ADVANCED ENERGY ECONOMY

PEAK DEMAND REDUCTION STRATEGY

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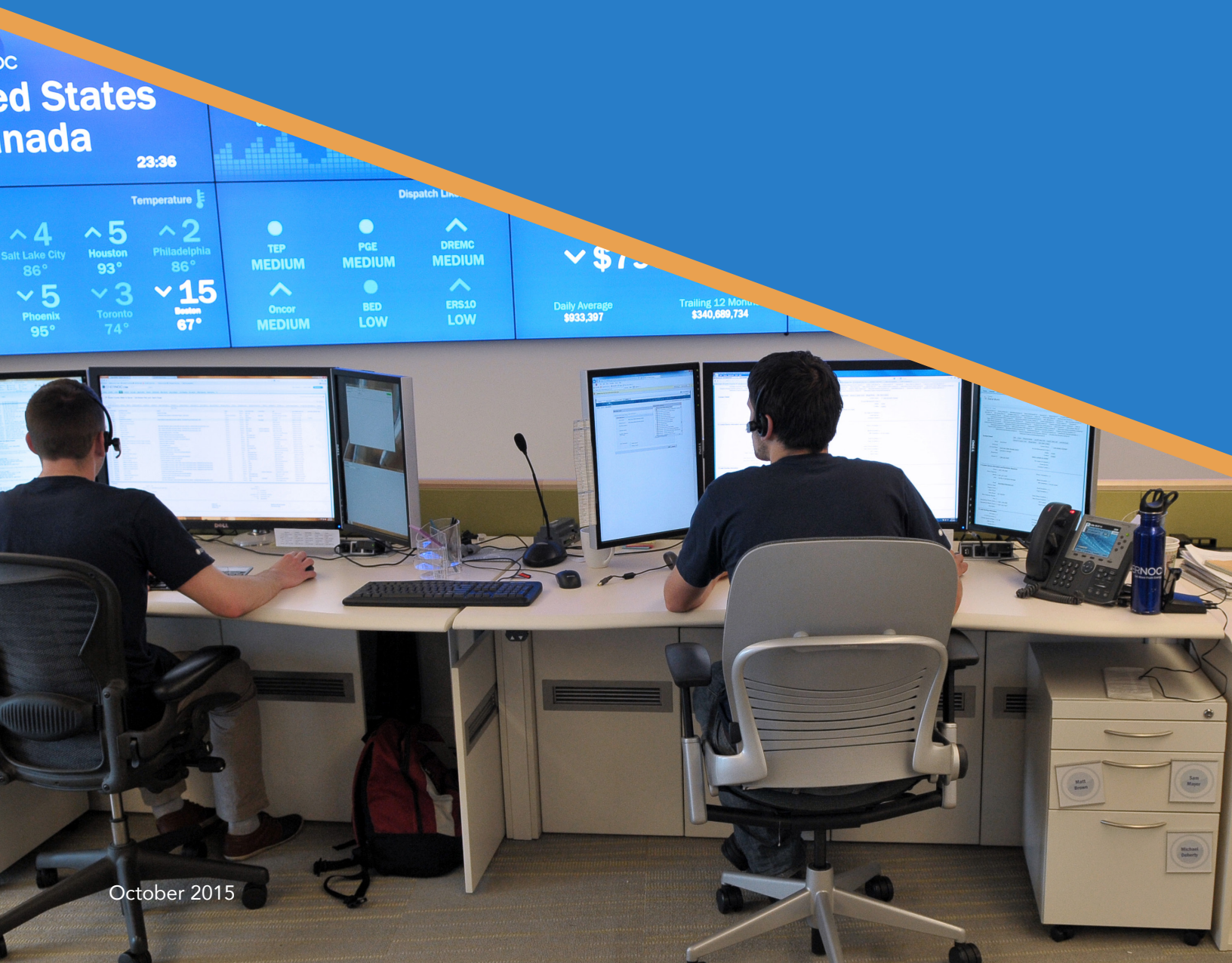

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ADVANCED ENERGY ECONOMY
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1. Executive Summary

1.1 Introduction

After launching a project assessing peak demand and demand response (DR) standards at the state level, Advanced Energy Economy (AEE) discovered that no currently existing study examined existing DR programs or made recommendations on best practices for structuring a DR/peak demand initiative. AEE engaged Navigant to perform quantitative and qualitative analysis in order to gain an understanding of peak demand reduction standards, their potential benefits, and how such standards should be designed.

