Demand Response Advanced Controls Framework and Assessment of Enabling Technology Costs

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Glossary of Terms

Aggregator: An intermediary between an energy supplier and its customers, providing the utility with demand response by spreading the request among multiple consumers. Also referred to as Aggregators of Retail Customers (ARCs).

Ancillary Services: Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (From FERC order 888-A.)

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.

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.

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").

Configurable DR Opportunities: Programs that provide a utility or ARC with the ability to control the electricity consumption of one or more customer devices for a specified period of time but the customer can configure the control technology to override the DR signals that are received under certain conditions.

Controllable DR Opportunities: Programs that provide a utility or ARC with the opportunity to directly control (via radio, internet, telemetry or other remote means) various customers' electricity consuming end-uses (e.g., electric water heaters, pool pumps) or some portions of their load which could be increased, decreased or even physically disconnected from the grid with little to no notice.

Critical Peak Pricing (CPP): Rates that institute a single or variable predetermined price for electricity during a narrowly defined period (e.g., summer weekday between 4 PM and 7 PM) that is only applied during specific system operating or market conditions and generally limited in the number of times it can be dispatched (e.g. twelve times per year).

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).

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.

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 the total 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.

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.

Internet of Things (IoT): The inter-networking of physical devices, vehicles (also referred to as "connected devices" and "smart devices"), buildings, and other items embedded with electronics, software, sensors, actuators, and network connectivity which enable these objects to collect and exchange data over a network without requiring human-to-human or human-to-computer interaction .

Open Automated Demand Response (OpenADR): An open and interoperable information exchange model and communication standard. OpenADR standardizes the message format used for ADR controls, gateways, and energy management systems to enable standardized communication of price and DR signals between customer facilities and utilities, Independent System Operators (ISOs), or Energy Service Providers.

Regulating Reserves: An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

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).

Shed DR Service: A reduction in load that provides relief to the grid during times of contingency reliability constraints or emergency events. This service includes conventional DR products as well as the load reduction that is realized through various forms of time-based pricing.

Shift DR Service: An energy-neutral movement of load which can be provided by DR resources dispatched to increase hourly energy consumption at certain points in the day and decrease consumption during alternative hours of the same day - effectively rearranging the load.

Shimmy DR 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. This service can be provided by DR Resources on either a 5-minute or 4-second dispatch signal,

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.

Variable Peak Pricing (VPP): A hybrid of time-of-use and real-time pricing where the different periods for pricing are defined in advance (e.g., on-peak=4 hours for summer weekday afternoon; off-peak= all other hours in the summer months), but the effective price for the on-peak period varies by market conditions and prices.

1 Introduction

Demand response (DR) technologies have long been considered a valuable resource for providing capacity services to the bulk power system during system peaks or contingency events. Over the last several years, DR technology advancements have expanded the services that DR can provide to the grid. Automated Demand Response (ADR) technology advancements have facilitated the control and response capabilities through embedded logic and smart algorithms in the controls, which enable automated response within seconds or minutes with virtually no human interaction. This advancement has created opportunities to control -end-use loads for services other than only capacity, including fast and flexible response services, such as ancillary services (AS) or regulation reserves.

A growing body of research assesses DR opportunities and the bulk power systems services that these resources can provide. Most of that research focuses on evaluation, measurement and verification (EM&V) of specific DR technology performance (e.g., Sullivan et al., 2013; Cook et al., 2014), but little of the work provides cost data for the DR enabling technologies. Other studies have examined the DR opportunities for specific industries, such as ADR applications in agricultural pump loads or wastewater treatment and pumping (e.g., Olsen et al., 2012; Olsen et al., 2015), data centers (e.g., Ghatikar et al., 2012), or have provided a performance assessment of a generalized group of commercial facilities (e.g., Kim et al., 2013). However, these more industry-focused studies likewise do not provide cost estimates for the DR enabling technologies.

The research and data on DR enabling technology costs does exist in the literature, but is largely disparate and not comprehensive. Research conducted by Piette et al. (2015) evaluated cost data from approximately 50 ADR systems installed in large commercial and industrial facilities over the last decade. Kiliccote et al. (2014) and Lanzisera et al. (2015) examined the ADR enablement costs and performance of small customer loads and -end-uses that could provide fast DR services. Alstone et al. (2017) is one of the few pieces of research that sought to comprehensively report on enablement costs of DR technologies that can provide various bulk power system services. However, that research was specific to California.

Leveraging this prior research, we evaluate, organize, and summarize in this study the enablement costs at a more national level for a significant number of end-use technologies by end-use and customer sector, the various bulk power system services that each specific technology and end-use can provide, and the total costs to enable a site with the end-use DR technologies. The goal is to provide a robust dataset and discussion of DR technology enablement costs, the technical elements that drive those costs, and the technical characteristics for providing DR services to the bulk power system.

This report supplements the Demand Response Advanced Controls Database and User Manual, and is intended to provide a comprehensive discussion of each enabling technology and their capacity to provide various services to the bulk power system. We begin with a description of the DR opportunities and the various bulk power system services they can provide in Chapter 2. We map the various bulk power system services to a generalized taxonomy of DR "service types", which allows us to discuss DR Opportunities and bulk power system services in fewer yet broader categories that share similar technological requirements which mainly drive DR enablement costs. In Chapter 3, we introduce the various DR enabling technologies and end-uses, while we also identify the various services that they can provide to the grid. In Chapter 4, we provide a description of the various elements that drive enablement costs. In Chapter 5 we provide the cost assessment for each enabling technology.

2 Intersection of Demand Response Opportunities & Bulk Power System Services

Bulk power system services are essential for maintaining reliability, resilience and power quality on the electricity grid. Bulk power system operators must manage their electric systems under tariffs and rules sanctioned by the Federal Energy Regulatory Commission (FERC) and regional reliability councils. State and local regulators determine the reliability requirements for their corresponding region, but those requirements must stem from the enforceable standards set by North American Electric Reliability Corporation (NERC).

These reliability requirements, tariffs and rules also help determine the types of resources that may provide such services to the bulk power system. While the vast majority of bulk power system services have historically been provided by conventional thermal or hydroelectric generating resources, DR has proven to be, over the past 15 years or so, a valued and effective resource capable of supplying a variety of services in organized wholesale markets across the US (e.g., Kirby and Kueck, 2003; Kiliccote et al., 2009; Todd et al., 2009; Eto et al., 2012). Acceptance of DR resources as comparable to generating resources varies by region and market (Hurley et al., 2013).

In the rest of this chapter we will describe the current DR opportunities and how they intersect with bulk power system services currently offered by Independent System Operators and/or Regional Transmission Organizations (ISO/RTO) in the United States.[1] First, in Section 2.1 we identify and describe the current designs of DR opportunities sponsored by electric utilities and/or offered by aggregators of retail customers (ARC). We then narrow the scope of our discussion to the dispatchable DR resources that require some form of enabling control technology. Section 2.2 provides a high level discussion of the current bulk power system requirements for providing DR services in order to identify how the various dispatchable DR Opportunities intersect. Finally, in Section 2.3, we introduce a simplified taxonomy that collapses the myriad DR Opportunities and the bulk power services they can provide into a set of DR Service Types.

[1] We focus herein on organized wholesale markets in ISO/RTOs, but the typology developed is still applicable to vertically integrated utilities who are their own balancing authority.

2.1 Demand Response Opportunities

The current portfolio of DR opportunities can be separated into time-based rates and incentive-based programs (see Table 1 and Table 2).

Table 1: Current Time-Based Rates DR Opportunities

Time-Based Retail Rates
Time-of-Use (TOU)
Critical Peak Pricing (CPP)
Variable Peak Pricing (VPP)
Real-Time Pricing (RTP)

Adapted from Cappers et al. (2016).

For time-based retail rates, the electric utility alters the price level charged to retail customers for electric commodity purchases in order to elicit a change in electricity consumption. At present, there are four general types of time-based rates:

- *Time of use pricing* (TOU) rates provide different but predetermined prices over specific temporal periods (e.g., summer weekdays between 4 PM and 9 PM).
- *Critical peak pricing* (CPP) rates institute a single or variable predetermined price for electricity during a narrowly defined period (e.g., summer weekday between 4 PM and 7 PM) that is only applied during specific system operating or market conditions and generally limited in the number of times it can be dispatched (e.g. twelve times per year).
- *Variable peak pricing* (VPP) rates provide different prices over specific temporal periods (e.g., summer weekdays between 4 PM and 9 PM) that vary daily based on system operating and/or market conditions. Often times the dispatch of the highest priced level is limited, as is the case with CPP.
- *Real time pricing* (RTP) applies a rate schedule where the price can differ by hour of the day. There are two common forms of RTP: one that provides the twenty-four hour price schedule a day in advance (DA-RTP) and another that provides the hourly price within 60 minutes after consumption has already occurred (RT-RTP).

Incentive-based DR programs provide an explicit payment, billing credit or other form of incentive (e.g., information feedback) if the customer has the potential and is willing to alter their electricity consumption.

Table 2: Current Incentive-Based DR Opportunities

Incentive-based Program	Automated Control Technology	Ability for Customer Override of Control Signal	Explicit Performance Payment
Controllable	●		●
Configurable	●	●	●
Manual			●
Behavioral			

- *Controllable* programs provide a utility or ARC with the opportunity to directly control (via radio, internet, telemetry or other remote means) various customers' electricity consuming end-uses (e.g., electric water heaters, pool pumps) or some portions of their load which could be increased, decreased or even physically disconnected from the grid with little to no notice. For example, large industrial customers in Texas have under-frequency relays that historically could be automatically tripped by an under-frequency system condition or more recently, manually tripped due to verbal dispatch instructions from ERCOT, the system operator, if bulk power system conditions warrant a rapid reduction in electricity demand (Zarnikau, 2010).
- *Configurable* programs are similar to *Controllable* programs in that the utility has the ability to control the electricity consumption of one or more customer devices for a specified period of time but the customer can configure the control technology to override whatever DR signals are received under certain conditions. For example, residential customers can be provided with a programmable communicating thermostat (PCT) that will automatically increase the temperature set point during a declared event, but the customer has the ability to turn the temperature back down at their discretion.
- *Manual* programs do not provide any automated control technology to participating customers, leaving them to alter their electricity consumption through purely manual changes in response to a discrete event signal in exchange for a defined financial payment. For example, at the larger customer level, Curtailable programs would generally fall into this category, provided they have no accompanying automated control technology. As another example, Critical Peak Rebate programs are usually offered to residential and small commercial customers without any form of automated control technology, like a PCT.
- *Behavioral* programs are intended to produce a change in electricity consumption, but are voluntary and do not provide any explicit performance payments. For example, Opower has a behavioral demand response program where they provide information to program participants both before and after a declared curtailment event to drive measurable peak reductions without a price signal or a device to control load in the home. This is a relatively new offering that is only available in a very limited number of jurisdictions, while many U.S. electric utilities offer home-energy reports to their customers which is another form of this type of program.

Since our interest is in better understanding the costs of advanced controls that enable customers to provide some form of DR, not all of the rates and programs listed above are of concern. Our focus is only on those for which response is contingent on some form of automated control technology that can be dispatched (see entries bolded in Table 1 and Table 2). At present, the only time-based rates that do incorporate some form of dispatchable automated control technology are Critical Peak Pricing, Real Time Pricing, and Variable Peak Pricing. For example, it is common for utilities to provide residential participants in VPP and CPP with some form of a programmable communicating thermostat which the utility can send an event signal to increase the temperature set point, but the customer almost always has the ability to override it (e.g., Oklahoma Gas and Electric, 2011; DTE Energy, 2014). In addition, energy management and control systems (EMCS) can accept an RTP schedule and adjust commercial or industrial customer's electricity consumption at the premise accordingly (Kim et al., 2014). There are many more types of incentive-based programs that rely on some form of dispatchable automated control technology to elicit a change in electricity consumption. For example, water heater direct load control programs are a form of controllable incentive-based program that would be considered dispatchable (Hammerstrom et al., 2008).

This subset of DR Opportunities has a number of unique characteristics associated with each class of rates or programs including: the amount of advanced notice of a dispatchable event signal; the maximum duration for an event; and the frequency of dispatchable events (see Table 3). For example, both VPP and CPP can have the price dramatically increased when events are called generally with 2 hours' notice or more. However, the frequency with which this price can be raised is much higher with VPP than with CPP, which is often limited in the tariff to no more than 20 events. In contrast, Controllable and Configurable incentive-based programs typically provide far less notice to customers (as little as 5 seconds in the case of the former) and can be called far more frequently.

