Synapse
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A Review of Demand Response Potential in the United States

November 21, 2011

Prepared for the U.S. Environmental Protection Agency

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1. Executive Summary

This report was prepared in response to a request from the U.S. Environmental Protection Agency (EPA) for a review of the demand resources that have the potential to delay or avoid the need for new large supply-side resources. The report summarizes and discusses the most recent literature relevant to projections of demand response (DR) with that potential. Our report does not include estimates of reductions in demand resulting from energy efficiency measures nor behind-the-meter generation.

DR, according to the definitions used by the Federal Energy Regulatory Commission (FERC) and the North American Energy Reliability Council (NERC), is:

> *Changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*[1]

This report provides estimates of reductions from two NERC categories of demand resources, *dispatchable reliability capacity* and *non-dispatchable time-sensitive pricing.* Demand resources in those two categories are designed to reduce electricity use during peak periods every year. These resources have the potential to reduce or avoid the dispatch of existing peaking capacity and, in the long-term, to delay or avoid the need for new peaking capacity. For completeness, the report describes the third NERC category of demand resources, *dispatchable other,* but does not provide an estimate of reductions from demand resources in that category. Those demand resources are designed to reduce electricity use only when electric energy prices are abnormally high, for reserves, or when emergencies jeopardize system reliability. As such, reductions from those resources only have the potential to delay or avoid the need to procure new supply-side generation projects that would be built to fulfill a need for reserves.

Our review indicates that it is reasonable to expect incremental DR (i.e., DR above and beyond what is expected under a business as usual scenario) to achieve reductions in demand of up to 44 gigawatts (GW) nationally by 2019, or 5 percent of the business-as-usual forecast national peak demand load of 912 GW. This incremental quantity of DR is approximately equal to the total level of DR expected under a BAU scenario (38 GW); thus, achieving the incremental potential would approximately double the DR in 2019 compared to BAU.

Almost all of the incremental DR potential by 2019 is projected to be achieved from demand resources categorized as dispatchable reliability capacity.

The incremental reductions in demand are primarily projected to be achieved in the large commercial and industrial (C&I) customer sector. The most comprehensive set of projections reviewed does not indicate the sources of those reductions within the C&I sector; however clean

[1] ____, *Assessment of Demand Response Potential and Advanced Metering*, FERC, February 2011, page 21.

energy reports for six states prepared by the American Council for an Energy Efficient Economy (ACEEE) project approximately 40 percent of C&I sector demand reductions from back-up generation (BUG). The majority of reductions in the residential sector are projected from reductions in CAC.

The forecasts reviewed indicate that the South and the Midwest census regions have the greatest potential for incremental DR. This potential arises from the high levels of CAC penetration in those regions and the lower levels of DR currently being achieved there.

Neither the forecasts nor our report estimate the extent to which this DR potential, if achieved, would delay or avoid the need to add new peaking capacity. Developing such an estimate for each region of the country will require analyses of the projected growth in demand, load factor[2], existing capacity resources, and costs of new capacity in each of those regions.

[2] Load factor is the ratio of annual energy used by a customer, or an end-use, divided by the maximum or peak demand of that customer or end-use in a given year. It is a measure of a load's` average annual utilization of the capacity needed to serve it. The higher a customer's load factor, the more electric energy it uses and the lower its total unit cost, since it is spreading its absolute fixed cost over more usage.

2. Introduction and Background

This report was prepared in response to a request from the U.S. Environmental Protection Agency (EPA) for a review of the most recent literature relevant to the future potential for demand resources. The purpose of the report is to provide an assessment of DR potential that will inform the EPA's future modeling and analyses of the impact of demand resources on the need for new large supply-side resources. The EPA indicated particular interest in information relevant to the following questions:

- Will the expected growth in DR be significant enough to reduce the need for large supply-side resources, such as coal-fired generation?
- Does the electricity sector foresee increased use of back-up generators to meet emergency, economic, and/or ancillary service DR? If so, to what extent does use of these generators dominate DR program growth?
- How significant is commercial and industrial end-use sector DR in future potential estimates? To what extent is on-site generation (renewable, CHP, back-up generators) contributing to this estimate?
- How significant is residential DR in future potential estimates? Under what timing do new grid-connected technologies (such as grid-connected appliances and in-home displays) factor into achieving these estimates?
- Do the studies speak to any critical enabling technologies, standards, or circumstances for widespread deployment of smart grid technologies in the residential customer domain?
- What end-use loads are included (e.g., heating, ventilating and air conditioning, water heaters, other household appliances, plug-in electric vehicles), and how much does each contribute to future estimates of DR?

This chapter provides an overview of DR and how it may affect the need for new generating capacity. Chapter 3 describes our review of the recent literature relevant to the future potential for demand resources. Chapter 4 summarizes the DR potential it is reasonable to expect in 2019 and presents information relevant to the questions of interest to the EPA.

A. Categories of DR

DR, according to the definitions used by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), is

> *Changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

The definition of DR refers to its ability to cause changes in electric usage in response to two driving factors, economics and system reliability. The definition makes a further distinction between electricity prices as an economic driving factor and incentive payments as an economic driving factor. NERC has drawn upon that general definition to create its Demand Response Availability Data System (DADS), which provides a detailed taxonomy of demand-side management categories and defines 13 specific demand resources. Appendix A provides definitions of these 13 demand resources.

Our report presents estimates of DR potential using a summary approach consistent with the NERC taxonomy. As indicated in Table 1, we have aggregated NERC's 13 demand resources and DR taxonomy into three broad categories: A. *dispatchable reliability capacity*, B. *non-dispatchable time-sensitive pricing* and C. *dispatchable other*.

Table 1. Categories of DR and Types of Demand Resources per NERC DADS

Categories of DR	Types of Demand Resources
A. Dispatchable Reliability Capacity	1. Direct Load Control (DLC) 2. Interruptible Load (IL) 3. CPP with control (CPP w C) 4. Load as Capacity Resource
B. Non-Dispatchable Time-Sensitive Pricing	5. Time-of-Use Pricing (TOU) 6. Critical Peak Pricing (CPP); Peak Time Rebate (PTR) 7. Real-Time Pricing (RTP) 8. System Peak Response Transmission Tariff (SPRT)
C. Dispatchable Other	9. Economic, Energy price, Demand Bidding & Buy-back 10. Reliability, Reserves, Spinning Reserves 11. Reliability, Reserves, Non-Spinning Reserves 12. Reliability, Energy Voluntary, Emergency 13. Reliability, Regulation

DR and energy efficiency (EE) can be differentiated by the differences in their focus. The primary goal of the demand resources in the first two NERC categories, i.e., Dispatchable Reliability Capacity and Non-Dispatchable Time-Sensitive Pricing, is to reduce electricity use during hours of highest system-wide use, or peak demand. As such those demand resources are primarily, if not solely, viewed as potential sources of capacity. In contrast, EE focuses on reducing electricity use in all hours of the year, and thus is primarily an energy resource although by reducing energy use in peak hours it does serve as a capacity resource to some degree. Appendix B describes the difference between DR and EE in more detail. This report does not cover estimates of reductions in peak demand resulting from EE.

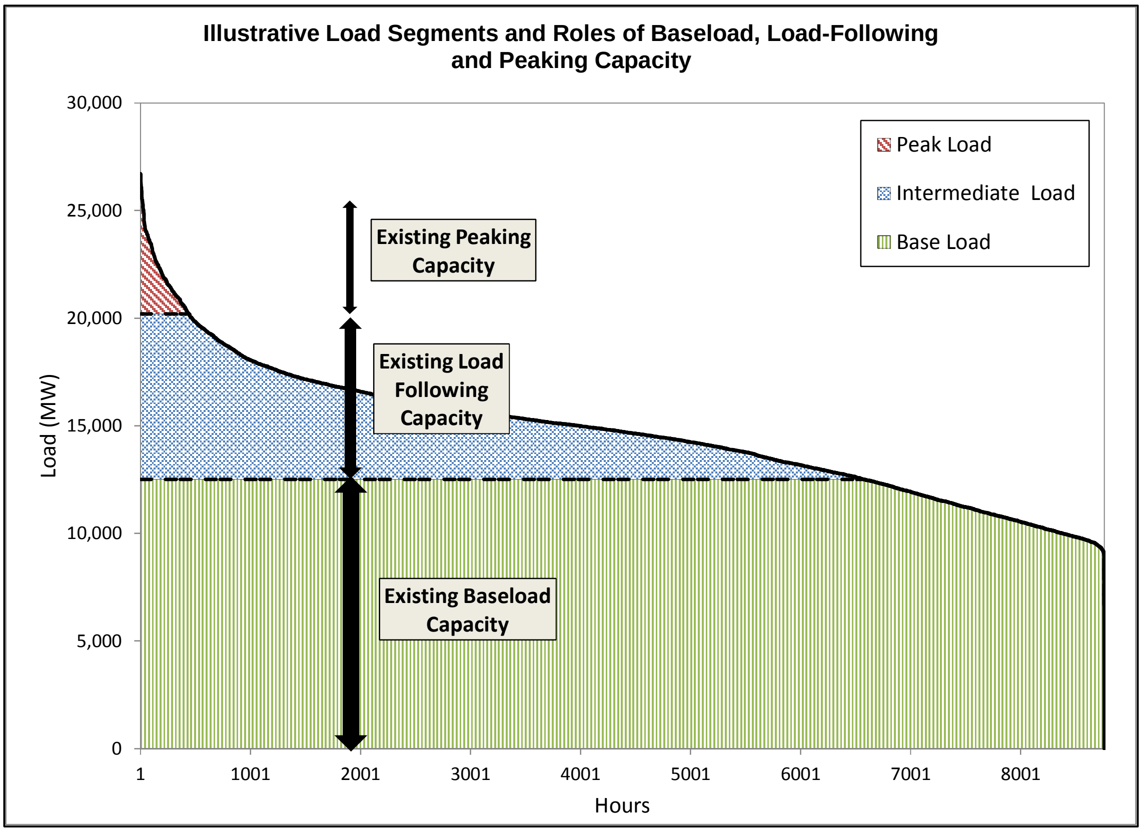
B. Impact of DR on Need for New Generating Capacity

In order to understand how DR may affect the need for new generating capacity, one must begin with an appreciation for two key elements of capacity planning. The first element is the difference in roles played by each major category of generating capacity, i.e., baseload, load-following/intermediate, and peaking. The second element is the planning process itself, and in particular the timing of key decisions, years in advance of the date when new capacity is required to be in-service.

Roles played by each major category of generating capacity

Traditional generating capacity can be grouped under three major categories - baseload, load-following, and peaking. The characteristics of, and roles played by, each of those categories of generating capacity is illustrated relative to a load-duration curve in Figure 1.

Figure 1.Illustrative Load Segments and Roles of Baseload, Load-Following and Peaking Capacity



The load-duration curve in Figure 1 plots the electricity load of customers in a particular region or service territory in each hour of the year. The curve does not plot that hourly load in its chronological order; instead it plots those hourly loads by magnitude of use, from highest to lowest. As a result, the curve does not give one a full appreciation for the hour-to-hour variation in chronological load to which generators must respond. Instead it provides a simple picture of the distribution of load from high to low over the year. (Appendix B uses the same load duration curve to illustrate the difference between DR and EE.)

