23. Improve Demand Response Policies and Programs

1. Profile

Demand response (DR) refers to the intentional modification of electricity usage by end-use customers during periods of system stress, system imbalance, or in response to market prices.[1] DR policies and programs were initially developed to help support electric system reliability by reducing load during peak hours. More recently, technical innovations have made it possible to expand DR capabilities to provide an array of ancillary services necessary to maintain grid reliability. The focus is no longer exclusively on peak reduction. DR is also capable of promoting overall economic efficiency, particularly in regions that have wholesale electricity markets.

Ancillary services, for example, include system balancing – actions to ensure that electricity supply is equal to demand in real time – and the regulation of frequency and voltage so they remain within acceptable limits.[2] Efficient ancillary services markets for balancing ensure adequate electricity supply at least cost, and they can deliver environmental benefits by reducing the need for reserves or backup generation. Frequency and voltage levels are maintained through automatic and very fast response services and fast reserves (which can provide additional energy when needed), the provision of reactive power, and various other services. Historically, balancing and regulation were managed primarily through supply-side resources; today, DR enables customers to change their operating patterns (in return for compensation) to aid in system balancing and regulation, giving grid operators greater flexibility and potentially reducing costs and emissions.

DR programs can take many forms. As illustrated in Figure 23-1, the North American Electric Reliability Corporation (NERC) categorizes different forms of DR in relation to overall demand-side management strategies. Within the broad category of DR, the management of end-use loads can either be initiated by end-users (referred to as "Non-Dispatchable" in the figure) or by the distribution utility, a third-party aggregator, or the transmission system operator (shown as "Dispatchable" in the figure). Dispatchable DR programs can be further categorized based on the purpose they serve for the utility or system operator. Some programs focus on maintaining reliability by using DR resources to provide capacity, reserves, energy reductions, or frequency regulation services (labeled as

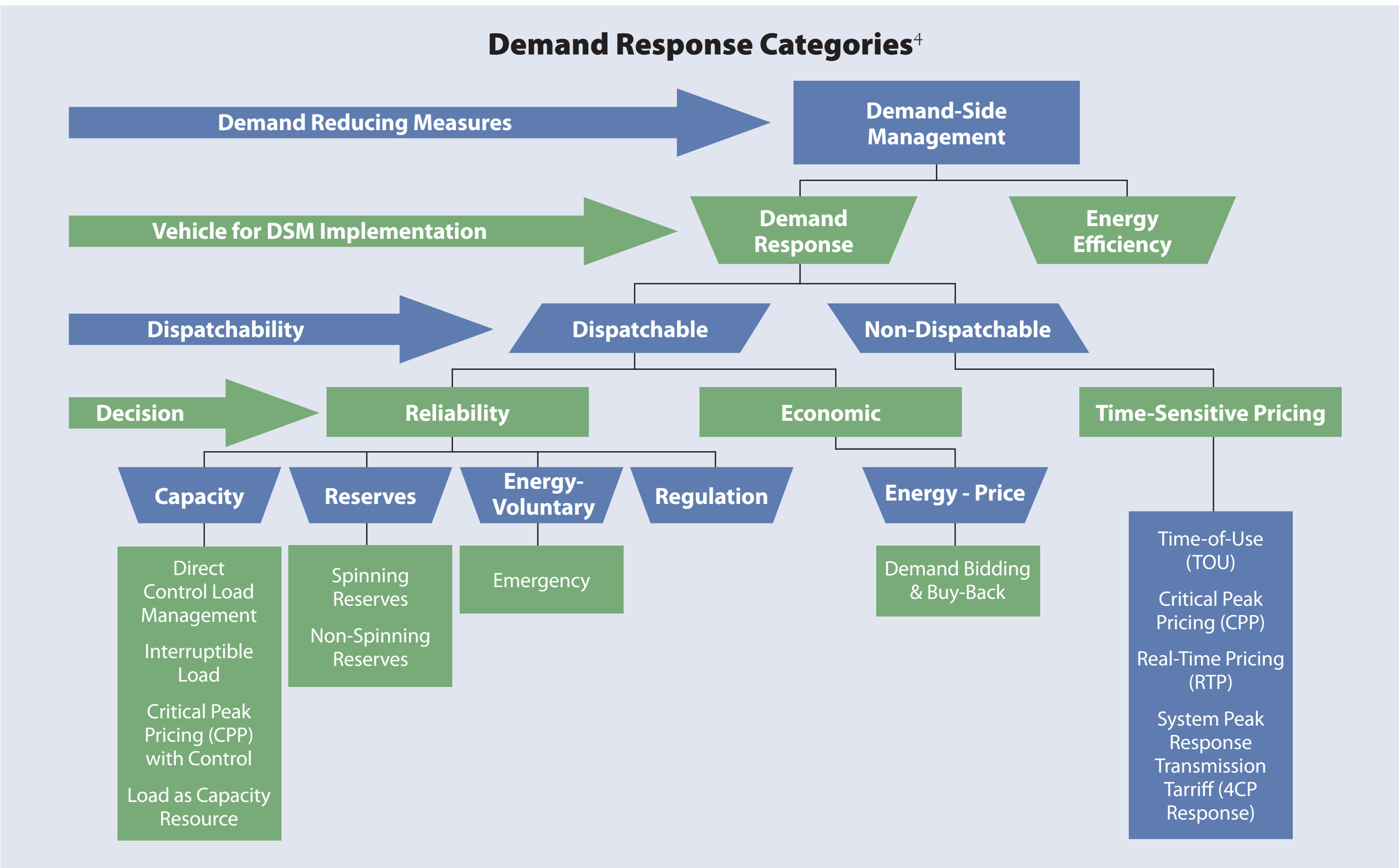
1 The Federal Energy Regulatory Commission characterizes DR more narrowly as "changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments *designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized* [emphasis added]." See: Federal Energy Regulatory Commission. (2011, February). *2010 Assessment of Demand Response and Advanced Metering–Staff Report.* Available at: http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf The broader definition used in this chapter recognizes the expanding role of DR in ancillary service markets. Refer to: Hurley, D., Peterson, P., & Whited, M. (2013, May). *Demand Response as a Power System Resource: Program Designs, Performance, and Lessons Learned in the United States,* p. 8. The Regulatory Assistance Project and Synapse Energy Economics. Available at: www.raponline.org/document/download/id/6597

2 The main purpose of the grid is to efficiently deliver reliable electricity to consumers. Voltage and frequency are the main variables to guarantee grid stability, so it is important to regulate the amplitude and frequency of the voltages throughout the system. Historically, regulation has been accomplished by adjusting generation and through various control devices. Now, however, demand response is able to provide regulation services through modifications to load. Using load response to provide ancillary services is often better for the grid because its faster, shorter response capability offers greater reliability value than slower, longer supply-side response capability; it frees up generation to supply energy; and it can often reduce emissions.

"Regulation" in the figure). Other programs focus on using DR resources to reduce wholesale electricity prices and provide economic benefits. But in all forms of DR, end-users intentionally modify their consumption in order to reduce their costs or to receive some form of compensation. Further information, including detailed definitions and data relating to each category of DR, can be found in the NERC report cited.[3]

DR policies and programs can play a crucial role in any plan to reduce power-sector greenhouse gas (GHG) emissions. To begin with, DR programs can mitigate the cost impacts of GHG reduction efforts to make them more acceptable to consumers and policymakers. In addition, under certain circumstances explained later in this chapter, DR programs can reduce net emissions of GHGs and other air pollutants from existing sources. Finally, and perhaps even more importantly, DR programs can facilitate the use of various emissions reductions strategies while ensuring reliable electric service. For example, DR programs can facilitate integration into the grid of greater amounts of zero-emissions electric generation, namely variable energy resources (VERs) (like wind and solar generators) and inflexible resources (like nuclear generators). It is important to note, however, that DR programs may not automatically result in lower emissions of GHGs or criteria pollutants, depending upon the practices used to achieve the electric service benefits. As detailed later in this chapter, air quality regulatory oversight may be necessary in some cases to ensure that DR programs do not have a negative impact on emissions and air quality.

Figure 23-1



3 NERC. (2013, March.) *2011 Demand Response Availability Report*. Available at: http://www.nerc.com/docs/pc/dadswg/2011%20DADS%20Report.pdf. In addition to the categories described by NERC, "behavioral DR" programs are emerging as a new category of DR. These programs are similar to the behavioral energy efficiency programs described in Chapter 13.

4 Ibid.

Mitigating Cost Impacts

DR programs can significantly reduce the costs of serving electricity demand, principally by reducing the usage of the electric generating units (EGUs) that are most costly to operate.

As explained in detail in Chapter 21, an approach known as "security-constrained economic dispatch" is the norm for scheduling the operation of EGUs. First, the system operator identifies the generating capabilities and the variable operating costs of all of the available EGUs.[5] With all of the information on capabilities and costs in hand, the system operator then ranks the available EGUs in "merit order" from the least costly to operate to the most costly, as depicted in Figure 23-2.