Table 3. Typology of Dispatchable DR Opportunities

Demand Response Opportunity	Time Scale		
	Advance Notice of Response	Duration of Response	Frequency of Response
Time-Based Retail Rates			
VPP	2 – 24 hrs.	Length of peak period (e.g., ~4-15 hrs.)	Daily, seasonal, etc.
CPP	2 – 24 hrs.	Length of critical peak period (e.g., ~2-8 hrs.)	Typically <100 hrs./year
Incentive-Based Programs			
Controllable	5 sec. – 30 mins.	5 mins. – 4 hrs.	Sometimes limited in tariff
Configurable	30 – 60 mins.	2-8 hrs.	Sometimes limited in tariff

2.2 Bulk Power System Services

The bulk power system is planned and operated to securely maintain a balance between the aggregate load and aggregate generation. To do so, a number of services have been specifically defined by NERC that organized wholesale markets procure. In addition, bulk power system operators have expanded their markets to encompass other services to ensure the grid is planned for and operated in a highly reliable fashion.[2] These various services differ based on: when the bulk power system operator procures or schedules this service; how frequently a control signal is sent out to resources providing that service; the amount of advance notice of deployment; the duration of response; and the frequency of response (see Table 4).[3]

Table 4. Bulk Power System Services

Bulk Power System Operations	Time Scale				
	Procurement or Schedule	Control Signal	Advance Notice of Deployment	Duration of Response	Frequency of Response
Spinning Reserves	Days ahead	<1 min	~1 min	~30 min	~20-200 times per year
Supplemental Reserves	Days ahead	<10 min	~10-30 min	~Multiple hours	~20-200 times per year
Regulation Reserves	Days to hours ahead	~1 min to 10 min	None	< 10-min in one direction	Continuous
Imbalance Energy	5 min to 1 hr.	5 min to 1 hr.	5 min to 1 hr.	5 min to 1 hr.	Depends on position in bid stack
Hour-ahead Energy	1-2 hrs.	5 min to 1 hr.	1-2 hrs.	>1 hr.	Depends on position in bid stack
Multi-hour-ahead Energy	None*	1 hr.	1-36 hrs.	>1 hr	As frequent as daily
Day-ahead Energy	24-36 hrs.	1 hr.	24-36 hrs.	>1 hr.	Depends on position in bid stack
Resource Adequacy	Years	1 hr.	Day ahead	Multiple hrs.	Seasonal

* This is a product that has not been defined by NERC nor instituted by any ISO/RTO in the US. This service would need to be procured in a multi hour, within- day, unit commitment market. However, it is a bulk system service that has been discussed and has potential to be valuable for bulk power systems that manage high volumes of variable generating resources. For example, this product could smooth net load ramps associated with daily patterns of solar energy generation (Alstone et al., 2017).
Adapted from Cappers et al. (2011).

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[2] The increasing penetration of variable generation resources, like wind and solar, have begun to cause challenges with historic operations of the bulk power system. For example, the degree of ramping that thermal generation resources previously needed to accommodate was modest and usually within their collective capabilities. However, as more and more grid-scale and distributed variable generation resources have come on line, the magnitude of this ramping up and down has increased dramatically (Cappers et al., 2011). System operators are now at a point where they are procuring resources on a day ahead basis to accommodate these large predicted multi-hour ramps required to maintain reliability. In day ramping requirements may differ from day ahead ramping requirements, necessitating a change in unit commitment on a multi-hour-ahead, within-day basis. At present, this multi-hour-ahead energy service is without any formal definition like the others identified by NERC.

[3] For more details on these various bulk power system services, see Cappers et al. (2011).

Organized wholesale markets in the United States, like Independent System Operators (e.g., NYISO, CAISO) or Regional Transmission Organizations (e.g., PJM, ISO-NE, MISO), have created opportunities through their demand response programs for customers to provide a number of these services (IRC, 2016). Although many of the specific rules and regulations governing participation, performance and settlement differ from entity to entity, there are a number of general statements that can be made about each class of ISO/RTO DR program.

2.2.1 Resource Adequacy

Emergency DR programs expect participants to provide load reductions to the bulk power system when grid conditions are expected to deteriorate beyond acceptable reserve margins. Such programs are usually voluntary and provide a performance payment to customers for verified load reductions relative to some deemed baseline level of consumption. Advanced notice of an event is usually given a day ahead, but most ISO/RTOs have the authority to dispatch participants with as little as 2 hours of notice.

Capacity DR programs are dispatched under similar circumstances to Emergency DR programs but provide an up-front payment in exchange for a requirement to reduce the agreed-upon amount of electricity when an event is called. Financial penalties are levied if the subscribed load curtailment is not met. Participants are expected to provide the load reductions within 30 minutes to 2 hours of being notified of an impending event; however advance notice of an event is commonly provided a day ahead of time.

Electric utilities and DR aggregators usually enroll the majority of their customers into these types of programs via their own controllable (e.g., direct load control) or configurable (e.g., critical peak rebate) incentive-based programs (see Table 5). However, CPP and VPP rate offerings can and in some jurisdictions are used to support resource adequacy (see Table 5).

2.2.2 Spinning, Supplemental and Regulation Reserves

Ancillary service programs allow end-use customers to offer fast response resources capable of providing spinning reserves, supplemental reserves and even regulation services to wholesale markets in exchange for a payment at the wholesale market price for that service. Advance notice of a need to respond to a reserve event is provided by the ISO/RTO with as much as 15-30 minutes for supplemental reserves to as little as 1 minute for spinning reserves. DR resources providing regulation reserves simply dispatch signals to participants to immediately increase or decrease consumption over the next 1 to 10 minutes. In order to ensure compliance with these dispatch signals, all ISO/RTOs require telemetry of some sort (e.g., 2-5 second sampling) at a participating customer's premise when providing regulation reserves. ISO/RTOs differ in these requirements for customers providing spinning and supplemental reserves; for example, in 2015, MISO required it for regulation participants but PJM did not (IRC, 2016).

As shown in Table 5, these DR resources are managed by electric utilities or, more likely, demand response aggregators via controllable incentive-based programs (e.g., direct load control of hot water heaters or large industrial loads like aluminum smelters) that may need to include an investment by the customer in telemetry.

2.2.3 Day-Ahead, Hour-Ahead, Imbalance and Multi-hour-Ahead Energy

Nearly all ISO/RTOs in the US provide end-use customers the opportunity to participate directly or indirectly in wholesale electricity markets. Typically, demand response resources bid into the day-ahead forward market, where the resources are committed to reduce load over some period of time the following day if their bid is economic. However, some ISO/RTOs also allow DR resources to actively participate in hour-ahead and real-time electricity markets, where advance notice of dispatch is much shorter.

Aggregators, and to a much lesser extent electric utilities, offer controllable and configurable incentive-based programs (e.g., energy bidding programs) that provide energy services to ISO/RTOs mainly from commercial and industrial customers (see Table 5).[4]

Table 5. Intersection of DR Opportunities and Bulk Power System Services

Bulk Power System Service	VPP	RTP	CPP	Configurable	Controllable
Spinning Reserves					●
Supplemental Reserves					●
Regulation Reserves					●
Imbalance Energy					●
Multi-hour -ahead Energy				●	●
Hour-ahead Energy				●	●
Day-ahead Energy	●	●	●	●	●
Resource Adequacy	●	●	●	●	●

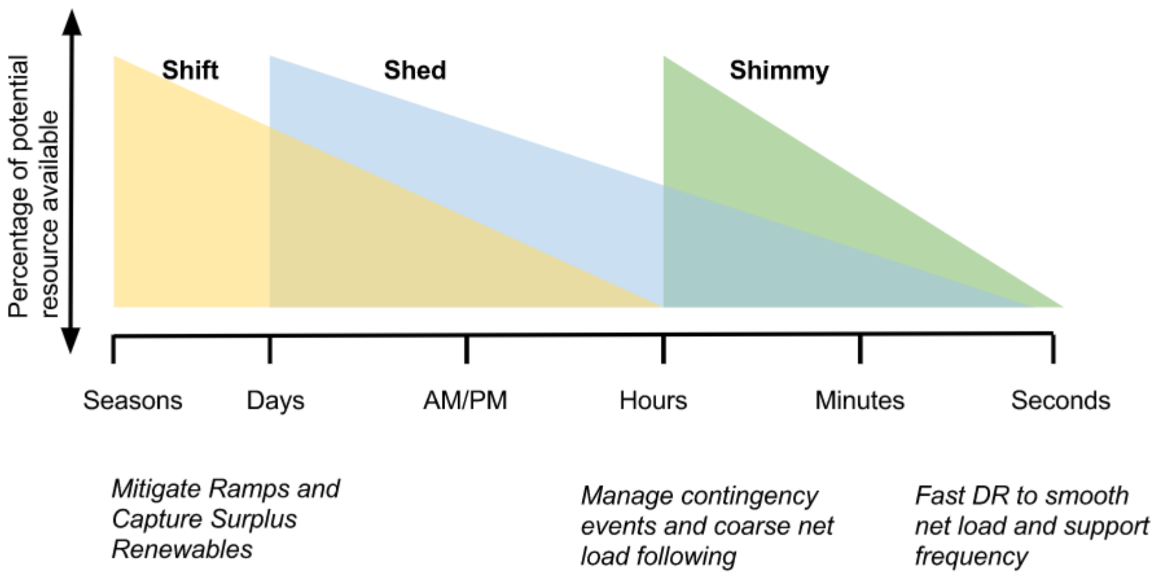
2.3 Demand Response Service Types

As Table 5 illustrates, there is a fair amount of overlap in the bulk power system services that the different classes of DR Opportunities can provide. To facilitate the assessment of costs to enable DR resources to provide these various bulk power system services, it would be advantageous to collapse these combinations of DR Opportunities and Bulk Power System Services into fewer yet

[4] VPP and CPP rates are currently designed with constraints on the number of times the resources can be dispatched (with a day-ahead notice), typically between 40-100 hours a year. This limits the availability of the resources for participation in the market to only providing day-ahead energy and resource adequacy services. However, it is possible for CPP or VPP programs to be designed/structured to provide shifting energy or hour-ahead energy for a limited number of days, but currently, that is not how the majority of these rates are structured.

broader categories that share similar technological requirements which mainly drive enablement costs.

Alstone et al. (2017) created just such a simplified nomenclature for discussing DR resource programs using: Shed, Shift, and Shimmy.[5] Each of these three Service Types has temporal attributes that characterize the dispatch and response times for the corresponding DR resources. Figure 1 below provides a mapping of the Service Types to a timescale of response. Each is discussed in more detail below.



Adapted from Alstone, et.al, (2017)

Figure 1: Service Type Temporal Attributes for Dispatch and Response of DR Resources

2.3.1 Shed Service Type

The Shed service type can be provided by DR resources that are dispatched to reduce customer load. Shed DR resources are often dispatched many hours or a day ahead to manage forecasted peaks at the system level to provide resource adequacy. They may also include fast-responding resources that can shed load in the event of a contingency event and/or emergency conditions by providing spinning and supplemental reserve services. Finally, Shed DR resources can also be

[5] The service type taxonomy established a generalized nomenclature to enable clear conversations about DR beyond peak capacity DR, with less jargon. The service type taxonomy also permitted the development of generalized system modeling frameworks, where the various bulk power system services and retail DR products are matched to the service types.

scheduled and dispatched to act as a supply resource in day-ahead and hour-ahead energy markets. All four classes of DR Opportunities qualify as Shed DR resources (see Table 6).

2.3.2 Shift Service Type

The Shift service type[6], which can be provided by DR resources dispatched to increase hourly energy consumption at certain points in the day and decrease consumption during alternative hours of the same day - effectively rearranging the load. System operators can use Shift DR resources to smooth net load ramps associated with variable generation resources or market conditions that warrant load shifting, including daily solar energy generation patterns. The Shift service type involves one or more periods of Shed (load reduction) paired with one or more periods of "take" (increasing load) during a single calendar day. It is a relatively small daily change in load, which should create a minimal impact on the customer. DR resources providing Shift services can be dispatched daily. Only customers participating in Configurable or Controllable incentive-based programs can provide a Shift service (see Table 6).

2.3.3 Shimmy Service Type

Certain types of advanced DR resources are capable of providing fast and continuous response services to the bulk power system. Customers that can follow sub-hourly to seconds-level control signals are characterized as Shimmy DR resources. These DR resources modify end-use loads to attenuate ramps and disturbances at timescales at the sub-hourly level and reduce the need for generation units to provide these services. Because of the need for fast response with very minimal, if any, advanced notice of dispatch, DR resources providing Shimmy services must be highly dependable. Thus, participants must have dispatchable control technology without the opportunity for customer override, thereby limiting Shimmy to only be provided via Controllable incentive-based programs.

[6] To the best of our knowledge, there is currently no Shift bulk power system market product. However, for our study, we have defined the characteristics of the Shift service to be an energy (kWh) neutral resource that an ISO/RTO could procure and dispatch. As previously discussed, there is a growing need for flexible resources that can provide load building and peak shedding service at different points in the day in response to high penetrations of variable generation resources. Therefore our study includes DR resources that can provide this Shift service, assuming at some point soon this service will become available to meet the clear market need.

