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Driving Towards Fast and Flexible Demand Response Leveraging Distributed Resources

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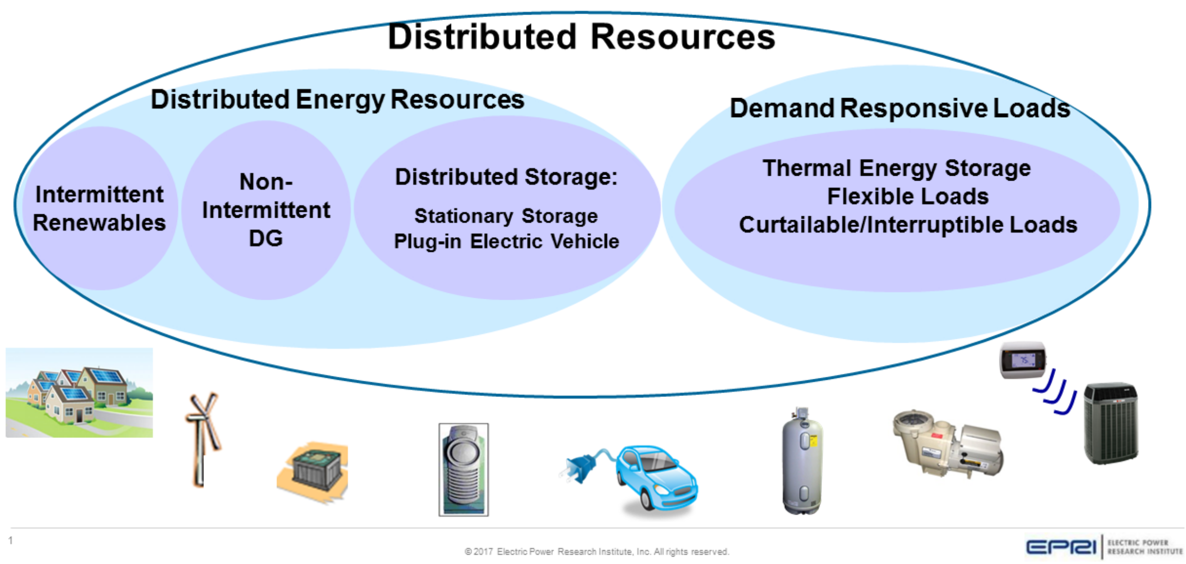

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Technical Update, December 2017

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THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT.

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ABSTRACT

Wholesale electricity markets and regulatory policies are driving an evolution in electricity demand and production, characterized by high penetration of intermittent renewable generation and new roles for distributed electricity systems. In turn, wholesale and retail market and technology evolution are opening new opportunities for provision of valuable services by distributed resources, including distributed energy resources (DER) and demand responsive loads.

The report highlights key trends in market and policy developments impacting demand response (DR) evolution, and resulting implications on DR programs and enabling technology alternatives. The report distills literature reviews and industry interviews to identify promising DR strategies for providing fast and flexible services in select industrial customer sectors, including refrigerated warehouse and data centers. Recommendations are presented on future work needed to mobilize different types of distributed resources to capture growing opportunities for providing fast and flexible DR services, as well as customer-sited DER services.

Utilities and DR practitioners can employ findings from this report to:

- Identify key market and policy developments driving evolution in DR with distributed resources
- Identify the distribution system operator's (DSO's) current and potential future role and functions compared to other stakeholder types in the electric power industry
- Clarify the DSO's essential role in DR evolution, and explain the next stage of DR advancement beyond DR as a "Balancing Resource" to DR as an enabler of price elasticity of demand, especially in high-DER systems
- Better anticipate impacts on DR program and technology evolution
- Prioritize DR research and technology investigation to support growing system needs for flexibility resources in the foreseeable future

Keywords

Demand response strategies
Distributed resources
Distribution system operator (DSO)
Flexible demand response
Information technology
Refrigeration units
Residential rate reform and demand charge

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1 INTRODUCTION

Bulk wholesale electricity markets and regulatory policies are driving an evolution in electricity demand and production. The evolution is characterized by high penetration of intermittent renewable generation replacing traditional fossil-fired generation, as elaborated in a prior EPRI report [1]. The evolution is also characterized by growth of decentralized energy sources connected to the distribution system (i.e., distributed resources), representing a shift from traditional reliance on bulk "centralized" generation [2].

This chapter highlights key developments impacting the current landscape for demand response (DR)[1], and provides an update on the state of demand response, market participation opportunities and associated rules. In particular, market and technology evolution coupled with changing regulatory policy are accommodating growing opportunities for provision of flexible, localized services by distributed resources. The changing landscape in turn drives evolution of DR program requirements, DR strategies, and enabling technology alternatives, which are discussed in ensuing chapters.

State of Demand Response

The latest Federal Energy Regulation Commission (FERC) report on Demand Response and Advanced Metering in 2016 [3], reports an increasing total peak load reduction potential across United States (U.S.) Independent Systems Operators and Regional Transmission Organizations (ISO/RTOs). This includes Pennsylvania-New Jersey-Maryland (PJM), ISO New-England (ISONE), New York ISO (NYISO), Midcontinent ISO (MISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP) and California ISO (CAISO). The DR potential was 31.8GW in 2015, compared to 28.9GW in 2014. In comparison, the combined peak demand of the seven U.S. ISO/RTOs exceeded 466 GW in 2014 and 481 GW in 2015, respectively [3]. The total peak load reduction potential increased not only in total GW amount, but also as a percentage of combined peak demand from 6.2% of peak demand in 2014 to 6.6% of peak demand in 2015. Moreover, FERC cites peak reduction potential from retail DR programs amounted to 31.2GW in 2014, compared to 27.1GW in 2013.

More recent findings published by Greentech Media (GTM) Research cite a total of 31GW of DR capacity across U.S. ISO/RTO markets [4]. This is based on total available DR during the third quarter of 2017 in those ISO/RTOs.

Interesting enough, several ISO/RTOs procured less DR capacity during more recent years compared to prior year results. For example, for the 2017/2018 capacity auction year, PJM DR capacity was reportedly 11,220MW compared to 11,909MW for 2016/2017, representing about a 5.8% decrease in DR capacity collectively in PJM's Economic DR, Load Management DR, and Capacity Performance programs [4]. The drop in DR capacity may be explained by changes in regulatory policy, market rules, and market conditions that create more challenges for DR

[1] Demand response is a dynamic change in electricity consumption coordinated with system or market needs [10].

participation. Changing conditions in turn require utilities, DR aggregators and DR service provides to adapt to evolving policy and market conditions. DR capacity in CA investor-owned utility programs also declined from 21,60MW in 2015 to 1996MW in 2016, representing a 7.6% decrease. The reason for this, cited in the analysis, was "mainly attributed to declining enrollments in price-responsive utility DR programs as a result of customer fatigue due to stringent requirements."

In contrast, MISO experienced increased DR capacity compared to the previous year. The total DR capacity of MISO in August 2017 was 12,363MW compared to 11,922MW during the same month of 2016, representing about a 3.7% increase. The majority of the increased DR capacity in MISO came from Load-Modifying Resources for Demand Response (LMR-DR) and Load-Modifying Resources for Behind-the-Meter Generation (LMR-BTMG). For the other four ISOs/RTOs, DR capacity data in [2] for Third Quarter 2017 reported 2222MW in ERCOT, 1500MW in SPP, 1267MW in NYISO, and 748MW in ISO-NE.

Another report [5] published by Smart Electric Power Alliance (SEPA) cities a total of 15.1 GW of demand response capacity in 2017 across 104 utility survey respondents within five U.S. ISO/RTO regions, not including MISO and SPP. This includes 9100 MW of respondent utility DR capacity within PJM footprint, 350 MW DR capacity within ISONE, 1150 MW DR capacity within NYISO, 2500 MW DR capacity within ERCOT, and 2000 MW DR capacity within CAISO, respectively. Overall, significant opportunities continue to be captured by demand-side resources in support of power system and market operations.

Major Policy Drivers Impacting Change

In addition to technological advances and cost factors, energy and environmental policy initiatives that are driving a paradigm shift in the electric power industry are also impacting the future of demand response. Major drivers include:

- Regional renewable portfolio standards
- Greenhouse gas reduction goals
- Policies encouraging accommodation of distributed energy resources in markets and distribution systems
- Retail electricity rate reform, including time-of-use rates and demand-based rate structures

Renewable Portfolio Standards Driving Growth in Renewable Capacity

A National Renewable Electricity Laboratory (NREL) report [6] cites new renewable capacity contributed 64% percent of total capacity additions in the U.S. in 2015, compared to 52% the prior year. However, renewable energy generation increased by only 2.4% from 2014 to 2015. The report also attributes global renewable generation to comprise 29% of total worldwide generation capacity, or 24% of global energy generation. U.S. renewable electricity, however, represented about 16.7% of total U.S. installed capacity in 2015, or 13.8% of total generated electricity that year [6].

The growth in renewable generation has been driven by regional Renewable Portfolio Standards (RPS). For example, many U.S. states have targets at or exceeding 20% renewable energy generation in by Year 2020. California and Hawaii currently have the most aggressive targets in the U.S., with California targeting 50% RPS by 2030 and Hawaii targeting 100% RPS by Year 2045.

Growing Need for Flexibility Services

As explained in a prior EPRI report [1], significant rapid growth in installed capacity of renewables is causing the need for greater system flexibility to balance intermittent generation. The significant rise and fall in output of intermittent generation sources like solar and wind power creates a net load (e.g., system load minus renewable output) that must be served by remaining resources.

Figure 1-1 from a CAISO study [7] illustrates evolving system needs for flexibility in California. The figure illustrates ramping energy needed to replace lost solar power as the sun sets during a typical spring day in 2012 and subsequent years through 2020. As indicated in the figure, CAISO experienced over 10.8 GW of ramping energy required within a three-hour period on February 1, 2016. Even greater ramping energy needs on the order of 13GW within three hours are forecasted for Year 2020. Even so, the CAISO reportedly is experiencing steep ramp requirements much sooner than originally forecasted. As Figure 1-1 indicates, net load at the belly of the duck was even lower on May 15, 2016 than forecasted for Year 2020.

This highlights the growing need for flexibility services to provide ramping energy and assist system operators with the challenge of balancing supply and demand in the face of high intermittent renewable generation. New flexibility products are being defined and procured in electricity markets to help system operators balance supply and demand in the face of large system ramps [8]. As regional markets expand, such as the Energy Imbalance Market (EIM) of the CAISO, more resources across a larger geographic area can help balance supply and demand in real-time. Market opportunities are also expanding for distributed resources including non-generation resources like distributed storage, electric vehicles, and demand responsive loads to help meet the challenge, which is discussed in Chapter 2.

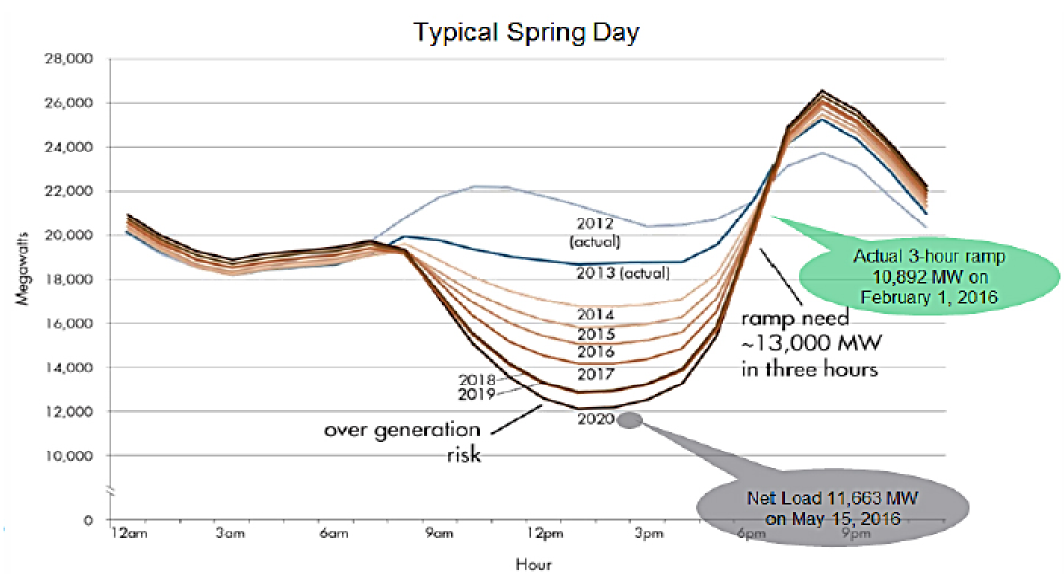

Figure 1-1
Steep Ramping Needs Illustrated by California ISO Duck Curve on a Typical Spring Day (Source: CAISO [7])

Negative Market Prices and Renewable Curtailments due to Overgeneration

Over-generation conditions occur during times when renewable generation is in abundance compared to system demand. Over-generation conditions in CAISO have increasingly led to negative wholesale market prices as well as renewable curtailments, particularly during spring and fall as well as periods of the summer, as previously reported in [1]. With the expansion of regional markets like the EIM, out-of-state purchases of over-generated electricity is made possible. At negative prices, this strategy equates to being paid for consuming electricity by EIM participants who can take delivery of over-generated energy.