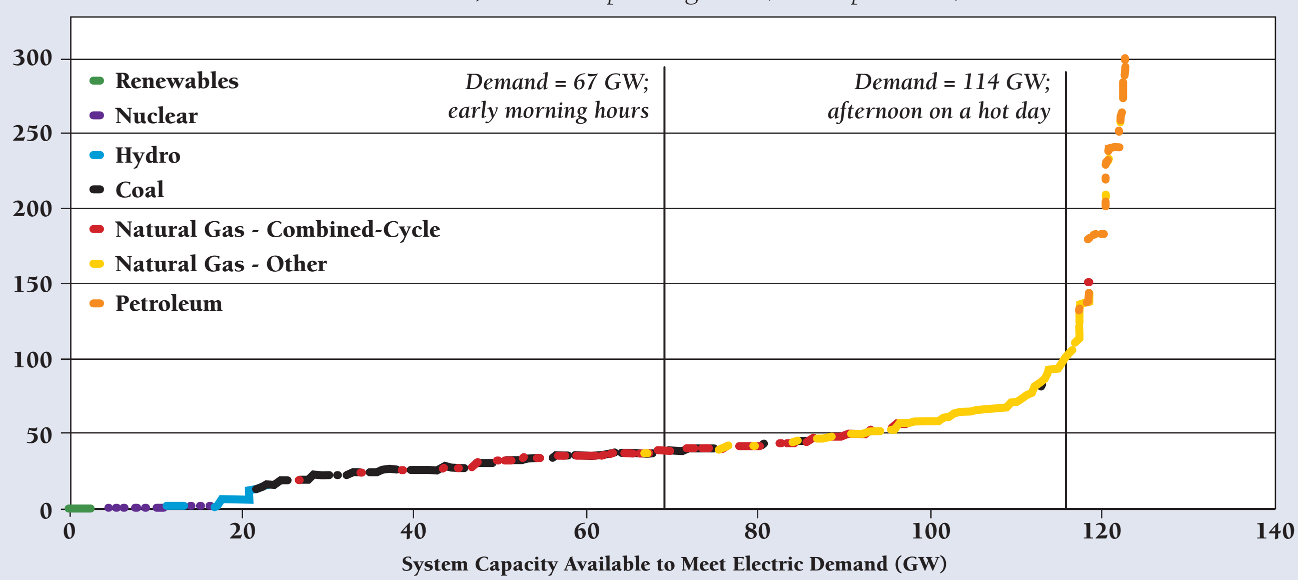
To minimize the costs of meeting electric demand, the system operator will first try to schedule EGUs for dispatch based on merit order. The least costly EGU will be scheduled first, and then the next least costly EGU, and so forth until enough generation is scheduled to meet the expected demand. This concept is shown in Figure 23-2 for two different hypothetical demand levels.[7] However, before the system operator actually schedules the dispatch of any EGUs, he or she will complete a reliability assessment that considers, among other key factors, the capabilities of the transmission system. Based on the reliability assessment, system operators sometimes must deviate from merit order dispatch, but this is generally the exception rather than the rule. Thus, the last unit dispatched to meet demand in a given hour (often referred to as the "marginal unit") will generally have the highest price. When demand is reduced through DR or energy efficiency programs, this most expensive marginal EGU may not need to operate and a different, less expensive EGU will be on the margin.

The cost of operating the marginal unit is especially

Figure 23-2

Hypothetical Dispatch Curve Based on Merit Order[6]

Summer 2011; Variable Operating Cost (dollars per MWh)

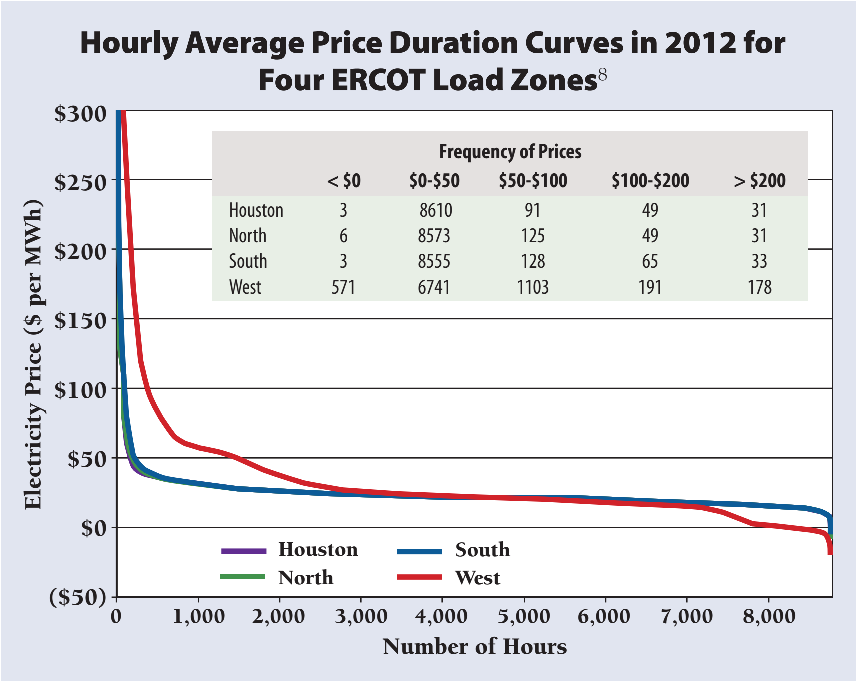


5 In areas that have established wholesale electricity markets, these capabilities and operating costs are revealed through competitive bids made by generators.

6 Note that this hypothetical illustration shows coal to be quite low in the dispatch order. Owing to recent price decreases in natural gas, coal is now much higher up in the dispatch order, at least in several jurisdictions. US Energy Information Administration. (2012, August). *Today in Energy*. Available at: http://www.eia.gov/todayinenergy/images/2012.08.17/DispatchCurve.png

7 The description here mostly describes "day-ahead" scheduling of EGUs to meet forecasted demand. System operators make similar decisions in "hour-ahead" scheduling adjustments and "real-time" balancing decisions based on actual demand, except that the capabilities most needed in those shorter time frames can be different (e.g., ramp rate can be more important), and the variable costs can be different (e.g., if a unit is already operating, its startup costs are not part of its variable costs over the next hour).

Figure 23-3



significant in areas that have established competitive wholesale electricity markets, because the price bid by the marginal EGU establishes a "market clearing price" and all generators (even the ones that are less costly to operate) are paid that price. As a result, electricity prices can rise exponentially during the highest few hours of peak demand in the year. Figure 23-3 offers one example of this phenomenon from the Electric Reliability Council of Texas (ERCOT) competitive wholesale market. The figure shows on the x-axis how many hours of the year the wholesale price of electricity exceeded a value specified on the y-axis (in dollars per megawatt-hour [MWh]). Through most of the year, prices fell within a fairly narrow range, but for a relatively small number of hours when more costly EGUs had to be dispatched to meet high demand, prices spiked dramatically.

DR programs can mitigate electricity costs by reducing demand during those relatively few hours when prices (or operating costs) would otherwise spike. The impacts will tend to be most dramatic in areas that have competitive wholesale electricity markets where all EGUs are paid the bid price of the marginal EGU.

Reducing Emissions

When electric demand is decreased through a DR program, the immediate impact is that the output of the marginal EGU is curtailed. If the marginal EGU is a fossil-fueled unit, as is usually the case,[9] this means that emissions also decrease in that hour.[10] However, it is often the case that a DR program participant will temporarily curtail its demand in order to reduce costs or earn a DR program incentive, but will make up for that reduced electricity use in a future hour. For example, a manufacturer may cut back production for two hours during a DR event, but increase future production to compensate. Thus, when considering the emissions impact of DR programs, air regulators will want to consider not just the immediate decrease in emissions from a marginal EGU, but also the possible increase in emissions at a later date from whatever EGU is marginal at that time. The net impact of a DR program on emissions will depend on how much of this load shifting occurs, and which EGUs are marginal at the times that loads are shifted. Although this is an important consideration, logic suggests that in most cases the net impact will be a reduction in emissions.

Generally speaking, DR events happen at times of peak demand. If a manufacturer or other DR program participant shifts load away from this peak demand period, they are

8 Potomac Economics, Ltd. (2013, June). *2012 State of the Market Report for the ERCOT Wholesale Electricity Markets.* Available at: https://www.potomaceconomics.com/uploads/ercot_reports/2012_ERCOT_SOM_REPORT.pdf

9 Zero-emissions resources are rarely marginal. Most of the renewable generating technologies have no fuel costs and near-zero variable operating costs. Nuclear EGUs also tend to have very low variable operating costs, because their fuel costs are considerably less than those of fossil-fueled EGUs.

10 This assumes that the DR participant does not shed its load from the grid and switch to onsite diesel generators that would otherwise not be in operation. Diesel generator sets can have relatively high emissions rates during startup, shutdown, and under load. If such units were operated in quantity in response to a DR call, emissions reductions, if any, might be minimal. The reader's attention is called to this concern repeatedly throughout the chapter.

unlikely to shift it to another time of peak demand. Instead, they will shift load to a period when system demand (and in competitive markets, the wholesale power price) is lower. And more often than not, the marginal unit in a time of peak demand will have a higher emissions rate than the marginal unit during times of lower demand. This is because the units that have the highest operating costs (and thus get dispatched only during times of peak demand) tend to be the least efficient ones (i.e., those with the highest heat rate). Because of their inefficiency, these EGUs can also have very high carbon dioxide (CO_2) and criteria pollutant emissions.[11] Actual case studies and data are presented later in this chapter to substantiate this claim.

The emissions benefits of shifting load away from times of peak demand are compounded when one considers avoided line losses. As explained in Chapter 10, system *average* line losses are in the range of 6 to 10 percent on most US utility grids, but they can reach as much as 20 percent during the highest peak hours. In other words, it can take fully 5 MWh of generation from an EGU to serve the last 4 MWh of load at peak times, whereas it may take only a little more than 4 MWh of generation from an EGU to do so during off-peak periods. Often, the generation resources called upon at peak times are also less efficient, higher emitting EGUs, such as simple-cycle gas plants. This is not always the case, however; prior to the decline in natural gas prices in recent years, efficient, lower-emitting combined-cycle gas plants often ran at the margin in favor of lower cost but less efficient and higher emitting coal-fired units.