Generation planners divide the load duration curve into base, intermediate and peak segments.

- The base load segment is, as the name implies, the level of load which occurs in most hours of the year, e.g., 85 percent of the hours of the year. In Figure 1 base load represents approximately 47% of total demand.
- Load in the intermediate segment varies substantially from hour to hour throughout the year. In Figure 1 intermediate load represents 29% of total demand.

- The peak segment represents extreme hourly peaks that occur in relatively few hours of the year, e.g., typically less than 5%. In Figure 1 the peak load of our illustrative system represents 24% of total demand. However, the loads in this segment occur in less than 300 hours each year. As indicated in Figure 1, system operators typically use a mix of baseload, load-following and peaking capacity in order to provide reliable service at reasonable cost. During hours of peak load the total demand will be met by generation from each category of capacity, i.e. baseload plus load-following plus peaking. In contrast, during hours of low load total demand will be met primarily, if not entirely by generation from baseload capacity.

The relative quantities of each category of capacity used to serve load in a particular service territory or region will vary according to the specific shape of the load curve and the fixed and variable costs of the generating capacity available to serve that specific load curve. In general, the relative quantities of each category of capacity are based upon the following planning principles:

- **Baseload capacity**. In a model generating portfolio, base load would be served by generating capacity with relatively high fixed costs and relatively low variable costs. This capacity would operate at a relatively steady level in most hours of the year, and thus would have a high capacity factor, e.g., 80 percent or more.[3] Operating this capacity at a high capacity factor minimizes their total unit cost of generation, i.e. fixed cost per kWh plus variable cost per kWh, because the fixed costs are spread over / recovered from a high quantity of annual generation. Because they provide generation in most hours of the year, baseload units are primarily a source of electric energy. These units do provide capacity, but that is not their primary purpose. One would not build a baseload unit solely as a source of capacity.
- **Load-following capacity**. In a model generating portfolio, intermediate load would be served by load-following capacity which has the flexibility to respond quickly to variation in load from hour to hour and to operate at a wide range of output levels. Load following capacity tends to have lower fixed costs than baseload capacity but higher variable costs. Load-following capacity is the economic choice to serve this segment because it operates at a lower capacity factor than baseload capacity. Like baseload units, load-following units provide generation in the majority of the hours of the year and are thus primarily a source of electric energy rather than of capacity.
- **Peaking capacity**. In a model generating portfolio, peak load would be served by capacity which has the flexibility to go from zero output to its maximum output very quickly and to operate at that maximum level for very short periods. The ideal capacity to serve this load segment has very low, or even no, fixed costs and high variable costs. Capacity with those characteristics is economic in this application because it will operate at a very low

[3] Capacity factor is the ratio of annual generation from a unit divided by the maximum annual generation that unit could generate. Thus, it is a useful indicator of a unit's annual average utilization. The higher a unit's capacity factor, the more electricity it generates and the lower its unit fixed cost of production, since its absolute fixed cost is being spread over more generation.

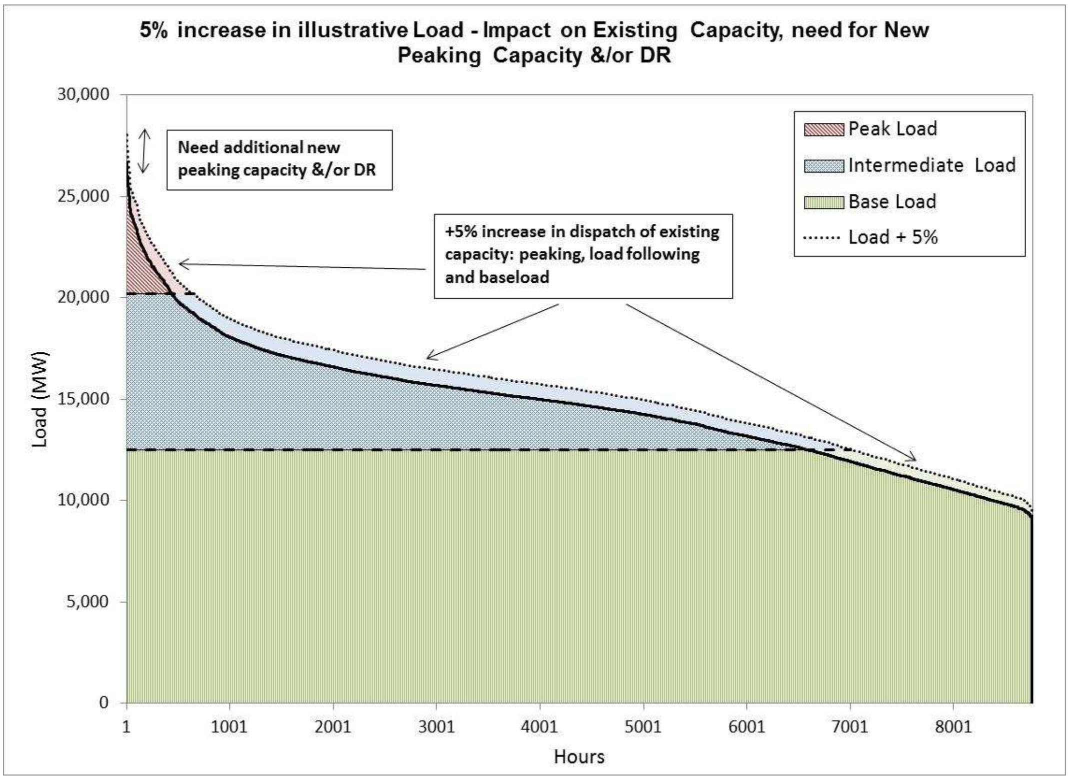
capacity factor, e.g., less than 5 percent. (An example of capacity with low, or no, fixed costs would be older capacity that may have initially been dispatched as baseload or intermediate, is no longer economic in those roles, is still functional and whose fixed costs have been fully recovered). Unlike baseload and load-following units, peaking units are primarily a source of capacity.

As noted earlier the primary goal of the demand resources covered in this report is to reduce electricity use during hours of the very highest system-wide use, or peak demand. For example, dynamic pricing is typically designed to apply to a sub-set of “critical peak” hours within the peak segment, typically the 60 to 80 hours during which the highest loads occur, because those are the hours when DR has the highest value and that is the maximum number of hours per year during which many customers are willing to reduce their load. The high value in those hours is comprised of the value of avoiding new peaking capacity, the value of avoiding the dispatch of existing peaking capacity plus the value of avoided distribution transmission and distribution infrastructure and avoided air emissions. The preference of many customers to limit the hours in which their load could be reduced to 60 to 80 hours per year is reflected in the design of various direct load control programs and dynamic pricing tariffs, as well as the fact that until recently PJM limited its use of demand resources to 60 hours per year.[4]

The high value of demand resources during these critical peak hours can be illustrated by assuming that the load presented in Figure 1 is forecast to increase by 5 percent in every hour of the year. In almost all hours of the year, that 5 percent increase in load can be met by increasing the dispatch of existing baseload, intermediate and peaking capacity, as shown in Figure 2.

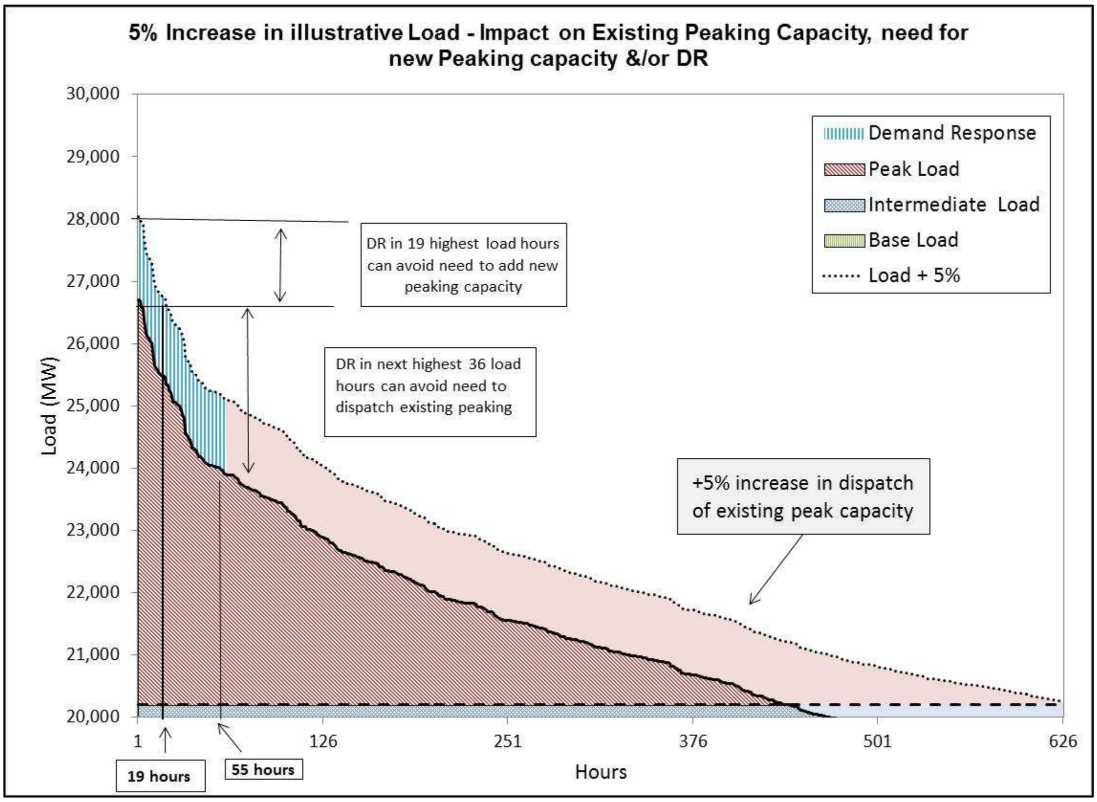
[4] FERC Order issued January 31, 2011 in Docket ER11-2288-000.

Figure 2. Increase in illustrative load – impact on all existing capacity and need for new peaking capacity &/or DR



However, a 5 increase in the very highest loads would require the addition of new peaking capacity. As shown in Figure 3, DR has the highest value when applied in the hours with the very highest loads, because in the 19 hours of highest load it is enabling the utility to avoid acquiring additional new peaking capacity and dispatching that new capacity while in the next 36 hours of highest load it is enabling the utility to avoid dispatching existing peaking capacity.

Figure 3 Increase in illustrative load – impact on existing peaking capacity and need for new peaking capacity &/or DR



DR has little or no potential to directly delay or avoid the need to add new intermediate capacity or new baseload capacity. As noted earlier, new units in those two categories of capacity are built primarily as sources of annual electric energy, i.e., to meet increases in annual electric energy requirements and to replace existing, less economic intermediate and baseload capacity which is taken out of service. However, DR does have the potential to displace the most expensive existing generating capacity within a particular control area in specific situations. The sources of this most expensive existing capacity may be peaking units or older baseload units that are now being dispatched only to ensure reliability in a load pocket or only during hours of peak demand. For example, the current forward capacity market structures in New England and in PJM do not distinguish between the types of units that are providing the necessary capacity, e.g., quick-start peaking units versus old baseload units. All else being equal, increases in the quantity of DR participating in those markets will result in corresponding decreases in, or displacement of, the quantity of capacity from older, more expensive baseload units or peaking units participating in those capacity markets. In turn, the loss of revenue from those capacity markets may cause the owners of those units to take them out of service.