Navigant has structured this study into two tasks based on the desired outcomes AEE provided. The first task was primarily a modeling exercise to estimate potential benefits and avoided costs from DR programs based on various scenarios of penetration and regulatory activity. The second task involved diving into various aspects of program design to figure out how to optimize the results from peak load reduction mandates, which involved reviewing program evaluations and talking with industry participants from all perspectives to determine which design mechanisms work and which do not.

1.2 Massachusetts and Illinois Peak Reduction Modeling

Navigant developed three scenarios to evaluate the benefits and costs of reducing peak demand in Massachusetts and Illinois, addressing two key aspects for each scenario: the ratio of benefits to costs and the feasibility of utilities procuring sufficient resources to meet the demand reduction goals of the scenarios. The study focuses on a 10-year outlook.

- Low Scenario: Actual peak demand does not increase over 10 years.
- Medium Scenario: Actual peak demand declines by 0.25% per year over 10 years.
- High Scenario: Actual peak demand declines by 0.5% per year over 10 years.

The purpose of studying all three scenarios is to illustrate the range of benefits and costs for a peak demand reduction policy.

The avoided costs (i.e., the benefits) and benefit/cost ratios for each scenario are summarized in Table 1.1 for Massachusetts and Table 1.2 for Illinois. In all scenarios the B/C ratios are strongly positive (i.e., >1), indicating that total benefits are significantly greater than the associated costs.

Another key point is that while the B/C ratio tends to increase as peak load is reduced, technical limits to the amount the peak load can be reduced with DR and energy efficiency resources limit how much of this benefit can be realized.

Table 1.1 Massachusetts Peak Demand Benefit/Cost: 2014

Scenario	Capacity Avoided Cost ($000, 2014)	Energy Avoided Cost ($000, 2014)	T&D Avoided Cost ($000, 2014)	Total Avoided Cost ($000, 2014)	Program Procurement Cost ($000, 2014)	B/C Ratio
Low	$243,538	$40,976	$82,908	$367,422	$112,774	3.26
Medium	$386,397	$58,026	$116,977	$561,400	$159,117	3.53
High	$607,460	$75,476	$150,591	$833,527	$204,839	4.07

(Source: Navigant)

Table 1.2 Illinois Peak Demand Benefit/Cost: 2014

Scenario	Capacity Avoided Cost ($000, 2014)	Energy Avoided Cost ($000, 2014)	T&D Avoided Cost ($000, 2014)	Total Avoided Cost ($000, 2014)	Program Procurement Cost ($000, 2014)	B/C Ratio
Low	$1,144,918	$315,091	$362,826	$1,822,836	$697,037	2.62
Medium	$1,387,232	$365,974	$426,066	$2,179,273	$818,557	2.66
High	$1,660,501	$415,008	$488,443	$2,563,953	$938,449	2.73

(Source: Navigant)

Navigant analyzed several cost categories:

- Under the peak demand reduction scenarios, additional DR enters the wholesale capacity markets, driving down capacity auction clearing prices and reducing total capacity payments.
- Because Massachusetts and Illinois are reducing their peak demand, they will have a smaller percentage of regional peak demand and, consequently, a smaller percentage of capacity market payments.
- The demand reductions directly prevent load-serving entities (LSEs) from having to procure energy during the periods when there is a load reduction. This provides much higher benefits than average load reduction, as the peak demand times often correspond with the highest prices.
- The demand reduction also can reduce energy prices for hours with high price spikes by reducing the marginal generating cost of the system.
- Because Massachusetts is a net importer of electricity, Navigant assumed that peak demand reduction programs would reduce both transmission and distribution (T&D) investment. Because Illinois is a net exporter of electricity, Navigant assumed that peak demand reductions would reduce only distribution costs.
- Compliance with the U.S. Environmental Protection Agency (EPA) Clean Power Plan will cause both Massachusetts and Illinois to incur costs as the power system is changed to reduce carbon emissions. Peak demand reduction provides significant benefits in mitigating this cost.