From the perspective of air regulators, some caution must be exercised in the development of DR policies, because some often-deployed DR resources can *increase* criteria and GHG pollutant emissions. For example, some customers participating in DR programs may curtail their use of grid-supplied electricity but switch to onsite backup generators. These generators are typically less efficient than EGUs serving the grid, and uncontrolled or marginally controlled for criteria pollutants. They can have significant emissions impacts, especially when fueled with diesel. DR customers who curtail their use of grid-supplied electricity by switching to onsite diesel generators may exacerbate several air quality concerns:

- Emissions of nitrogen oxides (NO_X), particulate matter (PM), and CO_2 are likely to increase;[12]
- The time periods when these engines are used is likely to coincide with periods of already unhealthy air quality, because peak demand in most parts of the country correlates with the same weather conditions that lead to high ambient air pollution concentrations; and
- Pollutants are emitted at ground level rather than from a high stack, and this can increase the risk of exposure to individuals living or working nearby.

In some cases, DR programs could also shift loads from relatively clean peaking resources (e.g., hydro or combined-cycle gas turbines) to dirtier baseload resources (e.g., coal), as might occur if a company temporarily shifted a production operation from peak daytime hours to nighttime. State environmental regulators have an important role in ensuring that customer backup generation is clean, and relied upon sparingly when there are material environmental concerns in play. Across its many manifestations, however, DR is increasingly recognized as offering potential environmental benefits when properly controlled and may contribute to a cleaner generation mix with the passage of time.[13]

Ensuring Reliability

One of the strategies for reducing GHG emissions that features prominently in this document is to increase generation from zero-emitting VERs like wind and solar.

11 Fuel costs generally comprise the largest portion of variable operating costs. Heat rate measures the amount of energy (in BTUs) used by an EGU to generate one kilowatt-hour (kWh) of electricity. An EGU with a high heat rate has to burn more fuel to generate one kWh than an EGU with a lower heat rate, and thus will emit more GHGs. Obviously, for criteria pollutant emissions, the types of installed control equipment on any given EGU will also bear heavily on emissions levels.

12 Hibbard, P. (2012, August). *Reliability and Emissions Impacts of Stationary Engine-Backed Demand Response in Regional Power Markets.* The Analysis Group. Prepared as comments on the US EPA's proposed regulations for Reciprocating Internal Combustion Engines. Available at: http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/August_2012_Hibbard_DemandResponseReport.pdf

13 Nemtzow, D., Delurey, D., & King, C. (2007). The Green Effect: How Demand Response Programs Contribute to Energy Efficiency and Environmental Quality. *Public Utilities Fortnightly, 45.* Available at: http://www.fortnightly.com/fortnightly/2007/03/demand-response-green-effect

Demand Response as Balancing Resource for the Grid

The potential to expand DR as a resource for balancing services exists across all customer classes. The nature of their loads, the untapped DR potential, and the means for accessing it vary, however.

Large Industrial Customers

Historically, most DR has come from large industrial customers with electricity-intensive processes. These customers typically have some discretion over when they run certain processes within a day, and they are more likely to have the infrastructure, expertise, and resources needed to contract with vendors for DR services. The large average size of these interruptible loads offers logistical and administrative advantages, but they have not generally been well matched for day-to-day balancing operations because they tend to be geographically concentrated, are typically on-or-off arrangements (rather than adjustable), and limited in the number of times they can be called on. Some facilities may also have operations with smaller loads similar to those of commercial customers; most of this potential remains similarly untapped.

Commercial, Small Industrial, and Government Customers

These nonresidential customers are typically smaller and less electricity-intensive, and therefore more challenging to access. However, in the aggregate they represent significant DR potential. They tend to be more business-savvy than residential consumers, but not as sophisticated as large industrial customers and with fewer technical, financial, and legal resources. These customers normally have fewer options for shifting demand, but they may have loads that can be modulated over short periods of time, such as variable-speed drives, area lighting, and space conditioning. They may also have loads such as commercial chillers or processes that are well suited to thermal energy storage applications.

The size and nature of these individual loads make them a good fit for day-to-day balancing operations, but this potential remains untapped owing to historical logistical, administrative, and regulatory barriers. Technology is rapidly reducing the cost and increasing the functionality of real-time automated control of smaller loads with little or no perceptible impact on the quality of energy services, and entrepreneurs are beginning to innovate ways to access this potential. Regulatory barriers and resistance from electricity suppliers remain, however.

Residential Customers

Residential customers are the largest untapped pool of DR potential. They are highly diffuse; vary widely in their levels and patterns of consumption; have low response to electricity prices; lack information, time, and specialized expertise; face financing constraints; and often do not have access to competitive wholesale markets like large customers. Because of technical constraints and regulatory practices, household energy consumption has largely been insulated from conditions on the power grid at any given time.

Some loads with the greatest DR potential, such as water heating and refrigeration, are non-seasonal uses and thus well placed to provide balancing services. Electric vehicles hold great potential for flexible loads and storage services, but broad commercial application is likely several years away. The residential sector nevertheless offers rich potential today at a fraction of the cost of other alternatives for expanding balancing services for the grid. Accessing that potential, however, will require a reconsideration of the potential uses of DR, how to expose the relative value of DR to all concerned, who has access to the market, what it will take to gain consumer acceptance, and how individual households can expect to be compensated for providing services that may initially benefit grid operators but ultimately all consumers.

Realizing DR benefits from this large untapped pool of residential load appears daunting today. However, the grid is rapidly transitioning to digital, multidirectional communication between devices, and the power sector to new business models and new market entrants. Emerging technologies, policies, and markets (discussed further in Chapter 26) will soon provide residential customers new options to manage their energy use, possibly including "apps" that send real-time pricing data to controllers that customers can "set and forget" to respond automatically to DR opportunities on the grid.

(For a more thorough treatment of this topic, see: Hurley, et al, at supra footnote 1.

However, as the penetration of VERs increases, it becomes increasingly challenging for grid operators to schedule the dispatch of EGUs to balance supply with demand in real time. The array of alternatives to deliver this flexibility are typically limited and expensive, except in systems like the Pacific Northwest, Quebec, and Brazil, which are dominated by flexible, large hydro systems. (This challenge is described in detail in Chapter 20.)

DR may have an important role to play in creating cost-effective ways of meeting system needs for greater flexibility. DR programs can make that challenge more manageable, and less expensive, because they provide the system operator with additional options. Instead of always adjusting generation levels to meet demand, DR programs create the possibility of adjusting demand to meet supply. Whichever option is less expensive at any given time can be used. DR programs can also provide a range of ancillary services that are essential for maintaining system quality, sometimes at lower costs than obtaining those services from supply-side resources (see text box p. 6).

2. Regulatory Backdrop

Regulatory oversight of DR programs can be complex, reflecting the complex landscape of US electricity markets and the variety of types of DR programs depicted in Figure 23-1. At the core of this complexity is a fundamental jurisdictional split, wherein states have authority to regulate retail electricity transactions and the Federal Energy Regulatory Commission (FERC) has authority to regulate interstate wholesale markets and transactions.[14] There is also significant variation in the extent to which states allow competition in retail electricity markets, and the extent to which states regulate the retail activities of consumer-owned utilities (e.g., municipal electric utilities and electric cooperatives) versus allowing those utilities to self-regulate. These jurisdictional distinctions are relevant because some categories of DR programs operate at the wholesale level, whereas others operate at the retail level. This means different types of DR programs can be subject to different regulatory oversight.

States have exclusive jurisdiction over the rates that are paid to end-use customers by utilities for participating in DR programs. This is relevant to most of the categories of DR programs shown in Figure 23-1, and especially the time-sensitive pricing options. This regulatory authority is generally vested in a state public utility commission (PUC). Traditional principles of public utility regulation apply, namely, that the PUC must determine that the rates for DR programs are just and reasonable, nondiscriminatory, and in the public interest. For the most part, this means that the benefits of DR programs will have to exceed the costs. Furthermore, any costs that utilities incur to support DR programs (e.g., metering or communications equipment, customer acquisition and enrollment, and so on), will have to be deemed prudent.

Some of the categories of DR programs are unrelated to retail rates and operate instead in a wholesale market context. Currently, DR can participate in all of the wholesale energy markets in the United States, and in some of the wholesale capacity markets. (Capacity markets are discussed in detail in Chapter 19.) Wherever wholesale markets have a mechanism for compensating DR customers, the terms of that compensation are subject to exclusive FERC jurisdiction under the Federal Power Act and based on two FERC orders, described below. However, the terms by which a utility or competitive retail electricity supplier (i.e., a "load serving entity") *purchases* DR from the wholesale market is subject to concurrent FERC and state jurisdiction.

In 2008, the FERC issued Order 719, which required the operators of competitive wholesale electricity markets – regional transmission organizations (RTOs) and independent system operators (ISOs) – to treat DR bids as comparable to generators' bids in hourly energy markets.[15] In essence, this decision held that offering to reduce demand by one MWh is comparable to offering to increase generation by one MWh. DR would therefore be treated like any other resource, and bids could come directly from end-use customers, or could be offered by "aggregators" who manage the wholesale market transaction on behalf of multiple end-use customers. States, however, retained the

14 Case law has established that, owing to the interconnected nature of the US electricity grid, all electricity transactions meet the definition of interstate commerce, regardless of the origin or destination of the electricity, except for transactions occurring entirely within Alaska, Hawaii, and the ERCOT portion of Texas.

15 FERC. (2008, October). *Order No. 719: Wholesale Competition in Regions with Organized Electric Markets – Final Rule.* Available at: http://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf

authority to prohibit end-users in their state from offering DR in the wholesale markets.