Capacity planning process

Parties involved in the capacity planning process must make key decisions regarding the quantity of capacity required, and the acquisition of that capacity, years in advance of the date when new capacity is required to be in-service. Regional Transmission Operators (RTOs) such as PJM establish the quantity of generating capacity that load serving entities (LSEs) are required to hold to ensure reliable service. RTOs establish those quantities, often referred to as resource adequacy reliability requirements, four years or less in advance of the actual power year in which they will be required.

RTOs set capacity requirements several years in advance to give LSEs who need new capacity to meet that requirement adequate time to build or acquire that new capacity. Three years is generally viewed as the minimum lead time required to bring new peaking capacity into service, including design, financing, siting, and construction. Lead-times longer than three years are needed to bring new load-following or baseload capacity into service.

The lead time required to achieve additional reductions from DR will vary depending upon the type of demand resource, the value of DR, the customer segment and the potential for additional DR. The entities responsible for achieving these additional reductions, such as curtailment service providers or local distribution utilities, need this lead time in order to market the demand resource to potential customers, make contract arrangements with customers who wish to participate and install the necessary control equipment. This lead time may range from less than one year to more than three years.

The potential for DR to delay or avoid the need for new capacity varies by category of DR. It also depends upon when, and how, that potential is considered in the capacity planning process.

- Demand resources categorized as *dispatchable reliability capacity* have the greatest ability to avoid or delay the need for new capacity additions in the near-term, i.e., during the capacity planning process. Reductions from those resources can be identified in advance and acquired through markets or contracts that specify the magnitude of their reductions and include financial penalties for failure to perform.[5] As a result, reductions from this category of demand resources are comparable to, and as reliable as, supply-side resources. For example, demand resources in this category compete with traditional generation resources in the PJM and New England capacity markets.
- Demand resources categorized as *non-dispatchable time-sensitive pricing* also have the ability to avoid or delay the need for new capacity additions, but not in the near-term. Because reductions from those resources are not acquired through contracts, system planners do not know their exact magnitude. Moreover, because the reductions are not acquired through contracts system planners have no leverage over those responsible for achieving them, for example they cannot impose a financial penalty if the actual reductions prove to be materially less than the projected reductions, i.e., for failure to perform. After there is enough experience with these reductions to enable accurate predictions of reductions based on statistically valid estimates of participation rates and price elasticities, system planners will likely be willing to consider reductions from this

[5] Retail customers may participate in these DR programs (e.g., dispatchable standby generation, direct load control, curtailment contracts) directly or through another party, such as their utility, an LSE, an energy service company, or a curtailment service provider.

category of demand resources as comparable to supply-side resources. In our experience it will likely be many years, more than five and up to ten, –before system operators are comfortable relying upon price-sensitive demand to respond in a pattern predictable enough to allow them to delay, or totally avoid, the addition of new generating capacity or dispatchable reliability DR. This length of time is needed to gain sufficient statistical data upon which to develop projections which have a reasonable confidence interval.

- DR in the *dispatchable other* category may have the ability to avoid or delay need for some types of new capacity additions. These resources are meant to be used for ancillary services, which include certain types of system reliability services. To the extent that DR provides, for example, spinning reserves, they may avoid or delay the need for new quick-start generation units that would have been constructed specifically to meet this need.

3. Literature on DR Potential

The primary objective of our project was to identify and review the most recent literature relevant to projections of DR that have the potential to delay or avoid the need for new large supply-side resources. This chapter summarizes the literature we identified and describes our review of the projections of DR potential in that literature.

A. Relevant literature

The EPA provided an initial list of reports for our review. Synapse identified additional reports that are relevant to the questions listed in Chapter 2. Appendix C provides a list of that literature and our contacts.

Our review of the literature listed in Appendix C identified only two recent, comprehensive long-term projections of DR potential by type of DR resource, customer sector, and state. They are *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010 – 2030)*, prepared for the Electric Power Research Institute (EPRI) and *A National Assessment of Demand Response Potential*, prepared for the FERC. We refer to the two reports as EPRI 2009 and FERC 2009, respectively. Both reports were completed in the first half of 2009. EPRI 2009 provides a projection of DR potential in 2020, while FERC 2009 provides a projection for 2019. The same consulting company, the Brattle Group, prepared the projections of DR potential presented in each study. Our report draws primarily upon the projections presented for 2019 in FERC 2009. As we explain in the next section, FERC 2009 is comprehensive and provides a more detailed treatment of DR than EPRI 2009, including Appendices that provide those detailed projections. The projections of DR potential in both reports are almost identical.

Our report also draws upon *Assessment of Demand Response Potential and Advanced Metering*, a FERC report from February of this year (FERC 2011). That report provides national projections through 2015. Finally, our report draws on state-specific projections of DR potential the ACEEE prepared for Virginia, Pennsylvania, Ohio, South Carolina, North Carolina, and Arkansas between September 2008 and June 2010.

B. Projections of DR potential by scenario

Projections of DR potential for a particular point in time are typically expressed in both absolute terms (e.g., GW) and as a percentage of forecast peak load, i.e., coincident peak demand. Both the absolute values and the percentage values are measured relative to a reference or baseline projection that reflects a continuation of current practices, or "business as usual." Therefore, before comparing projections from two different sources it is important to ensure that both sources are measuring potential from the same or similar reference points.

Our review indicates that the projections of potential presented in EPRI 2009, FERC 2009, and the ACEEE studies are measured from similar, but not identical, forecasts of summer peak demand. EPRI 2009 projects peak demand will have a national average annual growth rate (AAGR) of 1.5 percent starting in 2008, while FERC 2009 projects a national AAGR of 1.7 percent starting in 2009. The AAGR for peak demand in the seven ACEEE studies vary by state, and range between 1.0 and 1.4 percent, as indicated in Table 4.

Given this variation in reference case projections, our report focuses primarily on projections of the absolute magnitude of incremental DR potential.

Scenarios

FERC 2009 provides projections of DR potential in 2019 by state under four scenarios—Business as Usual (BAU), Expanded Business as Usual (EBAU), Achievable Potential (AP), and Full Potential (FP). Their projections of reductions in DR in 2019 under those scenarios are 38GW (4%), 82 GW (9%), 138 GW (14%) and 188 GW (20%) respectively.[6] None of the four scenarios assume the invention and rapid deployment of technology that does not yet exist. Instead, they assume broader adoption of DR "best practices" in terms of program design and aggressive marketing, more widespread deployment of advanced metering infrastructure (AMI), and higher levels of customer participation in DR programs and initiatives. The key assumptions of the four scenarios are as follows:

- **BAU.** Current and planned DR stays constant. Current programs continue at present levels. No growth in program impacts except where information on explicit growth projections was available.
- **EBAU.** Current mix of DR programs is expanded to all states where they achieve ''best practices" levels of participation. Estimates of reductions by residential customers from non-dispatchable time-sensitive pricing assume AMI is deployed to 40 percent of the country's customers by 2019 and five percent of customers eligible for dynamic pricing opt-in to that pricing option.
- **AP.** Current mix of DR programs is expanded to all states where they achieve ''best practices" levels of participation plus reductions from residential customers in response to non-dispatchable time-sensitive pricing based on assumptions of 100 percent deployment of AMI by 2019 and 75 percent of residential customers participate in dynamic pricing.
- **FP.** Current mix of DR programs is expanded to all states where they achieve ''best practices" levels of participation plus reductions from residential customers in response to non-dispatchable time-sensitive pricing based on 100 percent deployment of AMI by 2019 and 100 percent residential customer participation in dynamic pricing.

EPRI 2009 provides projections of EE potential and DR potential in 2020 under four scenarios, i.e., Technical, Economic, Achievable (AP), and Realistic Achievable (RAP). Thus, EPRI 2009 provides estimates of DR potential after taking into consideration improvements in energy efficiency. The EPRI 2009 assumptions for the RAP scenario correspond to the FERC 2009 assumptions for the EBAU scenario. The EPRI 2009 estimate of DR potential in 2020 under the RAP scenario is 44.4 GW. This estimate is essentially equal to the FERC 2009 estimate of a 44 GW DR potential in 2019 under the EBAU scenario.[7] The fact that these two estimates are essentially identical is not surprising since, as noted earlier, both estimates were prepared by the same consulting company.

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[6] FERC 2009, Figure ES-1.
[7] EPRI 2009, Table ES-3

The ACEEE studies provide projections of DR potential in the 2019/2020 timeframe under three scenarios—low, medium, and high. The assumptions for the medium scenario in the ACEEE studies are comparable to the FERC 2009 assumptions for the EBAU scenario.

Incremental DR potential in 2019. Based on our review of those scenarios, we consider the EBAU scenario from FERC 2009 to be a reasonable estimate of the incremental DR potential in 2019. That incremental potential equals the total reduction projected in the EBAU scenario minus the total reduction projected in the BAU scenario. We consider this to be a reasonable estimate of incremental potential for several reasons.

- First, the FERC 2009 estimates of BAU scenario reductions in 2019 appear to be consistent with the levels of reductions that EIA and NERC were reflecting in their forecasts for that timeframe under their "reference case" forecasts circa 2008. FERC 2009 presents a benchmarking comparison of those estimates in Chapter III, starting page 44. Therefore the incremental reductions under the EBAU relative to the BAU appear to provide a reasonable approximation of the incremental reductions in demand measured relative to EIA and NERC reference case forecasts of demand circa 2008.[8]
- Second, the FERC 2009 estimates of EBAU scenario reductions in demand reflect projected future improvements in energy efficiency. As noted, those estimates are essentially equal to the EPRI 2009 estimates of DR potential under the RAP scenario, which reflects improvements in energy efficiency.
- Third, the FERC 2009 estimates of EBAU scenario reductions EBAU estimates are based upon assumptions for 2019 regarding AMI deployment and customer participation in dynamic pricing which are consistent with the current outlook for AMI deployment and the results of various dynamic pricing pilot programs. In contrast, our review indicates that the estimates of total reductions from the AP scenario and the FP scenario are not based upon realistic assumptions regarding AMI deployment and residential customer participation in dynamic pricing.
- Fourth, the EBAU projections are consistent with estimates of DR reductions reported in FERC 2011 and, in aggregate, with ACEEE reports for six specific states.

We discuss the analyses underlying the last reasons in more detail below.

Realistic assumptions - AMI deployment and dynamic pricing participation

FERC 2009 has developed estimates of DR potential in each state by demand resource type and customer sector using a detailed, "bottoms up" approach. As noted earlier, FERC 2009 has made projections of reductions for demand resources in the Dispatchable Reliability Capacity category as well as for demand resources in the Non-Dispatchable Time-Sensitive Pricing category. These estimate reductions are based upon numerous assumptions regarding (i) the availability of demand resource programs and initiatives, (ii) the percentage of customers eligible for those programs and initiatives who will participate in them and (iii) the average reduction per participating customer for each demand resource. Table 2 presents the assumptions regarding

[8] The Reference Case forecast in AEO 2011 reflects the latest FERC data on "actual demand response as a percent of peak demand" and forecasts that quantity of DR to increase to 3% of peak demand in 2035.

participation in each of the four FERC 2009 scenarios. It also presents the assumptions regarding AMI deployment by scenario.