Negative wholesale prices along with rising need for ramping capability and mitigation of renewable curtailments, together point to a potential role for DR to help balance intermittent supply. Load shifting can also mitigate curtailment of renewables, by increasing load during hours of projected need for avoid renewable curtailment. These trends in renewable growth and resulting flexibility challenges are driving DR evolution to favor fast-responding and flexible resources that can be dispatched to provide ramping energy and other system balancing services (e.g., balancing energy and frequency regulation). Regional operators like CAISO and MISO have expanded opportunities for resources to help balance intermittent renewable generation, by defining ramping reserve products and other flexibility services [8].

Additional policy drivers also impacting DR programs and driving DR evolution are described next.

Greenhouse Gas Reduction and Energy Efficiency

Regional policies and goals to achieve reduction of greenhouse gas (GHG) emissions are gradually changing the types of consumer equipment deployed, including their fuel source. GHG emission reduction goals are compelling beneficial electrification opportunities to be examined region by region. Considerations include electrifying transportation, industrial sector equipment, heating equipment, and/or space conditioning systems to help achieve greater efficiency gains while enabling productivity gains for the end customer. In some cases, beneficial electrification may lead to technology deployments that can be leveraged for DR (e.g., electric vehicle adoption electrifying transportation may potentially also support DR programs).

Energy efficiency upgrades have also been used as a method for achieving emissions reductions. Moreover, greater energy efficiency has been demonstrated through electrifying select end-uses through fuel-switching (e.g., natural gas to electricity). The electrified end-use or energy efficiency upgrade, in turn, may provide a potential source for engagement in demand response. For example, inverter-based systems (e.g., variable capacity space conditioning systems, variable speed pumps, etc.) not only have been tested to be more efficient than single or dual stage system equivalents, but also are potentially more flexible in operation. The inherent flexibility characteristics of electric variable capacity systems could potentially be matched with system flexibility needs, to provide a viable source of fast and flexible DR.

Accommodation of Distributed Resources in Markets and Distribution Systems

Initiatives at the state and federal levels are driving accommodation of distributed resources in wholesale electricity markets as well as in distribution systems. For example, under the New York State Public Service Commission (NYPSC) proceedings on Reforming the Energy Vision (REV), the NYPSC has mandated all New York distribution utilities to expand DR programs and encouraged utilities to work with third parties (e.g., DR aggregators or curtailment service providers, solar companies, energy storage) to accommodate potentially high penetrations of distributed resources. Similarly, California agencies and the CAISO are engaged in proceedings and initiatives to accommodate distributed resources in utility distribution systems and wholesale markets, respectively. Moreover, FERC's Notice of Proposed Rulemaking (NOPR) on storage and distributed energy resources [10], issued in November 2016, seeks to mitigate barriers for distributed resource participation in wholesale electricity markets. Many ISO/RTOs have expanded opportunities for distributed resources to participate in wholesale markets, as detailed in Chapter 2.

Such drivers accommodating broad-based integration of distributed resources in markets and distribution systems is indicative of broad-sweeping changes coming in distribution planning practices and distribution operational functions like monitoring, control and settlement. To better accommodate high penetration of distributed resources, new planning and operational practices are needed in distribution system management. Chapter 3 describes the role of the distribution system operator (DSO), and identifies the functions it performs in comparison to existing power industry stakeholder types in North America. The chapter highlights the distribution management processes needing to be updated to accommodate widespread distributed resource integration.

Central to discussions is how distribution utility business models may evolve, compared to existing practices for earning a rate of return. Resulting technology impacts are far-reaching, extending from customer DER to distribution management; as well as interfaces between utilities, third parties, and ISO/RTO systems.

Electricity Rate Reform to Better Align Retail Pricing with Wholesale Costs

The electric power industry is a capital-intensive industry, with the majority of costs stemming from build out, management, operation and maintenance of high-value generation and substation assets as well as grid infrastructure. A recent international survey published in a CIGRE Symposium paper in [12] found that although utility costs primarily are comprised of capacity-related costs, utility revenue from retail customer billing is generally dominated by volumetric energy charges, wherein the primary billing determinant is measured energy consumption (kWh).

As explained in [12], "Regions enjoying cheaper electricity may have less concern with cost reflectivity issues in retail pricing, especially for residential customers that have traditionally been priced based on flat rates or inverted block tier rates. However, when electric service costs significantly rise compared to other costs incurred by customers as new technologies emerge, employing simple pricing structures may no longer suffice." New technologies like distributed generation, solar, storage, and electric vehicles are compelling investigation into retail electricity rate reform. In the absence of rate reform, volumetric energy charges that do not fully recover the cost of electric service and reliability provision enjoyed by prosumers of electricity (e.g., solar DG customers) do not reflect a sustainable billing arrangement.

An EPRI whitepaper [11] discusses the relationship between measured demand (or capacity usage measured in kW) and electric service reliability, highlighting the need for greater transparency over the demand component of electric service in customer bills, especially residential customer electric rates, if retail pricing is to better align with wholesale costs. The whitepaper provides various examples of demand-based pricing schemes.

Figure 1-2 highlights (inside red boxes) a few DR program types utilizing demand-based pricing. The two red boxes highlight methods that vary by participation or engagement model employed. Time-of-Use Demand Rates provide an alternative pricing mechanism based on measured demand usage, such as maximum measured demand for the month during peak hours or some variant. On the other hand, Demand Limiting and Demand Subscription type programs utilize technology to enforce maximum demand levels pre-designated by the customer. Customers are priced according to their demand limit or subscription level. Whereas Demand Limiting arrangements enforce the customer-designated limit upon service connection or seasonally, Demand Subscription programs can enforce limits on critical days or during critical hours only, so are more dispatchable by design. Each of these demand-based pricing programs have been trialed or can be found in effect in different regions around the world.

Engagement Model **Timeframe**	**Alternative Pricing & Rates** *(participant pays more without DR)*	**Direct Incentive** *(participant is paid for DR)*	**Public Cooperation** *(no financial exchange for DR)*	**Variable Service Subscription** *(more participant choice using DR)*
Seasonal	**Time-of-Use of:** Energy Demand	**Conservation Credit** **Capacity Program**	**Public Conservation Appeal**	**Demand Limiting upon:** Service Connect Seasonal Peaks
Day-ahead	**Dynamic Pricing:** Critical Peak Pricing Day-ahead Pricing	**Day-Ahead Program** Energy Economic	**Public Appeal for:** Voluntary Economic Demand Response	**Demand Subscription for:** Critical Days Only
Day-of	Real-time Pricing **Discounted Rate for Dispatchable:** Direct Load Control Interruptible Load Curtailable Load Standby Generation	**Paid-for-Performance for Dispatchable:** Direct Load Control Interruptible Load Curtailable Load Standby Generation	Voluntary Emergency Demand Response Pre-planned Voluntary Interruptible / Curtailable Load **Rolling Blackout**	Critical Hours Only **Premium Power** **Better-Served-for-Performance** **Priority Service**

Figure 1-2
Framing Demand Response Program Types (Source: [12])

Demand-based pricing can affect a desired change in load (i.e., demand response). For Time-of-Use type programs, the change in load is affected on a seasonable basis. Prior analyses conducted by EPRI showed an overall reduction in both total energy and peak demand achieved on average by a collection of customers that transitioned to APS' TOU Demand Rate in 2013 for which data was provided to EPRI for analyses. Findings are shown in Figure 1-3. The left-hand plot in the figure compares the monthly total energy consumption of the customers in 2012 when they were on APS' TOU Energy Rate, to their energy consumption in 2014 when they were on the demand rate. Under the demand rate, total monthly energy use decreased during the summer months when pricing for demand was higher.

The right-hand plot in Figure 1-3 compares average on-peak demand usage for the same collection of customers for the year before and the year after they transitioned to the TOU Demand Rate. The figure shows weather-normalized results. For the most part on-peak demand usage decreased during APS' defined summer period (e.g., May through October), except during the month of July when the same levels resulted (possibly due to unseasonable hot weather on record for July 2014). The analyses concluded demand rates can reduce average demand usage, though not necessarily during an abnormally hot month.

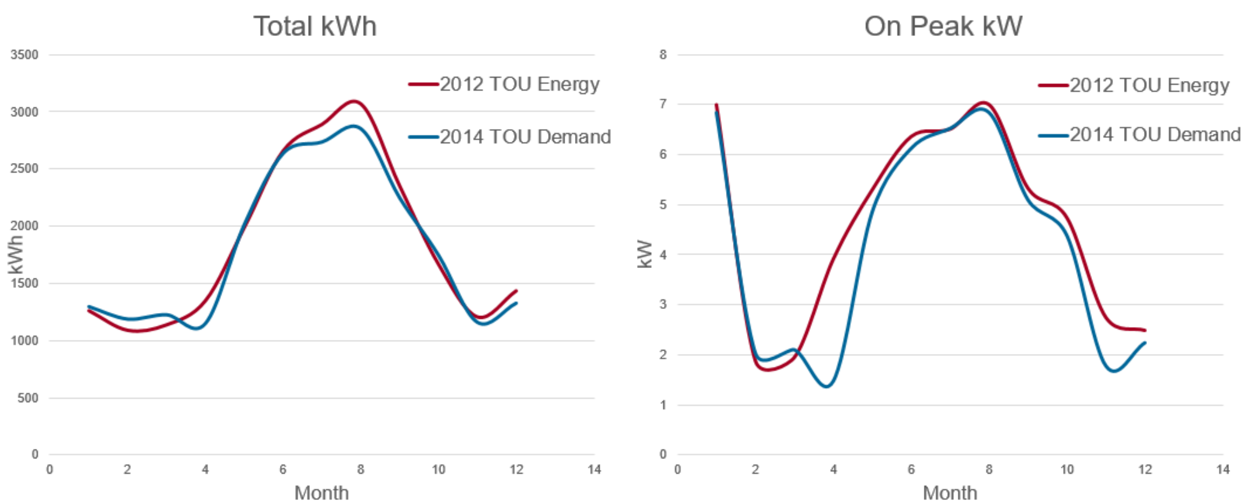

Figure 1-3
Total Energy (kWh) and Average On-Peak Demand (kW) Usage for a Collection of APS Residential Customers on a TOU Energy Rate in 2012 Versus a TOU Demand Rate in 2014

As remarked in [12], “Cost-reflective pricing mechanisms are, however, also tempered by concerns for simplicity and stability of rate design and receptivity of the public served. Moreover, customers differ in their willingness to engage in new electric service plans and programs. For example, a prior study [13] indicated that about 20% of customers are actively interested and able to manage their electric energy consumption, while another 20% are interested as long as no additional costs are involved, and the remainder are either too busy or electricity costs are too insignificant to cause” behavioral change.

Implications on Demand Response

Policy drivers are mandating more renewable generation, lower GHG emissions and accommodation of broad-based DER integration, as end-use loads become more energy efficient. These policy drivers along with technology advancements (e.g., in storage and communications) and economic incentives are together driving evolution of the DR landscape and the sources of DR that can best capture value. DR programs and DR aggregator platforms have been expanding to include alternative energy resources such as distributed storage, electric vehicles, and clean sources of distributed generation, to achieve higher levels of optimization of program offerings and dispatch outcomes.