DR resources are usually less costly to procure upfront than traditional generation resources. For all three scenarios, the benefit/cost ratio is above three (3) for Massachusetts and above two (2) for Illinois, indicating that peak demand reduction resources are a good investment.

Therefore, by passing peak demand reduction mandates into law, or creating peak demand reduction programs, policymakers and utilities in Massachusetts, Illinois, and neighboring states could significantly reduce costs for ratepayers, strengthen reliability, and facilitate compliance with the Clean Power Plan. At a minimum, the states should seek to achieve the MW reduction targets forecasted in the low scenario.

Although this report focuses on state level policy, it should be noted that realization of many of the benefits of state peak demand reduction efforts are predicated on demand response participation in wholesale markets. As such, the paper underscores the importance of continued demand response participation in these markets.

1.3 Peak Demand Reduction Mandate and Program Design to Maximize Benefits

A number of program design characteristics can affect the effectiveness of peak demand reduction programs. These considerations include wholesale market interactions, peak reduction valuation, cost recovery, third-party implementation considerations, and customer engagement. While some design components may be state- or program-specific, some best practices and lessons learned can be applied from past and current industry experience.

One important issue to address in states that reside within a regional transmission organization (RTO) or independent system operator (ISO) territory is how a state peak demand reduction mandate will affect wholesale electricity costs from the RTO/ISO. The largest impact is seen in the capacity market, where the bulk of savings potential exists.

The two main avenues to reduce wholesale capacity charges through peak demand reduction are shifting capacity cost allocation and reducing the installed capacity requirement (ICR). Transmission is another wholesale cost that may be reduced by a peak load reduction. Transmission is typically a much smaller charge than capacity, but in regions with transmission constraints, like New England, it constitutes a growing portion of the overall bill. Similar to capacity, there are two means to reduce transmission charges: direct load reductions and non-transmission alternatives (NTAs).

In addition to the utilities that reside within RTO/ISO territories with capacity markets are many utilities in other RTO/ISO areas (ERCOT, CAISO, and MISO) without mandatory capacity markets, as well as others that are vertically integrated outside of a wholesale market territory. Entities that operate in markets or regions without capacity markets must create non-market-based methods to determine avoided costs and peak reduction payment values for their programs. Such exercises involve estimating avoided energy, capacity and T&D costs, valuing DR program payments, and conducting cost-effectiveness testing on the programs.

Once program costs are determined, states must figure out how to recover them from ratepayers. States and utility territories use various methods to recover costs from DR and peak reduction programs. Some states allow those costs to be rate-based by utilities, but more commonly they use a combination of surcharges, like Systems Benefit Charges, and performance incentives to encourage utilities to meet or exceed goals.

Aside from cost-related metrics, several operational and program design elements affect the success of peak load reduction programs. One important decision is whether a utility should try to implement a program

internally or outsource some, or all, of the implementation to a third party. No answer fits all situations. Rather, the approach will depend on the utility's situation, the type of program, and the availability of qualified vendors.

The final area this report covers is DR and peak reduction in the residential sector, which has historically lagged behind participation in the commercial and industrial (C&I) sectors. The options to increase beyond current penetration levels include tweaks to existing program design, new technologies, expanding the availability of dynamic pricing, and new program models like behavioral DR and "bring your own device/thermostat" programs.

2. Peak Demand Reduction Scenarios

2.1 Introduction

In this study, Navigant has developed three scenarios to evaluate the benefits and costs of reducing peak demand, addressing two key aspects for each scenario: the ratio of benefits to costs and the feasibility of utilities procuring sufficient resources to meet the demand reduction goals of the scenarios. The study focuses on a 10-year outlook. The scenarios for Massachusetts and Illinois, using the ISO forecasted 2015 peak load as the baseline, are:

- Low Scenario: Actual peak demand does not increase over 10 years.
- Medium Scenario: Actual peak demand declines by 0.25% per year over 10 years.
- High Scenario: Actual peak demand declines by 0.5% per year over 10 years.