In 2011, in Order 745, the FERC expanded on its earlier ruling and ordered RTOs and ISOs to set compensation for wholesale DR bids in the hourly energy markets at the *same price* given to generators (the "locational marginal price"), so long as the DR helped balance supply with demand and was cost-effective.[16] Generators sued the FERC over Order 745, and in May 2014 the US Court of Appeals for the DC Circuit ruled that Order 745 was unlawful because the FERC was trying to regulate the level of compensation for what was effectively a retail transaction, and therefore the exclusive purview of state regulators (because the FERC's jurisdiction is limited to wholesale transactions in the bulk power system).[17] Although Order 745 is limited in scope to compensation in wholesale energy markets, many legal observers expect that the same reasoning will eventually be applied to compensation for DR in wholesale capacity markets as well. The FERC appealed the DC Circuit decision to the Supreme Court, and the DC Circuit decision is currently stayed. However, the uncertain status of Order 745 further complicates what was already a complicated regulatory landscape for DR programs. It may be that in the near future, the existence of most or all DR programs and the levels of compensation paid to participants will be exclusively regulated by states.

Oversight of environmental concerns can add to the complexity of DR regulation, especially if there is little coordination between environmental regulators and energy regulators. In general, federal and state utility regulators make no distinction between DR participants who might replace grid-supplied electricity with electricity from backup generators and those who truly curtail their consumption. From the perspective of utilities and electricity markets, curtailment looks the same as onsite generation. However, these two things are very different to environmental regulators if the onsite generation comes from a fossil-fueled generator. Backup generators, especially those fueled by diesel, often emit GHG and criteria pollutants at even higher rates than some of the least efficient generators selling power to the grid.

Over the course of the past decade, the US Environmental Protection Agency (EPA) has promulgated a variety of regulations for stationary internal combustion engines of varying designs and sizes at major and area sources.[18] The emissions limits in these rules generally cannot be met by an uncontrolled backup generator burning ordinary diesel fuel, but the rules exempt "emergency engines" from those limits. This exemption covers two kinds of operation. First, the rules allow for unlimited operation of emergency engines, even those with very high emissions rates, in true emergencies (e.g., power outages, fires, or floods). Next, emergency engines can operate for up to a combined total of 100 hours per year for maintenance and testing, blackout prevention,[19] and non-emergency (economic) DR, or non-emergency operation without compensation, for up to 50 hours of the 100-hour annual limit.[20] These rules are currently being litigated in the DC Circuit; the exemption for operation of emergency engines in nonemergency situations is one of the principal points of contention.[21]

Some states have adopted more stringent limitations on

16 The order explicitly instructs the wholesale market administrator (ISO or RTO) to put the energy market offers from DR providers into the stack with the generation offers, and if they are less expensive than the marginal unit, they will be dispatched and be paid the same price (subject to a minimum offer price to prove that it is cost-effective). FERC. (2011). *Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets,* 134 FERC ¶ 61,187. Available at: http://www.ferc.gov/whats-new/comm-meet/2011/121511/E-4.pdf

17 See: (2014, May 27). *DC Circuit Vacates FERC Rule on Pricing of Demand Response in Organized Energy Markets.* Available at: http://www.vnf.com/2909

18 This includes regulations on reciprocating internal combustion engines, commonly referred to as the RICE rule, which is among those being litigated by some states.

19 Blackout prevention refers to emergency demand response for Energy Emergency Alert Level 2 situations and situations when there is at least a five-percent or greater change in voltage. Energy emergency alert levels are defined in NERC Reliability Standards. A Level 2 situation occurs when a balancing authority or load serving entity is no longer able to satisfy its customers' expected energy demand, but has not yet forced involuntary curtailment of load.

20 Refer to the EPA website at: http://www.epa.gov/ttn/atw/icengines/

21 Delaware Department of Natural Resources and Environmental Control v. EPA, No. 13-1093. Available at: http://www.foley.com/files/Publication/d5db8cb7-233b-48d3-8356-909b9a488adc/Presentation/PublicationAttachment/c20daba5-c948-481a-87aa-ae97050379cf/DE_DNREC_v_EPA_13-1093.pdf

the operation of backup generators,[22] especially where the intersection of decades of unhealthy levels of ozone and a need to diversify energy resources has created an excellent crucible for air quality regulators, energy regulators, and system operators to analyze ways to assure electricity reliability without increasing emissions further. An example of such coordination was the New England Demand Response Initiative (NEDRI) that was convened in 2002 to develop a comprehensive set of energy and environmental policies that would:[23]

- Increase the quantity of resources available to quickly mitigate electricity price spikes;
- Amend state air quality regulations to permit clean, standby generating resources to operate for a defined number of hours in non-emergency conditions; and
- Require best available control technology-level emissions limits for resources qualified to operate during emergencies that also seek to run during non-emergency conditions.

NEDRI was monitored by the FERC and the EPA. The NEDRI process and progress informed national efforts by both regulatory agencies to develop a DR program and rules covering small generating resources. Shortly after NEDRI began, a similar effort commenced in the mid-Atlantic states, the Mid-Atlantic Distributed Resources Initiative,[24] followed later by the Pacific Northwest Demand Response Project, both of which continue today.

Turning specifically to the question of GHG regulation, it bears mentioning that in the proposed Clean Power Plan rules for GHG emissions from existing EGUs, the EPA did not include DR programs within the defined "best system of emission reduction." However, the EPA notes throughout the proposed rule that many strategies not included in the best system of emission reduction have the potential to reduce power-sector GHG emissions in the right circumstances.

3. State and Local Implementation Experiences

DR in the United States originated in the 1970s, in part because of the spread of central air conditioning which resulted in declining load factors and needle peaks during hot summer days. The advent of "integrated resource planning" in the late 1970s and 1980s drew attention to the high system costs of meeting these peak loads and encouraged utilities to look for load management alternatives.[25] Rate design (particularly time-of-use pricing) and incentive programs became standard DR programs at many regulated utilities. Most of these early programs served industrial end-users that curtailed their load in exchange for compensation from utilities during peak periods so that the utilities could avoid brown-outs or black-outs.

The DR programs of the 1970s through much of the 1990s were largely conducted by vertically integrated utilities in a structured, regulated environment, and therefore consumers were not exposed to real-time wholesale price signals, nor were consumers compensated for the full system value of their demand reduction. This began to change in the 1990s as the US electric industry initiated the restructuring process. Driven in large part by FERC Order 719 and Order 745, DR is now a crucial feature in all organized wholesale markets in the United States.

Currently there are numerous ways in which dispatchable DR can operate. In regions with organized wholesale markets, DR resources can typically bid

22 For examples, refer to: NESCAUM. (2012, August). *Air Quality, Electricity, and Back-up Stationary Diesel Engines in the Northeast.* Available at: http://www.nescaum.org/documents/nescaum-aq-electricity-stat-diesel-engines-in-northeast_20140102.pdf/download

23 The complete list of NEDRI policy documents, framing papers, presentations, and meeting notes is located at http://nedri.raabassociates.org. NEDRI's process was led by The Regulatory Assistance Project, facilitated by Jonathan Raab, with assistance from the Lawrence Berkeley National Laboratory, Efficiency Vermont, and Jeff Schlegel (consultant to several state energy efficiency programs).

24 The Mid-Atlantic Distributed Resources Initiative was established in 2004 by the public utility commissions of Delaware, District of Columbia, Maryland, New Jersey, and Pennsylvania, along with the US Department of Energy, the EPA, the FERC, and PJM Interconnection.

25 As discussed in detail in Chapter 22, integrated resource planning refers to the evaluation of demand and supply resources by public utilities and state regulatory commissions to cost-effectively provide electricity service. Integrated resource planning differs from earlier planning techniques in that it also considers environmental factors, demand-side alternatives, and risks posed by different investment portfolios.

directly into energy, capacity, and ancillary services markets or be dispatched in response to market signals. However, the degree to which DR is integrated into the wholesale market varies, with some regions allowing DR to set the market clearing price, whereas other regions restrict DR's ability to influence market prices. Finally, across the United States, and particularly in areas without wholesale markets, utilities may maintain their own DR programs such as direct load control for water heaters and air conditioning units.

Table 23-1

Customer Enrollment in Demand Response Programs (2012)[27]

By North American Electric Reliability Corporation Region

Code	NERC Region Name	Incentive-Based (Dispatchable) Programs	Time-Based (Non-Dispatchable) Programs
AK	Alaska	2,432	38
FRCC	Florida Reliability Coordinating Council	1,328,487	27,089
HI	Hawaii	36,703	323
MRO	Midwest Reliability Organization	795,345	82,310
NPCC	Northeast Power Coordinating Council	54,413	293,721
RF	ReliabilityFirst Corporation	1,398,341	433,879
SERC	SERC Reliability Corporation	715,225	180,619
SPP	Southwest Power Pool	91,585	61,618
TRE	Texas Reliability Entity	109,875	604
WECC	Western Electricity Coordinating Council	884,299	2,601,112
	Unspecified	15,004	57,435
	TOTAL	**5,431,709**	**3,738,748**

Participation by third-party (i.e., non-utility) providers of DR services has been an important factor in bringing DR services to scale, especially in wholesale markets. These "curtailment service providers" or "DR aggregators" seek out customers who have some flexibility in their load but are also large enough to make curtailment worthwhile to the system operator. Participating end-use customers are typically large commercial or industrial facilities. The aggregator can offer DR services to a vertically integrated utility on behalf of participating customers, or bid those services into competitive wholesale electricity markets where they exist. This lowers the transaction costs for participating end-users and increases participation. Aggregators can also make arrangements that give customers more flexibility than they might get if they contracted directly with a utility to provide DR services. Most importantly, loads can be aggregated and packaged in a way that provides the utility or system operator high confidence that the contracted load reductions or modifications will be realized whenever called upon.

Pursuant to a requirement of the Energy Policy Act of 2005, the FERC staff produce an annual assessment of DR and advanced metering implementation in the United States. The most recent such report was published in December 2014 and includes summary data on recent levels of DR deployment.[26] As shown in Table 23-1, more than 5.4 million customers participated in incentive-based DR programs in 2012. These include all of the DR program categories described in Figure 23-1 as dispatchable. In addition, more than 3.7 million customers participated in time-based DR programs. These include all of the DR program categories described in Figure 23-1 as non-dispatchable. Participants were broadly (but not evenly) distributed across all customer classes and all regions of the country (refer to Figure 23-4).

