Integrating Demand Response and Distributed Resources in Planning for Large-scale Renewable Energy Integration

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Abstract

The electricity grid is transitioning from a centralized and uncoordinated set of large generators and loads to a framework that also includes decentralized and coordinated "distributed energy resources" (DER). Advances in renewable generation, energy storage, efficiency, and controls technology present a significant opportunity for demand-side investment that is matched to the needs of the future grid infrastructure and operations, but the complex interplay of controls technology and grid operations makes estimating and realizing the potential of DER a significant challenge. Supply curves for conserved energy have long been used to synthesize energy efficiency opportunities for electricity system planners and show how demand side resources compete with building new power plants. We have developed a similar approach for supporting policymakers who now face a range of technology options for DER, with a focus on describing the potential for demand response (DR) to provide flexibility to the grid. We describe our modeling approach using supply curves for demand response across four key dimensions: reshaping with rates, shedding at critical time, shifting to capture renewables, and fast-response "shimmy" to balance the grid. In a California-focused study, we find a significant potential for DR to support the grid, and a need for integration between DR and energy efficiency. The combined efficiency benefits from a better-controlled and commissioned facility can lead to significant reductions in the cost of DR, increasing the quantity that is cost competitive by 5-200%. The benefit stream from DR can alternatively be framed to "buy down" the cost of EE investment.

Introduction

The rapid pace of solar and wind energy deployment is transforming the management and investment of the electric power system, which has significant implications for demand-side management (DSM) and the emerging technology category described as distributed energy resources (DER). There is a broad range of DER technology that could contribute to meeting renewables integration challenges, including energy efficiency (EE), demand response (DR), distributed generation, and distributed energy storage. In this work we describe a framework for assessing the potential of DER to support low cost and reliable electricity service in the context of power systems facing renewables integration challenges. We developed the framework in the context of the 2025 Demand Response Potential Study (LBNL 2017a), which supported a California Public Utilities Commission rulemaking (R.13-09-011) focused on "Enhancing the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements." The study was designed to bridge the analysis of DER with grid investment and operations and to communicate the results of the study clearly to policymakers and stakeholders in the power system who need to synthesize across those domains.

Our framework for analysis includes several key features: 1) a distributed energy resource potential model based on a large sample of SmartMeter load shapes that are synchronized with our modeling of grid dynamics; 2) distilling the capabilities of DER into four core functions: Shape, Shift, Shed, and Shimmy, which we describe below; and 3) designing our model for the potential and value of DER so the results can be expressed in terms of economic supply and demand curves that represent the long-run average cost and value of resources.

In this paper we describe the emerging challenges for grid management and the technology drivers for DER as background and context. Our modeling framework for DR potential incorporates those trends across timescales that range from years to minutes, and we describe the outcomes for California. The results suggest a range of policy and R&D responses are appropriate for capturing more of the value that is available to the grid from DER, and that an integrated approach between EE and DR could be critical for achieving the deep levels of deployment that are required for meeting climate and energy goals. A companion paper describes recent results on the effort to define the need and pathways for the Shift resource (Gallo et al. 2018).

Background

Grid integration of renewable electricity

Renewable energy deployment is accelerating; initially driven by the imperative to reduce global warming pollution, now the technology is cost competitive even without accounting for the climate externalities associated with fossil resources (Lazard 2017). Increasing the use of renewables are supported by policy interventions like renewable portfolio standards that specify minimum grid mix levels. California (the focus of this work) has a current RPS goal of 33% by 2020 and 50% by 2030, which was established in Senate Bill 350 (California State Senate 2015). The state is on pace, with 30% renewables by 2017 (CEC 2017). As states and regions continue to add renewable generation, there will be a range of approaches to reducing the cost of integrating new resources, including electricity transmission infrastructure, regional integration of grid management, and deployment of DER.

The renewables integration challenges for managing the California grid, with significant contributions from solar, are exemplified by the "duck curve" that is described by the California System Operator (CAISO 2016). Figure 1 (based on actual CAISO operational data) shows how in 2017 the predicted "duck curve" is already manifested and showing up in operations. There is steep downward and upward ramping to manage morning and evening transitions in the availability of solar generation, and periods of "oversupply" in which renewable resources are curtailed to maintain stability on the grid. Renewables have significantly reduced and delayed the evening peak load, and have introduced new, steep ramps (particularly in the evening). Throughout the day, additional solar and wind power adds to the short-run variability on the grid as well. From the period starting in 2014 through 2017, as renewable contributions to the grid have grown, the average 5-minute change in Net Load has increased by 28% (from an average magnitude of short-duration change of 102 MW to 131 MW over five-minute intervals[1]).