The purpose of studying all three scenarios is to illustrate the range of benefits and costs for a peak demand reduction policy in Massachusetts and Illinois.

As a baseline for the study, Navigant has used actual peak load (current day and forecast) from public documents provided by ISO-NE for Massachusetts and PJM/MISO for Illinois. "Actual peak load" is defined as the load actually consumed, taking into account existing energy efficiency (EE) and mandated EE programs. This is different from peak load numbers reported by regional transmission organizations/independent system operators (RTOs/ISOs). Those numbers add back demand-side MW that participate as supply resources in wholesale markets to the actual peak load. Using actual peak load results in a more straightforward analysis.

For each scenario, the requirement to reduce load versus the baseline is assumed to be met using either EE resources or active demand response (DR). The incremental impact of the scenario is the peak load reduction versus the baseline assumption of load and is given in MW. EE is assumed to affect load in all peak hours while DR is assumed to be called only when peak load is higher than the scenario requirement. For all scenarios, in either state, making an assumption of the split between how the policy is met between EE and DR is necessary for evaluating the amount that the DR would have to be called to reduce peak load sufficiently.

The feasibility of a scenario is evaluated based on whether it is likely that utilities could procure sufficient EE and DR to meet the requirement and whether DR is not being called upon more than is feasible for these types of programs. A typical peak demand reduction program is structured so that utilities call upon DR when peak demand reaches a set percentage of expected peak load. A similar Consolidated Edison program in New York State reduced peak demand when load reached 96% of expected peak load, providing an example of reductions that are easily feasible. Somewhat deeper reductions are also likely feasible.

2.2 Peak Demand Reduction Scenarios: Massachusetts

The peak demand forecast for Massachusetts given by ISO-NE includes a large amount of EE expected to be part of the market. The impact of this EE is that the average actual load growth in the market is only 0.6%

per year. Given the high amount of EE that is already expected in the market, for the peak demand reduction scenarios, this analysis assumes that all of the incremental demand reduction will be due to DR.

Table 2.1 shows the actual peak load forecast, the mandated peak load in the scenarios, and the incremental impact of the scenarios. For the low case, the program would require that resources be called whenever peak load is above 96% of expected peak load without the program, the middle case is within 93%, and the high case is within 91%.

Table 2.1 Massachusetts Peak Demand Reduction Scenarios: 2015-2025

		Mandated Peak Load by Scenario (MW)			Incremental Impact by Scenario (MW)		
Year	**Actual Peak Load Forecast (MW)**	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
2015	12,287	12,287	12,287	12,287	-	-	-
2016	12,438	12,287	12,256	12,226	151	182	212
2017	12,422	12,287	12,226	12,164	135	196	258
2018	12,507	12,287	12,195	12,104	220	312	403
2019	12,592	12,287	12,165	12,043	305	427	549
2020	12,651	12,287	12,134	11,983	364	517	668
2021	12,709	12,287	12,104	11,923	422	605	786
2022	12,777	12,287	12,074	11,863	490	703	914
2023	12,851	12,287	12,043	11,804	564	808	1,047
2024	12,933	12,287	12,013	11,745	646	920	1,188
2025	13,015	12,287	11,983	11,686	728	1,032	1,329

(Source: Navigant) Note: Actual peak load from CELT report 2015 (isone_fcst_data_2015 tab 12)

According to the Federal Energy Regulatory Commission's (FERC's) report, A National Assessment of Demand Response Potential, Massachusetts has 11.7% achievable potential for active DR participation. Even the high scenario in this study only hit 10.2% participation, so meeting these demand reduction scenarios is feasible from a program participation standpoint. In terms of the number of hours that program participants must be called,

the low case requirements are similar to other peak demand reduction programs (not all participants would need to be called in every hour to reduce demand sufficiently). The high case is possibly too aggressive for utilities to achieve sufficient customer participation without a more complex dispatch strategy.