Growing penetration of intermittent renewable generation is driving system and market operators to call for greater flexibility in resource capability, in wholesale and retail markets. This points to an opportunity to identify customer resources with flexible response capabilities for aggregation in DR programs and to deliver higher value service offering. Opportunities include providing flexible services like flexible ramping and frequency regulation to capture growing opportunities to support renewable integration. For example, battery storage technologies have reportedly been employed to provide frequency regulation services in PJM and CAISO, respectively. Beyond batteries, different types of end-use loads may also prove capable of providing flexibility services (e.g., water heating, water pumping, pool pumping, refrigeration, etc.).

Alternative retail pricing structures including demand rates have gained attention in recent years, with the possibility of including demand-based billing components in residential customer billing or another metric reflective of infrastructure capacity value. Rate reform investigations are being compelled by seeming inequities as high DG production displaces grid-purchased power under a volumetric rate structure; yet prosumers of the DG utilize the grid for reliability backup services, without necessarily being charged commensurate with the cost of the reliability services enjoyed.

As a result of the described policy and market drivers, implications on DR programs and technologies include anticipating the need for:

- Updating DR programs and investigating enabling technologies supportive of changing market requirements for flexibility services, as well as grid locational services. Beyond fast DR curtailment services, customer resources that provide flexible DR or customer locational DR need to be considered to potentially capture higher value as system needs evolve.
- Aggregating DR assets available to provide response during desired times (e.g., by season, time of day, or year-round) and dispatch conditions.
- Identifying DR operational strategies workable for customers, as well as the type of equipment from different customer sectors that can support targeted services
- Leveraging energy efficiency incentives and beneficial electrification initiatives to also expand DR resource capacity through energy efficient upgrades or electrified end-uses, in coordination with EE programs.
- Investigating methods to better position retail electric service plans (with a combination of retail electricity pricing and customer electric service choices) to capture value in wholesale markets, and make more transparent wholesale cost components that customers can readily impact (e.g., capacity-based charges that are not transparent on the customer bill).

Report Organization

Chapter 1 of this report identifies key policy drivers for DR evolution and implications on DR programs. Chapter 2 identifies market opportunities, participation rules, and technical requirements for enabling technology alternatives to support evolving grid needs. To accommodate broad-based integration of distributed resources on distribution systems, the envisioned role of the Distribution System Operator is summarized in Chapter 3, based on literature review. The chapter concludes with remarks on the role of the DSO as an enabler to more advanced stages of DR. Chapter 4 identifies strategies for provision of fast and flexible DR services by employing specific controllable equipment typically found in select industrial customer sectors. The report concludes with summary remarks and recommendations for future research and technology testing needed to mobilize significant contribution of flexibility resources from customer sectors, including DR from distributed resources.

2
DEMAND RESPONSE WITH DISTRIBUTED RESOURCES

Types of Distributed Resources

The evolution of the industry landscape for demand response includes market changes to better accommodate participation of distributed resources. In this report, the term distributed resources refers to both distributed energy resources (DER) capable of producing electricity as well as demand responsive loads capable of adjusting power consumption. As illustrated in Figure 2-1, types of distributed resources include loads that can decrease and/or increase consumption with or without thermal storage capacity. Distributed resources also include DER, which can be categorized into renewable sources (e.g., wind turbine, solar rooftop), fossil-fueled DG (e.g., microturbine), and distributed storage (e.g. stationary distributed storage, plug-in electric vehicle).

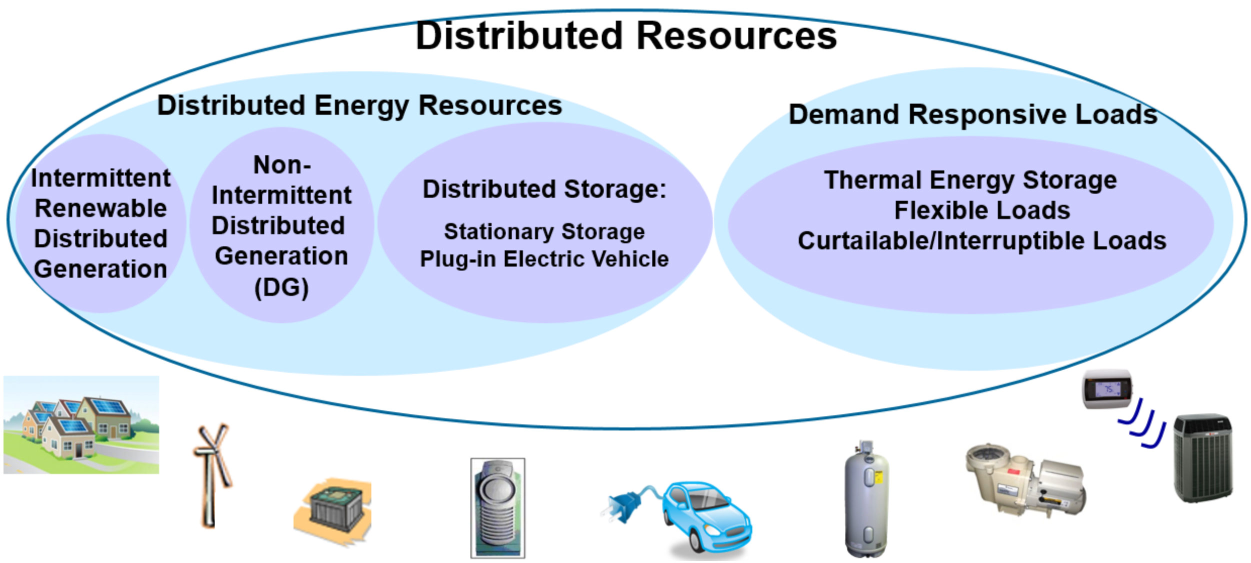

Figure 2-1
Types of Distributed Resources Capable of Providing Demand Response (Adapted from [27.])

Examples of the various types of distributed resources described are shown at the bottom of Figure 2-1, and can be grouped into the described categories shown at the top of the figure. The groupings were chosen to reflect general variation in physical capabilities as well as potential variation in program requirements governing distributed resource participation. Considering differences in technical capabilities and participation requirements, it is useful to group distributed resource types by: 1) intermittent renewables, 2) non-intermittent DG, 3) distributed storage, and 4) demand responsive loads, under which further subcategories of loads exist that differ by response capability.

Consistent with prior publications [23] [24], demand response (DR) refers to an adjustment in electricity consumption coordinated with electric power or market needs. The adjustment in consumption is achieved with distributed resources that can be operationally altered to impact power usage (e.g., interrupted, curtailed, energized, or dispatched to higher levels of consumption) through provisions in utility or market DR programs. Consequently, DR refers to a valuable service that distributed resources can provide, as arranged through market or DR program provisions.

Although traditionally provided by demand responsive loads, DR today is increasingly being provided by DER. Figure 2-2 differentiates distributed resource types, based on the resource's ability to consume and/or produce electricity. As illustrated in the figure, distributed energy resources like distributed generation (DG) and distributed storage differ from demand responsive loads, in that loads can only consume electricity whereas DER can produce electricity. However, distributed storage both consumes electricity and produces electricity, whereas thermal energy storage (TES) devices (e.g., water heaters) can only consume electricity, albeit more flexibly than other types of loads without inherent storage capacity.

Capabilities of demand responsive loads range from interruptible or curtailable loads that reduce power consumption upon dispatch, to flexible loads that can also strategically increase power consumption in coordination with system needs. The capability of a resource to deliver a targeted increase in power consumption is referred to as flexible DR in this report, a characteristic that is gaining importance as system operators seek to balance intermittent renewable generation.

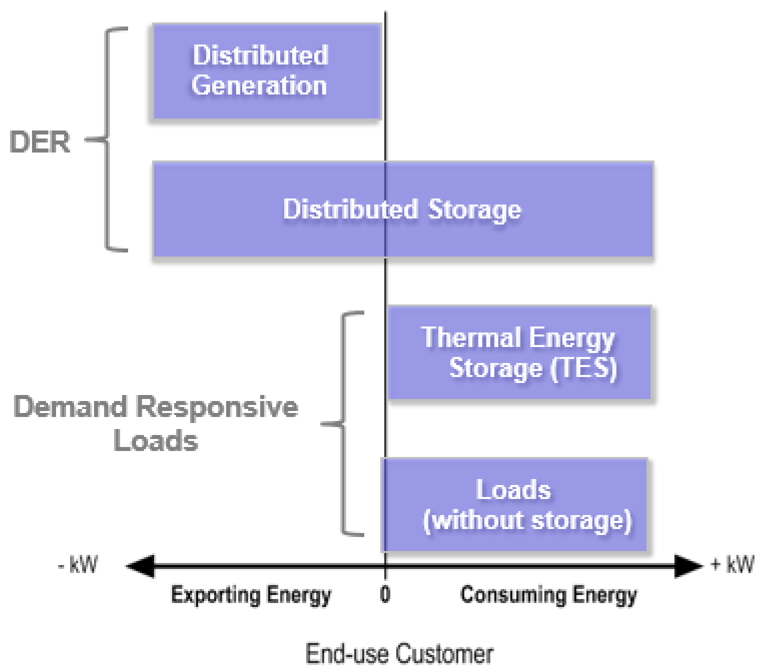

Figure 2-2
Distributed Resource Types Differentiated by Capability to Consume and/or Produce Electricity

DER supportive of DR is connected to the electric grid at distribution voltage levels. DER may be located behind the utility meter or in front of the meter. Behind the utility meter, DER output is commonly netted with overall facility electricity consumption, impacting net facility load measured at the utility meter. Alternatively, DER could be metered separately from facility load, as dictated by requirements of the particular market opportunity or utility program for demand response the DER is participating in. The cateogrizations of distributed resource types shown in Figure 2-1 and Figure 2-2 reflect potential variations in technical capability and participation requirements by resource type.

Advancing Market Opportunities for Distributed Resources

Issued in November 2016, FERC's Notice of Proposed Rulemaking (NOPR) on Storage and Distributed Energy Resources [10] seeks to mitigate barriers for DER participation in wholesale electricity markets.

DER could displace some power supplied by centralized generation, minimize transmission and distribution losses, including transmission and distribution costs, which represent significant portions of total infrastructure cost. Distributed resources have the potential of complementing centralized power generation by providing incremental capacity to the electric power system or directly serving end uses. Installing distributed resources at or near the point of use can provide additional benefits by avoiding or reducing the cost of transmission and distribution system upgrades, or by providing additional flexibility in addressing local control, reliability, scheduling, and other operational issues. Furthermore, for applications requiring variable levels of electric service, DER can offer alternatives for reliable, low cost, premium, green, and/or local power for homes and businesses.

EPRI interviewed North American ISO/RTOs during 2017 to provide an update on the market opportunities and participation requirements for distributed resources. Figure 2-3 through Figure 2-5 summarize findings. Figure 2-3 identifies what types of distributed resources are allowed to participate in which markets operated by six respondent ISO/RTOs. The figure provides market context for discerning participation requirements laid out in subsequent figures. The figures enable side-by-side comparison of ISO/RTO markets in terms of the specific market products permitting distributed resource participation as well as specific participation requirements. The figures represent a significant advancement in market evolution to accommodate distributed resources, compared to prior findings published by EPRI in 2009 [27]. Whereas DR was accommodated in select markets in 2009, today more forms of distributed resources including DG and storage are being accommodated uniformly across markets (or will soon be accommodated in the case of ISO-NE[2]).

Types of Distributed Resources that can Participate in Different ISO/RTO Markets

Figure 2-3 identifies distributed resource types permitted to participate in the market product represented in the row that is operated by the ISO/RTO represented in the column. Table entries include a combination of the following:

- DR (interruptible, curtailable, or flexible loads)
- DG (distributed generation)

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[2] In the figures, the asterisks shown under ISO-NE entries for provision of regulation products and ancillary service operating reserves (e.g., spin and non-spin) denote requirements to take in effect on June 1, 2018, upon ISO-NE's implementation of planned market changes.

- Storage (distributed storage)
- Renewable (intermittent renewable generation)

Entries are grayed out where product markets or opportunities do not exist.