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[1] This outcome and others in this report related to CAISO operations between 2014 and 2017 are based on data obtained from the CAISO website in March 2018. http://www.caiso.com/informed/Pages/ManagingOversupply.aspx

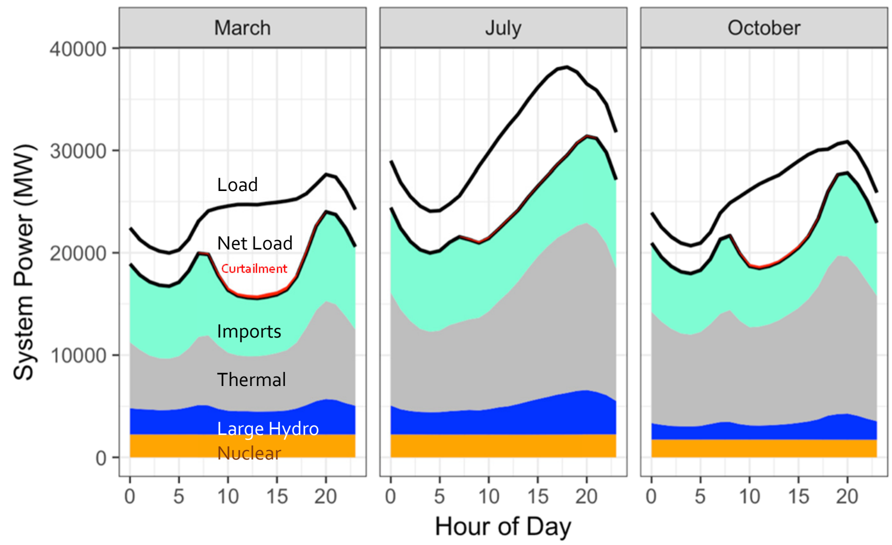

Figure 1: California ISO operations for three months in 2017 showing the daily profile for the average of all days in the month, including generation contributions from nuclear, large hydroelectricity, in-state thermal, and imports. Load and net load (load minus renewables) are shown as well, with curtailment of renewable generation is shown in red, layered next to net load. Data from: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx

Maintaining stability and security on the power system requires careful operation of resources, which can lead to situations where there is more renewable supply available than the load remaining after must-run generation resources that are needed online. One operational strategy for managing "excess" renewable generation on the grid is curtailment (highlighted in red in Figure 1). These renewable curtailment events totaled 400 GWh in 2017, which represents 0.2% of renewable generation for the year. Ultimately, curtailment makes it more expensive to meet RPS targets, since more renewable generation capacity needs to be installed to make up the difference. The relatively modest level of curtailment in 2017 is approximately equal to what is expected given the California's progress on RPS of 30% -- a technical report that estimated curtailment in 2024 reported an estimate of 0.1% curtailment with a 33% RPS (Nelson and Wisland 2015). The same report estimated that at a 50% RPS the curtailment could rise to 5% of the overall renewable generation, representing a significant challenge and opportunity to manage loads and capture the energy that would otherwise be curtailed.

Distributed Energy Resources

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

A core driver for DER is advances in information and communication technology (ICT). Both computational cost and efficiency and levels of connectivity have rapidly expanded over the past decades (Koomey et al. 2011). Combined with the widespread deployment of SmartMeters, including nearly 100% coverage in California (Cooper 2016), the spread of connectivity and computational applications for DER influences a range of technology. Connectivity and optimized control of systems is enabling new applications for DR, which relied previously on FM and cellular dispatch systems. Figure 2 shows how DR fundamentally is a coordination process between the grid and building or device-level control systems. The estimated investment required and performance capabilities of dispatch communication technology, local control, and telemetry were a core focus of our modeling work. ICT advances mean that the dispatch of DR can be targeted to the device level over the internet, the local control can be informed by adaptive and model-based control strategies, and telemetry and settlement is backed by high resolution meter data. Beyond DR, the ability to target energy efficiency investments based on load shapes, and to identify customer sites that are promising for DER, also follow from the same ICT advances. Energy efficiency has transformed in recent years from a focus on bulk energy savings through equipment efficiency improvement to a holistic approach that also includes building commissioning and controls upgrades, time-dependent value of savings, and monitoring-based approaches. Commissioning has the potential for 10's of billions of dollars in energy savings nationwide (Mills 2011).