2.3 Peak Demand Reduction Scenarios: Illinois

The peak demand forecast for Illinois is given by PJM for the Con Edison region and MISO for the rest of the state. There is some EE that is assumed in the forecast, but less than the potential for EE (the assumption is largely consistent with existing programs). Thus, the assumption for this report is that 50% of the incremental peak demand reduction comes from EE and 50% comes from DR.

Table 2.2 gives the forecasted peak load, the mandated peak load, and the incremental impact of the programs.

Table 2.2 Illinois Peak Demand Reduction Scenarios: 2015-2025

		Mandated Peak Load by Scenario (MW)			Incremental Impact by Scenario (MW)		
Year	**Actual Peak Load Forecast (MW)**	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
2015	31,700	31,700	31,700	31,700	-	-	-
2016	32,214	31,700	31,620	31,541	514	593	672
2017	32,563	31,700	31,541	31,383	863	1,021	1,179
2018	33,024	31,700	31,462	31,226	1,325	1,562	1,798
2019	33,158	31,700	31,384	31,070	1,459	1,775	2,088
2020	34,060	31,700	31,305	30,915	2,361	2,755	3,145
2021	34,477	31,700	31,227	30,760	2,778	3,250	3,717
2022	34,905	31,700	31,149	30,607	3,205	3,756	4,298
2023	35,421	31,700	31,071	30,453	3,721	4,350	4,967
2024	35,587	31,700	30,993	30,301	3,888	4,594	5,286
2025	36,563	31,700	30,916	30,150	4,863	5,647	6,413

(Source: Navigant) Note: Peak load from RTEP and MISO report, 1.53%

According to FERC's report, A National Assessment of Demand Response Potential, Illinois has 7.6% achievable potential for active DR participation. This would mean the low and middle scenarios are feasible in terms of potential, but the high scenario may not be feasible. In terms of the number of hours that program participants must be called, the low case would require that DR resources be called whenever peak load reaches 96% of expected peak load, which is very likely feasible. The middle case would require that DR be called when peak load reaches 95% of expected peak load, so this is likely feasible as well.

3. Peak Demand Reduction Scenario Benefits and Avoided Costs

3.1 Summary of Results

For the purposes of this study, Navigant has categorized the benefits of peak demand reduction by direct and indirect benefits.

- Direct benefits can be modeled and the avoided cost to consumers directly calculated. This includes capacity market benefits (direct resource payments, peak load allocation, and price suppression), energy market benefits (avoided costs during peaks and estimated price suppression), transmission and distribution (T&D) deferral benefits, and greenhouse gas (GHG) reduction benefits (avoided allowance costs).
- Indirect benefits largely include aspects of resource planning and reliability that are supported by peak demand reduction, but the impacts and valuations cannot be easily measured. Throughout this report, net present values are calculated using a 10% discount rate.

Table 3.1 shows the direct benefits calculated in Massachusetts for this study, Table 3.2 shows the direct benefits in Illinois, and Table 3.3 describes the indirect benefits discussed in more detail later.

Table 3.1 Massachusetts Direct Demand Reduction Benefits: $2014 NPV

Scenario	Capacity Avoided Cost ($000, 2014)	Energy Avoided Cost ($000, 2014)	T&D Avoided Cost ($000, 2014)	GHG Reductions Avoided Cost ($000, 2014)[4]	Total Avoided Cost ($000, 2014)
Low	$243,538	$40,976	$82,908	$61	$367,422
Medium	$386,397	$58,026	$116,977	$168	$561,400
High	$607,460	$75,476	$150,591	$358	$833,527

(Source: Navigant)

Table 3.2 Illinois Direct Demand Reduction Benefits: $2014 NPV

Scenario	Capacity Avoided Cost ($000, 2014)	Energy Avoided Cost ($000, 2014)	T&D Avoided Cost ($000, 2014)	GHG Reductions Avoided Cost ($000, 2014)[5]	Total Avoided Cost ($000, 2014)
Low	$1,144,918	$315,091	$362,826	$178	$1,822,836
Medium	$1,387,232	$365,974	$426,066	$259	$2,179,273
High	$1,660,501	$415,008	$488,443	$353	$2,563,953