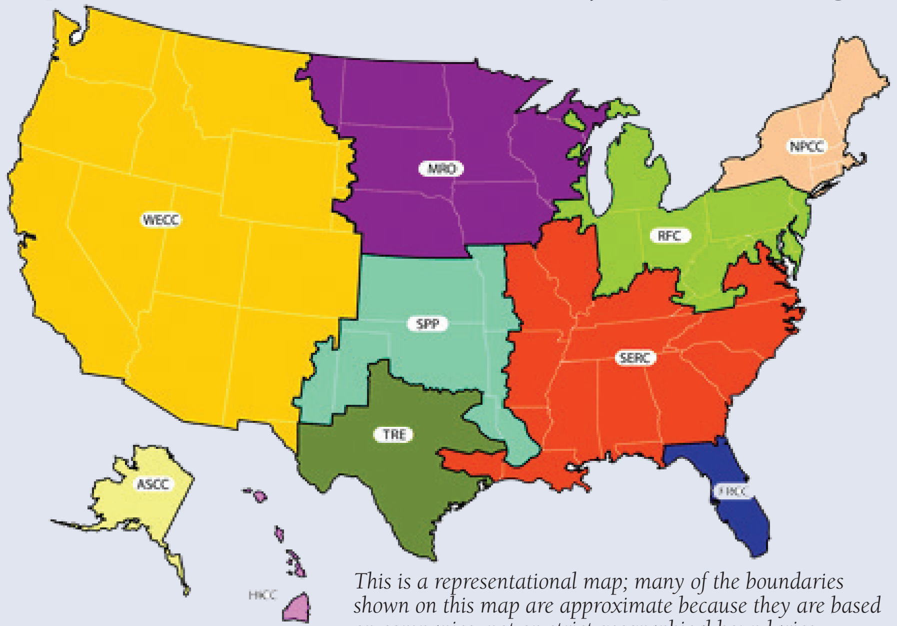
The FERC assessment also summarizes the total demand reduction that could occur at the time of the system peak if all DR program participants were called on to act. These data are broken down between the retail DR programs operated by utilities and other load-serving entities (shown in Table 23-2), and the wholesale DR programs operated by ISOs and RTOs (shown in Table 23-3). Nationwide, these two types of programs totaled almost 55,000 MW of potential peak demand reduction in 2012. In the competitive wholesale electricity markets, DR provided between 2.9 and 10.2 percent of each region's peak demand in 2013. In previous annual assessments, FERC staff have estimated that the contribution of DR to meeting peak

26 FERC. (2014, December). *Assessment of Demand Response & Advanced Metering: Staff Report.* Available at: http://www.ferc.gov/legal/staff-reports/2014/demand-response.pdf

27 Ibid.

Figure 23-4

Map of North American Electric Reliability Corporation Regions



This is a representational map; many of the boundaries shown on this map are approximate because they are based on companies, not on strict geographical boundaries.

US EPA. *Emissions and Generation Resource Integrated Database (eGRID).* Available at: http://www.epa.gov/cleanenergy/energy-resources/egrid/faq.html

demand nationally could be more than doubled, to 14 percent, and the Electric Power Research Institute (EPRI) estimates that DR could reduce nationwide summer peak demand seven to nine percent below what is otherwise projected by 2030.[28] As shown in Table 23-3, wholesale DR programs grew by 0.5 percent from 2012 to 2013 alone.

There is a wealth of data, especially from competitive wholesale markets, proving that DR is a reliable resource that delivers demand reductions when called upon to do so. Numerous examples are provided in a 2013 report by Synapse Energy Economics for The Regulatory Assistance Project of DR participants delivering 100 percent of their load reduction commitment, or more, in ISO New England, PJM Interconnection, ERCOT, and elsewhere.[30]

Despite the stated concerns of air pollution regulators about the use of backup diesel generators in association with DR programs, comprehensive data on this topic are currently lacking. Because of wholesale market rules and the role of DR aggregators, there are no standard data sources for identifying the extent to which backup generators are used during DR events. Efforts have been initiated by some states in the PJM Interconnection market to gather this information. Early results suggest that backup generators may comprise 30 to 50 percent of the total DR resource in some states, but these estimates have yet to be confirmed across the entire market.

Table 23-2

Potential Peak Reduction (MW) From Retail Demand Response Programs in 2012[29]

By North American Electric Reliability Corporation Region

NERC Region	Customer Class				
	Residential	Commercial	Industrial	Transportation	All Classes
AK	5	13	9	0	27
FRCC	1,762	1,097	447	0	3,306
HI	17	25	0	0	42
MRO	1,869	1,141	2,557	0	5,567
NPCC	84	421	88	14	606
RFC	1,520	815	3,502	0	5,836
SERC	1,399	1,170	3,475	2	6,046
SPP	172	391	760	0	1,323
TRE	88	333	59	0	480
WECC	1,684	1,056	2,365	165	5,269
All Regions	**8,600**	**6,462**	**13,261**	**180**	**28,503**

28 Refer to: FERC, at supra footnote 26.

29 Ibid.

30 Hurley, et al, at supra footnote 1.

Table 23-3

Potential Peak Reduction From Wholesale Demand Response Programs[31]

RTO/ISO	2012 Potential Peak Reduction (MW)	2012 Percent of Peak Demand[h]	2013 Potential Peak Reduction (MW)	2013 Percent of Peak Demand[h]
California ISO (CAISO)	2,430[a]	5.2%	2,180[i]	4.8%
Electric Reliability Council of Texas (ERCOT)	1,800[b]	2.7%	1,950[j]	2.9%
ISO New England, Inc. (ISO-NE)	2,769[c]	10.7%	2,100[k]	7.7%
Midcontinent Independent System Operator (MISO)	7,197[d]	7.3%	9,797[l]	10.2%
New York Independent System Operator (NYISO)	1,925[e]	5.9%	1,307[m]	3.8%
PJM Interconnection, LLC (PJM)	8,781[f]	5.7%	9,901[n]	6.3%
Southwest Power Pool, Inc. (SPP)	1,444[g]	3.1%	1,563[o]	3.5%
Total ISO/RTO	**26,346**	**5.6%**	**28,798**	**6.1%**

Sources:

a California ISO 2012 Annual Report on Market Issues and Performance

b ERCOT Quick Facts (Nov. 2012)

c 2012 Assessment of the ISO New England Electricity Markets

d 2012 State of the Market Report for the MISO Electricity Markets

e 2012 Annual Report on Demand Side Management programs of the New York Independent System Operator, Inc. under ER01-3001, et al. (Jan, 15, 2013). Figure includes ICAP/Special Case Resources (1,744 MW), Emergency DR (144 MW), and Day-Ahead Demand Response (37 MW)

f PJM 2012 Load Response Activity Report, Delivery Year 2012-2013 Active Participants in PJM Load Response Program at 2-3, (Apr. 9, 2013). Figure includes all resources registered as Emergency DR (8,552 MW), plus the difference between resources registered as Economic DR and both Emergency & Economic DR (229 MW)

g SPP Fast Facts (Mar. 1, 2013)

h Peak demand data are from the following: California ISO 2012 & 2013 Annual Reports on Market Issues and Performance; ERCOT 2013 Demand and Energy Report; ISO-NE Net Energy and Peak Load Report (Apr. 2013 & Apr. 2014); 2012 & 2013 State of the Market Reports for the MISO Electricity Markets; 2012 & 2013 State of the Market Reports for the New York ISO Markets; 2012 & 2013 PJM State of the Markets Reports, Vol. 2; SPP 2012 & 2013 State of the Market Reports

i CAISO 2013 Annual Report on Market Issues & Performance

j ERCOT Quick Facts (Nov. 2013) http://www.ercot.com/content/news/presentations/2013/ERCOT_Quick_Facts_November%20 2013.pdf

k ISO-NE Demand Response Asset Enrollments at 2, (Jan. 2014)

l 2013 State of the Market Report for the MISO Electricity Markets at 72. This figure excludes 366 MW of emergency demand response that is also classified as LMR

m 2013 Annual Report on Demand Side Management programs of the New York Independent System Operator, Inc. under ER01-3001, et al. (Jan. 15, 2014)

n PJM 2013 Demand Response Operations Markets Activity Report at 3-4 (Apr. 18, 2014), Figure represents "unique MW."

o SPP Fast Facts (as of Dec. 2013)

Note: *Commission staff has not independently verified the accuracy of RTO, ISO and Independent Market Monitor data for purposes of this report. Values from source data are rounded for publication.*

According to FERC, remaining barriers to DR include:

- The limited number of retail customers on time-sensitive rates;
- Measurement and cost-effectiveness of DR energy savings;
- Lack of uniform standards for communicating DR pricing signals and usage information; and
- Lack of customer engagement.

4. GHG Emissions Reductions

This section focuses on the GHG emissions reductions that result from and are directly attributable to DR policies and programs. Before diving into that topic, however, it bears repeating that DR programs can also be used to maintain reliability and lower electric system costs as other GHG reductions strategies, particularly those involving

31 Supra footnote 26.

variable or inflexible energy resources, are deployed. The potential of those other strategies is documented in other chapters.

Several factors will influence the GHG emissions impact attributable to a DR program:

- The amount of demand curtailed in each DR event;
- The emissions profile of the marginal emissions unit(s) operating at the time each DR event is called, which varies by time of day, time of year (summer vs. winter, or ozone season vs. non-ozone season), and geographic location;
- The extent to which participants replace grid-supplied electricity with electricity from backup generators, and the emissions characteristics of those backup generators; and
- Assuming some load is shifted to another time, as is normally the case, the emissions profile of the marginal emissions unit(s) operating at that time.