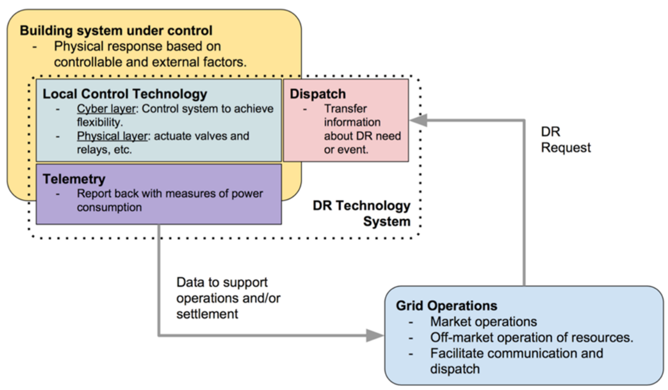

Figure 2: Interactions between building energy systems and grid operations. The dotted line area outlines the focus of our cost and performance modeling efforts

There are also new technology in deployment and development that could reshape the DER landscape: electric vehicles, electrified heating, and distributed solar and storage. A mass deployment of electrified heating and transportation is both necessary to meet climate stabilization goals (Williams et al. 2012) and will require significant upgrades to electricity systems and introduce new management challenges that could be facilitated with demand responsive features. While distributed solar generation has been cost-competitive and scaling up for several years, distributed storage is only emerging. As the cost of storage drops, deployment both in "front" and "behind" customer meters could in principle add a significant new resource base for flexibility in the timing of demand on the grid along with providing fast-response ancillary services that stabilize operations.

Energy Modeling to Inform Public Policy

It has long been a challenge to synthesize the opportunities in the electricity sector for informing public policy related to technology deployment in the face of tradeoffs between alternative options for providing service. The vast scale of the power system, and the need for specialized expertise to understand varied components from generation to T&D to loads and buildings, demands an analytic approach that synthesizes the key features in each area for informing development. A key innovation in energy analysis for distributed resources has been the concept of supply curves for conserved energy that were originally developed in the context of energy efficiency (Rosenfeld et al. 1993). These "EE supply curves" clearly show a range of costs and benefits and enable comparison to competing alternatives; they inspired our framework for DR.

Demand Response Analysis Framework

The goal of the 2025 DR Potential Study for the CPUC was to synthesize the trends in grid management needs with emerging opportunities for DR and estimate the potential with results that are actionable for policy development and technology deployment. A core challenge we identified was the fragmented framework for describing and modeling the capabilities of load control and grid operations. In response we developed a new framework for classifying DR approaches into four broad categories: *Shape, Shift, Shed, and Shimmy*. These provide a conceptual bridge between the emerging needs on the grid and discrete capabilities of DR technology systems that is tractable to include in both demand-side and grid modeling. Supply curves for DR service along these dimensions can inform grid planning and enable comparison to alternative investments. Table 1 lists the details of what service products fit conceptually in each category, and the names of markets, incentives, or revenue opportunities that are relevant in the California context. Other ISO/RTO regions and balancing areas have different market structures in place.