A "DR" entry in Figure 2-3 means behind-the-meter loads can participate; whereas an entry of "DG" or "storage" means DG or distributed storage is permitted to participate in the listed market. For example, the first entry under the column "CAISO" denotes that DG, storage, as well as capable demand responsive loads[3] are permitted to participate in CAISO's frequency regulation market.

Qualifiers are also noted in table entries of the figure, such as MISO reportedly allowing behind-the-meter DG and storage to participate in its frequency regulation market but not demand responsive loads. Moreover, the asterisks shown under ISO-NE entries for provision of regulation products and ancillary service operating reserves (e.g., spin and non-spin) denote participation is allowed starting June 1, 2018 for all distributed resource types including DR, DG, storage, and renewable.

Product	ISO-NE	NYISO	PJM	MISO	ERCOT	CAISO
Regulation	*	DR, storage	DR, DG, storage, renewable	DG behind the meter, storage	DR, DG, storage	DR, DG, storage
10 Minute Spin	*	DR (modifying the load)	DR, DG, storage, renewable	DG behind the meter	DR, DG, storage	DR, DG, storage
10 Minute Non-Spin	*	DR, DG, storage		DR		DR, DG, storage
30 Minute Non-Spin	*	DR, DG, storage			DR, DG, storage	
RT Energy	DR, DG, storage, renewable	DG, storage, renewable	DR, DG, storage, renewable	DR, renewable	DR, DG, storage	DR, DG, storage, renewable
DA Energy	DR, DG, storage, renewable	DR, DG, storage, renewable	DR, DG, storage, renewable	DG behind the meter	DR, DG, storage	DR, DG, storage, renewable
Capacity Market	DR, DG, storage, renewable	DR, DG, storage, renewable	DR, DG, storage, renewable	DR, DG, storage, renewable (for Resource Adequacy)		DR, DG, storage, renewable (for Resource Adequacy)

* Participation is allowed starting June 1, 2018 for all distributed resource types including DR, DG, storage, and renewable

Figure 2-3
ISO/RTO Market Opportunities for Distributed Resources

Findings generally indicate commonality across ISO/RTOs to accommodate different types of distributed resources. Whereas initial opportunities for DR originated in capacity and energy markets, today ISO/RTOs are increasingly accommodating distributed resource provision of ancillary services (e.g., spin and non-spin) and other reliability services (e.g., frequency regulation). However, participation requirements are more stringent for provision of reliability services, as evident in the subsequent two figures.

[3] Flexible loads like electric vehicles can participate in frequency regulation under CAISO's Non-Generating Resource (NGR) model.

Minimum Resource Size and Aggregation Requirements

Figure 2-4 identifies minimum size requirements for a distributed resource to be permitted to participate in the listed market product in the row of the ISO/RTO in the column. Table entries also note whether aggregation is permitted to reach the minimum size.

Minimum resource sizes range from 100kW to 1 MW across ISO/RTOs. In most cases aggregation is allowed to meet minimum size requirements. In select cases (e.g., MISO regulation and day-ahead energy) aggregation had not yet been allowed at the time of investigation in 2017. Generally, within each ISO/RTO, minimum size requirements are least stringent for capacity products and most stringent for reliability products like frequency regulation and ancillary service operating reserves (e.g., spinning and non-spinning reserves).

Product	ISO-NE	NYISO	PJM	MISO	ERCOT	CAISO
Regulation	1 MW* (aggregation allowed)	1 MW (aggregation allowed)	0.1 MW (aggregation allowed)	1 MW	0.1 MW	0.5 MW (aggregation allowed)
10 Minute Spin	0.1 MW* (aggregation allowed)	1 MW (aggregation allowed)	0.1 MW (aggregation allowed)	1 MW	0.1 MW	0.5 MW (aggregation allowed)
10 Minute Non-Spin	0.1 MW* (aggregation allowed)	1 MW (aggregation allowed)		1 MW (aggregation allowed for DRR Type I)		0.5 MW (aggregation allowed)
30 Minute Non-Spin	0.1 MW* (aggregation allowed)	1 MW (aggregation allowed)			0.1 MW, Aggregation Allowed	
RT Energy	0.1 MW (aggregation allowed)	1 MW (aggregation allowed)	0.1 MW (aggregation allowed)	1 MW (Exception: 0.1 MW for EDR and LMR) (aggregation allowed for DRR Type I)	0.1 MW, Aggregation Allowed	0.1 MW (aggregation allowed)
DA Energy	0.1 MW (aggregation allowed)	1 MW (aggregation allowed)	0.1 MW (aggregation allowed)	1 MW	0.1 MW, Aggregation Allowed	0.1 MW (aggregation alowed)
Capacity Market	0.1 MW (aggregation allowed)	0.1 MW (aggregation allowed)	0.1 MW (aggregation allowed)	0.1 MW (aggregation allowed)		Resource Adequacy: 0.1 MW (aggregation allowed)

Figure 2-4
Minimum Size and Aggregation Requirements for Distributed Resources

Telemetry Requirements

System operators rely on supervisory control and data acquisition systems (SCADA) to provide a real-time operational view of the bulk electric power system. SCADA systems provide the operator with real-time monitoring through telemetry of the electric power grid's major assets, including resources and major loads connected to the power system.

Product	ISO-NE	NYISO	PJM	MISO	ERCOT	CAISO
Regulation	4 seconds for DR*, same for Generator	6- second resolution (ICCP)	2 to 4- second resolution (ICCP)	2-second resolution (ICCP)	2-seconds (DNP 3)	4-second
10 Minute Spin	1 minute for DR*, 10 sec for Generator	6- second resolution (ICCP)	N/A	10-second resolution (ICCP)	2-seconds (DNP 3)	4-second
10 Minute Non-Spin	1 minute for DR*, 10 sec for Generator	6- second resolution (ICCP)		10- second resolution (ICCP) (Exception: For DRR Type I after-the fact metering with 5 min. resolution suffices)		4-second (1-min scan for PDR, 4-sec scan for NGR)
30 Minute Non-Spin	5 minute for DR*, 10 sec for Generator	6- second resolution (ICCP)			2-seconds (DNP 3)	
RT Energy	5 minutes for DR, 10 sec for Generator	N/A (Except for RT energy dispatched from AS Capacity as stated above)	N/A	4- second resolution (ICCP) (Exception: For DRR Type I after-the fact metering with 1 min. resolution suffices)	N/A	4-second (5-min scan)
DA Energy	N/A	N/A	N/A	N/A	N/A	N/A (for small resources)
Capacity Market	N/A	N/A	N/A	N/A		N/A

Figure 2-5
ISO/RTO Telemetry Requirements

Figure 2-5 summarizes minimum status update requirements for telemetry imposed on DR resources participating in the market product listed in the row for the ISO/RTO in the column. As evident from Figure 2-5, telemetry status update rates range from 2-seconds to 10-seconds. This is a function of existing SCADA system configurations of ISO/RTO Energy Management Systems utilized in bulk transmission real-time system operations. Generally, such telemetry requirements on the order of seconds are costly to meet, especially for smaller resources or small aggregations of loads (e.g., 100kW in resource size).

Telemetry requirements generally pose a barrier to greater distributed resource participation in ISO/RTO markets. Lower cost solutions are needed. Indeed, many of the ISO/RTOs EPRI interviewed in 2017 reported internal efforts with stakeholders to examine lower-cost telemetry alternatives to accommodate more DR participation. Advancements in this area pave the way for greater DR participation in wholesale markets, where tremendous value for DR originates and has the potential to be captured.

In select cases, telemetry requirements have been relaxed or pose no hurdle for DR participation. For example, PJM requires telemetry of DR resources only when participating in its frequency regulation market, unlike all the other ISOs that require telemetry of DR providing ancillary service operating reserves (e.g., spinning reserves and non-spinning reserves). Not having to overcome the cost hurdle to meet telemetry requirements can be linked to reportedly greater DR participation among DR aggregators in PJM’s synchronized reserve market (e.g., non-spinning reserve market), than in other ISO/RTO spinning reserve markets.

In the case of CAISO, telemetry requirements have been relaxed by lowering scan rate requirements below status update requirements for non-spinning reserve and real-time energy provision by DR. The differing requirements are noted in the table entries. In the case of DR participating in CAISO’s non-spinning reserve market, the telemetry scan rate required is at least 1-minute for Proxy Demand Response (PDR) resources, while the scan rate is 4-seconds for

Non-Generating Resources (NGR).[4] The slower scan rate compared to the telemetry status update rate represents a relaxation in CAISO telemetry requirement for PDR resource provision of non-spinning reserves, as it is easier for resources to meet a 1-min scan rate than a 4-second scan rate.

Efforts of ISO/RTOs over the past decade to accommodate more types of distributed resources of smaller size are well-aligned with FERC's NOPR on DER and Storage and its stated objective of decreasing barriers for distributed resource participation. Although concrete market opportunities continue to expand for distributed resources to support power system and market operations, other challenges exist, particularly at the interface of distribution system operations and transmission operations. Key challenges faced at the transmission and distribution operations interface are described in the next section, and broaden the context of DR evolution.

Advancing Distribution Systems for Widespread Distributed Resource Integration

High penetration of distributed resources on the distribution system brings operational challenges for both the distribution system operator (DSO) and ISO/RTO. Under current operational contexts, the ISO/RTO dispatches distributed resources without knowledge of potential impacts on the distribution system nor degree of feasibility for the distribution system to support the wholesale market-level dispatches. Moreover, information exchanges needed to provide situational awareness at the DSO level and to update ISO system forecasts are lacking. For example, the DSO lacks real-time visibility and control over distributed resources, that would be analogous to the ISO/RTO's visibility over bulk generation resources. The ISO/RTO lacks information to forecast impact of distributed resource participation on system load (or net load) as well as electrical impacts (e.g., voltage) on the transmission-to-distribution interface.

Consequently, there is greater need for operational coordination between DSOs and ISO/RTOs as penetration of distributed resources increase on the distribution system. Basic DSO roles are being defined regionally to address coordination needs between DSOs and ISO/RTOs, in a high DER grid. For example, DSO roles include determining what distributed resource to dispatch at the distribution level in coordination with the ISO/RTO, and providing a sense of locational cost or retail DER market clearing at the distribution level. The next chapter elaborates on operational challenges faced with high distributed resource penetration, envisioned roles of the DSO, and functions to be performed by the DSO to address the challenges.

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[4] PDR and NGR are two distinct models under which DR may choose to participate in CAISO, depending on resource capability. While CAISO PDR resources provide curtailment/interruption type response only, NGR resources are more flexible in capability and can provide advanced services including targeted load increase in the provision of services such as frequency regulation.

3
DISTRIBUTION SYSTEM OPERATOR ROLE IN DEMAND RESPONSE EVOLUTION

Overview

This chapter describes the expanding role of the Distribution System Operator (DSO) in the context of DR evolution. The chapter begins by highlighting the primary roles of the DSO by elaborating on the basic functions it performs to maintain grid reliability in coordination with the ISO/RTO. A figure is provided to contrast the DSO's functional roles in relationship with existing functions performed by other stakeholder types in the North American electric power industry. Based on literature review, the chapter identifies operational challenges, functional roles of the DSO, and anticipated beneficial impacts for consumers in a high distributed resource environment.

As defined in Chapter 2 and [14], distributed energy resources (DER) refers to energy resources connected to the distribution system, regardless of whether located on the customer or utility side of the customer meter. With behind-the-meter DER, consumers are transformed into prosumers. This along with the ability to trigger "Customer Locational DR" are key enablers in the advancement of DR evolution to the stage of "Elastic Demand", wherein DER enables consumers to express their true elasticity of demand for grid-supplied power.

Collectively, customer demand elasticity (e.g., the degree consumers are willing to adjust purchase of a product or service based on price of the product or service) can enable price discovery through Elastic Demand participation in wholesale electricity markets. The chapter concludes with remarks on how accommodation of high DER penetration on the distribution grid enables the ultimate DR stage of "Elastic Demand"[5], and the DSO's potential role in enabling elastic demand.

Operational Challenges with High DER Penetration on the Distribution Grid

The introduction of massive amounts of DER could impact grid reliability due to operational challenges. Such challenges have compelled industry investigations to propose solutions designed to minimize any negative impacts. While DERs impact both the transmission and distribution system when they participate in the ISO/RTO wholesale markets, they are expected to cause greater challenges to the distribution grid, which were designed for one-way power flow. The major operational challenges of high DER on the distribution grid, described in [2], are summarized as follows.