For example, if a very inefficient, high-emitting EGU is operating on the margin when a DR event is called, and all of the participating customers shift their load to times when more efficient, lower-emitting EGUs operate on the margin, the net effect will be a decrease in emissions. The amount of the decrease could be substantial, if the emissions rates of the marginal EGUs in question are very different. But the opposite case (shifting load to a time when a higher-emitting EGU is marginal) can also occur, or some customers could shift load to backup generators, and emissions could increase.

Quantifying the emissions impacts of DR can be complex and may require some level of active engagement by both environmental regulators and system operators. However, evidence suggests that the GHG emissions impact of DR programs can be positive.

For example, a recent study conducted by Navigant Consulting examined both the direct and indirect emissions impacts of DR programs, in part by modeling the impacts of demand reduction in the wholesale markets operated by PJM Interconnection, the Midcontinent Independent System Operator, and ERCOT. Navigant estimates that "DR can directly reduce CO_2 emissions by more than 1 percent through peak load reductions and provision of ancillary services, and that it can indirectly reduce CO_2 emissions by more than 1 percent through accelerating changes in the fuel mix and increasing renewable penetration."[32]

Another study by Pacific Northwest National Laboratory used modeling to estimate the expected emissions impacts of shifting roughly ten percent of load in each US region during peak hours (on average, 168 hours per year). This was equivalent to shifting about 0.04 percent of total annual load. Pacific Northwest National Laboratory found a positive result for GHG emissions, specifically a reduction of 0.03 percent of total annual emissions. The point to emphasize here is not the magnitude of the numbers but the fact that the modeling results found that load shifting resulted in decreased GHG emissions.[33]

In a third example, EPRI found that DR programs focused on peak load reduction generally resulted in net energy savings and net emissions reductions. EPRI estimated that these programs could save up to four billion kWh of energy in 2030 and that doing so could reduce CO_2 emissions by two million metric tons.[34]

These results may seem surprising, until one considers that most DR events occur at or near times of peak demand, when even the least efficient EGUs may be dispatched. This means the marginal unit could be an inefficient, high-emitting coal-fired or oil-fired unit, or it could be a simple-cycle combustion turbine that has such a high heat rate that its emissions rate in pounds per MWh is comparable to that of an average coal- or oil-fired EGU. In the next section, a case study of this phenomenon (focused on criteria pollutant emissions rather than GHG emissions) is presented. Some support for this idea can also be inferred from the EPA's eGRID database of EGU emissions rates.[35]

32 Navigant Consulting, Inc. (2014, November). *Carbon Dioxide Reductions From Demand Response: Impacts in Three Markets.* Prepared for the Advanced Energy Management Alliance. Available at: http://www.ieca-us.com/wp-content/uploads/Carbon-Dioxide-Reductions-from-Demand-Response_Navigant_11.25.14.pdf

33 Pratt, R., Kintner-Meyer, M. C. W., Balducci, P. J., Sanquist, T. F., Gerkensmeyer, C., Schneider, K. P., Katipamula, S., & Secrest, T. J. (2010). *The Smart Grid: An Estimation of the Energy and CO_2 Benefits.* Publication no. PNNL-19112, prepared for the US Department of Energy. Available at http://energyenvironment.pnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf

34 Electric Power Research Institute. (2008). *The Green Grid: Energy Savings and Carbon Emissions Reductions Enabled by a Smart Grid.* EPRI-1016905. Available at: http://assets.fiercemarkets.net/public/smartgridnews/SGNR_2009_EPRI_Green_Grid_June_2008.pdf

35 US EPA. (2010). *Emissions and Generation Resource Integrated Database (eGRID).* Available at: http://www.epa.gov/cleanenergy/energy-resources/egrid/

Although the EPA does not identify or collect data on marginal EGUs, eGRID does provide summary data for "non-baseload" EGUs.[36] In most regions of the country, the weighted average CO_2 emissions rate of non-baseload generators is higher than the weighted average CO_2 emissions rate for all generation. On average for the entire country, these non-baseload generators emit at levels about 25 percent higher than the average for all generation. However, there is significant regional variation. In parts of Alaska and New York, for instance, the non-baseload emissions rate is more than *twice as high* as the average for all generation, whereas in a few regions it is as much as ten percent *lower* than the average for all generation. This suggests that the GHG emissions impact of a DR program in one region could be substantially different from the impact in another region, and the impact overall could be positive or negative.

The best data for a state to use to assess the benefits for a DR program would be state-specific and for the most recent year. However, such granularity is not available for many parts of the United States today, and states may have to default to regional-level statistics.

ISOs and RTOs, where they exist, may offer another good source of emissions data. For example, ISO New England has worked with regional air quality regulators since 1993 to calculate marginal emissions rates for NOX, sulfur dioxide, and CO_2.[37] This information has helped regulators to assess the benefits of energy efficiency and renewable energy programs and, more recently, of "clean" DR programs (i.e., those that do not rely on or encourage the use of uncontrolled backup generators). The accuracy and granularity of ISO New England's data have improved over time, taking advantage of improved modeling and computing power such that today, the regional algorithm for marginal emissions estimates is grounded on hourly data from dispatched generation.[38] Other regions could benefit from replicating the kind of work that has been done in New England.

Regardless of whether state-specific or regional-level emissions data are available, the basic process steps for quantifying the emissions impacts of DR are the same for each region:

- Obtain the best-quality data profiles for the marginal units dispatched in your state. In order of preference, starting with the highest quality:[39]
  - Nodal[40] information differentiated by season, time of day, and type of EGU (i.e., baseload vs. peak, or baseload vs. non-baseload);
  - State-level information differentiated by season, time of day, and type of EGU;
  - State-level seasonal data (i.e., ozone vs. non-ozone season) differentiated by type of EGU;
  - Regional data differentiated by type of EGU;
- Compare emissions between baseloaded and marginal EGUs (or baseloaded and non-baseloaded EGUs if marginal data are not available);
- If marginal or non-baseloaded EGU emissions are higher than those of baseloaded EGUs, then a DR program will likely have an emissions benefit;
- If marginal or non-baseload EGU emissions are lower than those of baseload EGUs, then a DR program will likely increase emissions.

36 Non-baseload EGUs include both load-following generators and peaking plants, all of which could potentially operate on the margin in some hours. This does not imply that non-baseload emissions rates are the same as marginal emissions rates.

37 See, for example: ISO New England. (2014, January). *2012 ISO New England Electric Generator Air Emissions Report.* Available at: http://www.iso-ne.com/system-planning/system-plans-studies/emissions

38 Initial marginal emissions data were based on assessments of the last 500 MW of generation that were dispatched, and comparing marginal emissions data with and without nuclear and hydroelectric generation included. Because the latter units in New England operate as baseload EGUs, these are not affected by DR programs. Discussions with regional air and energy regulators, as part of ISO New England's Environmental Advisory Group, have led to continual improvement of the methodologies used to calculate the marginal emissions, and to joint understanding of what units comprise the marginal unit and their emissions profile.

39 This hierarchy of the relative precision of emissions factors is analogous to that for AP-42 emission factors, which is a very familiar topic to air regulators.

40 Electric grid operators configure their transmission and distribution systems based on the densities of energy use. These are referred to as "nodes," which often are coincident with the boundaries of major urban areas.

5. Co-Benefits

DR policies and programs can reduce costs for participants and deliver a wide variety of economic benefits across the electric power system. They can also help to maintain reliability as more VERs are added to the grid.

DR programs can also reduce emissions of criteria and hazardous air pollutants, in the same manner that they can reduce GHG emissions. As with GHG emissions, the results depend on several variables and may not always be positive. Nevertheless, carefully designed DR programs with appropriate limitations and controls on backup generators could potentially be useful in criteria pollutant planning.

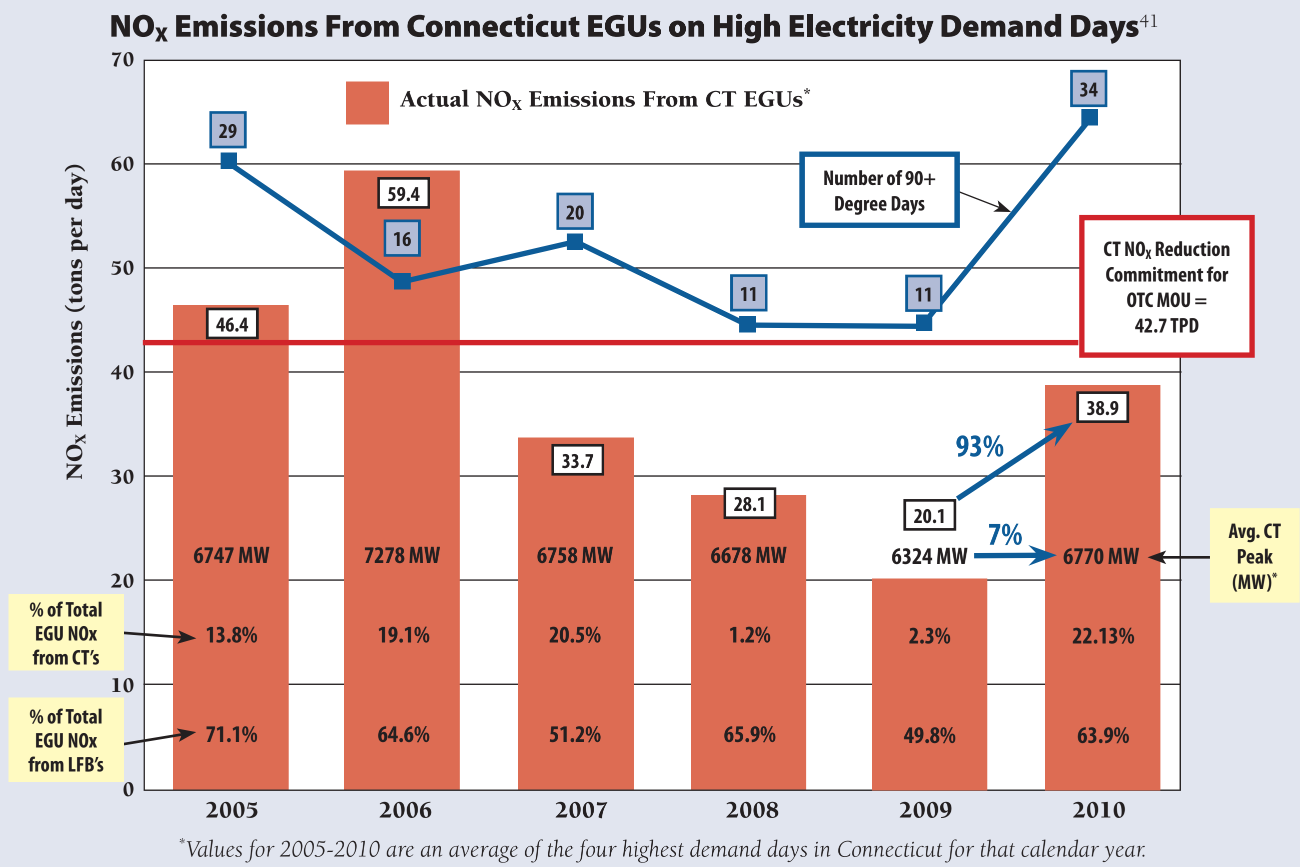
Figure 23-5 offers an illustrative example, based on actual data from Connecticut, of how NO_X emissions can increase significantly during high electricity-demand days when even the least efficient EGUs must be dispatched.