(Source: Navigant)

Table 3.3 Indirect Benefits of Peak Demand Reduction

Description	Magnitude of Benefits
State flexibility to comply with the Clean Power Plan by using demand reduction resources that can be procured with short lead times	Gives states more time to determine best compliance path
Reliability value of reducing reliance on natural gas during winter	Helps defer gas transportation investment and provide alternative resource investment
Value of reducing market uncertainty in energy and fuel markets	Significant increase in market risk premium after polar vortex; peak demand reduction in winter could help mitigate
Changing marginal unit from high emissions to lower emissions	Significantly increases the CO2 emissions benefits of peak demand reduction

(Source: Navigant)

3.2 Summary of Methodology

The benefits of peak demand reduction are estimated using results from Navigant's suite of wholesale energy market modeling and forecasting tools. Semi-annually, Navigant forecasts a Reference Case of wholesale market prices including energy prices, carbon prices, and capacity prices.

For this study, Navigant used the most recent Reference Case as a baseline and then modified the underlying assumptions to incorporate the peak demand reduction scenarios. The benefits of peak reduction are the calculated changes in system cost and forecasted market prices due to changing the underlying assumptions around peak demand.

3.3 Peak Demand Reduction Avoided Costs

In this section, the actual avoided costs for peak demand reduction are estimated and tabulated.

3.3.1 Capacity Avoided Costs

3.3.1.1 Demand Resource Participation in Markets

In order to assure that there are sufficient resources available to meet the projected load, PJM, MISO, and ISO-NE administer capacity markets. Capacity markets allow load-serving entities (LSEs) to purchase commitments from generators and demand resources that will be available to serve or reduce load in future years. LSEs in PJM and ISO-NE procure capacity three years before the delivery year. MISO LSEs procure capacity one year before the delivery year.

Demand resources actively participate in PJM, MISO, and ISO-NE capacity markets. DR must meet market-specific reliability requirements to be eligible for participation. The capacity avoided costs of a peak demand reduction program are realized for consumers by reducing the incremental capacity that must be procured to maintain reliability and also suppressing the prices in the markets for capacity that is procured. An assumption of this analysis is that a sizeable proportion of the resources procured under the peak demand reduction programs will enter the capacity markets.

3.3.1.2 Analysis Methodology

Navigant used its proprietary Capacity Market Forecasting Model (CMFM) to model avoided capacity costs under the Low, Medium, and High peak demand reduction scenarios. Note that this analysis assumes that all peak demand reduction in Massachusetts is met with DR and peak demand reduction in Illinois is met with 50% DR and 50% EE.

Calculation of Incremental DR Resources Participating in Capacity Auctions

Navigant calculated incremental DR participating in relevant capacity auctions as a result of the peak demand reduction scenarios using the below methodology. Incremental capacity participating in relevant capacity auctions for the middle peak demand reduction scenario in the year 2023 is used as an illustrative example.

- Navigant started with state peak demand reduction (Table 3.4, column D).
- For Massachusetts, all incremental real-time DR bids into the ISO-NE capacity market, and for Illinois incremental DR is split approximately 70/30 between the PJM and MISO capacity markets (Table 3.4, column E).
- Navigant subtracted the amount of DR it expects to clear each capacity auction without the peak demand reduction scenarios (Table 3.4, column F) to get incremental DR participating in each capacity auction (Table 3.4, column G).
- Navigant conservatively derated incremental DR participating in capacity auctions by 50% to account for resources that do not meet MISO, PJM, or ISO-NE DR criteria or do not want to participate in the forward capacity markets (Table 3.4, column H).