- **Two-way power flow.** Historically, electrical power at the distribution grid flowed only in one direction—from substation to end users. DERs can now inject energy onto the distribution grid

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[5] The "Elastic Demand" stage of DR advancement was previously identified by industry stakeholders at a DR 2.0 Roadmap Workshop conducted by EPRI in 2012.

and cause power to flow in reverse direction from customers to substation. This will significantly change the operation paradigm of the distribution system.

- **Complicated operating conditions.** The size of the distribution system is much larger than that of the transmission system when measured by miles of lines. For example, the CAISO-controlled transmission grid is comprised of 26,000 miles of lines, while the three IOUs in California have over 255,000 miles of lines in aggregate [2]. The large size of the distribution grid creates more potential DER interconnection points and complicates operating conditions.
- **Higher frequency of distribution outages and more use of switching configurations.** Due to variability and uncertainty, DERs may cause a significant number of unplanned outages and switching circuit changes. If there is a violation on loading or voltage conditions on the distribution system as a result, DERs may need to be ramped up or curtailed. Also reconfigurations between circuits may need to be initiated.
- **DER output and load forecasting.** Accurate forecasting of short-term DER output and loading on the distribution grid is a challenge to utilities. System operators have even less certainty about whether sufficient resources are available and committed to serve load and maintain overall system reliability.
- **Lack of visibility, situation awareness and control.** Currently, both the ISO and the utilities do not have enough visibility and situational awareness about the location, status, and output of DERs. Distribution grid operators need higher visibility into the distribution systems, including tools to predict DER behavior, view real-time DER response, and analyze DER impacts on the grid.
- **Issues on phase balancing and voltage regulation.** DERs usually connect to only one phase on the distribution grid. Consequently, balancing loads between the three phases of the distribution grid becomes more challenging when DER penetration is high across all phases.

A possible solution to overcome these challenges is to create an independent distribution system operator (DSO) who operates the distribution grid in a way like an ISO/RTO operates the transmission grid [15].

Distribution System Operator (DSO) Role

DSO Functions

The functionalities of a DSO have been discussed in various literature [16] through [18], and can be summarized as follows:

1) **Distribution System Planning**. Traditionally, utilities individually perform their own distribution planning within the respective service territories. A DSO would coordinate with multiple distribution utilities to conduct a more comprehensive planning process. The goal of distribution system planning is to satisfy the growing and changing system load forecasted for a planning period.

2) **Distribution System Operation**. The DSO would be able to monitor grid operations, predict DER output as well as demand, control physical devices, and maintain communications between its control center and the measured units. Four sub-functions of distribution system operation are described as follows.

a) **Maintain Distribution System Reliability**. Reliability of the distribution system is defined as the ability to deliver uninterrupted service to customers. Common reliability indices include System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Frequency Index (CAIFI), Customer Average Interruption Duration Index (CAIDI), Energy Not Supplied (ENS), Average Energy Not Supplied (AENS), and so on.

b) **Forecasting and Availability Assessment**. The DSO is better positioned to forecast local power demand, for both behind-the-meter demand responsive loads and DER. It can also assess the availability of those resources in real-time.

c) **Operating Distributed Energy Resource Management System (DERMS)**. DERMS represents an extension to distribution management system (DMS) concepts. Major functionalities of DERMS include Volt/Var control[6], demand-side management, operation of the DMS, mitigating solar resource intermittency, outage management, system reconfiguration, performance verification and analysis, etc.

d) **Real-Time Control**. The DSO can receive real-time data from sensors located in the distribution grid. It can also send setpoints to the controllable devices based on the dispatch solution obtained from a DERMS optimization engine.

3) **Transmission-Distribution Interface Coordination**. The ISOs have limited visibility and control over resources sited behind utility meters. A DSO can play a significant role in coordinating distributed resource participation in wholesale markets and maintaining reliability of the transmission-distribution interface. The transmission-distribution interface generally refers to the substations where the transmission (T) and distribution (D) grids interconnect. The DSO can play major roles in T-D coordination, including: 1) Provide information on predictability of DER responses to inform ISO/RTO dispatch instructions at the T-D interface. 2) Enable DSO to forecast the behavior, and control the operation of DER on the distribution grid to maintain reliability and safety. 3) Enable DER providers to participate in more markets by tracking physical feasibility considering power balance, renewable generation uncertainties, and potential curtailments.

4) **DER Market Operation**. The DSO operates an integrated distributed electricity system with a mixture of distributed resources, power flow and voltage control devices (e.g., smart inverter, capacitor banks), and sensing devices. The DSO can dispatch distributed resources in the distribution grid, like the ISO dispatches generation resources at the transmission level. As a dispatch coordinator, the DSO will consolidate and coordinate the energy transactions and distribution reliability services offered by individual DER, aggregators, services firms and end customers. A secure DER optimization system that determines resource dispatch and cleared prices is operated by the DSO, along with scheduling operations, issuing real-time controls, and processing settlements.

[6] Maintenance of voltage and reactive power control on the feeders to stay within required thresholds

Functional Comparison of Stakeholder Types

The key functionalities of a DSO can be compared to those performed by other stakeholder types in the electric power industry. Figure 3-1 identifies electric power industry stakeholders in North America, represented by colorized boxes in the figure. The key functions the stakeholder typically performs is shown in white boxes within the colorized boxes.

The key DSO functions are shown to the lower right of the figure under the colorized box labeled "DSO". The key functions can be compared to those of the ISO/RTO, shown to the upper right above the DSO. Analogous to the ISO/RTO which operates wholesale markets and coordinates regional transmission while operating its transmission network, the DSO would operate a market of DER located on its distribution system which the DSO operators in and coordination with transmission operations.

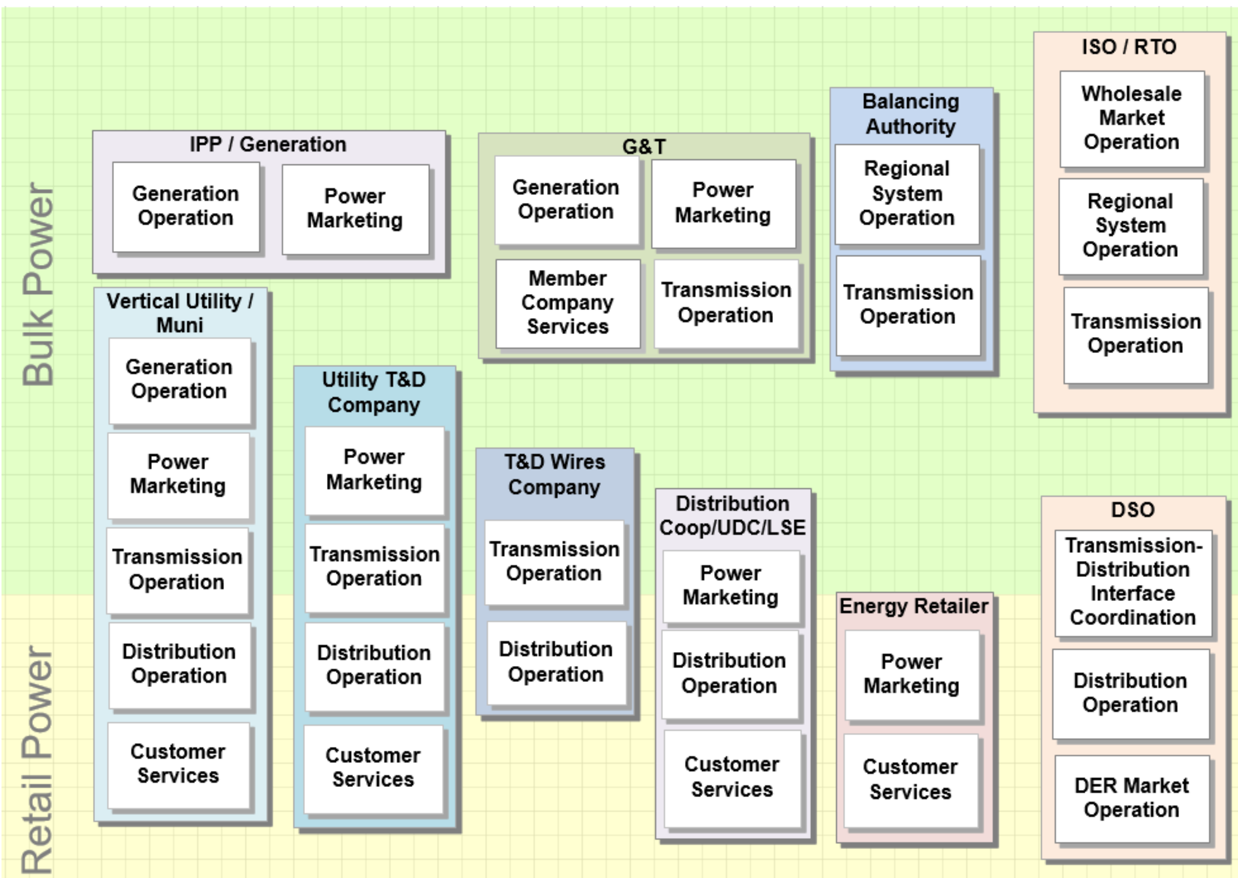

Figure 3-1
Electric Power Industry Stakeholder Types Depicted by Key Functions They Perform

Common stakeholder types found in the North American electric power industry are also shown in the figure. Additional types may exist in some regions that have undergone restructuring. The wholesale entities that only transact bulk power appear in the top portion of Figure 3-1 under "bulk power" (e.g., independent power producers, generation companies, G&T companies), while the retail entities that deal with end-use customers are depicted lower in the figure since they share a customer service function and transact "retail power".

The “T&D Wires Company” straddles at the interface of wholesale and retail operations since it operates both transmission and distribution systems. However, it does so without transacting retail power with end customers; hence, the customer service function is missing from this entity, as depicted in the figure. Examples include delivery companies such as CenterPoint Energy and Oncor Electric Delivery Company in Texas.

Whereas many stakeholders that transact retail power share some common functions (e.g., distribution operation, customer services, and/or power marketing), the DSO is unique in that is performs DER market operation and T-D interface coordination, while maintaining hierarchical management over the overall distribution system under its purview. The DSO model is just developing in some regions with additional changes expected as more experience with DER is gained.

Further details on other stakeholder types and the functions they perform are contained in EPRI publication [19].

Benefits to Customers in a DSO Environment

Optimized Customer Services Costs

Under the DSO framework, energy retailers, utility companies and load serving entities may expect optimized customer services costs. This general goal stems from four reasons. First, the operation of multiple distribution systems and the resources within them could be better coordinated to achieve more optimal outcomes by a single DSO. Currently, most of the relevant information concerning the operation of distribution grids, such as the topology detail of substations, wires and capacitor locations, and customer size, resides with the distribution utilities. This information, however, would be made available to a DSO to determine optimal operations for the benefit of DER suppliers, load aggregators, and buyers and sellers of core distribution level services.

Second, a DSO could operate a flexible, reliable and scalable platform for managing and optimizing the resources sited in the distribution grid; whereas traditional operation styles may rely more on rules of thumb resulting in less optimal outcomes. Third, a DSO is expected to have a mature retail price formulation mechanism in both the day-ahead and the real-time. This enables the possibility to provide customer services based on published price information (e.g., charging EVs when the price is low). Fourth, the amount of distributed renewable curtailment would conceivably decline in a DSO environment, due to the capability to optimize distribution system operation in a broader geographic context.

Coordinated Outage Management Service

The DSO could provide coordinated outage management service. For example, in the case of multiple utility distribution systems, the DSO can gain information from the various systems, to provide a more comprehensive analysis of the grid based on information collected from the SCADA systems both inside the utilities and on the interface between utilities. Advanced algorithms supported by DERMS could optimize the resources in a larger territory, and make it possible to increase the performance of outage management service for the whole system by increasing information expectations, and reducing unserved electricity and overtime pay. Moreover, one of the key functionalities of a DSO is to coordinate with the transmission grid. As a result, the traditionally separated EMS-SCADA systems of transmission and distribution operators may be integrated, providing the opportunity to restore electric service sooner to customers upon a network outage.