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

<table>
<tr><th>Category</th><th>DR Service Product</th><th>California Market Name</th></tr>
<tr><td rowspan="6">Shed</td><td>Peak Capacity</td><td>System and Local RA Credit</td></tr>
<tr><td>Economic DR</td><td>Economic DR / Proxy Demand Resource</td></tr>
<tr><td>Contingency Reserve</td><td>AS- spinning</td></tr>
<tr><td>Contingency Reserve</td><td>AS- non-spin reserves</td></tr>
<tr><td>Emergency DR</td><td>Emergency DR / Reliability DR Resource</td></tr>
<tr><td>DR for Distribution System</td><td>Distribution</td></tr>
<tr><td rowspan="3">Shift</td><td>Economic DR</td><td>Combination of Energy Market Participation</td></tr>
<tr><td>Flexible Ramping Capacity*</td><td>Flexible RA -- energy market participation w/ ramping response availability</td></tr>
<tr><td>Peak Capacity *</td><td>System and Local RA Credit</td></tr>
<tr><td rowspan="2">Shimmy</td><td>Load Following</td><td>Flexible Ramping Product / Real time market (similar)</td></tr>
<tr><td>Regulating Reserve Capacity</td><td>AS- Regulation</td></tr>
<tr><td rowspan="3">Shape</td><td>Responsive Behavioral DR - Event-based</td><td>Critical Peak Pricing (CPP)</td></tr>
<tr><td>Load shaping DR - Load shaping</td><td>Time of Use Pricing (TOU)</td></tr>
<tr><td>Load shaping with EE*</td><td>EE Time Dependent Value</td></tr>
</table>

The categories of DR service in Figure 3 illustrate how DR spans timescales from years to seconds. Starting at the long end of the time scale, we define *Shape* as long-term response to electricity rates and other incentives to change the timing of load, or reduce peak loads. Reshaping the load in the face of time-of-use rates is a fundamental element to matching loads with the typical patterns of generation on the grid and emerging surplus of renewable electricity in the mid-day period, and reducing the need for peak capacity. *Shift* is a service-neutral change in the timing of hour-to-hour energy use, in response to daily changes in the patterns of availability of renewable generation. A core goal of shifting energy is to avoid renewables curtailment and alleviate ramping from diurnal patterns in solar generation. *Shed* describes DR that curtails energy service in response to critical peak conditions on the grid. Reliably reducing loads at peak times can avoid or delay the need capacity investments in generation or T&D, and has been the core goal of conventional and existing DR programs. Finally, *Shimmy* is a category of DR that involves fast changes to loads for balancing the grid --- in the study we modeled two timescales: 15-minute “load following” responses and 4-second “frequency regulation” responses. Frequency regulation is a current ancillary service provided by generators and fast DR, and load following service is not explicitly implemented in California but is elsewhere, and in principle is similar to real-time energy market dispatch.

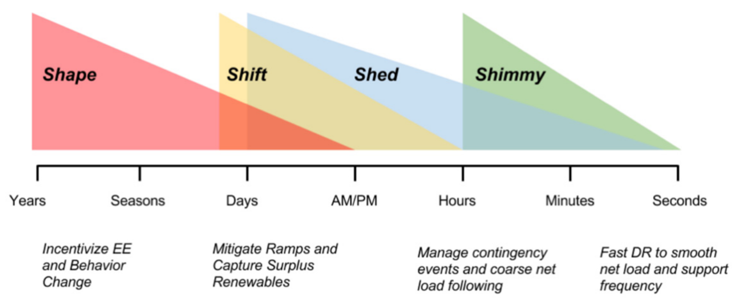

Figure 3: Dimensions of DR Service

Modeling Approach

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

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

Our end-use load shapes were developed using ~220,000 annual hourly sitewide load shapes from customers across California as a basis for capturing the timing and spatial variation of DR availability. We developed a model called "LBNL-LOAD" (LBNL 2017a) to develop a set of representative end-use load shape forecasts with estimated disaggregation in key end-use categories and forecasted consumption linked with scenarios in the CEC Integrated Energy Policy Report for 2020 and 2025. The data are aggregated into ~3,500 clusters that each represent typical loads for a customer class, in a geographic region, with similar demographic characteristics. These clusters were developed based on basic demographic information from all ~11 million customers of the major investor-owned utilities (Pacific Gas and Electric, Southern California Edison, and San Deigo Gas and Electric) and designed to be representative of the diversity in statewide demand.

The technology model we built includes estimates for the cost and capabilities of over 100 possible DR measures that each apply to a specific sector and end-use (with the scope described in Table 3). The model includes information about the response time, magnitude of load flexibility, and required investment and operations costs for different combinations of dispatch, local control, and telemetry options. Our customer adoption model was developed by a team from Nexant consulting and results in estimates of the fraction of customers in various sectors who will adopt DR technology in the face of different incentive or benefit levels and marketing approaches; it was calibrated based on historical participation in DR programs. We synthesize the techno-economic potential using the "DR-PATH" model (LBNL 2017a), which combines the technology inventory and customer adoption propensity models with the clustered load shapes to estimate the available resource at a range of cost levels, for each of the core DR services, developing supply curves that represent the long-run average cost of providing various quantities of each service. Because the clusters are geographically specific, it is possible as well to estimate the DR resource potential for local planning areas where different needs and constraints on the transmission and distribution system, and the presence of local renewable generation, could result in different values of the service.