While there is some degree of uncertainty associated with each assumption in FERC 2009, there is generally less uncertainty associated with the assumptions regarding demand resources in the Dispatchable Reliability Capacity category because numerous utilities have had many years of experience with those demand resources. In contrast, there is a high level of uncertainty regarding two of the key assumptions underlying the estimates of reductions from dynamic pricing in the Non-Dispatchable Time-Sensitive Pricing category, i.e. the availability of dynamic pricing to residential and small C&I customers, which hinges on the deployment of AMI, and the percentage of customers eligible for dynamic pricing who will actually participate in that demand resource.[9] There is much less uncertainty regarding the price elasticity of customers who participate in dynamic pricing, i.e., the average reduction per participating customer, because of the data that has been collected on price elasticities from the various dynamic pricing pilots conducted to date.[10]

[9] FERC 2009, Appendix E
[10] FERC 2009, page 18

Table 2 - FERC 2009 scenario assumptions regarding participation of eligible customers in 2019, by sector and type of DR

DR category and Type of demand resource	Percent of Eligible Customers Participating			
	Residential	Small C&I	Medium C&I	Large C&I
Category A. Dispatchable Reliability Capacity, Non-Pricing demand resources; all scenarios				
DLC	25%	1%	7%	N/A
Interruptible Tariff	N/A	N/A	2%	17%
Other DR	N/A	N/A	0%	19%
Category B. Non-Dispatchable Time-Sensitive Pricing; Dynamic Pricing demand resources				
BAU & EBAU (40% AMI deployment)	5%	5%	5%	5%
AP (100% AMI deployment)	75%	75%	75%	75%
FP (100% AMI deployment)	100%	100%	100%	100%

Our review indicates that the EBAU estimates are based upon reasonable assumptions for AMI deployment and customer participation in dynamic pricing. The EBAU assumes that by 2019 AMI will have been deployed to 40 percent of the country's customers and that 5 percent of customers eligible for dynamic pricing will opt-in to that pricing option. Those two assumptions are consistent with the current outlook for AMI deployment and with the results of residential sector dynamic pricing pilots conducted in New Jersey, Connecticut, the District of Columbia, Ontario, California, Maryland, and Illinois.

AMI deployment. First, FERC 2009 states that the projection of AMI deployment under the EBAU scenario is the most likely. [11] Second, it is the residential and small C&I sectors for which AMI deployment is critical, customers in the medium C&I and large C&I sectors currently have the metering and communication functionality required to take advantage of dynamic pricing. Based upon our participation in several AMI/smart meter deployment proceedings and the cost recovery, cyber security and public relations issues that have arisen regarding those deployments, we believe that the FERC 2009 assumption of AMI/smart meter deployment for the residential and

[11] FERC 2009, page 59.

small C&I sector reaching approximately 50 percent of the country's customers by the 2019/2020 time period is realistic but somewhat optimistic.[12] [13]

Residential customer participation in dynamic pricing. FERC 2009 itself states that there is limited knowledge regarding participation rates in dynamic pricing, and more research is needed regarding this independent variable.[14] More recently, one of the authors of FERC 2009, Dr. Stephen George, testified:

> *Without a doubt, the most important issue requiring more investigation is understanding the best way to get customers to sign up for time-varying rates. This is an understudied area that is vitally important to designing good pricing policies and to implementing successful pricing and demand response programs. Predicting the aggregate impact of dynamic tariffs and other demand response programs requires estimates of the average response associated with customers who enroll in these programs as well as estimates of the number of customers who are likely to enroll. The 17 pilot programs mentioned above have focused almost exclusively on estimating average dynamic rate impacts and hardly at all on understanding customer preferences for such rates and how to effectively enroll consumers in these programs.*[15]

Over the past ten years, utilities in the United States and Canada have conducted at least 18 pilot projects of dynamic pricing in the residential sector. Seventeen of these pilots were designed to analyze the price elasticity of customers on those rates, i.e., customer reaction to dynamic rates once those customers had agreed to enroll in the pilot in exchange for special financial incentives. In other words, the pilots were not designed to analyze the percentage of residential customers who would voluntarily agree to switch from their current rates in order to take service under dynamic rates, i.e., to "opt-in" to dynamic pricing.

The one pilot which has tested customer voluntary participation in some form of dynamic pricing is the Commonwealth Edison Customer Application Program Pilot, conducted in the summer of 2010. That pilot placed test groups of customers on different time-varying rates, including PTR, and allowed them the opportunity to opt-out. While very few customers placed on those rates chose to opt-out, only 7.4 percent of the customers in that test group actually responded to the PTR. This result indicates that even though 100 percent of residential customers in a group may be eligible for a PTR, only a small percentage are likely to take actions to respond to that rate.

Figure 4 presents our review of residential customer participation in several different types of time-differentiated pricing. The figure presents bar charts of residential customer participation in two categories of pricing:

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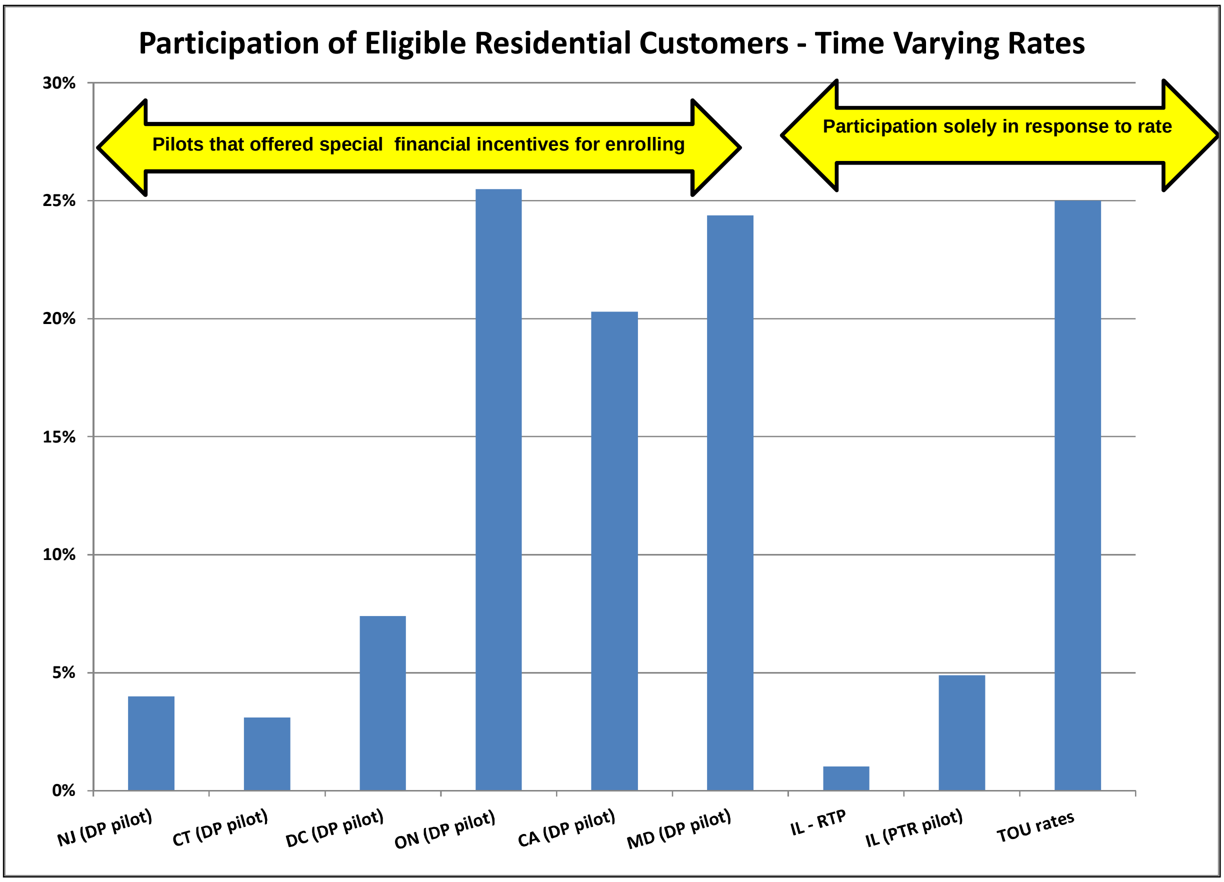
[12] Participation in AMI/ smart meter proceedings in NJ, ME, PA, MD, DC, NV, TX, AR
[13] FERC 2011, pages 17-20.
[14] FERC 2009, pages 49 and 59-62.
[15] Pennsylvania Public Utility Commission, Docket No. M-2009-2123944, PECO Energy Company Statement No. 2, Direct Testimony of Dr. Stephen S. George, October 28, 2010, p. 6.

- Dynamic pricing pilots in which residential customers were given special financial incentives to enroll. These are pilots conducted in New Jersey, Connecticut, the District of Columbia, Ontario, California, Maryland, and Illinois; and
- Pricing offers in which residential customers participated based solely on the value of the pricing offer. These are a real time pricing (RTP) rate offered to residential customers by an IL utility, a PTR rate offered in the Commonwealth Edison pilot in IL, and TOU rates of utilities with "best practices."

This review indicates that voluntary residential participation, referred to as "opting-in," in time-varying rates such as CPP and actual response to PTR is likely to be less than 10 percent. Residential participation in those dynamic rates is likely to be less than the 25 participation experienced in "best practices" TOU rates, because dynamic rates provide participants a lower amount of savings than TOU rates, which are in effect many more hours of the year.

Figure 4. Participation of Eligible Residential Customers - Time Varying Rates



Reasonable estimate of incremental DR potential in 2019

The EBAU projections are consistent with estimates of DR reductions in FERC 2011. FERC 2011 provides projections of reductions from DR through 2015 based upon survey responses from

1,755 entities serving over 77 percent of the nation's retail electric customers. The total projected reductions for 2015 reported in FERC 2011 are consistent with the trajectory implied by the FERC 2009 projections for 2019/2020. As indicated in Table 3, the FERC 2011 projections for 2015, approximately 5 years or 50 percent of the FERC 2009 planning horizon, are approximately 40 percent to 50 percent of the FERC 2009 projections for 2019.

Table 3. Projections of Reductions from DR - FERC 2011 Projections for 2015 versus FERC 2009 Projections for 2019

		FERC 2011			FERC 2009	FERC 2011 for 2015 vs FERC 2009 for 2019
		Reductions in 2015			Reductions in 2019	
		MW	MW	GW	GW	%
A. Dispatchable capacity	DLC	6,301	19,656	**19.7**	41.7	47%
	IL	8,328				
	CPP w C	915				
	Load as capacity	1,390				
	OTHER	2,722				
B. Non dispatchable Time-sensitive pricing	TOU	1,489	5,146	**5.1**	2.0	39%
	CPP w C	910				
	RTP	1,271				
	PTR	1,165				
	SPRT	311				
Sub-total				25	44	57%

The EBAU projections are also consistent, in aggregate, with the projections in the ACEEE clean-energy studies for OH, VA, PA, NC, SC, and AR. The FERC 2009 projections for those specific states under the EBAU tend to be higher than, but generally consistent with, the ACEEE state-specific projections for 2020 under the medium scenario. In aggregate, the FERC 2009 projections for the six states are 113 percent of the ACEEE projections, as indicated in Table 4.