The orange bars in the figure show the average NO_X emissions from EGUs located in Connecticut on the four highest demand days of each year from 2005 through 2010. The figure also indicates for those four highest demand days in each year what the average peak demand was, the percentage of emissions coming from simple-cycle combustion turbines, and the percentage of emissions coming from load-following boilers.

Figure 23-5 reveals two important points:

- A seven-percent increase in the average of the four highest days of electricity demand (from 6324 MW in 2009 to 6770 MW in 2010) caused NOx emissions to nearly double, from 20.1 tons per day to 38.9 tons per day.
- Simple-cycle gas-fired combustion turbines were the marginal units in Connecticut during this time period. These units typically had not installed best available control technology for NO_X emissions, and their

Figure 23-5



*Values for 2005-2010 are an average of the four highest demand days in Connecticut for that calendar year.

OTC – Ozone Transport Commission; MOU – Memorandum of Understanding; CTs – Combustion Turbines; LFBs – Load-Following Boilers.

41 Rodrigue, R. (2011, May 4). Connecticut Department of Energy and Environment, personal communication.

contribution to total NOx emissions from all EGUs increased from 2.3 percent in 2009 to 22.13 percent in 2010.[42]

The Connecticut example points to an obvious conclusion: reducing demand during peak days can avoid reliance on uncontrolled simple-cycle turbines, producing multiple benefits (e.g., lower NOx emissions, decreased hourly electricity costs, and so on). Of course, the data shown in the figure are specific to Connecticut, and each state will be different. In fact, the results may not be positive in every single case. But the potential to reduce criteria pollutant emissions on high-demand days (which often coincide with exceedances) is clearly present in some regions, and air regulators are recognizing the potential of DR programs to support their efforts.[43]

The environmental benefits of DR hold great promise over time, as some of the previously discussed long-term projections (e.g., by EPRI) indicate. But some forms of DR create environmental risks that may need to be addressed by energy and air quality regulators. As noted previously, load shifting runs the risk for increasing emissions through the dispatch of higher-emitting generation resources, in some circumstances, and the use of uncontrolled diesel backup generators may have significant air quality impacts. Air regulators should be careful to minimize the risk for inadvertent net GHG and criteria pollutant emissions increases when considering DR options.

The full range of co-benefits relating to DR is summarized in Table 23-4; many entries cite "Maybe" reflecting the variety of possible DR strategies (i.e., some approaches will decrease GHG emissions but others may increase emissions).

Table 23-4

Types of Co-Benefits Potentially Associated With Demand Response

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Maybe
Nitrogen Oxides	Maybe
Sulfur Dioxide	Maybe
Particulate Matter	Maybe
Mercury	Maybe
Other	Maybe
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Maybe
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Maybe
Avoided Costs of Future Environmental Regulations	Maybe
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Maybe
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Maybe
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Yes
Other	Maybe

42 The magnitude of the increase shown, although large, may be somewhat overstated, because the "marginal" simple-cycle combustion turbines may have utilized default NOx emissions-rate values, instead of actual emissions measurements, to estimate and report their emissions (as permitted by EPA regulations). The NOx emissions reported from these units may be exaggerated by the use of a default 1.2 lb/MMBTU NOx emission rate, which would tend to increase the percentage of NOx emissions shown from these units relative to entire EGU fleet emissions.

43 In March 2007, several member states of the Ozone Transport Commission signed a Memorandum of Understanding that agreed to limit emissions during high electricity demand days. A copy of the signed MOU is available at: http://www.ct.gov/deep/lib/deep/air/climatechange/otcheddmou070307.pdf

6. Costs and Cost-Effectiveness

DR programs generally incur one-time, upfront costs and ongoing or recurrent costs. Depending on the category of DR program, one-time costs can include equipment and devices for communicating with participating customers or automatically curtailing load, program marketing costs, and participant sign-up incentives. For example, a utility might pay a residential customer a $25 sign-up incentive and spend $300 on equipment to automatically curtail the customer's air conditioner during peak events. Recurrent costs can include incentive payments to participants, program administrative costs, and program evaluation costs. Because of this combination of fixed and variable costs, the total costs of a DR program will depend to a great extent on the category of program, the number of participants, and the level of incentives offered. In areas where peak energy prices are unusually high, or extremely expensive system upgrades can be avoided, the utility or DR aggregator may be able to offer more lucrative incentives than a utility or DR aggregator working in an area with low electricity costs. The key consideration then is not the costs of DR programs, but their cost-effectiveness.

When DR programs are offered by a regulated utility, the utility will generally have to demonstrate to the state PUC or its governing board that the programs are cost-effective (i.e., the benefits exceed the costs). In competitive wholesale markets, DR aggregators and other participants don't have to prove that programs are cost-effective, but they will lose money if the costs exceed the benefits over the long run.

In 1983, the California Public Utilities Commission

Table 23-5

The Five Principal Cost-Effectiveness Tests[44]

Test	Key Question Answered	Summary Approach	Implications
Societal Cost	*Will total costs to society decrease?*	Includes the costs and benefits experienced by all members of society	Most comprehensive comparison but also hardest to quantify
Total Resource Cost	*Will the sum of utility costs and program participants' costs decrease?*	Includes the costs and benefits experienced by all utility customers, including program participants and non-participants	Includes the full incremental cost of the demand-side measure, including participant cost and utility cost
Program Administrator Cost	*Will utility costs decrease?*	Includes the costs and benefits that are experienced by the utility or the program administrator	Identifies impacts on utility revenue requirements; provides information on program delivery effectiveness (i.e. benefits per amount spent by the program administrator)
Participant Cost	*Will program participants' costs decrease?*	Includes the costs and benefits that are experienced by the program participants	Provides distributional information; useful in program design to improve participation; of limited use for cost-effectiveness screening
Rate Impact Measure	*Will utility rates decrease?*	Includes the costs and benefits that affect utility rates, including program administrator costs and benefits and lost revenues	Provides distributional information; useful in program design to find opportunities for broadening programs; of limited use for cost-effectiveness screening

44 Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013, February). *A Framework for Evaluating the Cost-Effectiveness of Demand Response.* Prepared for the National Forum on the National Action Plan on Demand Response: Cost-Effectiveness Working Group. Available at: http://emp.lbl.gov/sites/all/files/napdr-cost-effectiveness.pdf

adopted a *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs*. This Standard Practice Manual described five different "tests" that could be used to determine whether an energy efficiency or DR program was (or will be) cost-effective.[45] The California manual has been revised over time and adapted for use in many states. More recently, the question of cost-effectiveness specifically for DR programs was addressed by a working group convened by the FERC and the US Department of Energy as part of the National Action Plan on Demand Response. That working group found that the five tests in the Standard Practice Manual were still largely relevant, but it offered a new way of thinking about the five tests and insights on some of the unique costs and unique benefits of DR programs. The five standard tests, as described by this working group, are summarized in Table 23-5.

Although a detailed description of these tests and their use is beyond the scope of this chapter, it is important for air regulators to know that each state PUC uses some or all of the five cost-effectiveness tests to evaluate whether DR programs save money or not, that each state is different, that the PUC review process is open for public comment and input, and that air regulators have an opportunity to submit comment and testimony in PUC review processes. Used properly, the societal cost or total resource cost test permits the broadest and most comprehensive evaluation of the costs and benefits of DR programs.

The environmental costs and benefits of DR programs are components of these standard cost-effectiveness tests, but in practice they – as well as other non-energy benefits[46] – are difficult to quantify and frequently overlooked in even the most thorough evaluations of DR programs. Part of the reason is the complexity of quantifying environmental impacts, as was explained in previous sections of this chapter. Program evaluators and regulators often put these costs and benefits down as unquantifiable. The state of California addressed this challenge with legislation that specifically requires assessments of the GHG and criteria pollutant impacts of DR programs (see text box).

With greater participation from air quality regulators, the environmental benefits of DR programs could be better quantified and included in cost-effectiveness tests. Programs that encourage the use of backup diesel generators might end up being less cost-effective than they appear to be when emissions impacts are ignored, whereas programs that shift load away from system peaks could potentially be even more cost-effective and changes could be made to increase participation.