- Note that Navigant only modeled incremental DR participation in auctions that new DR resources could feasibly bid into (i.e., the auctions have not happened and resources would have time to register). These years, by auction, are listed below:
  - MISO: 2017–2025
  - PJM: 2020–2025
  - ISO-NE: 2020–2025

Table 3.4 Load Reduction Calculations Example (2023, Middle Case)

Year	Stae	ISO	State Peak Demand Reduction (MW)	ISO Peak Demand Reduction (MW)	Cleared DR/ EE (MW)	Peak Demand Reduction, Less Cleared DR	Adjusted Peak Demand Reduction
A	B	C	D	E	F	G	H
2023	MA	ISO-NE	808	808	182	626	313
	IL	PJM	4,350	2,968	1,322	1,646	823
	IL	MISO	4,350	1,382	455	927	464

(Source: Navigant)

The resources that reduce peak demand that do not participate directly in capacity markets can still reduce capacity costs by reducing the installed capacity requirement. An analysis from ISO-NE suggests that for each MW of peak load reduction (separate from capacity resources), the installed capacity requirement can be assumed to fall by 0.3MW. This can be valued at the marginal cost of procuring additional capacity.

Calculation of Avoided Capacity Costs Due to Price Suppression

Once Navigant calculated incremental derated DR participating in capacity markets as a result of the peak demand reduction scenarios, Navigant used the CMFM to calculate avoided capacity costs due to price decreases caused by additional DR bidding into the market. Navigant used the following methodology:

- Navigant ran its CMFM bidding incremental derated DR for the peak demand reduction scenario into the ISO-NE, MISO, and PJM capacity auctions for relevant delivery years.
- Navigant calculated ISO-wide annual capacity costs for the peak demand reduction scenarios (Table 3.5, column E). Annual capacity costs are calculated as follows: ISO Annual Capacity Cost = ISO Clearing Prices (MW-Day) x ISO Cleared MW x 365.

- Navigant derived state-level annual capacity costs as follows:
  - Massachusetts Annual Capacity Costs = ISO-NE Annual Capacity Costs x Massachusetts' share of ISO-NE peak load
  - Illinois Capacity Costs = (PJM Annual Capacity Costs x COMED Share of PJM Peak Load) + (MISO Annual Capacity Costs x LRZ4 Share of MISO Peak Load) (Table 3.5, column F)
- Navigant compared Massachusetts and Illinois total capacity costs in the Middle scenario (Table 3.5, column G) to Massachusetts and Illinois capacity costs in Navigant's Base case scenario (Table 3.5, column F) to obtain avoided capacity costs for the Middle scenario (Table 3.5, column I).
- Navigant calculated the net present value (NPV) of price suppression over the study period using a 10% discount rate for each of the Low, Medium, and High scenarios.

Table 3.5 Avoided Capacity Costs due to Price Suppression Example (2023, Middle Case)

Year	Stae	ISO	ISO Area	Base Case ISO Total Cost ($000)	Base Case ISO Area Total Cost ($000)	Medium Case ISO Total Cost ($000)	Medium Case ISO Area Total Cost ($000)	Price Suppression Avoided Cost ($000)
A	B	C	D	E	F	G	H	I
2023	MA	ISO-NE	MA	$4,501,064	$1,814,445	$3,885,752	$1,566,403	$248,041
	IL	PJM	COMED	$22,071,744	$3,239,211	$19,712,601	$2,892,987	$346,224
	IL	MISO	LRZ4	$10,520,943	$942,573	$10,041,270	$899,599	$42,974

(Source: Navigant)

Calculation of Avoided Capacity Costs Due to Peak Demand Allocation

Capacity costs are allocated based on a capacity zone's share of ISO coincident peak load over some historical years. In ISO-NE, the averaging is done over the previous two years. Because Massachusetts and Illinois are reducing their peak load, they will have a smaller percentage of ISO peak load and consequently, a smaller percentage of capacity market payments. Navigant calculated avoided capacity payments due to changes in peak demand allocation using the following methodology:

- Navigant calculated Base Case ISO Annual Capacity Market costs using the methodology described above.
- Navigant calculated each ISO subregion's share of ISO peak demand in the Base scenario (Table 3.6, column F).
- Navigant multiplied annual capacity costs by each ISO subregion's share of ISO total peak demand over the previous two years to arrive at ISO subregion annual capacity costs for the base case (Table 3.6, column G).