Table 4 reveals a major difference between the approach FERC 2009 used to estimate demand reductions and the ACEEE approach. The ACEEE studies explicitly estimate reductions from BUG as part of their estimates of DR potential in the C&I sector. On average, the ACEEE studies estimate that BUG accounts for about 40 percent of the DR potential of C&I customers. In contrast, FERC 2009 does not project explicit reductions from BUG, or from any other specific measure a C&I customer might take in order to achieve its demand reduction.[16] Instead, FERC 2009 simply estimates the quantity of DR that C&I customers achieve at the meter in aggregate, as a sector, via each type of demand resource. They treat the customer side of the meter as a "black box" and make their projections based on the price elasticities C&I customers have demonstrated in current, "best practices" programs. (EPRI 2009 has also apparently excluded BUG, since it is prepared by the same consultant using the same types of demand resources and results in the same estimate of DR potential.) However, the FERC 2009 estimates do assume that BUG is a measure that some C&I customers might use to achieve their reductions.[17]

[16] FERC 2009, page 22.
[17] FERC 2009, page 45.

Table 4. Estimates of DR potential in six states in 2019/2020: FERC 2009 vs. ACEEE studies

Estimates of MW reduction potential by state in 2019/2020 : FERC 2009 vs ACEEE							
State	**Projection**	**Peak Demand AAGR**	**R**	**C&I - DR excluding BUG**	**C&I -BUG**	**C&I Total**	**Total**
VA	**ACEEE**	1.4%	499	844	865	1709	**2208**
	FERC 2009	1.7%	471	N/A	N/A	1219	**1690**
	% of ACEEE		94%			71%	**77%**
PA	**ACEEE**	1.2%	583	1378	1238	2616	**3199**
	FERC 2009	1.7%	687	N/A	N/A	2993	**3680**
	% of ACEEE		118%			114%	**115%**
OH	**ACEEE**	1.0%	1680	1424	1089	2513	**4193**
	FERC 2009	1.7%	779	N/A	N/A	3491	**4270**
	% of ACEEE		46%			139%	**102%**
SC	**ACEEE**	1.0%	395	640	400	1040	**1435**
	FERC 2009	1.7%	370	N/A	N/A	1539	**1909**
	% of ACEEE		94%			148%	**133%**
NC	**ACEEE**	1.4%	960	753	796	1549	**2509**
	FERC 2009	1.7%	1089	N/A	N/A	2049	**3138**
	% of ACEEE		113%			132%	**125%**
AR	**ACEEE**	1.1%	193	408	251	659	**852**
	FERC 2009	1.7%	215	N/A	N/A	1327	**1542**
	% of ACEEE		111%			201%	**181%**
Six States	**ACEEE**		4310	5447	4639	10086	14396
	FERC 2009		3611	N/A	N/A	12618	16229
	% of ACEEE		84%			125%	**113%**

4. Projected DR Potential By 2019

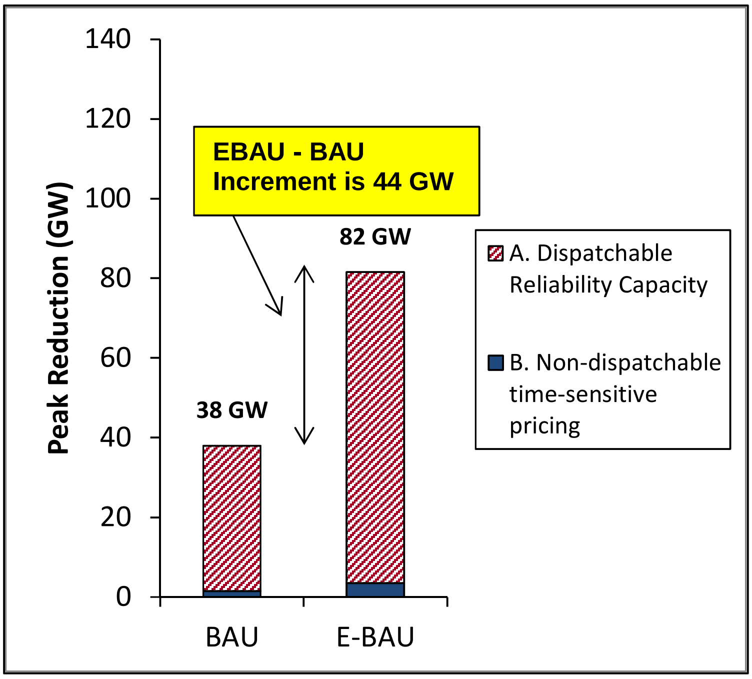
This chapter presents the projections of DR potential by DR category, customer sector, and census region. We present the potential in bar charts. Appendix D provides tables with the numerical values used to create each bar chart. Each presentation of potential is accompanied by a discussion of the questions of particular interest to the EPA.

A. Reasonable potential for national DR

The estimates of national DR in 2019 under the BAU and EBAU scenarios are presented in Figure 53. Our review indicates that it is reasonable to expect incremental DR (i.e., the EBAU projection minus the BAU projection) to achieve reductions in demand of up to 44 GW nationally by 2019, or 5 percent of the BAU forecast national peak demand load of 912 GW.

Figure 5 demonstrates that this incremental quantity is approximately equal to the total level of DR expected under the BAU scenario (38 GW); thus, the total EBAU DR potential is approximately double the BAU DR potential for 2019.

Figure 5. DR Potential in 2019 under BAU and EBAU Scenarios



Discussion

A key question of interest to the EPA is whether the expected growth in DR will be significant enough to reduce the need for large supply-side resources, such as coal-fired generation. As discussed earlier, to the extent that DR has an impact on new capacity it will be to delay or avoid the need to add new peaking capacity. The extent to which the DR potential projected in FERC 2009, if achieved, would delay or avoid the need to add new peaking capacity will vary by state and region throughout the country. Those impacts will be a function of the magnitude of each category of DR, projected growth in demand, existing capacity resources, and total costs (capacity plus energy) of generation from various types of new capacity available to that particular state or region.

B. Estimate – DR potential by category and type of demand resource

FERC 2009 projects DR potential for five demand resources: automated/direct load control, interruptible/curtailable tariffs, other DR programs, pricing with technology, and pricing without technology. Table categorizes the first four resources as *dispatchable reliability capacity,* and categorizes pricing without technology resources as *non-dispatchable time-sensitive pricing*. FERC 2009 does not project DR potential for demand resources in the *dispatchable other* category. These groupings are based on the FERC 2009 definitions of those demand resources and the NERC DADS taxonomy of DR.

Table 5. Categories of DR and types of demand resources NERC DADS and FERC 2009

Categories of DR per NERC DADS	Types of Demand resources per NERC DADS	Types of demand resources per FERC 2009
A. Dispatchable Reliability Capacity	1. Direct Load Control 2. Interruptible Load 3. CPP with control 4. Load as Capacity Resource	• Automated/direct load control • Interruptible/curtailable tariffs, • Other DR programs • Pricing with technology
B. Non-Dispatchable Time-Sensitive Pricing	5. Time-of-Use Pricing 6. Critical Peak Pricing; Peak Time Rebate 7. Real-Time Pricing 8. System Peak Response Transmission Tariff	Pricing without technology (excludes time-of-use pricing)
C. Dispatchable Other	9. Economic, Energy price, Demand Bidding & Buy-back 10. Reliability, Reserves, Spinning Reserves 11. Reliability, Reserves, Non-Spinning Reserves 12. Reliability, Energy Voluntary, Emergency 13. Reliability, Regulation Service	**FERC 2009 does not model**

Table 6 provides the FERC 2009 projections of BAU, EBAU and incremental DR by category, type of demand resource, and sector.   This Table indicates that the large C&I sector provides the greatest reductions, both in absolute and relative terms, followed by the residential sector.

Table 6. FERC 2009 Projection of DR Potential in 2019

Projected DR Potential in 2019 by Category, Customer Sector and Demand Resource Type					
		DR Potential (MW)			
DR Category	Customer Sector and Demand Resource Type	BAU	EBAU	Increment = EBAU - BAU	Increment as % of Projected Peak excluding BAU
	Residential				
A	Automated/Direct Load Control	6,138	20,394	14,256	
A	Interruptible/Curtailable Tariffs	0	0	0	
A	Other DR Programs	0	0	0	
A	Pricing with Technology	0	0	0	
A	Subtotal	6,138	20,394	14,256	
B	Pricing without Technology	434	1,862	1,428	
	Residential Total	**6,572**	**22,256**	**15,684**	**4%**
	Small / Med C&I				
A	Automated/Direct Load Control	1,263	2,217	954	
A	Interruptible/Curtailable Tariffs	1,800	3,624	1,824	
A	Other DR Programs	161	165	4	
A	Pricing with Technology	0	0	0	
A	Subtotal	3,224	6,006	2,782	
B	Pricing without Technology	139	459	320	
	Small / Med C&I Total	**3,363**	**6,465**	**3,102**	**1%**
	Large C&I				
A	Automated/Direct Load Control	0	0	0	
A	Interruptible/Curtailable Tariffs	12,008	23,799	11,791	
A	Other DR Programs	15,067	27,939	12,872	
A	Pricing with Technology	0	0	0	
A	Subtotal	27,075	51,738	24,663	
B	Pricing without Technology	935	1,168	233	
	Large C&I Total	**28,010**	**52,906**	**24,896**	**11%**
	All Sectors				
A	Automated/Direct Load Control	7,401	22,611	15,210	
A	Interruptible/Curtailable Tariffs	13,808	27,423	13,615	
A	Other DR Programs	15,228	28,104	12,876	
A	Pricing with Technology	0	0	0	
A	Subtotal	36,437	78,138	41,701	
B	Pricing without Technology	1,508	3,489	1,981	
	All Sectors Total	**37,945**	**81,627**	**43,682**	**5%**

As shown in Figure 5 and Table 6, the overwhelming majority of potential DR comes from dispatchable, reliability, or capacity programs. This result is consistent with what we are seeing reported from various RTOs, for example PJM. In its 2010 Demand Side Response Activity Report[18], PJM shows a similar result, that the overwhelming amount of revenue made by demand

[18] Slide 5 of PJM report.

response customers is from the capacity market. The literature that we reviewed for this project did not report an expected change in this situation. As we write this report, the FERC is reviewing numerous compliance filings (and protests thereto) upon their Order 745 which required the nation's RTOs to change their market rules to allow DR to participate in energy markets. As noted earlier, we expect that system planners may require 5 to 10 years of experience with DR driven by pricing before they will be comfortable counting on that DR when determining whether to acquire additional generating capacity or DR dispatched for reliability

Discussion

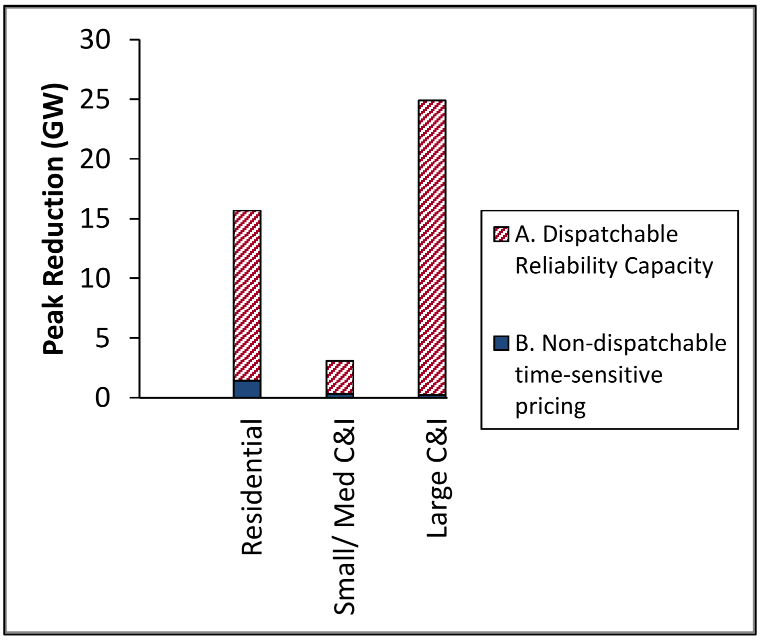
The EPA is interested in whether the electricity sector foresees increased use of back-up generators to meet emergency, economic, and/or ancillary service DR and, if so, to what extent use of these generators will dominate DR program growth.