Requiring Demand Response Providers to Calculate Environmental Benefits

The state of California public utilities code specifically requires DR providers to calculate criteria pollutant and GHG emissions reduction benefits:

743.1. (a) Electrical corporations shall offer optional interruptible or curtailable service programs, using pricing incentives for participation in these programs. These pricing incentives shall be cost effective and may reflect the full range of costs avoided by the reductions in demand created by these programs, including the reduction in emissions of greenhouse gases and other pollutant emissions from generating facilities that would have been required to operate but for these demand reductions, to the extent that these avoided costs from reduction in emissions can be quantified by the commission. The commission may determine these pricing incentives in a stand-alone proceeding or as part of a general rate case.

California Public Utilities Commission. (2010, December). *Demand Response Cost-Effectiveness Protocols*. Available at: http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

45 The manual was revised and updated in 1987-1988 and again in 2001, and corrections were made in 2007. The current version is available at: http://www.cpuc.ca.gov/NR/rdonlyres/004ABF9D-027C-4BE1-9AE1-CE56ADF8DADC/0/CPUC_STANDARD_PRACTICE_MANUAL.pdf

46 The identification and quantification of non-energy benefits is an ongoing endeavor, with progress slowly but regularly achieved. Many non-energy benefits of DR programs resemble those for energy efficiency programs. Readers interested in more details on this subject may wish to consult a comprehensive treatment of energy efficiency non-energy benefits: Lazar, J., & Colburn, K. (2013, September). *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits)*. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6739

7. Other Considerations

As noted throughout this chapter, air quality regulators may find it difficult to project the future emissions impacts of DR programs and policies, or to quantify and verify the impacts after the fact. There are many variables in the equation, few rules of thumb, and the analytical techniques are still evolving. This is not surprising, given that DR programs were created fundamentally for reliability and economic purposes, not environmental purposes.

As noted previously, greater participation from air quality regulators in program review processes could lead to greater attention and more rigorous quantification of the environmental benefits of DR programs. State regulators have less opportunity for involvement, however, where an RTO, ISO, or similar regional grid organization contracts with aggregators or others who bid DR resources into the market. In these cases, the regional authority contracts to attain only "load service," with little to no knowledge or control of how the "additional load capacity" or "load reduction" will be provided. In such cases, the emissions of any fossil-fueled generators providing the contracted DR services will be governed only by existing federal, state, or local regulations applicable to those units during DR events. In some instances, these existing regulations are insufficient to protect air quality downwind. Through Title V permitting processes, impacted downwind states may have opportunity for input regarding the operations of EGUs located in an upwind state, but they may have no similar opportunity regarding the operation of DR resources in the upwind state. These circumstances result in significant air quality issues for states served by a regional grid operated by an ISO or RTO.

Understanding several factors that influence marginal emissions requires at least a basic appreciation of how electricity is transmitted and how generators are dispatched to satisfy hourly and daily demand. Intimate knowledge of energy principles is not a prerequisite, but it is important for air quality regulators to know where and from whom to get answers in their state. The collaboration between air and energy regulators and the grid operator in New England provided benefits that are readily available to other regions as well. To echo the efforts of regulators in New England, and now in the Middle Atlantic, air regulators could engage with their energy regulators and the regional grid operators on these key topics:

- Discuss how emissions data are used and key principles concerning data precision and accuracy;
- Work with energy regulators and grid operators to identify and prioritize the critical variables needed by air regulators to assess the emissions benefits from clean DR;
- Advocate for improving data capture and quality over time; and
- Sustain engagement with these officials over the long term to assure that data continue to be useful for air regulators.[47]

Quantifying the emissions impacts of DR in a way that could garner approval from EPA (e.g., in the context of a state plan for compliance with the Clean Power Plan rules) and withstand potential legal challenges might prove to be extremely challenging. The EPA can now point to examples of approved state implementation plans that have included energy efficiency or renewable energy as a criteria pollutant control measure, but there are no proven examples for using DR to reduce emissions in a regulatory context. DR was not considered by the EPA to be a component of the best system of emissions reduction for GHG emissions in the power sector, and thus the EPA has offered little guidance on the subject.

Even if a state is leery of including DR in a GHG emissions reduction compliance plan, there is still a role for DR as a complementary policy. A strong DR policy can keep costs down and keep the lights on as other strategies are deployed and the status quo changes.

Regulators will also benefit from staying informed about the influence of new and developing technologies on DR. Innovations in the power sector are coming at a fast pace, from smart grids to the "Internet of things."[48] Some of these emerging technologies are discussed in more detail in Chapter 26. Collectively, the advances in technology are making it increasingly possible for both end-use customers

47 For additional details and a complete list of actions, see: Colburn, K., & James, C. (2014). *Preparing for 111(d): 10 Steps Regulators Can Take Now.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7208

48 The "Internet of things" is a term used to describe an increasingly interconnected, responsive, and dynamic world in which many millions of new devices capable of two-way communication with each other (not just with humans) are being connected to the Internet every year. This interconnectedness offers convenience and comfort, but can also be designed to reduce costs and improve efficiency economy-wide.

and system operators to see the potential economic value of DR, act on that information, and document and quantify those actions and their impacts.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on DR policies and programs.

- EPRI. (2008). *The Green Grid: Energy Savings and Carbon Emissions Reductions Enabled by a Smart Grid.* EPRI-1016905. Available at: http://assets.fiercemarkets.net/public/smartgridnews/SGNR_2009_EPRI_Green_Grid_June_2008.pdf
- EPRI. (2009, January). *Assessment of Achievable Potential From Energy Efficiency and Demand Response Programs in the US (2010–2030).* Available at: http://www.edisonfoundation.net/iee/Documents/EPRI_SummaryAssessmentAchievableEEPotential0109.pdf
- FERC. (2014, December). *Assessment of Demand Response & Advanced Metering: Staff Report.* Available at: http://www.ferc.gov/legal/staff-reports/2014/demand-response.pdf
- Hurley, D., Peterson, P., & Whited, M. (2013, May). *Demand Response as a Power System Resource: Program Designs, Performance, and Lessons Learned in the United States.* The Regulatory Assistance Project and Synapse Energy Economics. Available at: www.raponline.org/document/download/id/6597
- Navigant Consulting, Inc. (2014, November). *Carbon Dioxide Reductions From Demand Response: Impacts in Three Markets.* Prepared for the Advanced Energy Management Alliance. Available at: http://www.ieca-us.com/wp-content/uploads/Carbon-Dioxide-Reductions-from-Demand-Response_Navigant_11.25.14.pdf
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- Pratt, R., Kintner-Meyer, M. C. W., Balducci, P. J., Sanquist, T. F, Gerkensmeyer, C., Schneider, K. P., Katipamula, S., & Secrest, T. J. (2010). *The Smart Grid: An Estimation of the Energy and CO_2 Benefits.* Publication no. PNNL-19112. Prepared for US DOE. Available at http://energyenvironment.pnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf
- Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013, February). *A Framework for Evaluating the Cost-Effectiveness of Demand Response.* Synapse Energy Economics and The Regulatory Assistance Project for the National Forum on the National Action Plan on Demand Response: Cost-Effectiveness Working Group. Available at: http://emp.lbl.gov/sites/all/files/napdr-cost-effectiveness.pdf
- California has an extensive DR history. The December 2013 California ISO report, *Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources,* recognizes the role of demand-side resources to achieve a better environmental outcome and to integrate with the increased presence of renewable generation in that state. More information is available at: http://www.caiso.com/Documents/DR-EERoadmap.pdf
- The California Energy Commission's *Integrated Energy Policy Report 2013* is a comprehensive treatise on that state's energy resources and requirements, including DR. More information is available at: http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF-small.pdf

9. Summary

DR resources are capable of providing numerous services that can enhance the efficiency and reliability of bulk power systems. These services span the range of resource adequacy, energy, and ancillary services. The DR opportunity faces some legal turmoil as authority issues are adjudicated, and its application shares the collective uncertainty facing the electric power industry (changing business models, disruptive technologies, new markets and market entrants, and so on), but its economic performance to date ensures that it has a secure place in grid operations going forward. DR will play a larger, not smaller, role as a grid resource.

On a regional and on a state-by-state basis, DR is already providing substantial contributions to resource adequacy mechanisms as both a capacity and reserve resource. In wholesale markets, DR also participates as an energy resource (both day-ahead and real-time). There are many new DR applications being tested and developed that can provide specialized operational services (including load-following, frequency regulation, and special reserves) to system operators. DR is reliable, can provide a significant amount of a region's resource adequacy needs, can achieve participation in market areas, and can lower the cost of reliability.

The exact GHG and criteria pollutant benefits of DR will vary by region, as the marginal units dispatched also vary. Air regulators can improve the accuracy and usefulness of GHG and criteria emissions data from energy saved by following the example of New England's regulators to work directly with their energy and grid operator counterparts.

DR offers the potential for significant environmental benefit. Load curtailment typically results in load reductions with little or no environmental harm. DR programs that avoid the need to dispatch less efficient small-scale generation can reduce GHG emissions. These programs also have the potential to significantly reduce NO_X emissions, and to do so during time periods that are often coincident with unhealthy ambient concentrations of ozone. Load shifting often translates into shifting loads from higher emitting fossil generation to lower emitting sources. DR can also enhance opportunities for integrating clean energy renewable resources.

Environmental benefits from DR are not a given, however. They are only guaranteed if sufficient policy direction or regulatory oversight (from legislative bodies, environmental agencies, or PUCs) is provided to ensure that: (1) actual load curtailment occurs (rather than a shift to onsite generation); (2) load shifting results in lower emissions or emissions at less dangerous times or places; or (3) any substitute generation resources used by DR participants are lower-emitting than those that shed load under the program. With the prospective implementation of the Clean Power Plan and many other emerging power sector issues, air quality regulators would be wise to engage regularly with their state PUC counterparts to ensure that DR programs provide economic and environmental/public health benefits in equal measure.