Table 3: End uses and enabling technology included in these results.

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

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

Interpreting Modeling Results

Figure 6 shows two methodological options for how the supply curves we develop are compared with estimates of the value of the resource to the power system to estimate a cost effective resource quantity: a price referent approach (the standard for capacity payments to DR Shed resources), and an approach based on a demand curve for the DR service that has diminishing returns to additional DR capacity.

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

2) In an alternative "**system levelized value** approach" we use a grid planning and operations model (RESOLVE, developed and implemented by E3 (E3 2018)) to estimate the additional value to the grid of various quantities of DR resource. The result is a set of estimates for the long-run average ("levelized") reductions in the cost of building and operating the power system across a range of capacity levels for DR that is analogous to a demand curve. Assuming the model structure is accurate and given the input assumptions, these demand curves can be compared to supply curves to estimate an economically cost effective quantity and price of DR at the intersection. Additional methodological details and assumptions for our study are in the reports and supporting documentation we developed for the CPUC (LBNL 2017a). In the sections below we describe the results and interpret the opportunities that are suggested for integration of DR, EE, and distributed energy in general as renewables ramp up.

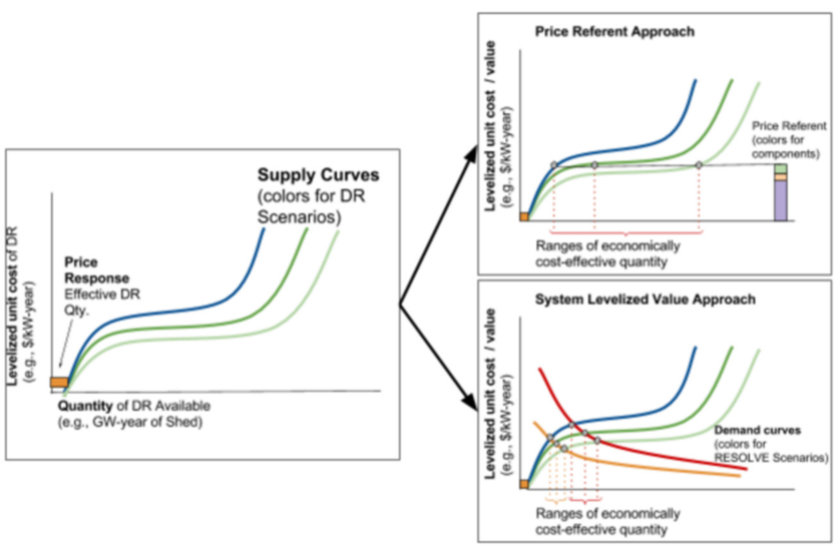

Figure 6: Methods for assessing supply curves for DR in the context of different valuation approaches.

California Demand Response Potential

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

Shape

Our estimates of load reshaping through TOU and CPP prices was based on a range of residential prices that were proposed for the 2019 TOU rate design cycle, and have an evening peak period with lower prices in the middle of the day. The commercial and industrial TOU rates were based on existing estimates of response (Christensen and Associates 2015). We estimate these prospective near-term rates will result in reductions in the peak load equivalent to approximately 1 GW (~2% of the overall peak), and result in ~2 GWh of shifted load per day through changes in behavior and schedule (~0.5% of volumetric energy demand), assuming the response is similar to past TOU rates. These Shed and Shift outcomes that can be achieved with a Shape pathway – at essentially zero cost since the rates are constructed to be revenue neutral – represent an important and foundational element of DR futures.

Shift

We found there is a significant emerging opportunity to support the grid with DR through frequent Shifts to capture renewable generation that would otherwise be curtailed. Unsurprisingly in retrospect, the ideal Shift dispatch profile resembles the opposite of the duck curve --- shifting load from the evening peak time to mid-day when renewables may be curtailed, and night-time and morning shifts depending on the conditions of the wind power resource. These shifts create value for the system by avoiding curtailment and thus reducing the cost of RPS compliance since fewer additional solar and wind projects are required to compensate for curtailment. There are also reductions in the ramps between low and high demand times, reducing ramping pressure on the generation fleet and relaxing the constraints on dispatch, which can also result in lower system operating costs and further reduced curtailment.