As noted earlier, the ACEEE studies explicitly estimate reductions from BUG as part of their estimates of DR potential in the C&I sector, but FERC 2009 does not. On average the ACEEE studies estimate that BUG accounts for about 40 percent of the DR potential of C&I customers.

C. Estimate - DR potential by customer sector and end use

FERC 2009 provides projections of DR potential for four customer market segments—residential, small commercial/industrial (peak demand < 2 MW), medium commercial/industrial, and large commercial/industrial. Because the projected potentials for small C&I and for medium C&I are minimal, our report consolidates those projections into an aggregate small/medium C&I sector. Figure 6 plots the estimates of incremental national DR potential in 2019 by customer sector.

Figure 6. Incremental DR potential in 2019 by sector



Discussion

The EPA is interested in the quantity of DR potential by customer sector, and by end-use within each sector. Figure 6 demonstrates that the large C&I sector has the most significant DR potential (24.9 GW, 11% of sector demand), followed by the residential sector (15.7 GW, 4% of sector demand) and the small/medium C&I sector (3.1 GW, 1% of sector demand).

When estimating the potential for DR, it is important to recognize the differences in key characteristics of each major customer sector to which demand resources may be targeted, and the key attributes of those resources. Three key characteristics that affect DR potential by customer sector are electricity use per customer, opportunities for DR, and availability of advanced metering infrastructure (AMI) to enable DR.

Electricity usage per customer varies significantly by sector, with a great concentration in the large C&I sector. In 2009 that sector, with approximately 0.2 percent of the country's retail customers, accounted for 29 percent of annual electricity use and 23 percent of peak demand. Thus customers in this sector account for a disproportionate amount of electric demand and are the most attractive targets for DR. A dollar spent to attract one large C&I customer to participate in a DR program will typically produce a much greater reduction in peak demand than a dollar spent to attract a residential customer to participate in a DR program.

Our review of FERC 2009, EPRI 2009, and the ACEEE reports indicates that cooling has the greatest potential for DR in the commercial sector, and machine-drive loads have the greatest potential in the industrial sector. FERC 2009 provides projected reductions by type of demand resource; however, it does not provide detail on the specific measures C&I customers would use to achieve those reductions.

In the residential sector, the greatest potential for DR by far is cooling, which accounts for 60 percent of summer peak demand.[19] The studies indicate that central air conditioning has the greatest potential for DR, followed by water heating and pool pumps.[20] If the feasibility of automating the cycling of room air conditioners can be improved the potential for DR in this sector would increase.[21]

In terms of demand resources, the studies indicate that DLC has significant potential in the residential sector. DLC requires the installation of special load control switches or thermostats, but does not require the installation of new smart meters or AMI. In contrast, the various types of pricing demand resources in the non-dispatchable time-sensitive pricing category require, at a minimum, that the customers taking service on those pricing tariffs have smart meters.

It is important to note that the potential of various demand resources is a function of their ability to attract and enable customers to achieve reductions from a given set of loads. Further, some demand resources may be substitutes for each other. For example, in the residential sector CAC has the major potential for reductions. Reductions in CAC load can be achieved either through DLC or through dynamic pricing. The subset of customers with CAC will be choosing between enrolling in DLC or enrolling in dynamic pricing. The more customers who choose DLC the fewer will be available to choose dynamic pricing and vice versa.

Enabling technologies

The EPA is also interested in whether the studies speak to any critical enabling technologies, standards, or circumstances to achieve the demand response scenarios.

In all sectors, at least two of these five demand resources rely on an “enabling technology” according to the FERC 2009 definition of that term, which is “devices that automatically reduce consumption during high price hours.” Those two demand resources are automated/direct load control and pricing with technology.

Our review indicates that AMI is also, in effect, a critical enabling technology. AMI enables providers to offer two demand resources in the residential and small commercial sectors, i.e., pricing with technology and pricing without technology. Utilities need to deploy AMI, or smart meters to support those two pricing options because they provide the functionality required to send pricing signals to the consumer and to record the hourly use of customers participating in either of those two demand resources. Most utilities currently do not have that functionality for those two sectors because they record the usage of residential and small C&I customers with simple electromechanical meters which are read monthly and do not have the capability to measure and record energy use in peak hours. In contrast, medium and large C&I customers do not require new utility AMI to participate in those pricing options because most utilities already use interval meters to record the electricity use of those customers and have the software and hardware needed to process that hourly usage data. Utilities who do not currently have this

[19] EPRI 2009, page 3-17.
[20] EPRI 2009, Table ES-4.
[21] ___, *Advancing Energy Efficiency in Arkansas: Opportunities for a Clean Energy Economy,* ACEEE, March 201 page 214

metering and data processing functionality for residential and small C&I customers cannot easily and inexpensively offer those DR pricing tariffs to all customers in those sectors.

Utilities can offer dynamic pricing to individual residential and small C&I customers by installing the necessary metering on their specific premises, which is how utilities currently offer TOU pricing, but that individual participant approach is much more expensive than system-wide deployment of AMI. Thus, universal deployment of AMI represents the “critical enabling technology” for the non-dispatchable time-sensitive pricing category of DR potential. The availability of AMI to all residential customers is a necessary, but not sufficient, condition of achieving the potential from that category.

The other necessary conditions to achieve that potential are that suppliers offer time-sensitive pricing tariffs and that the customers choose to respond to those tariffs.

FERC 2009 identified the lack of interoperability standards as one of the barriers to more widespread deployment of AMI and customer-side enabling technologies.[22]

D. Estimate - DR potential by census region

The majority of the 44 GW of incremental DR potential is projected to be in the South and the Midwest census regions. FERC 2009 attributes the higher potential in those regions to higher saturations of central air conditioning and to lower current levels of DR, i.e., less potential being achieved in the BAU scenario.[23]

Figure 7 plots the estimates of incremental DR potential in 2019 for each of the four major census regions (i.e., West, Northeast, Midwest, and South).

[22] FERC 2009, pages xvi, 65, 70-71.
[23] FERC 2009, page 31.

Figure 7 Incremental DR potential in 2019 by census region

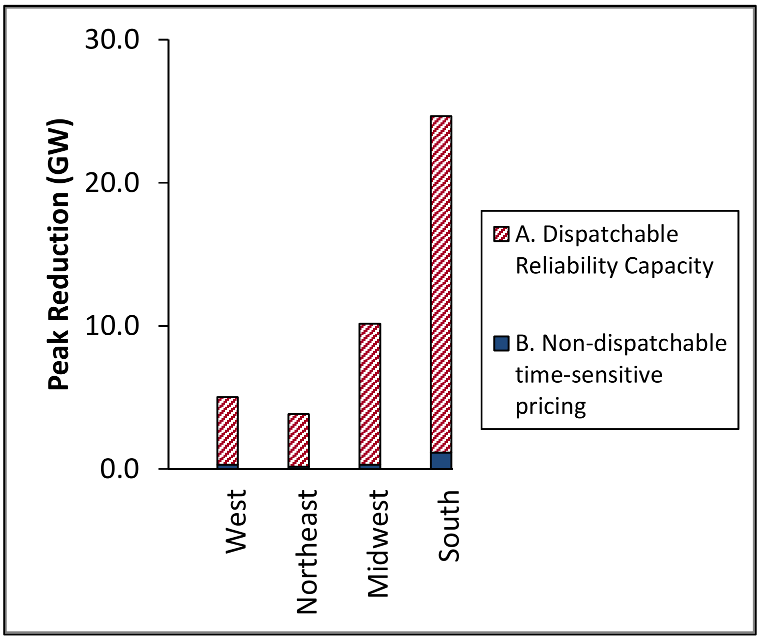
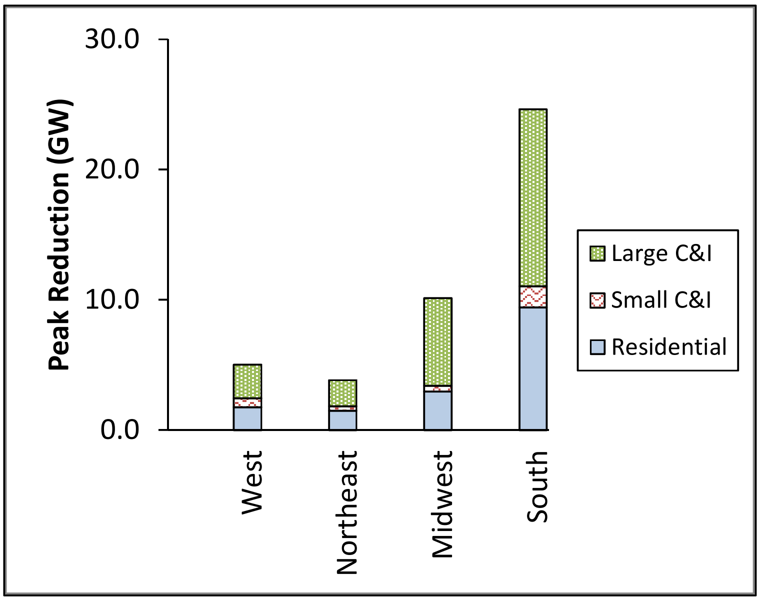


Figure 8 plots the estimates of incremental DR in 2019 by customer sector within each of the four major census regions.

Figure 8. Incremental DR potential in 2019 by census region and customer sector



5. Conclusion

FERC and NERC define DR as:

> *Changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

NERC has developed a taxonomy of energy efficiency and demand resources. According to that taxonomy, demand resources can be placed into three broad categories: dispatchable reliability capacity, non-dispatchable time-sensitive pricing, and dispatchable other. Demand resources in the first two categories are designed to reduce electricity use during peak periods every year and, in the long-term, have the potential to delay or avoid the need for new large supply-side resources. Demand resources in the third category are designed to reduce electricity use only when electric energy prices are abnormally high, for reserves, or when emergencies jeopardize system reliability. As such, reductions from those resources only have the potential to delay or avoid the need to procure new supply-side generation projects that would be built to fulfill a need for reserves.

Our review indicates that it is reasonable to expect incremental DR to achieve reductions in demand of up to 44 GW nationally by 2019, or 5 percent of the BAU forecast national peak demand load of 912 GW. This incremental quantity of DR is approximately equal to the total level of DR expected under a BAU scenario (38 GW); thus, achieving the incremental potential would approximately double the DR in 2019 compared to BAU.

