the same period. Any decrease in system costs was attributed to the added DR resource. For more information on RESOLVE, see Appendix H.

I-4. Distribution System Value of DR

For constrained feeders, value may be captured by DR technologies if the resources can be reliably dispatched and controlled to support distribution system operations. In the version of the model used for this report we *randomly assign* these "distribution system co-benefits" throughout IOU service territories as an illustrative case in the model results. Pilot studies have shown that distribution system DR value is highly concentrated and depends on feeder-level diversity.[85] Our assumptions are a synthesis of possible cases that mirrors early understanding of potential and are described in Table I-6 below.

[84] For more on SB-350, see https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

[85] *Nexant Study for NY, NV Energy filings & Woychick. 2015. "2030 Vision for 100% Clean Energy"*

Table I-6: Distribution System DR benefits assumption summary. Distribution System benefits were randomly assigned within the DR Futures model throughout the IOU service territories to model, at first order, the potential cost savings from avoiding distribution system infrastructure upgrades required from load growth.

Distribution system DR illustrative example assumptions	
Performance estimate	Equivalent to "conventional DR" shed in magnitude (limited by installed equip. capacity as well). Does not change propensity to adopt.
Mean Value	\$25/kW-year system-wide
Site-specific value assignment *(Modeled as truncated log-normal)*	▪ 50% of sites < \$1.50 /kW-y ▪ 75th percentile is \$20/kW-y ▪ Only top 5% of sites \$160-300

Research conducted by Eric Woychik in 2016 found that distribution system benefits, in particular, avoided distribution system upgrades required to support load growth in the distribution system, can be upwards of \$230/kW-year for heavily constrained areas.[86] For our analysis, we estimated that the values provided by Woychik could serve as a high bounds estimate for a probability distribution, where \$0/kW-yr is the minimum, and \$300/kW-yr is the maximum. Based on the CA IOU DRP hearings and research conducted by Nexant, we conservatively estimate that most feeders and sites within each IOU service territory do not have distribution deferral value; that is, most IOU distribution system feeders do not need to be upgraded due to load growth. For our analysis, we allocated distribution system savings to the various sites, with 50% of sites receiving distribution system benefits of less that \$1.50/kW-year. Five percent of the sites received benefit values of \$160-\$300/kW-year.

We used a truncated log-normal distribution for estimating the distribution of the values, where most values were zero, and a very few sites were given high values. These benefits were randomly assigned to sites with random clusters, so they do not match up to actual

[86] *Eric Woychik. August 2015. "2030 Vision for 100% Clean Energy" Presentation.*

constrained feeders in the system, but we believe that this is a good first order effort to estimate the value of distribution system benefits from DR resources, and it provides a glimpse into how the DR potential changes when accounting for Distribution benefits, assuming that DR can reduce the need for upgrades.

Below in Figure I-5 and Figure I-6, we provide graphics on the probability density and cumulative distribution of the Distribution system benefits. As is depicted, most sites have zero value assigned to them, and the long tail on Figure I-5 illustrates that very few sites have high values for the benefits.

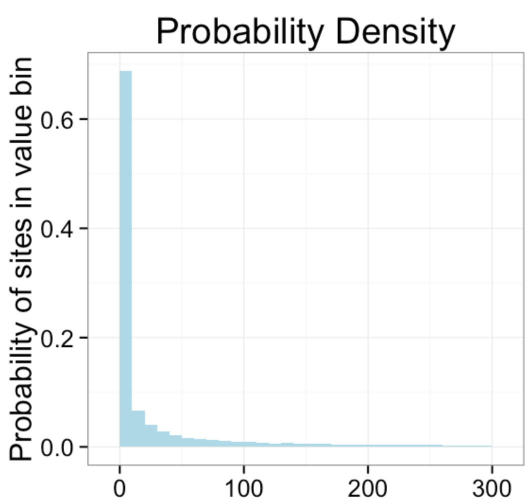

Figure I-5: Probability density of the distribution system benefits.

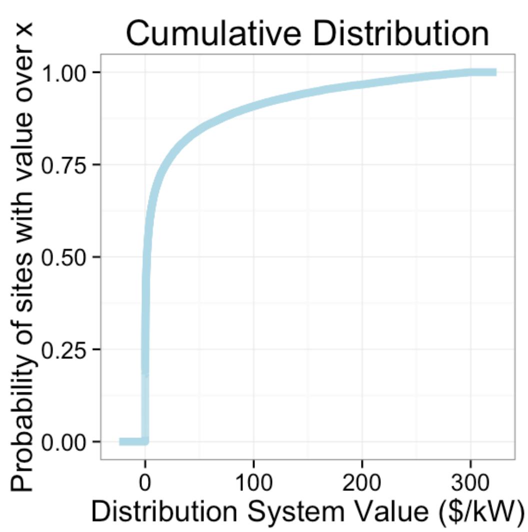

Figure I-6: Cumulative distribution of the distribution system benefits.

Appendix J: Technical Advisory Group (TAG)

Name	Party
Kenneth Abreau	PG&E
Fabienne Arnoud	PG&E
Rick Aslin	PG&E
Barbara Barkovich	CLECA
Serj Berelson	Opower
Eric Borden	TURN
Jennifer Chamberlin	Joint Parties
Fred Coito	DNV-GL
Paul DeMartini	Newport Consulting
Chris Ann Dickerson	DAWG
Kent Dunn	Comverge
James Fine	EDF
Debyani Ghosh	Navigant
John Goodin	CAISO
Marcel Hawiger	TURN
Don Hilla	CFC
Eric Huffaker	Olivine
David Hungerford	CEC
Mike Jaske	CEC
Xian (Cindy) Li	ORA
Mona Tierney Lloyd	EnerNOC
Alex Lopez	Opower
David Lowrey	Comverge
Carol Manson	SDG&E
Mark Martinez	SCE
Ali Miremadi	CAISO
Neda Oreizy	PG&E
Sam Piell	PG&E
Jill Powers	PG&E
Heather Sanders	SCE
Nora Sheriff	CLECA
Mike Ting	Itron
Greg Wikler	Navigant
Gil Wong	PG&E