Ease of Participation in DER Markets

The DSO will provide a unified standard for customer DER participation including participation enrollment, metering and billing. The information required in a distribution grid is very dynamic in an easily reconfigurable grid. Without a unified standard, customer participation with DER will be difficult, given large volumes of data and decisions or transactions needing to be handled in a retail DER marketplace, especially in real-time.

In addition, much of the market information handled by the DSO needs to be published to participants. Like the ISO/RTO who publishes the day-ahead and real-time dispatches, congestion, forecasting and prices on a website, the DSO will also make DER market information public to participating customers. This will in turn facilitate ease of customer participation in DER markets and decision-making in a more efficient and effective manner.

Access to More Opportunities

The DSO will create significant opportunities for DER and end-users by expanding their market access. Under the current utility structure, DER and end-users have limited opportunities to participate in wholesale power markets due to a variety of market rules restricting participation and other practical reasons. Although DER may be allowed to participate in wholesale markets directly or through a retail DR program, existing participation requirements often limit access. For example, as depicted in Figure 2-4, for some ISOs only DER larger than 0.5MW can participate in select wholesale market opportunities. Under a DSO environment, however, the DER owner can sell energy directly into either the retail DER market, wholesale market, and/or both. In addition, retail customers can directly transact for services with each other. As a result, DER owners and customers can access more opportunities by participating under a DSO environment.

DR Evolution

The DSO plays a key role in advancing DR to higher stages of capability and value capture for customers as well as the electric power industry, as explained next.

Advancing Towards "Elastic Demand"

Table 3-1 depicts the stages of DR advancement as published in EPRI's DR 2.0 Roadmap[7]. The roadmap distinguishes key capabilities of DR for value capture at each stage of DR advancement. Each stage (in the table row) is characterized by a minimum level of capability of DR and the level of locational targetability for triggering DR. The last column of the table provides examples of grid services and other opportunities DR can capture given the level of capability characteristic of DR in that stage.

For example, DR 1.0 refers to the class of capability to reduce load, wherein DR is triggered based on system-wide peak conditions for annual peak load reduction, or based on forward economic conditions for economic dispatch of resources. Grid Locational DR refers to the class

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[7] The roadmap was produced from EPRI's Demand Response 2.0 Roadmap Workshop conducted in Houston, Texas hosted by CenterPoint Energy in August 2012, as described in [20] and [21].

of capability to reduce load for a variety of grid needs including grid asset overload mitigation at a distribution or transmission facility, congestion management, substation deferral, and transmission system reliability support through the provision of operating reserves. The next class of capability, referred to as DR 2.0, refers to the ability to adjust load in either direction so that DR can serve as a Balancing Resource in the provision of flexibility services such as balancing energy, ramping energy, and frequency regulation. The ultimate class of DR capability is referred to as Customer Locational DR, wherein DR enabled by customer facility-sited distributed resources provides value-added electric services. Examples include green, clean, or local power (wherein the electron's renewable attribute or local origins is differentiated); premium power (wherein the customer's chosen level of service reliability is differentiated); or cheap power (wherein the free or nearly free cost to consume electricity is the differentiator).

Table 3-1
Stages of Demand Response Identified in EPRI's DR 2.0 Roadmap

Class	Stage	Location	Value Capture Example
DR 1.0	Resource Adequacy	System-wide	Annual peak load reduction
	Forward Economics	Generation or Energy Node	Economic dispatch
Grid Locational DR	Distribution Management	Distribution Facility	Transformer overload mitigation
	T&D Deferral	Network Node	Substation deferral
	Ancillary Service Reserve	Transmission Facility	Operating reserves
DR 2.0	Balancing Resource	Generation or Energy Node	Imbalance energy, ramping, regulation
Customer Locational DR	Elastic Demand	Customer Facility	Green, clean, local power Premium power Free or cheap power

Each stage in the depicted roadmap can be referred to by name, as shown in the second column of Table 3-1. The last stage of the roadmap is referred to as "Elastic Demand", wherein customer-sited distributed resources serve as enablers for discovery of price elasticity of demand for electric service, based on individual customer sensitivities to the price of grid-purchased power. As DER proliferates behind-the-meter, as well as on institutional campuses and local communities, consumers become more and more prosumers of electricity possessing viable alternatives to grid-purchased power from the utility, load aggregator, or third-party service provider. In this way, customer-owned distributed resources serve as key enablers towards an Elastic Demand side of electricity markets, by providing customers with a recourse to grid-purchased power, while maintaining essential services.

DSO Role in DR Advancement

The establishment of a DSO is another key enabler towards advancement of DR to the ultimate stage identified in Table 3-1, characterized by Customer Locational DR capabilities. As discussed earlier in this chapter, DSOs fulfill an essential role in maintaining reliability of the distribution system, while supporting transmission system reliability within a high-DER system. Moreover, the DSO facilities a DER market in an integrated distributed electricity system containing a mixture of distributed resources, as well as distribution system power flow and voltage control devices (e.g., smart inverter, capacitor banks) and sensing devices.

The DSO performs a range of essential services in the coordinated dispatch of distributed resources on the distribution system, like the ISO/RTO dispatches generation resources at the transmission level. As a dispatch coordinator, the DSO will consolidate energy transactions and distribution reliability services offered by individual DER, aggregators, services firms and end customers. Performing such DSO services are prerequisites for a highly functional reliable grid supporting high penetration of distributed resources. Distributed resources like DER and flexible loads are needed to enable customer expression of individual elasticity of demand for grid-purchased power. The combination of customer-sited DER and DSO service functions enable discovery and expression of individual customer demand elasticity within a market context.

In aggregation, the collective contribution of individual customer demand elasticity forms the basis for a truly elastic demand-side of wholesale electricity markets. The absence of elastic demand is especially evident in wholesale markets of last resort providing reliability services, such as ancillary services reserves, wherein the ISO/RTO is willing to pay essentially anything at any time for procurements needed to meet reliability requirements. This is an artifact of traditional power system operations, which can result in costly premiums paid for reliability procurements in wholesale markets especially during times of generation scarcity[8]. Expression of customer elastic demand for grid-purchased power, can serve as a recourse when faced with the risk of wholesale procurements at literally any cost.

Several ISO/RTOs have approved market provisions to engage demand-side participation in select wholesale markets (e.g., PJM's Price Responsive Demand[9] mechanism which enables demand-side participation in capacity and energy markets). Doing so would introduce demand elasticity in the clearing of supply and demand. However, lack of actual participation to date by load serving entities in such market provisions to bid DR on the demand-side of electricity markets instead of the supply-side, reflects present barriers. Among the barriers cited include requirements for supervisory control of loads with demand bids that don't clear the market bid into. As Customer Locational DR is made possible by customer-sited DER and demand responsive loads, DSOs may one day serve an important role in enabling Elastic Demand in wholesale markets. However, details surrounding coordination of DR participation at both ISO and DSO levels need to be worked out.

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[8] Times of scarcity and premium wholesale costs were experienced during the California Energy Crisis of 2000-2001 as reported in [22].

[9] https://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/price-responsive-demand.ashx

Summary Remark

Regional market and policy drivers push DR to advance in stages at different pace in different geographic regions and states. Customer Locational DR is emerging in capability, though is not yet prevalent in most regions. However, the need for fast and flexible DR to provide Balancing Resources for renewable integration is a reality today in select regions with high intermittent renewable penetration (e.g., California and Hawaii). The next chapter identifies strategies for provision of flexibility services with example equipment in select large customer sectors conceivably capable of bi-directional load adjustment or DR 2.0.

4

STRATEGIES FOR FAST AND FLEXIBLE DEMAND RESPONSE

To help position utilities to better prepare DR programs to be capable of meeting future needs, this chapter summarizes strategies for provision of fast and flexible DR services from select industrial customer sectors. Strategies are identified based on literature review and EPRI assessment. Recommendations are also provided on technical development needed to mobilize different types of customer loads for growing opportunities to provide flexibility services.

Background

As discussed in Chapter 1, in power systems with high penetration of renewable generation, it is increasingly becoming beneficial to increase or ramp up load at targeted times to balance renewable intermittency. While increasing load is important at certain times, decreasing or ramping down load is important at other times due to the intermittency of renewable generation. Flexibility requirements for demand response, originating in bulk power systems, are discussed in detail in [25].

Prior publications on "AutoDR" and "Fast DR" strategies primarily focus on simple load reduction. This chapter extends beyond existing literature by identifying strategies for both fast and flexible demand response. In this chapter, "fast DR" refers to capabilities to decrease load rapidly enough to provide services like "Ancillary Service Reserves" (e.g., 10-minute response to system contingencies). "Flexible DR" refers to capabilities to increase and/or decrease load rapidly enough to provide "Balancing Resource" type grid services (e.g., real-time balancing energy, ramping energy, or frequency regulation).

DR strategies are identified in this chapter for providing fast and flexible demand response, in select customer sectors. The strategies were identified based on literature review and interviews with industry experts. Many have yet to be proven, especially for achieving coordinated increase in power consumption, so further investigation is recommended.

Generally, Flexible DR strategies for coordinated increase in consumption are not yet well-known in industry. The strategies identified below are specific to the type of equipment that can be controlled. Operational limitations are also noted on the extent each strategy may be exercised. Applicability of identified DR strategies depend on customer receptivity, considering differing levels of organizational willingness to adopt strategies that may impact operations, degree of operational flexibility, and compatibility of current operational processes.

Example 1: Refrigerated Warehouse

The refrigerated warehouse industry provides one example for investigating the potential of providing flexibility services. As of 2016, the United States (U.S.) had a gross refrigerated warehouse storage capacity of 4.17 billion cubic feet [30]. Based on the previous benchmarking studies, the average refrigerated warehouse uses approximately 1.54-kilowatt hours per cubic foot [31]. This equates to a significant energy use of 6,422-gigawatt hours by the refrigerated warehouses in the U.S. Based on a 2008 study, demand from refrigerated warehouses in California is around 360 MW. The study estimates a theoretical potential for demand reduction ranging from 45MW to 90MW, from 220 facilities, most of which have certain equipment that can be automated to provide fast response [32].

Most of power demand in refrigerated warehouses is from process cooling loads. Sources of demand reduction include cold refrigeration and freezer units, and associated evaporator coil fans, compressors, and condensers. Refrigerated warehouses store perishable products or products that need stringent temperature controls, within a range. Examples include beverages, cold storage, and frozen food warehouses.

Large facilities that have stringent quality of service requirements, such as refrigerated warehouses, typically have some level of automation and integrated, automated controls. For example, a programmable logic controller (PLC) may be used to control evaporators and there may be stand-alone controllers for compressors and condensers. A multi-prong strategy of employing integrated and stand-alone controllers for DR can enable fast-responding strategies. An example is adjusting both lights and evaporator fan speeds [33].

Refrigerated warehouse facilities that have a combination of cooler and freezer units can be strategically employed for adjusting loads for fast and flexible response. It should be noted that previous quantitative and qualitative analysis and field tests of fast DR with refrigerated warehouses focused on load reduction. Identified strategies for fast load reduction are summarized below based on prior work. Strategies for flexibly increasing loads are identified based on qualitative assessment.

Summary of Demand Response Strategies

The tables below provide a summary of demand response strategies identified for different controllable equipment typically representing a significant load in refrigerated warehouses. Due to the complexity of strategies and operational limitations considered, fast load reduction strategies are presented in Table 4-1, separately from strategies to increase load shown in Table 4-2.