Table 6: Service Type Mapping to DR Opportunities and Bulk Power System Services

Shimmy	Shift	Shed	Bulk Power System Service	VPP	CPP	Configurable	Controllable
		●	Spinning Reserves				●
		●	Supplemental Reserves				●
●			Regulation Reserves				●
●			Imbalance Energy				●
	●		Multi-hour-ahead Energy			●	●
		●	Hour-ahead Energy			●	●
		●	Day-ahead Energy	●	●	●	●
		●	Resource Adequacy	●	●	●	●

3 Categorization of End-uses and Enabling Technologies that Can Provide Bulk Power System DR Services

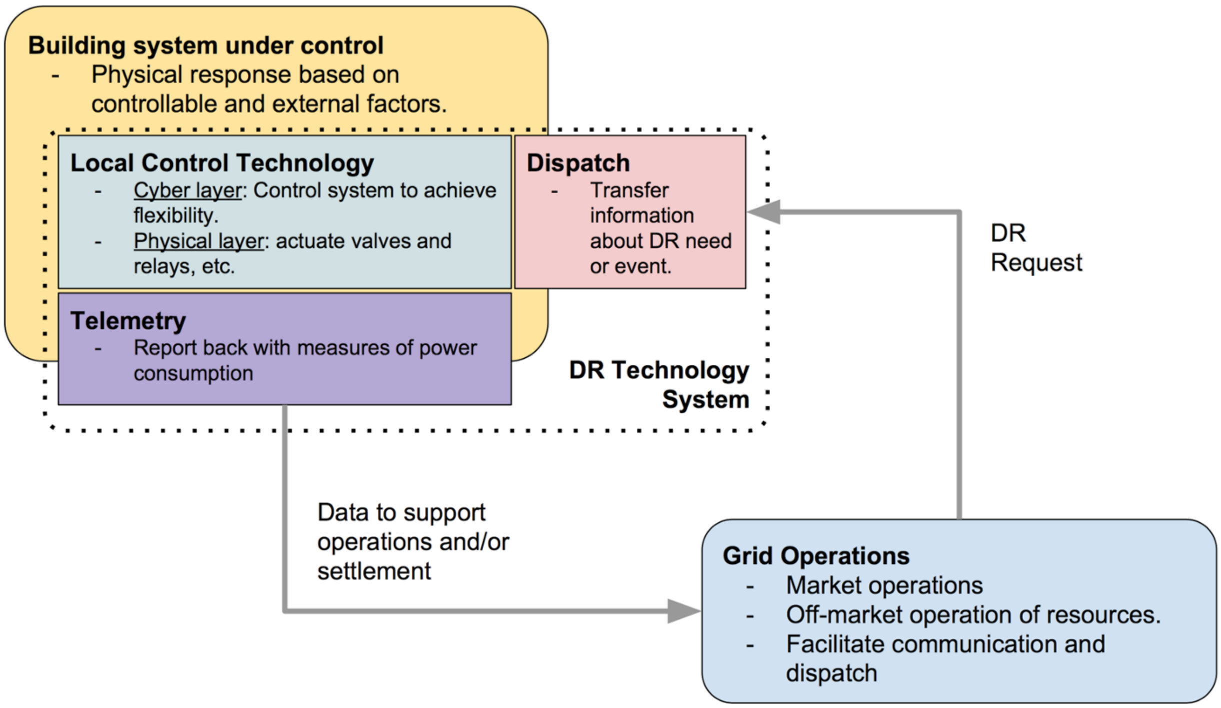
In order to provide Shed, Shift and Shimmy services, DR resources must have dispatchable enabling technology that is a mix of load control and communications hardware and software that make it possible to change the energy consumption patterns of end-uses. The enabling technologies examined in the current study are defined in terms conducive to estimating the expected costs and ability to provide each of the three Service Types listed in Section 2.3. Table 7 below describes the various end-uses and enabling technologies that we evaluated for this cost assessment.

Table 7: End-uses and DR Enabling Technologies Considered in this Assessment

Sector	End-Use	Enabling Technology Summary
Commercial and Residential	Battery-electric & plug-in hybrid vehicles	Automated Demand Response (ADR)
All	Behind-the-meter batteries	ADR
Residential	Air conditioning	Direct load control (DLC), programmable communicating thermostats (PCT).
	Electric hot water heaters	DLC or ADR
	Pool pumps	DLC
Commercial	HVAC	Depending on site size, energy management system ADR, DLC, and/or PCT.
	Lighting	A range of luminaire, zonal & standard control options.
	Electric hot water heaters	ADR
	Refrigerated warehouses	ADR
Industrial	Processes & Large facilities	Automated load Shedding & process interruption.
	Agricultural pumping	Base Switch & ADR
	Wastewater treatment	ADR

Adapted from Alstone, et.al, (2017)

To determine which enabling technology and end-use combinations can provide each Service Type to the bulk power system, we define each enabling technology in terms of three key attributes: Local Control Technology, Dispatch communication, and Telemetry requirements. Figure 2 describes the role each of these attributes plays in facilitating interaction between a DR technology system, a building system, and the bulk power system grid. We compare the capabilities of each DR technology system to the needs and requirements of specific grid services (i.e., participation as resource for Shed, Shift, and Shimmy). Thus, we determine whether each technology system meets the response characteristics necessary to provide each candidate grid service.



Source: Alstone, et al. (2017)

Figure 2: Interactions Between the DR Technology System, Grid Operations, and the Building Systems under Control

Within the framework of this assessment, each end-use/technology combination has a set of characteristics (i.e. communication resource, telemetry, local control) that define the ability for the end-use to respond to a DR dispatch signal. We define a set of filters, described in Table 8, that we use to determine whether a particular end-use/technology pair matches the response characteristics required to provide each specific grid service type.[7]

[7] For a detailed description of the requirements and methodology for applying the filters to each technology for the corresponding service type, see Alstone et al. (2017).

Table 8: 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	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 (e.g. DLC programs that are called no more than 10 times per year)
Maximum dispatch delay allowed	Seconds	Maximum time between when a dispatch request is made 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 seconds)	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	Time, as specified (e.g., minutes or hours)	The minimum continuous time that a load must be able to participate when dispatched.
Maximum telemetry delay	Time, as specified (e.g., minutes or seconds)	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	Time, as specified (e.g., minutes or seconds)	The maximum time step resolution on telemetry.

Adapted from Alstone, et al. (2017)

The following sections provide a summary of the enabling technologies and end-use combinations that have the technical and temporal capabilities to provide Shed, Shift or Shimmy services to the bulk power system. For each row with the technology and end-use combination, we have indicated that the combination is technically capable of providing the Shift, Shed, or Shimmy service with a dot.

3.1 Residential Sector Enabling Technologies

Residential sector DR programs have historically focused on controlling residential central air conditioning units with a DLC switch in order to provide peak capacity relief. Recent programs have begun to include programmable communicating thermostats[8] that can receive DR signals over a Wi-Fi connection (commonly referred to as "Internet of Things" or IoT). 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 and charging units, which are emerging technologies in the marketplace now, but should have a strong presence in the residential sector within ten years.

This study focuses on six residential end-uses, as outlined in Table 9. We have identified two technology pathways for central HVAC and electric hot water heaters, including DLC, ADR and/or PCTs. For the remaining end-uses, we focus on a single technology, including DLC switches on pool pumps, and ADR technologies for batteries, EVs, and PHEVs.

DLC technologies on HVAC, pool pumps, and room AC are limited to providing only Shed services to the bulk power system, since their functionality is limited to interrupting service to the end-use. While this dispatch control can be done almost instantaneously, most DR Service providers (i.e., utilities and aggregators) notify customers several hours, if not a day, in advance of a DR event. Advanced DLC controls[9] that enable an electric hot water heater can provide Shift, Shed, and Shimmy services.

HVAC units controlled with a programmable communicating thermostat can provide both Shed and Shift services to the bulk power system. PCTs can alter the set-points thereby allowing HVAC load to be moved around throughout the day as well as providing curtailment of the end-use, both in response to a dispatch signal.

End uses in the residential sector controlled with ADR enabling technologies can provide Shift, Shed, and Shimmy services. These residential end-uses with ADR have the flexibility to respond quickly to dispatch signals, and can provide short or long duration response to DR events.

[8] For the purpose of this study, we refer to "smart" thermostats and communicating thermostats as "programmable communicating thermostats". There are distinctions between smart and programmable communicating thermostats. Both smart and communicating thermostats are two-way communicating and both may have accompanying web portals and mobile apps that provide insight into a user's energy consumption and tips for increasing energy efficiency and reducing monthly bills. The distinction is smart thermostats have added algorithms that enhance heating and cooling performance by data gathering and analytics that optimize HVAC settings for efficient and automated energy consumption(Silverstein, 2016).

[9] Advanced DLC controls for hot water heaters have become commercialized in recent years and are either installed as a retrofit to existing units or as a replacement unit. These controls can respond in less than 4 secs and are connected via Wi-Fi to a proprietary cloud based platform. Several vendors offer this technology and one vendor in particular, Mosaic Power, has successfully bid these resources into the PJM Ancillary Services market.

Table 9: Residential Sector Enabling Technologies and End-use Combinations that Have the Technical and Temporal Capabilities to Provide Shed, Shift or Shimmy Services

End Use	Enabling Technology Component	Shift	Shed	Shimmy
HVAC	Direct load control switches (DLC)		●	
	Programmable Communicating Thermostat (PCT)	●	●	
Electric Hot Water Heaters	Direct load control switches (DLC)	●	●	●
	Automated demand response (ADR)	●	●	●
Pool Pumps	Direct load control switches (DLC)		●	
Residential Battery Storage	Automated demand response (ADR)	●	●	●
Residential Battery Electric Vehicles	Level 2 charging ADR	●	●	●
	Level 1 charging ADR	●	●	●

Adapted from Alstone, et al. (2017)

3.2 Commercial Sector Enabling Technologies

Within the Commercial customer sector, similar to the residential sector, the most common means of enabling DR is to apply some form of control technology in commercial HVAC systems. Lighting controls have evolved to the point where they can now be leveraged to provide various forms of DR. In addition, there are a number of automated DR technologies available to commercial customers across a variety of end-uses. All of these can be used to provide at least one of the DR Service Types (see Table 10).

With respect to HVAC systems, DLC switches have historically been installed on the central air conditioner (or heat pump), and function by cycling the units on and off during a Shed DR event. This technology is most common in small to medium commercial buildings, rather than in large commercial buildings. Smart thermostats are becoming popular for controlling HVAC units in small commercial building, while medium and large commercial buildings utilize ADR technologies to control HVAC units for both Shift and Shed services. DR-enabled variable frequency drives (VFDs) in Commercial HVAC are an extremely responsive technology that has only recently begun to penetrate the market. The functionality of the VFDs allows for full automation technology to maintain customer comfort levels, limit disruption to operations, and can provide Shift, Shed, and Shimmy services to the grid.

Refrigerated warehouses and cold storage facilities could provide Shift, Shed, and Shimmy services to the system without compromising the quality of products stored in these facilities when automated with ADR. These facilities can provide curtailment services (Shed), but more importantly, their thermal load is an excellent resource to provide Shift services by moving cooling cycles around 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. Additionally, these facilities can provide Shimmy service when ADR control technologies are configured to respond within 5 minutes or less to dispatch signals. Full automation technologies are readily available and can optimize energy operations for DR and Efficient Energy as a Resource (EE) for these facilities.

For Commercial Lighting controls, we focus on two advanced lighting systems: digitally addressable luminaire lighting systems and zone-based digital lighting systems. 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 panel controls each channel (or circuit) in unison. Zonal and luminaire lighting systems are enabled with ADR technologies and are capable of providing Shed and Shimmy Services, but cannot provide Shift. Standard lighting controls with ADR technology can only provide Shed type services to the bulk power system, since the controls are not sophisticated enough to permit dimming and day-lighting sensing (Wei et al., 2015).

Commercial batteries, EVs, PHEVs, and electric hot water heaters controlled with ADR enabling technologies can provide Shift, Shed, and Shimmy services. These commercial end-uses with ADR have the flexibility to respond quickly to dispatch signals, and can provide short or long duration response to DR events, including load shifting, (Shift), and load following, (Shimmy), primarily because of their storage (both thermal and energy) capabilities.

Table 10: Commercial Sector Enabling Technologies and End-use Combinations that Have the Technical and Temporal Capabilities to Provide Shed, Shift or Shimmy Services

End Use	Commercial Size (kW demand)	Enabling Technology Component	Shift	Shed	Shimmy
HVAC	Small	Direct load control switches (DLC)		●	
		Smart thermostats	●	●	
	Medium	Direct load control switches (DLC)		●	
		Automated demand response (ADR)	●	●	● w/VFD
	Large	Automated demand response (ADR)	●	●	● w/VFD
Lighting	Small	Office Luminaire (ADR)		●	●
		Office Zonal (ADR)		●	●
		Office Std. (ADR)		●	
		Retail Luminaire (ADR)		●	●
		Retail Zonal (ADR)		●	●
		Retail Std. (ADR)		●	
	Medium	Office Luminaire (ADR)		●	●
		Office Zonal (ADR)		●	
		Office Std. (ADR)		●	
		Retail Luminaire (ADR)		●	●
		Retail Zonal (ADR)		●	●
		Retail Std. (ADR)		●	
	Large	Office Luminaire (ADR)		●	●
		Office Zonal (ADR)		●	●
		Office Std. (ADR)		●	
		Retail Luminaire (ADR)		●	●
		Retail Zonal (ADR)		●	●
		Retail Std. (ADR)		●	
Electric Hot Water Heaters	Small and Medium	Automated demand response (ADR)	●	●	●
Refrigerated warehouses	All Commercial	Automated demand response (ADR)	●	●	●
Commercial Battery Storage	All Commercial	Automated demand response (ADR)	●	●	●
Commercial Electric Vehicles	All Commercial	Charging Level 2 Automated demand response (ADR)	●	●	●

Adapted from Alstone, et al. (2017)

3.3 Industrial Sector Enabling Technologies

Within the industrial sector, we focused on DR enabling technologies at three types of customer sites: large production facilities, wastewater treatment facilities, and agricultural water pumping facilities. For each, our research showed potential for either direct load control switches or automated DR technologies to provide at least one of the three services types, with industrial battery technology being able to provide all three (see Table 11).

DR can be enabled for agricultural loads by either a basic DLC switch or with an ADR system on the water pumps and other irrigation devices. Wastewater treatment and agricultural pump facilities enabled with ADR are capable of providing Shift and Shed services. Facilities that have Variable Frequency Pumps (VFPs) enabled with ADR, which are capable of changing pumping speeds in response to DR dispatch signals within 5 minutes or less, can provide Shimmy services. Additionally, industrial processes, such as manufacturing and fabrication, that utilize VFDs and are enabled with ADR can provide Shift, Shed, and Shimmy services. Lastly, industrial batteries enabled with ADR are capable of providing all three service types as well.