Almost all of the incremental DR potential by 2019 is projected to be achieved from demand resources categorized as dispatchable reliability capacity.

The incremental reductions in demand are primarily projected to be achieved in the large commercial and industrial (C&I) customer sector. The most comprehensive set of projections reviewed does not indicate the sources of those reductions within the C&I sector; however, clean energy reports for six states prepared by the ACEEE project approximately 40 percent of C&I sector demand reductions from BUG. The majority of reductions in the residential sector are projected from reductions in CAC.

The forecasts reviewed indicate that the South and the Midwest census regions have the greatest potential for incremental DR. This potential arises from the high levels of CAC penetration in those regions and the lower levels of DR currently being achieved there.

Neither the forecasts nor our report estimate the extent to which this DR potential, if achieved, would delay or avoid the need to add new generating capacity. Developing such an estimate for each region of the country will require analyses of the projected growth in demand, load factor, existing capacity resources, and costs of new capacity in each of those regions.

Appendix A - Definitions of Demand Resources[1]

A. Dispatchable Reliability Capacity

1. **Direct Load Control**. A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. Also known as direct control load management.

2. **Interruptible Load.** Electric consumption subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

3. **Critical Peak Pricing with Load Control.** Demand-side management that combines direct load control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

4. **Load as a Capacity Resource.** Demand-side resources that commit to make pre-specified load reductions when system contingencies arise.

B. Non-dispatchable Time Sensitive Pricing

5. **Time-of-Use.** A rate where usage unit prices vary by time period, and where the time periods are typically longer than one hour within a 24-hour day. Time-of-use rates reflect the average cost of generating and delivering power during those time periods.

6. **Critical Peak Pricing.** Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours. **Peak Time Rebate.** Peak time rebates allow customers to earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days. Like Critical Peak Pricing, the number of critical peak days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.

7. **Real Time Pricing**. Rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day ahead or hour-ahead basis.

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[1] ___. *Assessment of Demand Response Potential and Advanced Metering*. Federal Energy Regulatory Commission. February 2011

8. **System Peak Response Transmission Tariff.** The terms, conditions, and rates and/or prices for customers with interval meters who reduce load during peaks as a way of reducing transmission charges.

C. Dispatchable Other

9. **Demand Bidding & Buy-Back.** A program which allows a demand resource in retail and wholesale markets to offer load reductions at a price, or to identify how much load it is willing to curtail at a specific price.

10. **Spinning/Responsive Reserves.** Demand-side resource that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an Emergency Event.

11. **Non-Spinning Reserves.** Demand-side resource that may not be immediately available, but may provide solutions for energy supply and demand imbalance after a delay of ten minutes or more.

12. **Emergency Demand Response Program.** A demand response program that provides incentive payments to customers for load reductions achieved during an Emergency Demand Response Event.

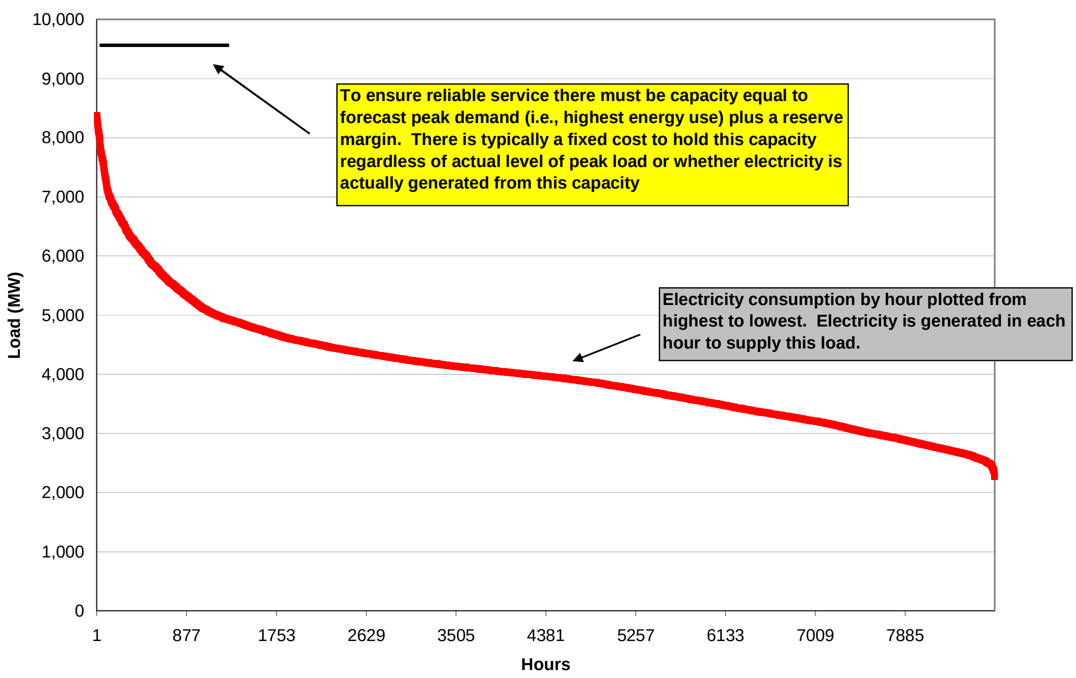
13. **Regulation Service.** A type of Demand Response service in which a Demand Resource increases and decreases load in response to real-time signals from the system operator. Demand Resources providing Regulation Service are subject to dispatch continuously during a commitment period. This service is usually responsive to Automatic Generation Control (AGC) to provide normal regulating margin. Also known as regulation or regulating reserves, up-regulation and down-regulation.

DIFFERENCE BETWEEN DEMAND RESPONSE (DR) AND ENERGY EFFICIENCY (EE)

DR reduces electricity use during hours of highest system-wide use, or peak demand. These hours, usually less than 100 per year, are sometimes referred to as critical peak hours. EE reduces load in most, if not all, of the 8,760 hours in a year. Thus EE reduces load during critical peak hours as well as during non-peak hours.

To appreciate the differences between DR and EE it is useful to begin with a review of the fundamental characteristics of annual electricity consumption and how those characteristics drive decisions regarding capacity additions. Those fundamental characteristics include the peak load, the annual load and the shape of that annual load. Those characteristics are illustrated in Figure A. This chart, referred to as a load duration curve, plots the total electric energy consumed by customers of a representative electric utility in each hour of a year. That consumption is plotted in decreasing quantity from the hour with highest use to the hour with lowest use.

Figure A: Illustrative Load Duration Curve (8,760 hours)

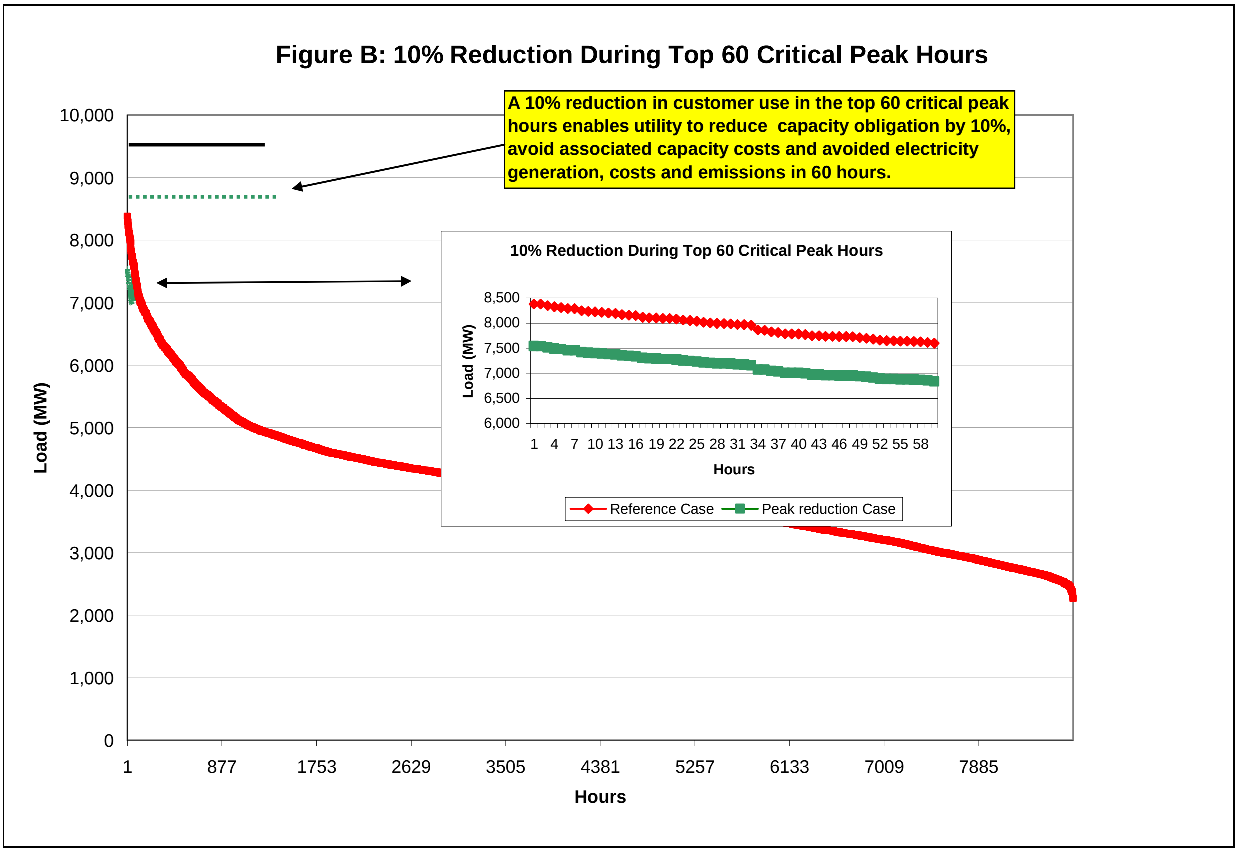


Electric industry planners determine the quantity of capacity needed in any given year to ensure reliable service by forecasting peak demand, i.e., the maximum quantity of retail load (MW) under extreme conditions, and then adding allowances for line losses and for a target reserve margin. Coincident peak demand is a measure of the highest system-wide electricity use in a calendar year. The time periods during which demand is at or near its peak are sometimes referred to as critical peak periods. Most utilities typically experience critical peak periods in less than 100 hours each year. In Figure A the capacity required to ensure reliable service for our representative utility is approximately 9,600 MW. That quantity is plotted in the solid horizontal line.

The other two fundamental characteristics of electricity use are the annual load and the shape of that annual load. Those two characteristics are a function of the quantity of electric energy, in MWh, retail customers consume in each hour of the year. In Figure A that hourly consumption is plotted in the solid line. That hourly consumption begins at over 8,000 MWh in critical peak hours and declines to approximately 2,500 MWh in off-peak hours.

DR refers to the reduction of electricity use during the hours of highest system-wide electricity use, or critical peak hours. A common DR measure is to reduce central air conditioning (‘cac’) electricity use during critical peak periods by increasing the room temperature setting or by cycling the operation of the unit.