Table 4-1
Load Reduction Strategies and Operational Limitations for Refrigerated Warehouse

Controllable Equipment	DR Strategy (Reduce Load)	Operational Limitations
Cold (32-55F) refrigeration unit	1) Raise unit temperature 2) Switch off select units 3) Limit unit power capacity	Food temperature exceeding guidelines to avoid food spoilage
Freezer (<32F) unit	1) Raise unit temperature 2) Switch off select units	Food thaw leading to spoilage
Battery Chargers	Switch off forklift or pallet lift charging periods.	Adequate fork/pallet lifts for essential tasks during DR.
Lighting	Switch off or dim select lights	Productivity and safety of workers

Table 4-2
Load Increase Strategies and Operational Limitations for Refrigerated Warehouse

Controllable Equipment	DR Strategy (Increase Load)	Operational Limitations
Cold (32-55F) refrigeration unit	1) Lower unit temperature 2) Switch on select units 3) Raise unit power capacity	Food temperature exceeding guidelines to avoid food spoilage
Freezer (>32F) unit	1) Reduce unit temperature 2) Switch on select units	Food freeze leading to spoilage
Battery	Switch on forklift or pallet lift charging periods.	None
Lighting	Switch on or brighten select lights	None

Cold Refrigeration Unit

Control of refrigeration units is applicable in refrigerated warehouse facilities that have cooling units with centralized or standalone controls. Examples of refrigerated warehouse types that use cold refrigeration units are frozen food and frozen bakeries. The cold refrigeration unit is one of the high load equipment in this type of refrigerated warehouse. Based on prior work on automated load reduction opportunities for refrigerated warehouses [34], fast load reduction can be achieved through raising the temperature set-point by a few degrees within acceptable norms, as determined by a facility manager. Depending on the type of refrigerated warehouse, select units may be switched off during a DR event. Instead of switching off, the other option is to limit the power capacity at the evaporator coils by managing the fan speed. Depending on the state of defrost cycle in progress, the power capacity can be reduced by using controls that stop the defrost cycle.

To increase load, operating temperature set-points of cold refrigeration units can be lowered by a few degrees within acceptable norms, as determined by a facility manager. Depending on the type of refrigerated warehouse and its operational state, select units may be switched on during a DR event. For units that are already operational, another option is to raise the power capacity at the evaporator coils by managing fan speed. Depending on the state of defrost cycle in progress, the power capacity can be increased by using controls to start the defrost cycle.

The key concern modifying the use of refrigeration units for DR is food spoilage, albeit food may have higher tolerance for lower temperature set-points than higher set-points. The degree of acceptable temperature changes heavily depends on the type of product being stored. For example, bakery products may have more temperature flexibility than other food products requiring cold storage.

Freezer Unit

Control of freezer units is applicable for refrigerated warehouse facilities that have freezer units. Examples of refrigerated warehouse types that use freezer units include storage of beverages, dairy, produce, and/or bakery goods. Like the refrigeration unit, the freezer unit is one of the high demand equipment in a refrigerated warehouse. Automated demand response for load reduction can be achieved through raising the temperature set-point of freezer units by a few degrees within the accepted norms, as determined by a facility manager. Depending on the type of refrigerated warehouse, select freezer units be switched off during the DR event.

For flexible strategies to increase load, the operational temperature set-point of the freezer unit can be reduced by a few degrees within accepted norms, as determined by the facility manager. Depending on the type of refrigerated warehouse and the operational state, select units may be switched on during a flexible DR event.

The key concern for modifying load of fast and flexible DR using a freezer unit is the type of goods being stored, where beverages and produce may have more temperature flexibility than dairy products.

Battery Chargers

Refrigerated warehouses to transport goods have fork lifts and pallet lifts that are battery operated and need to be charged. Like stationary battery storage their charge cycles can be minimized by switching off or switching on the charging during the DR period—a strategy that can be used for either increasing or decreasing loads. For example, an operator may shift charging to a non-DR event period to reduce the load, or charge depleted battery units during DR event periods to increase loads. Intelligent plug-load controller strategies can be deployed to automatically switch off or switch on charging in response to DR signals.

Movement of goods is essential in operations of a refrigerated warehouse. A charging strategy to reduce the loads can be employed in so far as a facility has adequate reserve capacity either in the form of stored energy or extra fork and pallet lifts to continue warehouse operations during a DR event.

Lighting

Similar to other facilities, select lights may be switched off, dimmed or switched on, brightened to decrease or increase load, respectively, in the case of lights managed by either centralized or individual lighting control systems. Lighting fixtures such as T8, T5, and other fluorescent and LED fixtures can be quickly switched off based on the aggressive use of occupancy and photo sensor technologies, or can be switched on during a Flexible DR event period. Considering lighting load constitutes a small percentage of the total facility load, this strategy works best in tandem to those aforementioned.

Generally, the limitation in employing these strategies in practice is inadequate perception of occupant security in the facility due to lack of lighting or low lighting levels. However, security risk is less of a limitation in the case of increasing lighting load to support flexible increase in consumption.

Recommendations

While the previous studies have looked at the role of refrigerated warehouses for DR, they have primarily focused in identifying strategies for reducing peak summer loads in California. A significant opportunity exists in understanding how these facilities and their equipment can support flexibility to increase loading, when beneficial for intermittent renewable integration. Not all DR strategies in refrigerated warehouses can be automated. Hence an evaluation of control systems capabilities is needed to understand feasibility of automating participation, including measuring and verifying performance characteristics to better understand customer economics and value of participation. Similar to other end-use sectors, bill cost impacts resulting from the participation in DR programs need to be weighed against any operational costs and participation risks to the customer.

Example 2: Data Center

The data center industry provides a second example for investigating the potential of providing flexibility services. U.S. data centers consumed about 70 billion kilowatt-hours of electricity in 2014, representing about 1.8% percent of the country's total energy consumption, according to a recent study on the current growth trends of data centers [35]. That's equivalent to the amount consumed by about 6.4 million average American homes that year. This is a 4 percent increase in total data center energy consumption from 2010 to 2014, and a huge change from the preceding five years (2005-2010), during which total U.S. data center energy consumption grew by 24 percent; and an even bigger change from the first half of the last decade (2000-2005), when their energy consumption grew nearly 90 percent. Electricity use of data centers varies by region. For example, data centers account for roughly 10% of California energy use, compared to a national average of 1.5–2% [36].

Data centers have the potential of providing system benefits through well-coordinated DR participation. DR strategies for data centers are identified below for providing fast load reduction. These strategies are summarized based on literature review. Sources stem from field test, qualitative assessment, and industry interviews with data center experts summarized in prior LBNL studies [36], [37]. Though the strategies are not yet in wide use, they have been deemed quantitatively feasible based on findings from field testing at six pilot sites employing different sets of strategies, and qualitatively feasible based on expert feedback.

Demand Response Strategies for Data Centers

DR strategies are specific to each type of information technology (IT) equipment that can be controlled in data centers. IT equipment refers to information processing systems or devices that typically include servers, storage, and networking equipment, which altogether constitute the fundamental machinery in data centers. Consequently, DR strategies are grouped by equipment type.

The tables below provide a summary of demand response strategies identified for different controllable equipment typically representing a significant load in data centers. Due to the complexity of strategies and operational limitations considered, fast load reduction strategies are first shown in Table 4-3, followed by flexible strategies for load increase in Table 4-4. Each strategy is described in the ensuing text.

Table 4-3
Load Reduction Strategies and Operational Limitations for Data Center

Controllable Equipment	DR Strategy (Decrease Load)	Operational Limitations
Computing server (cluster, rack, server)	1) Server shutdown 2) Server idling 3) Queuing of jobs (shift to decrease load)	1) Response rate, process loss 2) Refresh rate for user 3) Potential job processing delays
Storage cluster (hard disks or tape drives)	1) Storage cluster shutdown 2) Storage cluster idling 3) Queuing of jobs (shift to decrease load)	1) Response rate, lack of data availability 2) Data retrieval rate for user 3) Potential job processing delays
Network device (switch, hub, router, gateway)	Switch to or activate low power mode using intelligent power management capabilities	Perceived slow-down in network speed
HVAC system	1) Increase zone temperature 2) Raise inlet temperatures 3) Chiller plant optimization	IT equipment failure from overheating
Any equipment by geography	Load migration between data centers	None, assuming redundancy of data centers
Lighting system	Turn off or down lights	Security concerns for server room occupant

Table 4-4
Load Increase Strategies and Operational Limitations for Data Center

Controllable Equipment	DR Strategy (Increase Load)	Operational Limitations
Computing server (cluster, rack, server)	1) Start server(s) 2) Increase server utilization 3) Queuing of jobs (shift to increase load)	1) None 2) None 3) Potential job processing delays
Storage cluster	1) Start storage clusters 2) Increase cluster utilization 3) Shifting of storage jobs	1) Potential drive failures 2) None 3) Potential job processing delays
Network device (switch, hub, router, gateway)	Deactivate low power mode using intelligent power management capabilities	None

Table 4-4 (continued)
Load Increase Strategies and Operational Limitations for Data Center

Controllable Equipment	DR Strategy	Controllable Equipment
HVAC system	1) Reduce zone temperature 2) Reduce inlet temperatures 3) Utilize onsite thermal storage (building mass, ice)	Overcooling of IT equipment and/or IT equipment room
Any equipment by geography	Load migration between data centers	None, assuming redundancy of data centers
Lighting system	Turn on extra lights	None

Computing Server

DR strategies for load reduction using servers include:

1) Shutdown server – Turn off specific data center servers, by activating shutdown mode to initiate a graceful shutdown process.
2) Idling server – Switch to idling mode to save energy, which enables quick awakening (e.g., few seconds to few minutes). This mode often preserves key processes during server idling and avoids any potential loss of key processes that need to be manually initiated during or after server start-up from a full shutdown.
3) Load shifting by queuing of computing jobs – shift or run computing jobs at a later time to avoid DR event period (e.g., users submit the jobs and wait for their completion). Increased virtualization particularly in cloud-enabled datacenters has created an opportunity to implement geographic load balancing techniques to improve efficiency. Building upon the same concepts, rate tariff can be used to co-optimize the CPU job scheduler submissions to shift loads. Effectively employing such a strategy requires a policy discussion with data centers on user expectations to ensure adequate timing of completion of jobs. Datacenters typically have an idea of what user job processing expectations are, including their schedule of completion. For example, some jobs of users have flexibility of completion after a whole week (e.g., running a grid or climate change model).

When beneficial for application to balance intermittent renewable generation, DR strategies for load increase by employing servers could include:

1) Start server – Start specific data center servers, by activating server start-up power to initiate start-up process.
2) Increase server utilization – when possible, increase server utilization to higher rates by either adding more jobs to the queue or adding resource intensive activities. This strategy is similar to load shifting except that jobs are queued to be executed during times load increases are needed.

3) Load shifting by queuing of computing jobs – shift or run computing jobs at a later time to increase load during a Flexible DR event period

How far a DR strategy for load reduction or increase can be employed is determined by operational limitations. Limitations in data centers are tied to diminished value of the intended function of servers. Servers can either decrease or increase load by delaying job processing to a non-DR event period or moving job processing to occur during a period calling for load increase. The shift in processing time away from a load reduction event or to run later or to run during a Flexible DR event period, may cause excessive delay for the user. This is the only identified operational limitation for load increase with servers.

Fast load reduction can be employed to the extent of not putting into jeopardy the intended function of the servers (e.g., running a job or providing a search function with high response rate). Functional compromises include loss in computing a job, excessive delay in getting a job done, or loss of processes after shutdown of a server. These are further described below.

1) Process loss or response rate – Server operational changes may lead to low response rate for users or low quality of service. This is not an issue when the servers are started to increase the load, since starting servers does not slowdown operations. Production data centers tend to be mission critical and so are generally regarded as unsuited for DR. However, backup and development data centers generally have more leeway for employing the server shutdown strategy. Development servers are not directly user-facing in function and may be better suited for slow or traditional DR, whereas backup IT loads may be better suited for fast or flexible DR.

2) Refresh rate for user – Server idling outside data center normal operation may lead to lower than desirable refresh rates of production servers for users. For example, application servers of organizations like Facebook are monitored to track time of page refresh from the user's perspective (e.g., refresh time of a Facebook page).

3) Potential delay in processing a job – Queuing of computing jobs to provide load shifting may result in job delays for users. Consequently, time to job completion after user submittal must be monitored and managed within user expectations.

Storage Cluster

Fast DR strategies for load reduction using storage clusters include:

1) Shutdown storage clusters – Turn off specific data center storage clusters, by going through a graceful shutdown process built into the storage systems.

2) Idling storage clusters – Switch to idling mode to save energy. Under this mode the storage systems are able to quickly wake (e.g., few seconds to few minutes).

3) Load shifting by queuing of storage jobs – shift or run storage jobs at a later time to avoid DR event period (e.g., users submit the jobs and wait for their completion).