Table 11: Agricultural and Industrial Sector Enabling Technologies and End-use Combinations that Have the Technical and Temporal Capabilities to Provide Shed, Shift or Shimmy services

End Use	Customer Type	Enabling Technology Component	Shift	Shed	Shimmy
Pumping	Agricultural	Direct load control switch (DLC)		●	
		Automated demand response (ADR)	●	●	● w/VFP
	Waste Water Treatment Pumping	Automated demand response (ADR)	●	●	● w/VFP
Process	Industrial	Automated demand response (ADR)	●	●	● w/VFD
	Waste Water Treatment	Automated demand response (ADR)	●	●	
Battery	Any	Industrial. Battery (ADR)	●	●	●

Adapted from Alstone, et al. (2017)

4 Key Elements Driving Enablement Costs

Important distinctions exist between conventional DR enabling technologies and advanced DR technology infrastructure that can provide fast and flexible service to the bulk power system.

As described by Cappers et. al. (2013), conventional DR programs are typically designed to elicit load reductions during periods of high system demand, when system reliability is threatened, and/or when electricity prices are very high. This approach generally limits customer interruptions to 8-20 times per year with duration limited to 2-6 hours each interruption. Although participating customers can potentially rely on manual efforts (e.g., dimming lights, increasing thermostat set-points, shutting off equipment) to become a viable DR resource, automation and control technology may increase the size and persistence of load curtailments.

Mass market residential and small commercial site enablement for conventional DR programs typically targets specific end-uses for automated control technology (e.g., a DLC switch for an HVAC unit). DLC switches are the most obvious conventional DR enabling technology since they have a long history in the industry for providing peak load reductions. Industrial agricultural pumping loads have been successfully controlled with DLC switches for peak shed events.

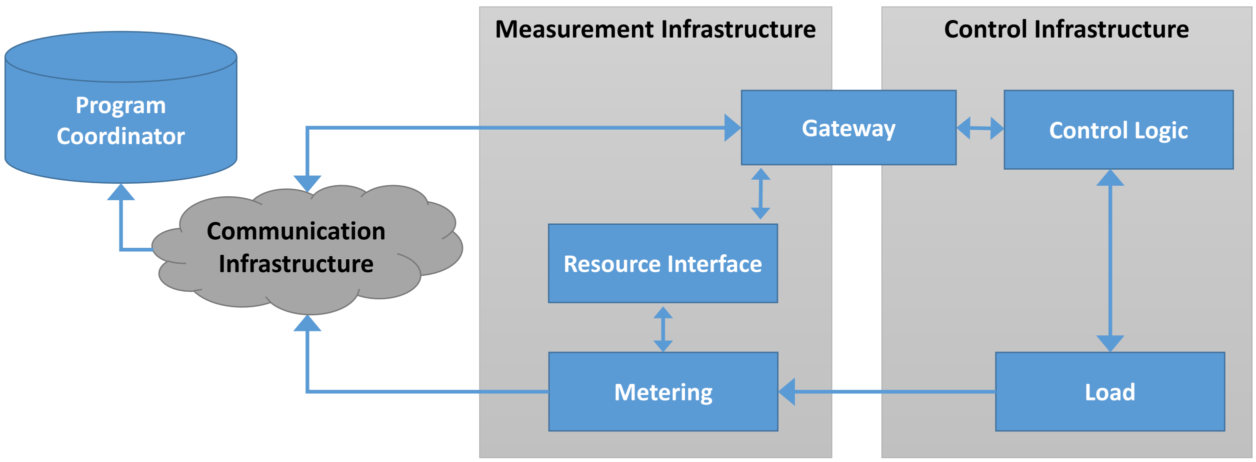
For commercial and industrial (C&I) process loads, conventional DR is often a manual process, whereby facility operators manually curtail operations after receiving a day ahead or day-of signal, and there is little, if any, automation involved (Alstone et al., 2017). In recent years, many large C&I customers have installed EMCS with ADR technologies to control non-critical loads, thus allowing the facilities to provide DR resources other than conventional load reduction, such as Shift or fast response Shed service.

In contrast, DR resources that provide regulating reserve services face much greater technical requirements for compliance with market rules necessitating investment in advanced DR enabling technologies. For example, such resources must provide a faster response to a dispatch signal, with the fastest requirement of 2 seconds for regulation up or regulation down market participation (IRC, 2016). To accommodate such rigorous measurement and communications requirements, telemetry is typically required to capture granular energy data and transmit it back to an aggregator or an ISO/RTO in near real time. Since EMCS and ADR technologies typically control more than a single end-use at the site act as a reserve resource, the infrastructure for fast response DR site enablement typically occurs at the premise level, rather than at the end-use level. These costs are considered incremental to the conventional DR site enablement costs.

As such, demand response technology enablement costs can be organized into three general categories (see Figure 3):

- Communication infrastructure;
- Measurement infrastructure; and
- Control infrastructure.

Each of these components is required for proper enabling technology operation and performance measurement. We describe each of the categories and their specific elements below.



Adapted from Piette et al. (2015)

Figure 3: Basic Elements of DR Technologies

4.1 Communication Infrastructure

Communications in DR technology solutions refer to the components that receive DR dispatch signals (one-way communication) and in more advanced systems, receive signals and submit information back to a head-end DR platform (two-way communication). There are four primary solutions used to send a dispatch signal to end-uses or to the energy management control systems at the customer premise, which include:

- FM Radio or pager based communication solution
- Wi-Fi or Broadband communication solution
- Cellular communication solution
- Advanced metering infrastructure (AMI) network communication solutions

While the costs of these dispatch communication solutions influence the cost of providing DR, these costs were not examined within this assessment, because these costs are associated with operational communication to the site, and our assessment examines the upfront costs to enable a site. These operational communication costs are typically paid by the DR service provider or possibly passed through to the customer as a condition of participation in the DR Opportunity.

4.2 Measurement Infrastructure

The second group of components in the DR automation system encompasses the electric meter or other data source, the communication resource interface, and the "gateway" communication of measured data back to the program coordinator. For ADR applications, the typical telemetry architecture includes several components. At the site-level, a data collection mechanism measures the premise and end-use loads, delivers that data to a resource interface which then packages and delivers the data to send to a Gateway. The Gateway packages and encrypts the data using protocols such as DNP3-L2 over PKI, ICCP and sends the data to a bulk power system operator or Aggregator.[10]

In order for end-uses to deliver advanced DR services, there are specific telemetry and dispatch configurations that must be met for participation in Shimmy services. While the specific requirements may vary, telemetry and communication system upgrades for advanced DR, which could include metering, a resource interface, a gateway or another component, are costs above those required for the conventional demand response resources.

4.2.1 Energy measurement

Several candidate technologies were identified for energy measurement. Energy measurement captures, consolidates and delivers energy measurement data to a head end meter data management system (MDMS) or a Communication Resource Interface.

According to Alstone et al. (2017), four possible options for energy measurement for DR include:

- **AMI Meter**: An advanced meter[11] that is commonly deployed with AMI has the capability of recording interval data from DR events at a variety of time intervals. For residential customers, the AMI meter is typically programmed to capture energy consumption at one hour intervals, whereas C&I standard practice is to program the meters for 15-minute intervals. However, many utilities are now capturing large industrial customer energy consumption at 5 minute intervals. For conventional DR programs (e.g., DLC pool pump load curtailment programs), hourly interval data provides adequate energy measurement for evaluation of performance and load reduction.
- **High-Resolution AMI**: An advanced meter programmed to record data at intervals of five minutes or less can meet the majority of energy measurement requirements for a provider of various bulk power system services. High-resolution advanced meters can meet

[10] Intra-Protocols enables the resource interface to communicate with a Remote Intelligent Gateway (RIG). The RIG aggregates individual data streams from many sites and communicates the aggregate signal to the ISO Energy Management System using DNP3, PKI, ICCP protocols for encryption.

[11] Throughout this report, we use the term "advanced meter" to refer commonly to any meter deployed as part of an AMI rollout, regardless if it has a home-area network (HAN) gateway embedded in the meter or not. This deviation from common practice is a reasonable simplification, since our assessment intends to capture the features of the meter that relate to interval measurement, rather than the existence of the HAN gateway.

telemetry requirements for supplemental reserves (Fagen, 2016).[12] Because bandwidth constraints exist for many AMI backhaul communication systems, further study is needed to determine whether broad application of high-resolution advanced meters for Shimmy services can simultaneously support data collection for billing purposes. Since a utility could conceivably reprogram a customer's advanced meter remotely, there should not be any incremental enablement cost associated with this technology.

- **Revenue Quality Meter**: An advanced meter specifically designed to provide data for energy billing purposes and whose components are typically approved by both the Transmission Operator (ISO/RTO) and the state regulator for revenue settlements. The Revenue Quality Meter typically uses cellular communications technology to deliver data in near-real time to a DR service provider or the bulk power system operator. In 2009, PG&E conducted a successful commercial pilot using AMI meters with built-in cellular modems to collect and transmit sub-minute interval electricity consumption data to CAISO as a requirement to provide 10-minute supplemental reserves.
- **Power Quality Meter**: An advanced three phase meter that provides measurement of current, voltage, real and reactive power, energy use, power factor and frequency. A power quality meter can capture a very high granularity of data, less than one second in some models. A power quality meter costs is one of the most expensive telemetry options on the market.

4.2.2 Communication Resource Interface

For ADR technologies and controls, a Communication Resource Interface, typically comprised of stand-alone hardware and software, are required for DR participation in supplemental reserves, regulation reserves, and imbalance energy bulk power system services. The Communication Resource Interface is the mechanism for receiving data from the meter, or some alternative energy measurement data source, and packaging it to enable the next step to a gateway connected to the wholesale market operator systems. Telemetry from the data source must be packaged and made available to the gateway, (e.g. a Remote Intelligent Gateway (RIG), or a Smart Energy Gateway (SEG)) within the time restrictions for each bulk power system service as specified by the wholesale market entity. For example, to support one-minute data samples, the Resource Interface must be able to query for the data from the meter or data source no less than at one minute frequencies, and then push those samples to the gateway for aggregation with the streams from other meters at the premise.

In order to provide Shimmy services in organized wholesale markets, a building must be able to communicate energy measurements to a gateway connected to market operators. Alstone et al. (2017), suggests that Communication Resource Interface options include:

- KYZ Modules: The KYZ module is an add-on that plugs into an existing AMI meter and submits energy use data from the meter to some other piece of remote equipment (Solid

[12] For example, Silver Spring Networks reports that their advanced meters can also meet spinning reserves requirements, although this has not been thoroughly evaluated. http://www.silverspringnet.com/wp-content/uploads/SSN_SilverLink_DR_MnV_Brochure.pdf

State Instruments, 2011). The KYZ board can support the ISO/RTO response times, transmitting 57,600 pulses per second with transmission latency of 200 milliseconds. However, KYZ modules are 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 (Fagen, 2016).

- ZigBee radio: The ZigBee radio is a potential cost competitive resource interface for residential and small commercial customers because it is already included (but typically is not enabled) in most advanced meters. It can be enabled for residential and commercial customers who install a Home Area Network (HAN) device and can pull data as frequently as every five seconds (Potter et al., 2014). The current ZigBee protocol, to which most advanced meters conform, allows multiple devices to be connected to the meter simultaneously, therefore allowing multiple applications to notionally communicate in parallel. The ZigBee protocol can provide a very low bit-error rate and assures negligible interference since the standard assures 16 channels. The optimal method for utilizing an advanced meter's internal ZigBee radio as Resource Interface is to use the radio to transmit energy data to an external gateway that then sends information over broadband to the "cloud" or to an Energy Management Data System (EMDS).[13] The gateway must be capable of seamless communication and compatibility with the AMI meter by way of the ZigBee radio.
- Network Interface Card (NIC): A NIC is included in most advanced meters deployed; it communicates only over the AMI network. One challenge associated with using the meter NIC for telemetry is the timing associated with sampling and forwarding, for which the NIC is responsible. The NIC is capable of capturing and forwarding the data at intervals less than five minutes, but utilities typically capture these meter reads over several hours and transfer the reads back to a head-end AMI system only a few times a day. Although there is no additional hardware cost associated with a NIC, the use of the NIC has not typically been employed because of concerns with AMI platform bandwidth limitations (Fagen, 2016).

4.2.3 Gateways

Gateways are logical interface hardware systems that interconnect and exchange energy information between the customer facility and one or more Energy Service Providers (ESPs). Gateways are also known as Energy Service Interfaces (ESI), and are utilized in residential homes or commercial customer facilities to connect two incompatible networks (networks with different protocols) and facilitate bidirectional communications by translating messages passed between

[13] We use the term Energy Management Data System as a general term to refer to various systems that collect data from various end-uses or gateways. These are typically head end systems used by utilities and aggregators to dispatch event signals and monitor the performance of premises and/or end-uses during DR events and can include: Demand Response Management Systems (DRMS) (e.g. Siemens), Data Visualization and IoT operational analytics platforms (e.g. SpaceTime Insights or Bit Stew), Distributed Energy Resources Management Systems (DERMS) (e.g. OATI), and Meter Data Management Systems, (e.g. Itron, Silver Springs). These platforms allow utilities and aggregators to monitor and analyze data in near real-time or within 24 hours, depending on the platform.

the two networks. Gateways provide other features such as data logging and control and monitoring of device response.

With the interoperability enabled between the systems, customer facilities can receive pricing and DR signals to dispatch and/or manage the operation of customer systems and devices, including HVAC, VFD/VFPs, lighting Distributed Energy Resource (DER), electric storage, and PEVs. A gateway typically interconnects to both the AMI meter and to an ESP's EMDS. Depending on the system architecture, the AMI system may be the only system that a gateway interconnects to for DR signals. Alternatively, a device can include embedded software that connects to an ESP system, and not to the meter (e.g. a PCT connecting to a cloud based platform). Another option is that the gateway connects to both the ESP and DR systems, receives dispatch instructions from the ESP system and polls the AMI meter for load data. A gateway can collect data from the meter's NIC, KYZ module, or ZigBee radio interface, and relay it to the cloud or to ESP's system for monitoring or reporting (e.g. transmittal to an ISO/RTO). The gateway can also be used for aggregation of multiple data streams from other meters at a customer facility.