There were two scenarios included to estimate the value of Shift (and the other categories we modeled) to the grid using the RESOLVE model: the "High Curtailment Case" represents a future with policy and technology deployment assumptions that result in the high end of plausible curtailment levels, and the "Low Curtailment Case" represents one where other non-DR renewables integration reforms have reduced curtailment. These were designed to be bookend cases; the future activities and deployment of integration strategies is uncertain. Figure 7 shows both demand curves in the context of Shift supply curves for a range of scenarios. The light blue and blue represent a 2015 technology baseline, and business-as-usual progress respectively. The green supply curves represent a "medium" and "high" case for advances in the cost and performance of DR technology[2]. Overall, there is 10-20 GWh of cost effective Shift

[2] Details on the assumptions for the scenarios we defined are in the DR Potential Study (LBNL 2017a)

resource (equivalent to 2-5% of the daily load Shifted through load control). The technology included in the cost-effective Shift resource was predominantly based on load shifting of commercial HVAC, industrial processes, and water pumping. Based on the estimated savings from avoided investment and operations costs, we expect the value of this prospective Shift resource to the power system is $200-500 million annually.

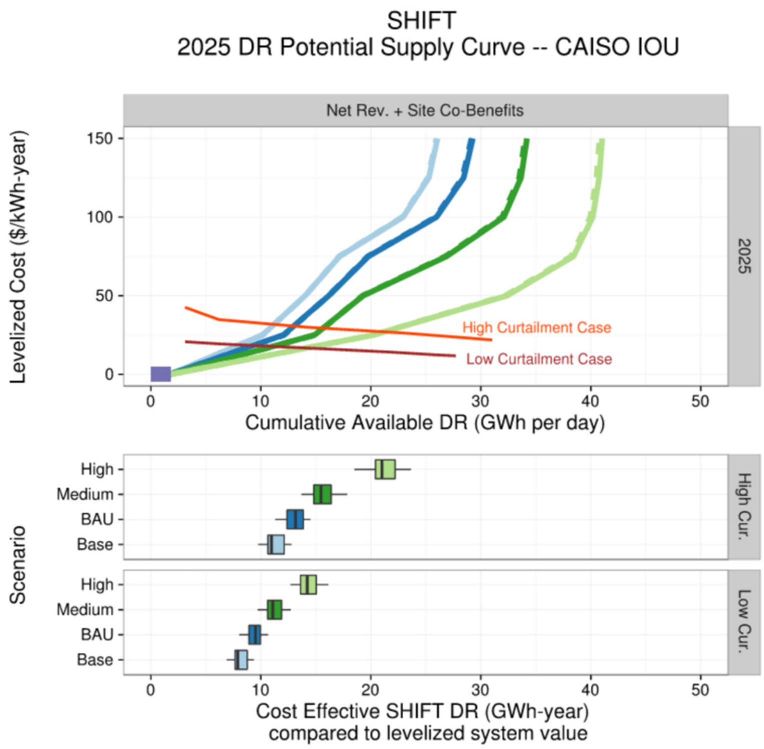

Figure 7: 2025 Shift supply and demand curves for four supply scenarios and two demand scenarios (upper panel), and box plots showing the range of outcomes for the scenarios, with uncertainty based on a Monte Carlo analysis that varied the cost and performance estimates for DR technology (lower panel).

Shed

Conventional DR programs have focused on peak load Shed and we found that there is a significant role these resources in the future, but that capturing the value will require a change in approach. The DR programs circa 2017 in our study area totaled ~2 GW of Shed capacity, and are structured primarily to meet *system-wide* peak capacity needs and local needs in transmission-constrained areas. Because of the significant additions of renewables to the CA grid, the overall system net load peak is below what was planned for. Based on background research by E3 that supported our study there is now excess thermal capacity in the state and low probability that new plants will be needed until well after 2025. Thus there is no capacity expansion to avoid and system-wide value for Shed is very low based on the assumptions and structure of our model for the next decade of California grid capacity expansion and operations.