Flexible DR strategies for load increase using storage clusters include:

1) Start-up storage clusters – Start specific data center storage clusters, by going through a graceful start up process built into the storage systems.

2) Increase storage cluster utilization – When possible, add more data processing to increase utilization and energy use during the event period.

3) Load shifting by queuing of storage jobs – shift or run jobs at a later time to increase load during a Flexible DR event period

Constraints have to do with the potential diminishing value of the intended function of storage systems in data centers, thereby putting into jeopardy their normal function (e.g., lack of data availability, higher data retrieval rate). Operational limitations of storage clusters include the following.

1) Refresh rate – Storage cluster slowdown to decrease load may lead to low response rate for users or jeopardize data availability in data centers. However, this is not an issue when storage clusters are started to increase load, as starting additional clusters is operations-enhancing rather than slowing.

2) Data retrieval rate – Storage cluster idling could lead to lack of data availability upon request by users. Data retrieval rates must be maintained, however, within user expectations to maintain quality of service. Retrieval rates are not expected to be diminished when increasing cluster utilization to increase load.

3) Potential job processing delay - The limitations in employing DR strategies with shifted storage cluster utilization are shared regardless of whether increasing or decreasing load. Limited data availability from shifted storage cluster utilization can result when rescheduling data processing for storage job completion to a later period, regardless of whether shifting storage processing before, during, or after a targeted DR event period.

4) Limited spin cycle life of mechanical hard drives is still a major concern for system operators, albeit newer solid state technologies offer longer life and can better withstand wear and tear suffered by equipment.

Networking Devices

For network devices, a strategy for load reduction is to switch to or activate a lower power mode. This strategy is applicable to networking devices in data centers such as routers, switches, gateways, and hubs that have the ability to switch or be switched to lower power modes when not actively being used. This strategy can be manually activated with older devices that have a physical or remote control capability to switch to lower power modes. Newer network devices often have auto-switch capabilities to enter into intelligent power modes based on real-time utilization, providing an inherent energy efficiency strategy with newer equipment. Operationally, the switching strategy is limited by data center managers' perception of slowdown in network speed from activating this strategy.

DR strategies for increasing load using network devices include deactivating any low power mode when equipment with intelligent power modes are operating in them. There are no foreseen operational impacts that would constrain running networking equipment in full power mode.

It is also important to analyze the cost and benefit in implementing any DR strategies for networking equipment, due to their usage comprising a very small percentage compared to the storage and computational resources. Additional research and development needs to be carried out to understand qualitative and quantitative benefits.

HVAC system

Data centers heavily consume power through utilization of their HVAC systems. Strategies for load reduction with HVAC controls include:

1) Increase zone temperature – Many data center HVAC systems are set to lower zone temperatures than required for meeting guidelines. For such data centers, HVAC zone temperature can be setback to higher temperatures yet still maintain zone temperatures within ASHRAE guidelines. For data centers already operating per ASHRAE temperature guidelines, further setback of zone temperature can be trialed by employing setback only during DR events.

2) Raise inlet temperature – For many data centers operating HVAC systems (water or ice) set to low zone temperatures, HVAC inlet temperatures can be increased to higher temperatures yet still maintain ASHRAE guidelines for zone temperatures. Even for data centers already operating per ASHRAE temperature guidelines, inlet temperature can be raised to trial further setback of zone temperature just during DR events.

Strategies to increase load using HVAC controls include:

1) Decrease zone temperature – Adjust HVAC zone temperature to lower temperatures yet maintain zone temperatures within ASHRAE guidelines. Or reduce zone temperature on a trial basis just during DR events.

2) Lower inlet temperature – Lower HVAC inlet temperatures to reduce IT equipment zone temperatures, while still maintaining ASHRAE guidelines. Or lower inlet temperature on a trial basis to effect further setback of zone temperature just during DR events.

3) Advanced technologies like a chiller plant optimization system track the efficiency of the entire plant similar to the PUE measurement at the datacenter level. Such systems can be used to track and mitigate efficiency drifts. Building up the same platform capabilities, DR market signals can be utilized to co-optimize the chiller system. In essence, the chiller plant energy consumption can be ramped-up or down depending on market signals.

The primary limitation in employing these DR strategies lies with the risk of server failure—either through over-heating or over-cooling. That is, how far temperatures can be adjusted is limited by concern over server failure. Most HVAC systems in data centers make an effort to meet the ASHRAE Technical Committee 9.9 temperature and humidity guidelines for IT equipment [38]. The 2008 ASHRAE zone temperature guidelines for allowable temperatures range between 59°F to 90°F and for recommended temperatures range between 64.4°F to 80.6°F [39]. Monitoring of server conditions is needed when employing any temperature adjustment, especially if temporarily operating beyond ASHRAE recommendations by temporarily transitioning to higher yet allowable temperature ranges in data centers.

Geographically Dispersed Equipment

A geographical shifting of loads as a DR strategy is applicable in the case of distributed and networked data center facilities with redundant infrastructure. Geographically dispersed data centers with redundancy provide flexibility to manage operations across data centers. Networking enables work transfer (e.g., data transfer) to alternate data centers in different geographic regions, thereby enabling adjustment of load in on location by increasing or decreasing loads in another location.

Load migration between data centers can be employed with any of the previously identified types of IT equipment in a data center. This is employed by shutting off or partially transferring processing to another data center from a power-constrained or power-abundant geographic region. Transfer of IT equipment load, depending on if a data center is used for server or storage processing, also impacts the network equipment and HVAC load. Depending on the circumstance, lighting loads may also be adjusted.

No operational constraints are foreseen when employing such DR strategies, under the assumption of continued operations in data centers wherein load migration is occurring just during a DR event period.

IT Equipment Room Lighting

DR strategies can employ lighting adjustments in IT equipment rooms within data centers (e.g., area lighting in rooms with servers, networking equipment, and/or storage systems). In these room settings, general area lighting can be shut off completely or turned up, as applicable using bi-level and/or dimming strategies.

Considering lighting load constitutes a small percentage of total facility load, this strategy works best in tandem to those aforementioned. Generally, the operational limitation in employing lighting for DR is perceived compromise of occupant security in equipment rooms. Though IT equipment rooms are generally not occupied spaces, lights are often kept on to maintain a sense of security for the occasional occupant. So DR strategies that result in lack of or low lighting levels can compromise the sense of security.

Recommendations

Most data centers due to the nature of their operations are risk-averse. Considering the high cost of energy and large loads, significant DR opportunities exist. A specific recommendation is to conduct scaled demonstrations with leading data centers that are potential trend setters for the industry to spur adoption of DR strategies.

Demonstrations are to focus on how data center operators can implement DR strategies and respond to different utility DR program signals. The investigation would need to be designed to recognize data centers are unique loads with high reliability requirements, and stringent service level agreements. Data centers require enough economic incentive to participate in order to adequately address operator comfort, given their nature of being risk averse.

Targeted outreach with data centers is also needed to educate how to implement the DR strategies and to assess resulting economic and societal benefits.

5 CONCLUSION AND FUTURE WORK

Market and Policy Drivers

Key market and policy developments driving demand response evolution include:

- Maturing Renewable Portfolio Standards (RPS) causing higher penetrations of intermittent renewable generation which is changing the nature of system load as well as net load over time and driving need for flexibility services in electric power and market systems
- Greenhouse gas reduction goals that are being advanced with energy efficiency measures, which in some cases encourage beneficial electrification and/or customer adoption of more efficient technologies that in turn may be a source for equipping to provide flexibility services.
- Policies encouraging accommodation of distributed energy resources in markets and distribution systems are driving industry attention to work out ways to accommodate broad-based distributed energy resource (DER) integration, including demand responsive loads. Depending on the region, distributed resources being accommodating may include preferred resources like distributed renewables, energy efficiency, and demand response, and excluding “dirty” generators (e.g., combustion back-up generators)
- Retail electricity rate reform, including time-of-use rates and demand-based rate structures, can significantly change the equation for value capture and incent customer-sited distributed resources like batteries and demand responsive loads, which are better compelled by dynamic or time-varying rates than relatively flat rates.

DR Advancing in Stages

The described drivers are propelling demand response into more advanced stages, as depicted in EPRI’s published DR 2.0 Roadmap summarized in Chapter 3. The roadmap describes advancing stages of DR from traditional forms (e.g., DR 1.0 for peak load reduction) to more advanced stages (e.g., DR 2.0 for system balancing needs) and beyond. The combination of technological advances (e.g. advancements in battery technology at lower costs) and policy initiatives are compelling DR programs to leverage DER for both Grid Locational and Customer Locational DR applications, respectively.

Higher penetrations of intermittent renewable resources are driving the need for fast and flexible DR to serve as Balancing Resources. This report identified specific strategies for information technology in data centers and equipment in refrigerated warehouses to provide fast and flexible DR services.

The report elaborates on the ultimate stage of DR called “Elastic Demand” enabled by Customer Locational DR capability; and the market forces driving advancement to accommodate DER. DER is instrumental for providing consumers with greater electric service choices. As more consumers become prosumers, their alternative energy sources provide alternatives to grid-purchased power. For example, DER can be configured to support value-added electric service offerings to customers, such as green, clean, or local power to those who value such attributes; premium power to customers who have high reliability needs; and free or cheap power to those who can shift electric usage to advantageous times (e.g., times of excess renewable generation leading to near zero or negative electricity market prices).

Future Work

This report summarizes wholesale market advancements in accommodating distributed resources, and associated market participation requirements for these resources, typically much smaller than traditional generation resources. Not all ISO/RTO markets enable DR participation today nor separately procure flexibility services like ramping energy. Moreover, many ISO/RTO markets have yet to allow demand responsive loads to participate by increasing consumption to capture opportunities, despite projected growth in flexibility needs due to renewable penetration. Continued development is needed of workable market mechanisms enabling demand-side participation, if DR is to contribute significantly to renewable integration, especially during times of negative wholesale market prices when increasing consumption is beneficial. Moreover, a unified approach to T-D coordination supported by enabling technology like retail DER platforms can unleash a dramatic increase in DR participation in wholesale market opportunities.

Policy drivers mandating more renewable generation, lower GHG emissions and accommodation of broad-based DER integration, while loads become more energy efficient, are together driving evolution of the DR landscape and the sources of DR that can best capture value. To enhance DR program flexibility for greater value capture, it is recommended for DR programs to continue to expand and include alternative energy sources such as distributed storage, electric vehicles, and clean sources of dispatchable distributed generation, as well as flexible loads. The inherent flexibility of these resource types can well-position DR programs to support evolving grid needs as DR advances to support system balancing and more grid locational needs.

Customer adoption rationale for DR enabling technologies is informed by retail electricity rate design. To the extent that customers see compelling rationale from economic and value-addition standpoints, they may choose to adopt new technologies (e.g., storage technologies and electric vehicles). However, retail rate structures that are primarily based on volumetric energy charges (e.g., flat rates, inverted block tier rates, net metering) challenge customers to discern value in adopting DR enabling technologies like batteries, energy management systems, and other demand modulating automation technologies. Retail rate reform investigations are being conducted to address seeming inequities as high DG production displaces grid-purchased power, yet prosumers with DG utilize the grid for reliability backup services, without necessarily being charged commensurate with the cost of the reliability services enjoyed. “Until customer bills expose the demand component of electric service [where lacking in volumetric electric rates], customers will have difficulty in discerning the value of demand responsive technologies on the customer-side of the meter, such as energy storage technology and home energy management systems.” [11] Retail rate structures, therefore, greatly influence speed of advancement towards widespread integration of DER behind the customer meter.

Industry Collaboration

Broad collaboration across the electric power industry, with vendors, customer associations, research organizations, and standards-setting bodies is needed to advance distributed resource provision of fast and flexible DR services in wholesale and retail markets, facing high intermittent renewable penetration. Beyond technological advancements, business practices and well-defined processes can pave the way for end-to-end integration of wholesale and retail markets with customer systems capable of automating demand response.

Ultimately, pilots are needed to demonstrate integration steps and high-value propositions achievable through end-to-end systems integration. Beyond integration between ISO/RTO and DSO systems, this includes integration between utility distributed resource management systems and customer automaton technologies that implement DR strategies. Successful demonstration of such end-to-end capabilities for flexible energy management in initial customer sectors, can prepare the way for engagement of additional customers.

6
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