Energy Management Control Systems are increasingly installed and utilized in commercial and industrial customer facilities in order to manage and control end use loads. These systems often utilize popular open protocols such as BACnet, LonMark and the Smart Energy Profile for controlling devices and end-uses within the building. However, for these EMCSs to participate in DR programs and receive signals from an ESP's system, an external gateway is usually required to translate between the EMCS and the ESP/Utility/ISO system. EMCS and EMDS that are equipped with OpenADR 2.0 are becoming increasingly common as manufacturers/vendors are opting for interoperability to ease installation and to facilitate communication between the DR service provider, ISO, or utility and a facility's EMCS and device controls.

Note that gateways are generally utilized for more complex DR applications where more than one device in a customer facility is receiving price, energy or DR signals from an ESP's EMDS. Gateways are not required for conventional DR, but in advanced DR applications that are providing in Shimmy or fast response Shed services to the bulk power system, a gateway would be required to transmit data to the head end systems that are managing the DR events.

4.3 Control Infrastructure

The final cost element is the DR control technologies which are listed in Table 7 and discussed in detail in Chapter 5. After a signal via the DR communication system is received, either through a gateway device or directly by the end-use control technology, the signal is translated into a control action. For example, there are a number of different technologies capable of controlling an HVAC system in order to provide Shift or Shed services. These technologies include DLC switches or ADR controls that manipulate fan speed and compressors within the unit. In the case of residential or small commercial buildings with split HVAC systems or rooftop air-handling units, a relay switch can be installed that temporarily disables the compressors. Another option is the installation of a programmable communicating thermostat that can increase zone temperature set point for the duration of a DR event and decrease the set point prior to the event to precool the space. Other cases include systems in which HVAC equipment is outfitted with control logic hardware capable of receiving remote messages and translating them to "low-power" operating modes.

ADR controls can be fitted to a variety of end-uses to manipulate energy consumption during a DR event. The advancement of ADR control logic and sophisticated algorithms that convert DR signals into actionable load control enable real-time response to signals. In commercial and industrial facilities, most ADR controls are managed through an EMCS that is programmed to control how the lights, temperature, chillers, compressors, and other electrical and mechanical equipment will be sequenced and manipulated to reduce consumption and drop load.

Electric Vehicle charging units and battery inverters can be manufactured with ADR hardware embedded in the end use which permits control with no external hardware, (such as a gateway or EMCS), and are capable of providing Shed, Shift and Shimmy services when needed. Electric Hot Water Heaters equipped or retrofitted with ADR controls also include hardware that permits remote dispatch and intelligent load response in near real-time.

5 Enabling Technologies Cost Assessment

As noted in Alstone et.al (2017), DR enabling technology can be defined as 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.

Our cost assessment provides estimates of initial costs for the installation, communication resource interface, telemetry, and control hardware for DR enabling technology.[14] This assessment is organized to provide the costs by each customer sector (i.e., residential, commercial, and industrial), by electricity consuming end-use, and enabling technology for our three types of bulk power system services: Shed, Shift, and Shimmy service types. Our approach uses an independent perspective of estimating the total costs to enable a site. That is, our estimates cover all the costs to enable the site or end-use, irrespective of the entity responsible for commissioning (e.g., aggregators, retail service providers, or business owners).

The majority of the cost data that is presented in this study was collected by Lawrence Berkeley National Laboratory (LBNL) for the California Demand Response Potential Study project (Alstone, et.al. 2017). That research utilized prior LBNL reports focused on DR technologies in specific sectors (industrial, commercial, agricultural) for data on the cost of DR enablement (e.g., Lekov et al., 2009; Olsen et al., 2012; Piette et al., 2015). For DR technologies with limited publicly available cost data, the research team consulted industry experts, including DR providers, to obtain estimates of DR technology cost. For the residential sector, the research team also referenced prices for DR technologies that were currently on the retail market. Costs estimates use 2017 prices for the technologies.[15]

5.1 Technology Solutions for DR Site Enablement

The research results presented in this study cover costs for a broad selection of enabling technologies across the United States. The costs estimates are averages for the enabling technologies, from the various sources discussed above. However, costs for the specific components, technologies, or solutions may and likely will differ depending on vendors, geographic location, customer sector, and technology application. The data provided herein are average estimates, and are not taken from price quotations for procuring the enabling technologies in a competitive bid process.

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[14] It is important to reiterate that non-dispatchable/non-controllable demand response is not included in this assessment because it is not a DR enabling technology, but rather a manual or behavior based response to a DR signal (see Table 1 and Table 2). Our research focuses solely on technology based control DR solutions.

[15] Cost data we utilized was collected by researchers between 2007 and 2017. Data that was collected prior to 2015 were first converted to 2015 CPI in Alstone et. al. (2017) and then further adjusted to CPI 2017 in this study. For the 2016 and 2017 data, we used the most recent published value at the time the data was collected and adjusted for inflation to 2017 CPI.

5.2 Attribution of Enablement Costs

This study considers the total costs for enabling a premise and its end-uses with DR enabling technologies. However, by attributing the costs exclusively to DR, we are overstating the costs for some technologies. For many consumer end-uses, some technologies or device upgrades that enable DR (e.g., PCTs, building Energy Management System (EMS), or lighting controls) produce other benefits by allowing a building to operate more efficiently (Goldman et al., 2010). In addition, most DR technologies can be deployed coincident with EE upgrades or DER resources, like solar & batteries, and can result in lower transaction and capital costs for the participant and the ESP. Some DR enabling technologies may have other non-DR benefits for the building occupant or owner in addition to providing DR. For example, advanced DR-enabled lighting is also more efficient than standard lighting and batteries can provide backup power and earn revenue from streams unrelated to DR (e.g., arbitrage of TOU pricing). However, the vast majority of these end-use installations are completed with the customer's EE savings as the priority. The attribution of 100% of the total costs to DR does not properly reflect the proportional share of the non-DR benefits, such as EE upgrades, but for this research we make no assessment of that share of total costs which should be assigned to DR functions. Instead, we report the total cost to enable DR, knowing that in reality that share assigned to DR is likely to be less.

In practice, non-DR economic benefits could be realized through customer bill savings that come from DR-device-induced efficiency or energy efficiency incentives paid by a retail ESP or other third party entity that helps buy down the upfront cost of the DR enabling technology. While it would be prudent to include a cost "buy-down" that allocates a percentage of the costs to non-DR benefits (e.g. EE, revenues from wholesale market participation, service optimization), there is little, if any, empirical evidence as to what an appropriate percentage of cost attribution should be. As a result, the non-DR benefits and cost sharing are not included in our study and cost assessment of the DR enabling technologies, but should be considered as potential revenues that support DR investments.

Industry experts continue to discuss the interactive effects of energy efficiency and DR. One could broadly consider energy efficiency as a load-modifying DR measure, whereby the load is decreased by an efficiency investment (and the timing of service remains unchanged). Thus, EE investments in general have "load-modifying" DR effects, and in general, reduce 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 that less flexible ramping capacity 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 taken from Alstone et. al, (2017):

> *"… an HVAC load that has a 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 improving the cost-effectiveness of enabling DR control upgrades. However, the markets for energy management technologies that provide multi-attribute services are still evolving, and there are significant challenges to ensure the services are appropriately valued. In particular, the industry has not established a solid methodology for determining the cost effectiveness of an integrated portfolio of energy management technologies, such as EE, DR, and DERs. The evolution and growth of the DR market for advanced technologies will depend on market transformation and education, including: building product availability, lowering technology cost, increasing reliability, improving market knowledge (i.e., designers, customers, contractors, building owners/occupants, building officials, and facility managers all understanding the business opportunities and the appropriate design and control applications of energy management technologies), and aligning capital investment priorities and incentives.

5.3 DR Site Enablement Cost Categories: Installation and Labor, Enabling Tech Costs, Telemetry, Communication, and End Uses

As discussed in Chapter 4, three main technical elements enable DR: communication infrastructure, energy measurement infrastructure, and control infrastructure. In addition to these technical costs, there are labor and installation costs for site enablement, which can include the costs for design and configuration of communications and DR control system logic and can include up-front engineering, installation by a technician, and commissioning tests. In large commercial and industrial buildings with EMCS to be integrated with DR controls, a DR control expert must be retained to program the changes to the building control sequences.

For the purpose of our assessment, we did not assume that end uses would be replaced or procured, with the exception of commercial lighting, residential hot water heaters with ADR controls, electric vehicle chargers, and behind-the-meter Li-Ion batteries. Most DR enabled lighting controls are sold as *systems*, where the fixtures and controls are DR enabled and allow for advanced sensors and controls. For DR enabled battery systems, we assumed that the whole system would be purchased as a DR ready solution. Since behind the meter battery systems are an emerging technology solution, there is little evidence that there are a significant number of battery systems that could be retrofit with DR enabling controls. For some electric hot water systems in residential and small/medium commercial sectors, the entire unit is replaced with an ADR ready system. Therefore, we consider behind-the-meter battery systems, electric vehicle chargers, electric hot water heaters, and lighting control systems to be purchased as a new end-use systems. In all other cases, our cost estimates presume that the end uses under control are in operation and are capable of DR enablement.

For each of the end-uses, we estimate the initial up front enablement costs for a customer site or end-use, based on customer sector and size. These include technology and installation costs, and are either provided as an aggregate cost for enabling an entire site (in $/customer site), or calculated by enablement costs per kW of load enabled to provide DR (in $/kW)[16], or the costs to enable an end-use ($/end-use).

In the commercial and industrial sectors, enablement costs are estimated for each kW of load that is enabled to provide DR services: Shed, Shift, or Shimmy. The cost estimates reflect the maximum predicted load impact from installed controls for each end-use or premise. We borrow this accounting framework for the costs of enabling technology from Piette et al. (2015), in which the cost categories, described below, are used to develop comparable and scalable estimates and averages for unit enablement costs in $/kW.

A description of each category is as follows:

- The fixed initial **communication and hardware costs** for achieving controllability "per site" for the given end-use or customer premise. Costs included in this category are telemetry, communication resource interface, and installation costs. These are reported in $ per site.
- The variable initial **costs for the control technology** for achieving controllability "per kW" (e.g., HVAC and retail lighting controls). These are reported as $ per kW enabled for DR services.
- The fixed initial **end-use control technology and communication costs** for achieving controllability "per end-use". These costs are specific to Electric Vehicles and the Residential sector end-uses and are reported as $ per end-use enabled for DR services.

5.4 Conventional DR cost Assessment and the Incremental Cost for DR Site Enablement to Provide Shimmy Services

For DR resources with control technology that provides Shimmy services, we assume the same control technology may also be used to provide Shed as well as Shift (e.g. ADR, energy management control systems, and end-use local controls). For example, a Variable Frequency Pump (VFP) that can be ramped up or down for frequency regulation (Shimmy) can also provide a Shift service resource that increases load by ramping up the pumping speed during several hours of the day to build load and slowing down the pumping speed in the evening hours to curtail energy consumption. As such, for the same customer sector, size and end-use, the hardware and installation costs for the control technology to provide Shimmy services is the same as it is to

[16] These cost estimates are based on the predicted load impact of the specific end use being enabled in isolation. However, as a resource, the various end-uses are likely managed as a portfolio and thus may not be operated independently resulting in the actual kW reduction for each enabled end-use being lower than the cost estimates suggest.
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provide both Shed and Shift services. However, telemetry and communication system upgrades are incurred to enable a site to provide Shimmy services, which could include metering, a resource interface, a gateway or similar components.

For the commercial and industrial customer sectors within the database, DR technology costs to enable the provision of Shimmy services are captured in the Communication and Hardware Cost field, are considered applicable to the entire customer site, and are incremental to the control technology costs ($/kW). For the residential customer sector and electric vehicle technologies, the control technologies, communication, and hardware costs for each end-use are organized by the applicable bulk power system Service Type.[17]

For those technologies that are listed as providing "Shed & Shift" service, they are limited to providing those two services. Technologies that are listed as only providing Shed service can only provide peak capacity shedding and contingency/supplemental reserve.

5.5 Costs not Included in Assessment

This study did not capture site-to-site enablement cost variability and all numbers presented reflect the average national costs. However, it is important to note that there can be variability in enabling technology costs and in site-specific enablement costs. The first arises from a lack of perfect information about current and future costs of DR enabling technologies, while the second arises from site-to-site variability in cost.

Additionally, this study did not include ongoing operational costs that could be required for operation of a DR program. The costs captured within this analysis include only those costs estimates for bringing a DR resource online. Examples of ongoing operational costs include incentive payments for customer participation, costs to dispatch control technologies, and marketing material for customer recruitment, equipment maintenance costs, network monthly charges, and program administration costs. These would be considered programmatic expenses, which are not within the scope of the analysis, since this study is not estimating the costs for DR programs, but rather, for DR site and end-use enablement.

5.6 Demand Response Advanced Control Enablement Costs, by Sector

In the following sections, we assess the enablement costs for each specific DR technology within the framework of the customer sectors, including: residential, commercial, industrial. We present the DR technology enablement costs by customer sector to capture the variety of end-use applications and nuances between the sectors. While some technologies are pertinent for more than one customer sector, such as battery storage or HVAC controls, there are diverse enablement

[17] Residential sector and electric vehicle charging unit enabling DR technologies are applied to each end-use under control typically at a fixed price (e.g. the cost for a Smart Thermostat is $279 and enables the entire central HVAC unit in a single family home), and thus are not estimated in variable $/kW. Therefore, for this study, we report all end-use control technology and communication costs for the residential sector and electric vehicles into a single field of initial costs titled.

costs for the various technologies depending on the sector. Additionally, not all customer sectors are eligible for all technologies. For example, it is unlikely that an ESP would install ADR controls on a residential or small commercial HVAC unit, as it is more cost effective to use a PCT to control the unit. By comparison, it is not cost-effective to install a PCT in a medium or large commercial building, since those facilities usually have multiple package HVAC units that need separate controls. Therefore, ADR controls would be the ideal application for those facilities.