However, there are significant areas where Shed does add value at the local level, and our study suggests that the overall Shed resource should grow compared to the status quo. About half of the Shed capacity we estimate in the model is in areas where local constraints are still binding and a need for peak load reduction; our estimate is that there is between 2-7 GW of Shed in these constrained areas, with the wide range based on a plausible range of assumptions for future market and technology trajectories (LBNL 2017b). Furthermore, there may be significant Shed needs to serve distribution system needs (up to 5-10 GW depending on uncertain future frameworks for valuing and operating distribution-level Shed DR), and value for reliability in system emergencies and contingency events. Overall, our analysis indicates a steady and growing need for the Shed resource, but focused on local needs and contingency events rather than system-wide peaks. Figure 7 shows the mix of technology we modeled and how combinations of technology lead to a supply curve for the Shed resource. The value of Shed depends on the location and local needs; at a conventional value ranging from $50-100 /kW-year, the value of the annual resource could be between $100-700 million.

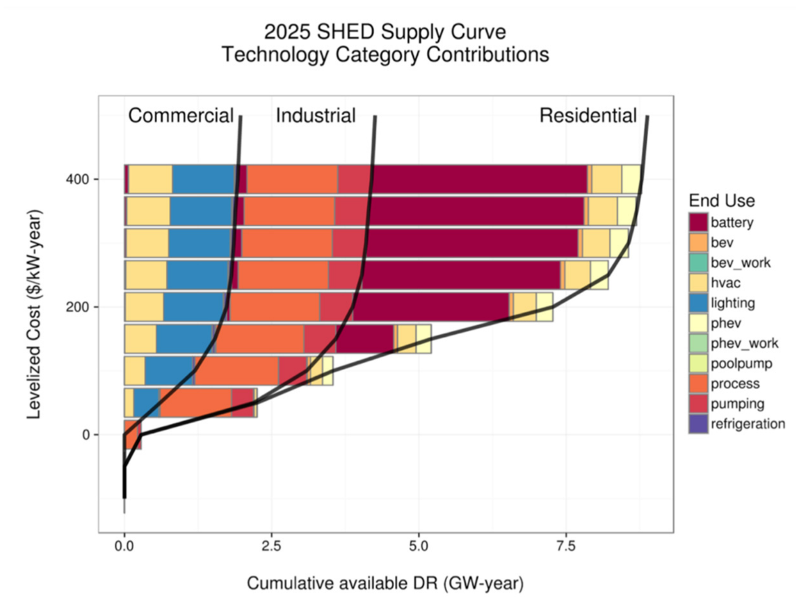

Figure 7: Technology contributions to the 2025 Shed supply curve

Shimmy

The two pathways for Shimmy we modeled have different timescales – 15-minute load following and 4-second frequency regulation – but for both we estimate approximately 300 MW of potential for load to stabilize the grid with bidirectional, fast response. The estimated value of these grid services is $25 million per year, and the markets for Shimmy are “thin” compared to Shift and Shed (i.e., there are steep downward slopes in the demand curve, with significantly diminishing returns to additional resources after the needs for Shimmy are met).

The specific pathway to creating system wide value for Shimmy was interestingly related to freeing batteries from the need to provide Shimmy, and enabling them to increase Shift and avoid curtailment. This dynamic where the value of Shimmy is related to opportunity costs in other services is similar to the conventional description of price formation for frequency response, where the price for the ancillary service is directly related to the opportunity cost of lost revenue in the energy market (and thus is tied to energy market prices). Our result reinforces the concept that fast-response Shimmy is a secondary service where the value will be related to opportunity costs in serving load with energy, or (new to the operational paradigm) shifting energy.