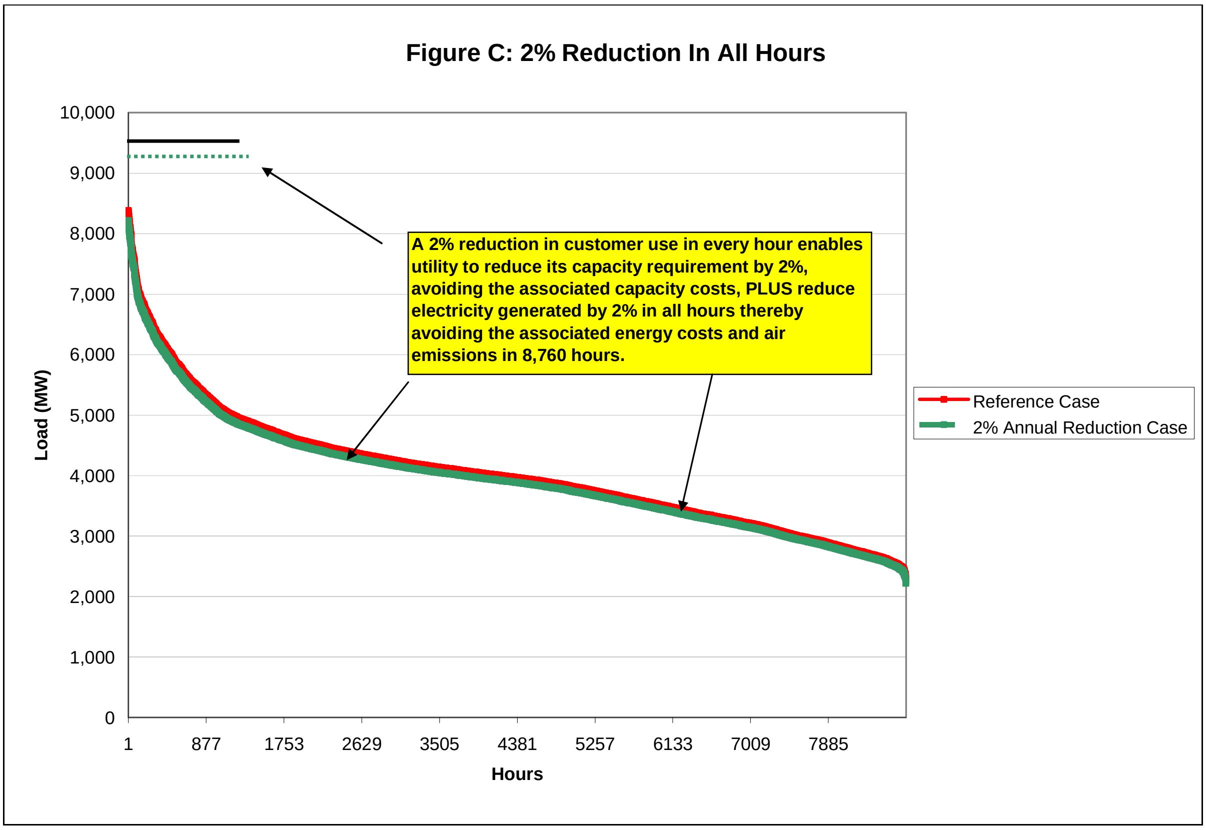
The impact of DR on the fundamental characteristics of the illustrative utility from Figure A is shown in Figure B. This chart illustrates the impact of DR that reduces load by 10 % in the top 60 critical peak hours



That illustrative reduction from DR would enable the utility to reduce the quantity of capacity it requires by 10%, and to avoid the costs associated with that avoided capacity. That illustrative reduction from DR would also enable the utility to reduce the quantity of energy it requires in those 60 hours by 10%, and avoid the cost associated with that avoided energy.

EE refers to measures that reduce electricity use in all hours of the year affected by the EE measure. EE measures reduce electricity use during critical peak periods, like DR, as well as in all other hours of the year during which the application affected by the EE measure operates. For example, an EE measure such as insulating a home will reduce the air conditioning load of the home in all the hours when air conditioning is required, not just during critical peak periods.

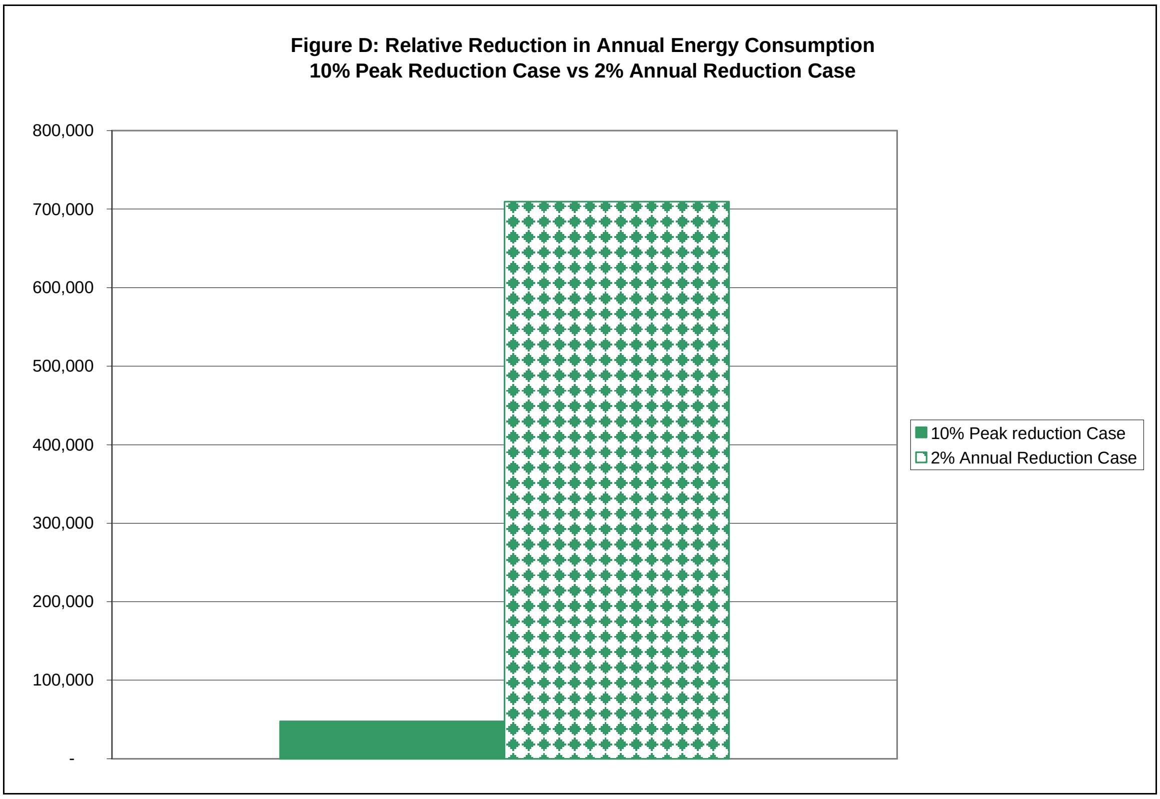
The impact of EE on the fundamental characteristics of the illustrative utility from Figure A is shown in Figure C. This chart illustrates the impact of EE that reduces load by 2 % in all 8,760 hours of the year.



That illustrative reduction from EE would enable the utility to reduce the quantity of capacity by 2%, and to avoid the associated capacity costs. It would also enable the utility to reduce the quantity of energy it acquired in all 8,760 hours by 2%, and avoid the cost of that energy. Finally, the utility would avoid the air emissions associated with that 2% reduction in electricity use in those 8,760 hours.

Reductions in peak load from DR are valuable in terms of avoiding capacity costs and the costs of energy in critical peak periods. For example, a 10% reduction in peak load will certainly avoid more capacity costs, and peak hour energy costs, than a 1% reduction in peak load. However, DR produces much less reduction in annual energy consumption than EE because DR reductions occur in less than 100 hours, or 1%, of the year. In contrast, EE causes reductions in both critical peak hours and in many additional hours of the year.

For example, the illustrations in Figures B and C indicate that, all else equal, an EE measure that reduces energy use by 2% in every hour would produce a reduction in annual energy consumption about 15 greater than a 10% reduction in critical peak hours from DR. Those relative reductions are presented in Figure D.



APPENDIX C

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Table D-1. U.S. Demand Response Potential by Category (2019)
Peak Reductions (GW)

		B. Non-dispatchable time-sensitive pricing	A. Dispatchable Reliability Capacity	Total
All Regions and classes	BAU	1.5	36.4	37.9
	EBAU	3.5	78.1	81.6
	EBAU - BAU	2.0	41.7	43.7

Table D-2. U.S. Demand Response Potential by Customer Sector and Category (2019)
Peak Reductions (GW)

		B. Non-dispatchable time-sensitive pricing	A. Dispatchable Reliability Capacity	Total
Residential	BAU	0.4	6.1	6.6
	EBAU	1.9	20.4	22.3
	EBAU - BAU	1.4	14.3	15.7
Small/ Med C&I	BAU	0.1	3.2	3.4
	EBAU	0.5	6.0	6.5
	EBAU - BAU	0.3	2.8	3.1
Large C&I	BAU	0.9	27.1	28.0
	EBAU	1.2	51.7	52.9
	EBAU - BAU	0.2	24.7	24.9
Total	BAU	1.5	36.4	37.9
	EBAU	3.5	78.1	81.6
	EBAU - BAU	2.0	41.7	43.7

Table D-3. U.S. Demand Response Potential by Region and Category (2019)
Peak Reductions (GW)

		B. Non-dispatchable time-sensitive pricing	A. Dispatchable Reliability Capacity	Total
West	BAU	0.5	5.2	5.8
	EBAU	0.9	9.9	10.8
	EBAU - BAU	0.3	4.7	5.0
Northeast	BAU	0.0	9.1	9.1
	EBAU	0.2	12.8	13.0
	EBAU - BAU	0.2	3.7	3.9
Midwest	BAU	0.1	10.2	10.3
	EBAU	0.5	20.0	20.5
	EBAU - BAU	0.3	9.8	10.2
South	BAU	0.8	11.9	12.7
	EBAU	2.0	35.4	37.3
	EBAU - BAU	1.2	23.5	24.6
Total	BAU	1.5	36.4	37.9
	EBAU	3.5	78.1	81.6
	EBAU - BAU	2.0	41.7	43.7

Table D-4. U.S. Demand Response Potential by Region and Sector (2019)
Peak Reductions (GW)

		Residential	Small / Med C&I	Large C&I	Total
West	BAU	1.7	0.9	3.2	5.8
	EBAU	3.4	1.6	5.7	10.8
	EBAU - BAU	1.8	0.7	2.6	5.0
Northeast	BAU	0.3	0.1	8.7	9.1
	EBAU	1.8	0.5	10.7	13.0
	EBAU - BAU	1.5	0.3	2.0	3.9
Midwest	BAU	1.5	0.5	8.3	10.3
	EBAU	4.4	1.0	15.1	20.5
	EBAU - BAU	3.0	0.5	6.7	10.2
South	BAU	3.2	1.7	7.8	12.7
	EBAU	12.6	3.4	21.4	37.3
	EBAU - BAU	9.4	1.6	13.6	24.6
Total	BAU	6.6	3.4	28.0	37.9
	EBAU	22.3	6.5	52.9	81.6
	EBAU - BAU	15.7	3.1	24.9	43.7