Electric Vehicles, battery storage, and commercial lighting technologies are evaluated in distinct categories because of the unique attribution of the DR enablement costs. However, as noted in their respective sections below, electric vehicles and batteries are germane in most sectors and we provide DR enablement cost data for each sector.

5.6.1 Residential DR Site Enablement Costs

The enabling technology cost estimates for the residential sector, presented in Figure 4 are specific to a single end-use and include the costs for the control technology, installation, and the communication platform, which is typically an internet based or radio-based solution.

For residential space cooling and heating, we focused on PCT technologies that target central HVAC and plug load controls that work on room air conditioning units.[18] The costs for an installed PCT is approximately $279 per controlled end-use, while room air conditioning unit controls range from $75 to $100 (Alstone et al., 2017). This study did not examine technologies that could automate evaporative cooling units.

Electric hot water heater end-uses enabled with ADR and DLC technologies can provide Shed, Shift, and Shimmy services. The water heaters with ADR controls are typically sold as a complete system, and require that the entire water heater be replaced. These systems include the use of wireless networks and embedded sensors, commonly referred to as the "Internet of Things, (IoT), and can be procured and installed for approximately $2,136 per unit[19]. For water heaters controlled with advanced DLC, which are installed as a retrofit to the existing end-use, the average costs is approximately $350 per unit installed. While there are technologies that control heat pump water heaters, those cost estimates are not included.

The costs for pool pump DLC controls are approximately $146 per device, installed (Valmiki et al., 2013). These technologies can provide Shed service.

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[18] Plug load control solutions are available with 120V and 220V adapters that connect over IoT for approximately $100 per device. These devices can be utilized on residential HVAC units and appliance plug loads. All of the controls are managed in the cloud over the vendor platform, and can be DR-ready. For example, BOSS Controls is a manufacturer that specializes in plug load controls with an open source IoT energy management platform.

[19] By comparison, a high efficiency 50+ gallon standard electric hot water heater, with no DR communication or controls, can range from $800- $1,400, not including tax, labor and installation.

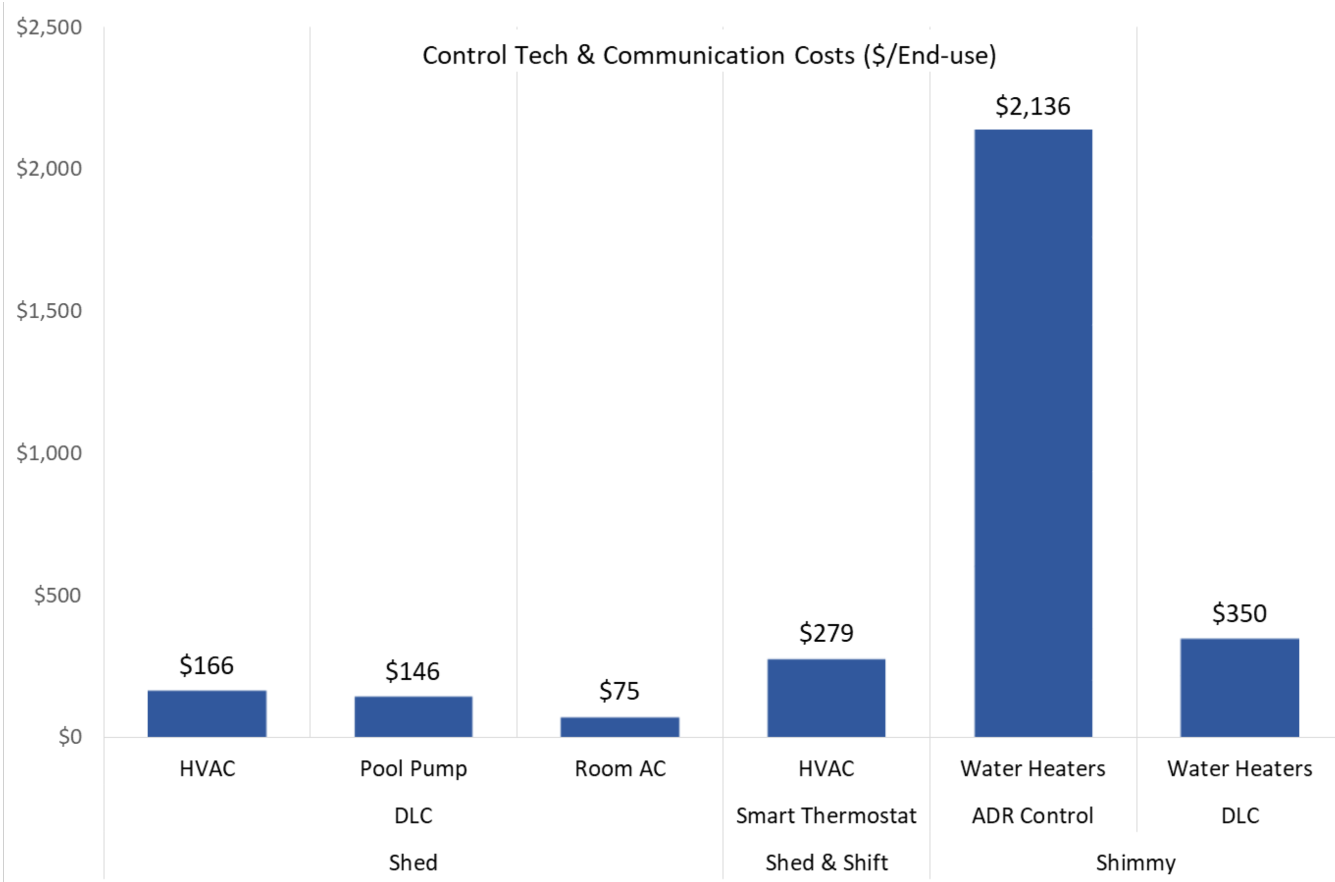

Figure 4: Residential DR Technology Enablement Costs

5.6.2 Commercial Sector DR Site Enablement Costs

Figure 5 provides cost estimates for commercial sector end-uses and DR technologies. 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. For small commercial customers, cost estimates are made for enablement at the site, whereas for medium and large commercial customers, costs are estimated as $/kW enabled. Technology vendors, aggregators, and utilities provided cost estimates for the DR enabling technologies, which were then averaged across data sources for reporting purposes. Cost estimates for ADR technologies in refrigerated warehouses were taken from Lekov et al. (2009) .

The hardware and communication (telemetry and gateway) costs for large commercial HVAC and refrigerated warehouses Shimmy resources average around $2,066 per site. Enabling control technologies in the commercial sector range from $62/kW for DLC switches (small and medium commercial HVAC) to $310/kW for ADR controls on large commercial HVAC units. For small commercial customers, we assumed that a PCT control could provide Shed and Shift Services and could be procured and installed for $171/kW. Costs for ADR controls in refrigerated warehouse average around $289/kW installed. Costs for electric hot water heater ADR controls, which can provide Shimmy, Shed, and Shift, include $1,000 for the communication and hardware components, and $166/kW enabled for controls (Alstone et. al, 2017).

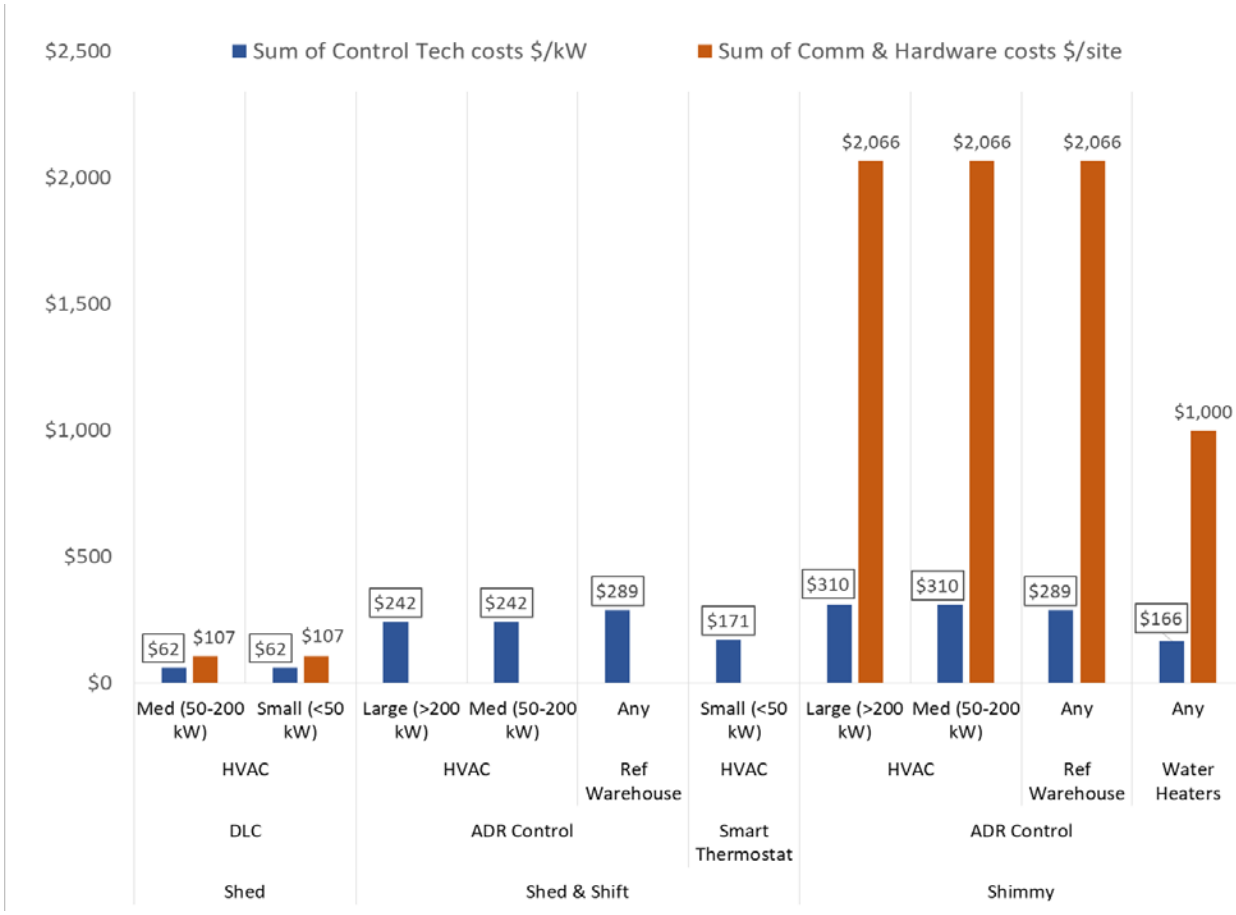

Figure 5: Commercial Sector DR Technology Enablement Costs

5.6.3 Commercial Lighting DR Site Enablement Costs

For Commercial lighting, we include the cost estimates for small, medium and large commercial office and retail buildings, using the same size distinctions as in Section 5.6.2. A key challenge with estimating the costs to enable advanced lighting control systems for DR is that they are typically installed for purposes other than DR. Rather, these systems are commonly installed either for non-energy benefits (e.g., occupant comfort) or for their EE benefits as discussed in Section 5.2. As such, neither the enabling costs nor the associated benefits should be attributed exclusively to DR. However, for this study, we do not attempt to quantify or attribute any portion of the enablement costs to energy efficiency or customer comfort, but rather, we look at the total costs to install a DR enabled lighting system.

To better capture the costs of lighting controls for DR, we consider three end-use cases with ADR enabled technologies:

- **Luminaire:** highly granular control including digitally addressable, individual luminaires fixtures;
- **Zonal**: zonally controlled luminaires; and
- **Standard**: existing standard practice lighting system consistent with meeting CA Title 24 Energy Code baseline.

It is important to note that most lighting controls are sold as complete systems, where the ballast includes the DR controls, and the entire system is controlled via an energy management control system or similar platform. Luminaire and zonal lighting control systems can provide Shed and Shimmy Services, but in order to provide Shimmy, the additional communication and telemetry expense of $2,080 per site is required. Depending on the size of the building and sector, the luminaire and zonal system costs can range from $216 -$886 per kW installed. Standard lighting systems lack the control granularity of the luminaire and zonal systems but can provide Shed Services. These system costs range from $381- $787 per kW installed. In Figure 6, we provide estimates for each of the DR enabled lighting control systems (Alstone et. al, 2017).