Distributed Energy Pathways to 100% Renewables

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

Where and when matters for energy demand

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

A new compact with customers

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

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

The Battery Cost Wild Card

Behind the meter storage can, in principle, make any load demand responsive across the dimensions of Shed, Shift, and Shimmy with appropriate control. In our study, the forecasted cost of batteries dedicated to DR was sufficiently high that they were just at the boundary of economic cost effectiveness. However, as distributed batteries are deployed to serve multiple value streams including managing site-level bills (essentially serving as a "Shape" resource), increasing the reliability and resilience for critical loads, and serving the needs of the distribution system there may be opportunities to reduce the effective cost of providing DR through multi-use applications. Furthermore, our assumptions about the costs and scale of batteries is highly uncertain, and if batteries get cheaper faster than our forecast they could outcompete and significantly grow the DR resource we identify, particularly for Shift but also for Shed and Shimmy. Given the historical trend of "conservative" forecasts that under estimate the improvements in clean energy technology (Gilbert and Sovacool 2016) and emerging evidence that battery costs and performance are improving more quickly than conventional forecasts on a trajectory towards $100/kWh (Kittner, Lill, and Kammen 2017). At these low price points, assuming a ~5 year battery lifetime, the levelized cost of Shift from batteries could be $20/kWh-year, providing Shift (and other DR services) at lower cost than most of the projections we made for load control. Since batteries scale across sites and can be installed in large capacity at substations, the levelized cost of storage will serve as a kind of price reference ceiling for DER in the future (similar to the concept of a capacity price referent tied to the construction of a new combined cycle natural gas plant). Load control and new generation capacity alike will need to beat the cost of storage to compete.

Integrating EE and DR

In our study we treated potential "co-benefits" from implementing EE and DR together as a reduction in the expected cost of implementing a DR project, since the benefits from EE can help to defray a portion of the initial investment in equipment and controls setup that dominate the cost of many DR resources. Based on our findings, the savings result in a growth in DR potential of 5-200% depending on the scenario and DR category. The low end of the range is Shift DR, where there is a large resource that is already cost effective for DR-only implementation, and the additional savings from EE do not significantly increase the resource. The high end is for Shimmy applications where there are particular benefits to a portfolio approach. Our project confirms there is a compelling case for integrating EE and DR to achieve cost savings in implementation, but in practice there are significant challenges related to administrative and implementation requirements to jointly-executed projects (Starr, Preciado, and Morgan 2014; National Action Plan for Energy Efficiency 2010). What could integrated EE and DR look like?

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

Beyond load shaping, there could be significant benefits to DR and EE in integrating deployment where there are opportunities to leverage fixed costs of a project (like engineering, controls hardware, monitoring and evaluation, metering, etc.) to serve both needs. This effectively reduces the cost of DR, as was the framing in our study, but could similarly be framed as EE costs being reduced through capturing benefits and revenue from DR market and program participation. In the California context the most recent EE potential study estimated that behavioral, retro-commissioning, and operational EE has a market potential of 600-1000 GWh/year by 2030, or 20-30% of the EE resource (Navigant 2017). The associated controls upgrades required for these approaches to EE could be used for DR as well in many cases.

Policy pathways to unlock DER potential

The features of our results that are useful for guiding deployment of DER for supporting renewables integration include the following:

- Understanding and modeling the interaction between DER and grid operations and investment is a significant challenge, as is communicating the results of the analysis. The simplified framework for DR we developed helped facilitate and accelerate conversations in contexts ranging from stakeholder meetings to modeling team discussions, and shows potential to serve a role in facilitating integration between DR and other DER.
- Integration between EE and DR is important for reducing the costs of deployment for both.
- Policy interventions should be crafted with the pathway to value for DR resources in mind, and a particular focus on the certainty required from resources. Shed has value based on long-run avoided capacity through infrequent dispatch, Shift resources derive value from repeated and frequent dispatch that results in operational savings and avoided curtailment of low-cost renewables, and Shimmy from providing grid balancing service that frees other resources to serve higher value needs. This suggests that it is appropriate to ensure that Shed and Shimmy resources are highly reliable given their role in system reliability, but the day-to-day precision of dispatch could be less important for Shift.
- The cost and performance of storage is a critical factor for determining the cost effectiveness of load control, and serves as a kind of price referent.

- A core challenge is to create business model pathways for DR aggregators serving multiple applications (including broader EE, distributed storage, and PV) to reduce the fatigue and transactions costs to customers for unlocking the potential from integrated DER deployment. The relationship between customers, aggregators, load serving entities (LSEs), and the system operator needs careful design to align incentives and value streams for DER.

Further research related to this project is continuing in 2018. A diverse stakeholder working group (the "Load Shift Working Group" convened by the CPUC) is considering new approaches to develop Shift resources in California. This includes looking at seasonal shift needs, baseline issues, and market integration opportunities.

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