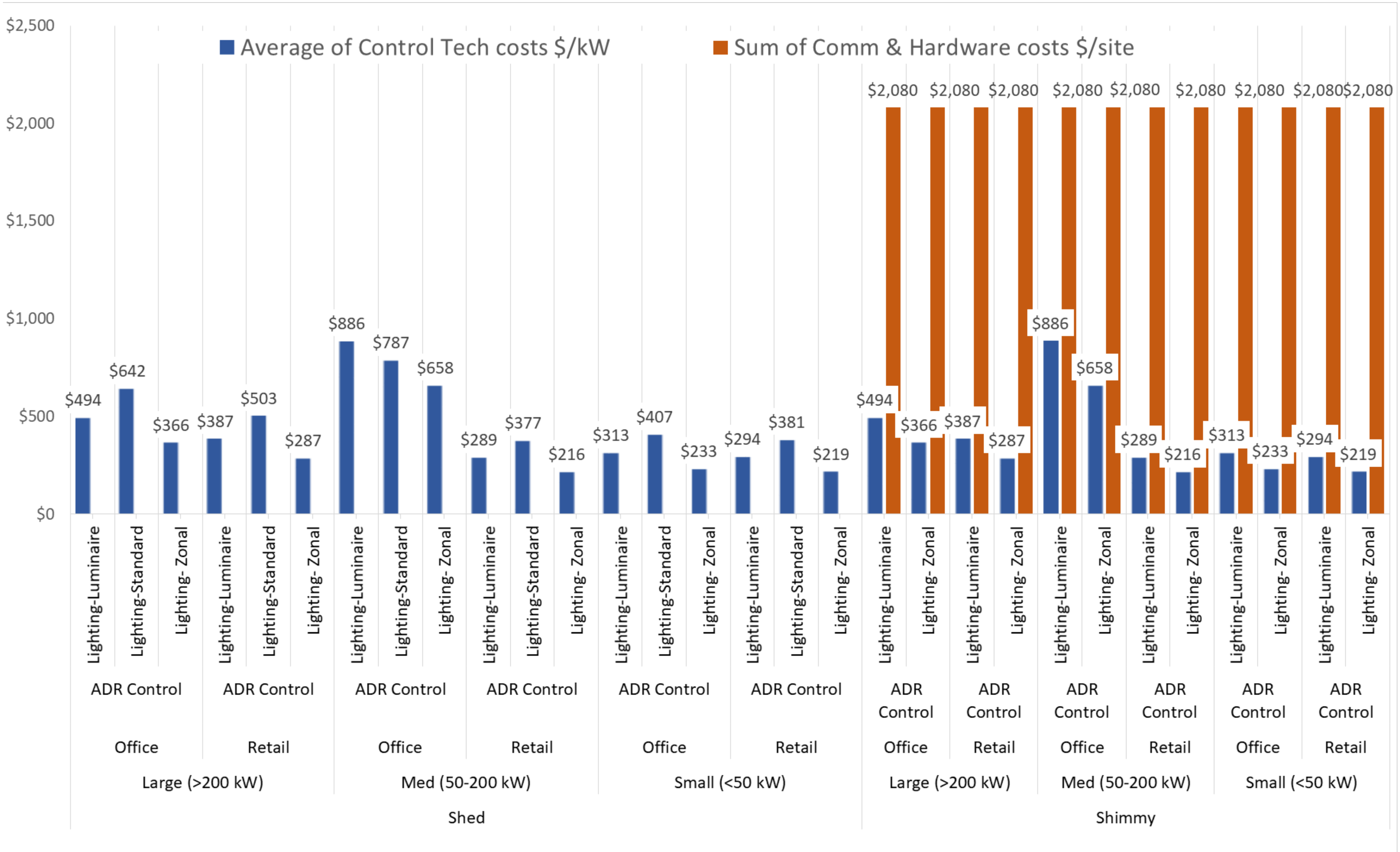

Figure 6: Commercial Lighting System DR Technology Enablement Costs

5.6.4 Industrial and Agricultural Sector DR Enablement Costs

Within the industrial sector, we focused on DR enabling technologies at three types of customer sites: large production facilities, wastewater treatment facilities, and agricultural water pumping facilities (see Figure 7).

For large production facilities such as factories, food processing plants or metal product manufacturing sites, we examined the costs for ADR enabled process load interruption using research by Piette et al. (2015) that examines ADR installations at over 50 sites. The data from the ADR installations in commercial and industrial facilities was used to develop the enabling technology costs estimates for the industrial sector. The costs for ADR systems that control industrial process loads average around $258/kW installed, and include communication resource interface (gateway).

Agricultural pumps enabled with a DLC switch are limited to providing Shed services. For those pumps enabled with ADR, the end-use resources can provide both Shed and Shift services. A base switch for a DR pump cost $41/kW with an additional $104 for the communication platform. The cost for ADR is approximately $242/kW installed, including the communication resource interface.

Enablement costs for ADR installations in wastewater treatment and pumping facilities are based on research by Thompson et al. (2009) and Olsen et al. (2012). When loads at these facilities are enabled with ADR, they are capable of providing Shed and Shift Services. The costs for ADR enablement at wastewater facilities is approximately $270/kW installed (Alstone et al., 2017).

Advanced end-use variable frequency pumps or drives (VFPs and VFDs) technologies control the rotational speed of an electric motor by controlling the frequency of the electrical power supplied to the motor. This technology allows such end-uses to provide Shed, Shift, and Shimmy services. In order to do so, the pump or drive must be fitted with an automated controller to receive the DR signal and adjust the drive or pump schedule according to the DR event. These end-uses are also capable of substantially reducing energy use. Agricultural and wastewater loads with VFP/VFDs equipped with ADR have significant potential to provide DR and permanent load shifting while requiring limited customer interaction with the controls (Alstone et. al, 2017). The costs for VFP/VFDs enabled with ADR are approximately $349/kW installed. In order to provide Shimmy service to the bulk power system, the system costs for the advanced telemetry and communications will be an additional $1,290- $2,080 per site.

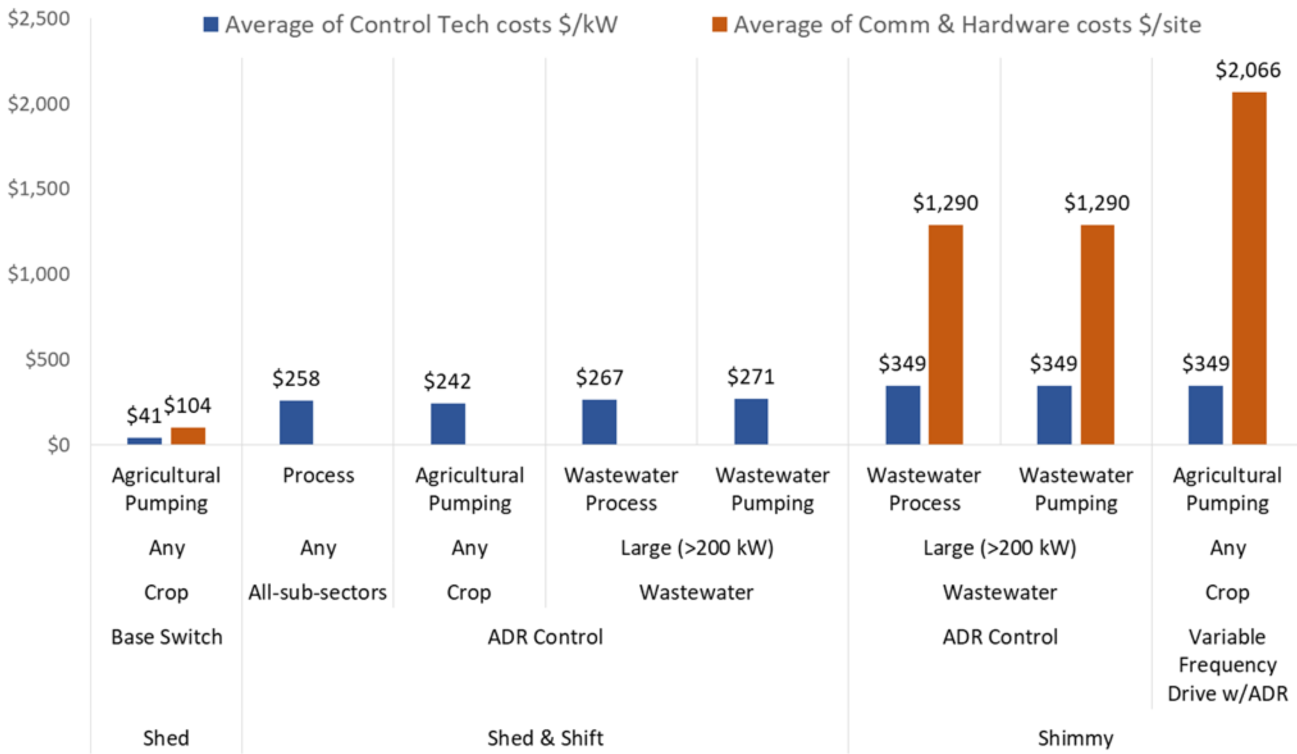

Figure 7: Industrial and Agricultural Sector DR Technology Enablement Costs

5.6.5 Behind-the-meter Battery DR Enablement Costs

Our Battery Storage cost estimates are for behind-the-meter Lithium-ion battery storage technologies for the residential, commercial, and industrial sectors, based on 2017 data (Selmon and Wynne, 2017).[20] We do not attempt to forecast or reflect the rapidly declining costs for Lithium-ion storage technologies.

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). The energy output from a battery can vary considerably because of the duration of discharge and round trip efficiency, even for units with similar capacity. Energy storage systems require equipment such as inverters/converters and specific power electronics to manage the duration and conversion of AC/DC. This equipment, as well as the permitting and interconnection, is commonly called the 'balance of system' (BOS). BOS costs are often not reported by manufacturers; rather, costs are reported only for the energy output ($/kWh) of the battery systems. However, Zakeri and Syri (2015) conducted field research that examined the total installed costs of battery storage systems, which included the cost estimates for BOS ($/kW) in a separate category from the energy output ($/kWh). This study includes the BOS cost estimates from that research.

For this assessment, we report 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). For each of the customer sectors, the BOS costs are $500/ kW, while the storage costs range from $250 to $285 per kWh. In order to provide Shimmy service to the bulk power system, the system costs for the advanced telemetry and communications will be an additional $105- $2,066 per site.

Figure 8 provides the cost estimates for DR enabled battery storage systems for the commercial, residential and industrial sectors. The behind-the-meter battery storage cost data presented here is taken from Alstone et al. (2017) which relied heavily on Zakeri and Syri (2015), along with Akhil et al. (2013).

[20] We focus on Lithium-ion batteries in the study as a representative case for energy storage, but we acknowledge that there are several viable and competitive battery storage solutions on the market, including sodium-based, flow and advanced lead-acid technologies.

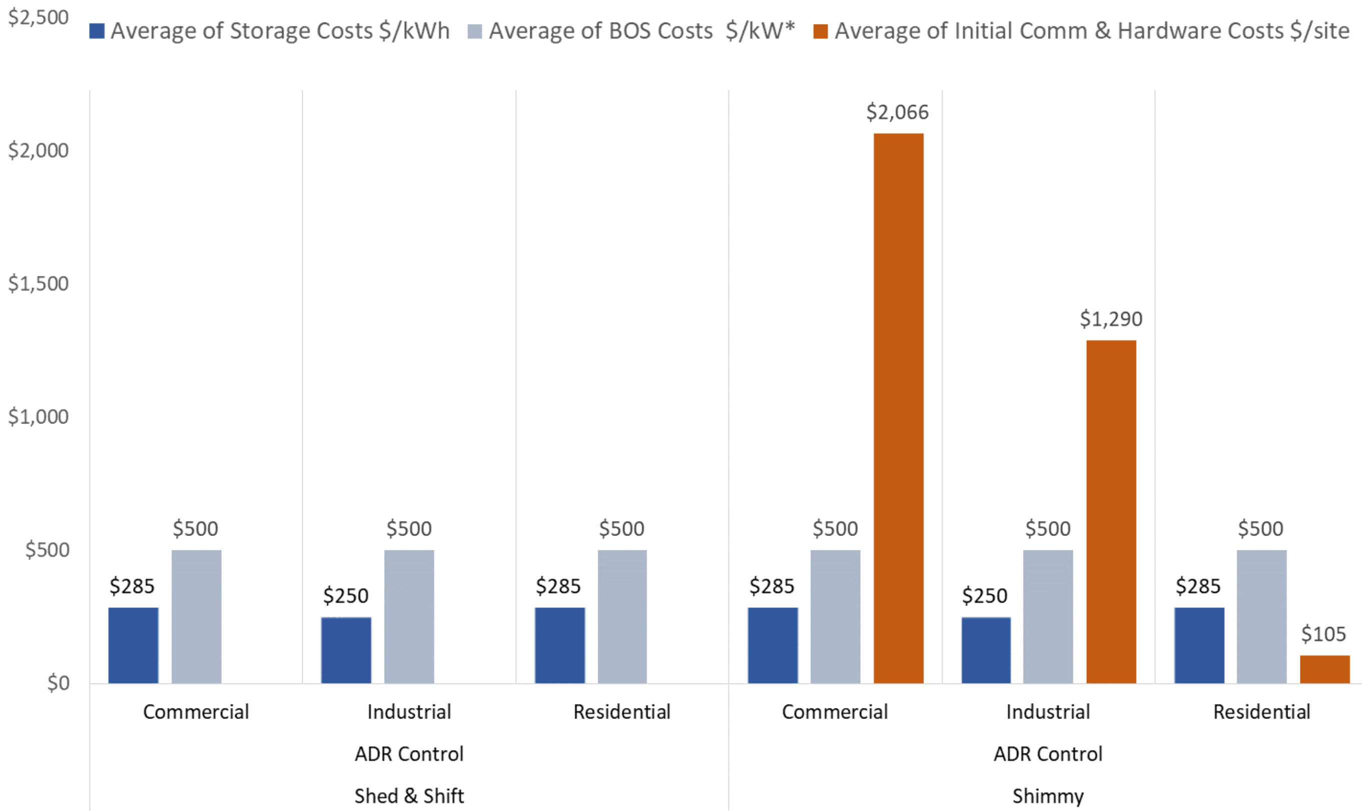

Figure 8: Behind-the-meter Li-ion Battery Storage DR Enablement Costs

**BOS stands for "Balance of System" in energy storage systems. BOS equipment include permitting and interconnection, inverters/converters, and specific power electronics. These costs are often not reported by manufacturers. The breakdown the costs are 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).*

5.6.6 Electric Vehicle DR Enablement Costs

Commercial and residential electric vehicle charging units equipped with control technologies can enable electric vehicles to serve as flexible DR resources and provide Shift services (i.e., both shedding and taking load from the grid). We derive the residential cost estimates from several recent pilot programs, including SDG&E's Plug-in EV Time-of-Use Pricing and Technology Study (Cook et al., 2014) and the U.S. Department of Energy's Smart Grid Investment Grant EV Charging Pilots (DOE, 2014). In the various pilots, utilities report combined technology and installation costs at around $1,300 for residential technologies enabling two-way communication with the EV. The costs included dedicated circuit and meter socket box, a smart charging station with Level 2 power at 240 Volts, and a DC charge port on the vehicle. Costs for Commercial EV chargers are estimated to be higher than for residential applications. Cost estimates for the Commercial EV applications were gathered from EV vendors and California utilities during the California DR Potential Study project and averaged $4,200 for a single port Level 2 charger equipment that enables Shimmy services (Alstone et al., 2017).[21]

Figure 9 presents the cost estimates for EV and PHEV DR enabled charging stations for the residential and commercial sectors.

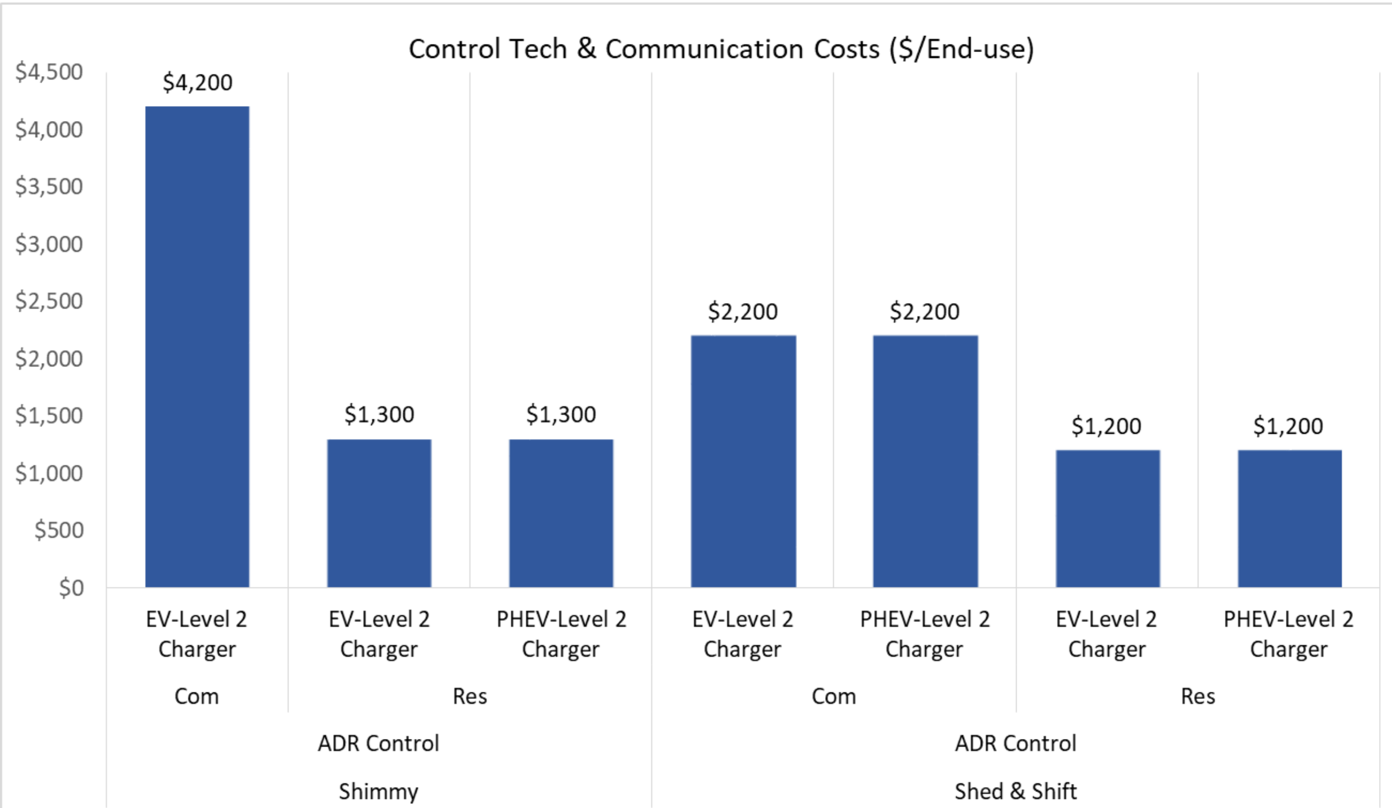

Figure 9: Electric Vehicle DR Enablement Costs

[21] In commercial applications, it is not uncommon to have charging units that enable charging for more than one vehicle, however, this study did not capture those costs.

6 Conclusion

Bulk power system services will continue to evolve as the grid's needs transform with the influx of distributed energy resources, grid scale renewables, and retirement of legacy generation units. With this market evolution and mutable generation fleet, the rules and requirements that govern DR participation in various markets and bulk power systems will adapt to encourage and allow participation from both demand side and supply side resources. To be more specific, DR resources have typically been excluded from AS markets, because there was little evidence that DR could perform in these markets and the technical requirements and rules have historically been too stringent for DR technologies (Cappers et al., 2013). The DR technologies were either unable to (or perceived to be unable to) respond to signals within the required dispatch response, or did not have the appropriate energy measurement infrastructure for participation. Over the last several years, significant improvements have been made to DR technologies signal response time, demonstrating their capabilities to provide various forms of AS. For commercial customers, an EMCS enables data collection and transmittal to a gateway, therefore providing a solution for complying with the energy measurement requirements in many markets. For residential customers, Advanced Metering Infrastructure and the embedded ZigBee radio resource interface permit data transmittal to a gateway and subsequently to an ESP's platform in the cloud (IoT), thereby also complying with market requirements.

The evolution of DR technology functionality and performance along with inconstant grid needs has prompted operators and administrators within organized wholesale markets to re-evaluate the rules governing AS and capacity market participation. In some markets (e.g., NYISO, MISO, ERCOT), this has resulted in permitting DR resources to directly provide a number of services, include spinning reserves and regulation services. In recent years, DR aggregators have entered the market to bid aggregated DR resources into the wholesale market and supplying services that individual loads could not provide. Additionally, we would expect that as the markets evolve, additional services (e.g. load following and shifting) will be introduced in a number of bulk power system markets.

An alternative example of the changing bulk power system landscape and requirements is the PJM market. The rules for participation in PJM's capacity markets were changed in 2017, stating that capacity resources must be able to provide service year-round, as opposed to the previous requirement of availability during summer months. As a result, the technical qualifications for DR technologies and end-uses require adjustment to continue participation in that market. For instance, HVAC units enabled with DR controls are a typical capacity resource that can participate when air conditioning loads are available, typically in summer months. However, air conditioning loads are not available year round and therefore cannot meet the year-round availability requirements for participation in the PJM market.

As bulk power system services and market product definitions advance, manufacturers of DR technologies will likely continue to improve the technical capabilities of advanced technologies to match market needs and provide grid services. As a result, the composition of enablement costs is likely to change over time. Utilities are already introducing new programs aimed at managing their distribution systems with DR and load management (e.g., NYPSC, 2014). New programs that increase the adoption of control technologies will likely influence the costs for advanced enabling technologies.

Furthermore, policies that require utilities to adopt Integrated Demand Side Management (IDSM)[22] programs could result in a market transformation for DR technologies.[23] Program administration costs could decrease with an integrated approach to program delivery. However, the industry needs to develop cost-effectiveness metrics and portfolio optimization frameworks for IDSM that would enable more appropriate cost allocation for DR enabling technologies, EE end-uses, and DERs. This would permit the allocation of costs to other non-DR energy services and potentially improve the cost effectiveness of DR technologies and controls. In addition, utilities and ESPs could accelerate customer adoption of DR technologies and controls. Integrated Demand Side Management offerings that appropriately incentivize end-use controls, automation and efficiency (e.g. smart PV and battery invertors or EE end-uses with embedded DR controls) have the potential to improve the customer value proposition for technologies that improve demand side energy consumption. As a result, customer adoption of integrated end-use technologies should increase, and it would be safe to assume that these integrated resources will become more cost effective.

Over the next few years, we anticipate that the DR communication infrastructure will continue to transition away from paging and FM radio networks to broadband. In order to provide fast Shed and Shimmy services to bulk power systems, ADR technologies need to be connected to a bidirectional communication infrastructure that can reliably control multiple loads simultaneously with low latency, and within a specified response time is necessary. Internet services are capable of providing a fast communication infrastructure for DR services, while the AMI meter typically provides the telemetry. While AMI Meters and the ZigBee radio are capable of dispatching DR signals to devices, in more complex DR architectures where more than one device is controlled, the AMI meter is typically only utilized for telemetry. Advanced DR programs require a more automated bidirectional communication, broadband solutions will become increasingly utilized for DR. This transition could potentially shift the operational costs for DR communication from the ESP/utility to the participating customer. As a result, there are implications for social equity at the residential level, where those households that do not have Wi-Fi (e.g., low income populations) are excluded from participation in DR programs because they do not have the communication infrastructure that enables participation.

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[22] Integrated Demand Side Management can be defined as any two or more of Energy Efficiency as a Resource (EE), Demand Response (DR), distributed generation (DG), and storage (ST).

[23] The industry has been trying to launch IDSM projects for many years and yet there are a limited number of utilities across the country that have been successful. For those utilities that have IDSM, it is typically limited to PCTs that are used for EE and DR. Based on discussions with a number of utilities, there are significant challenges in implementing a holistic IDSM portfolio, primarily due to a lack of a cost effectiveness framework for evaluate a portfolio approach. Essentially, there is a question of how the costs for each component be allocated effectively. There is a concern among utilities that the benefits and energy savings will diminish through an interactive effects. A forthcoming LBNL report on IDSM will provide case study examples of the various barriers and opportunities for implementing IDSM programs and portfolios.

We foresee that energy measurement infrastructure, which enables control, monitoring and measurement of one or more devices in a home or facility, will continue to advance in their technical capabilities and automated functionality. The market will likely continue to develop improvements in gateway system logic which will enable faster response times for dispatch signals, thereby enabling more customers to provide Shimmy-type services. The electric industry's march towards broader and deeper investment in advanced metering functionality (Cooper, 2016) will increase customer accessibility to participate in DR opportunities and technological advancements in the metering and communication capabilities will enable more granular data to be collected. Likewise, this should also create opportunities for more customers to provide Shimmy-type services.

Advance Metering Infrastructure simplifies DR enablement and deployment as the "smart" meters include ZigBee radios that can dispatch DR and price signals to devices and gateways in customer facilities and homes. Most importantly, AMI meters collect interval load data that captures event specific load reductions during an event and can be used for innovative pricing. AMI meters are the backbone of a digital grid and are essential to increasing customer accessibility to participate in DR programs. Furthermore, AMI meters improve the cost effectiveness for deployment of DR technologies, and improve grid operators' visibility of distributed resources. However, despite the fact that roughly 50% of residential household in the US had AMI meters in 2016 (Cooper, 2016), the majority of the residential population did not participate in DR opportunities (FERC, 2016). As deployment of AMI progresses, direction from policymakers is needed to encourage greater utilization of AMI assets for DR and load management. This should seemingly further drive down the enablement costs for DR.

Over the last decade, we have also seen continuous advancements in automation technology, interoperability standards and end-use controls. While the market continues to develop advanced controls, policymakers, utilities, ESPs, and ISO/RTOs are responsible for determining the best application of these resources for supporting the bulk power system and how to best deliver these technologies to customers. While this study examined the total enablement costs for DR advanced controls, there are many non-DR benefits that influence customers' decisions to purchase ADR enabled end-uses or technologies. Demand response advanced controls and technologies have many technical elements that influence the costs, including, the communications infrastructure, the measurement infrastructure, and control infrastructure, all which could be impacted by policy driven market transformation and/or improvements in interoperability standards.

Industry trends for DR include the development of interoperable advanced technologies and platforms that use standardized OpenADR protocols. OpenADR can improve interoperability of control devices and platforms in building and homes, which simplifies the deployment of ADR technologies. An increasing number of manufacturers and vendors (e.g. Digi, Siemens and EnerNoc) are utilizing OpenADR in EMCS, which serves as an internal gateway to devices in the customer facility. Improving and simplifying the automation process can expand the pool of ADR resources that are capable of providing services to the bulk power system by reducing the costs for the EMCS, device controls, installation and programming of the EMCS. We anticipate that the number of OpenADR compliant devices and platforms will increase, which will help utilities capitalize on their grid modernization infrastructure investments (e.g., AMI) and the capabilities enabled by those investments. Since the OpenADR data model interacts with building control systems that are preprogrammed to take action based on a DR signal, the process for DR enablement is simplified and limits the amount of programming required in the EMCS. This simplification could improve DR adoption rates. As the adoption rates for these technologies increase, the costs for the systems are likely to decrease.

All in all, there is reason to believe that the aggregate costs to enable a site or end-use to provide system services are likely to come down in the future, even if particular sub-elements (e.g., communications infrastructure costs) may rise as costs are shifted from ratepayers to participating customers. Also as discussed above, policymakers have a distinct role to play in helping drive those costs down as more opportunities are opened up for customers to provide DR in its many forms and invest in automated control technologies, the more certain measurement and control infrastructure costs can be reduced due to economies of scale.

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