- Navigant calculated each subregion's share of ISO total peak demand in the peak demand reduction scenarios by taking peak demand reductions out of both the ISO and ISO subregion peaks (Table 3.6, column H).
- Navigant multiplied total ISO annual capacity costs by each subregion's share of ISO peak demand under peak demand reduction scenarios to arrive at peak demand reduction scenario annual capacity costs (Table 3.6, column I).
- Navigant subtracted peak demand reduction scenario annual capacity costs from base case annual capacity costs to arrive at peak demand shifting cost savings (Table 3.6, Column J).
- Navigant calculated the NPV of peak demand shifting over the study period using a 10% discount rate for each of the Low, Medium, and High scenarios.

Table 3.6 Avoided Capacity Costs due to Peak Demand Shifting (2023, Middle Case)

Year	State	ISO	ISO Area	Base Case ISO Total Cost ($000)	Base Case ISO Area % of Peak Load	Base Case ISO Area Cost ($000)	Medium Case ISO Area % of Peak Load	Peak Demand Shifting Savings ($000)	Peak Demand Shifting Savings ($000)
A	B	C	D	E	F	G	H	I	I
2023	MA	ISO-NE	MA	$3,642,804	40.9%	$1,490,026	39.6%	$1,443,872	$46,154
	IL	PJM	COMED	$19,526,855	14.5%	$2,834,510	13.3%	$2,590,132	$244,377
	IL	MISO	LRZ4	$5,091,658	8.6%	$436,675	7.8%	$396,639	$40,036

(Source: Navigant)

Results and Discussion

Under the peak demand reduction scenarios, additional DR enters the capacity markets driving down capacity auction clearing prices and reducing total capacity payments. Table 3.7 and Table 3.8 give avoided capacity costs due to price suppression and avoided capacity costs due to peak demand reductions for Massachusetts and Illinois, respectively. For Massachusetts, price suppression NPV is between $122 MM and $378 MM over the study period. For Illinois, price suppression NPV is between $400 MM and $646 MM over the study period.

State capacity payments are based on that state's share of ISO total load. Because Massachusetts and Illinois are reducing their peak demand, they will have a smaller percentage of ISO peak demand and consequently, a smaller percentage of capacity market payments. For Massachusetts, peak demand shifting NPV is between $105 MM and $193 MM. For Illinois, peak demand shifting NPV is between $723 MM and $980 MM.

The value of reducing the overall installed capacity requirements in these markets is smaller but still significant. In Massachusetts, the NPV of this value is between $16 MM and $36 MM while in Illinois it is between $20 MM and $33 MM.

As discussed in the methodology section (3.1.2.1), avoided capacity costs for Illinois are a sum of the avoided capacity costs in PJM's ComEd zone and MISO's LRZ4. During MISO's 2015/2016 capacity auction, LRZ4 cleared at $150.00 per MW-day, substantially higher than the rest of MISO ($3.29–$3.48 per MW-day). MISO has stated that LRZ4's high clearing prices are not indicative of supply shortages in the region, but rather, due to participant bidding behavior and the fact that more capacity was procured through the auction rather than by direct contracts compared to previous years. Because there are no supply shortages, Navigant is operating under the assumption that LRZ4 prices will fall back in line with the rest of MISO in future years.

Table 3.7 Massachusetts Avoided Capacity Costs: 2016-2025

	Low Case			Middle Case			High Case		
Year	**Price Suppression Value ($000)**	**Incremental FCM MW ($000)**	**Clearing Price ($/MW-Day)**	**Price Suppression Value ($000)**	**Incremental FCM MW ($000)**	**Clearing Price ($/MW-Day)**	**Price Suppression Value ($000)**	**Incremental FCM MW ($000)**	**Clearing Price ($/MW-Day)**
2016	-	-	105	-	-	105	-	-	105
2017	-	4,473	231	-	5,397	231	-	6,293	231
2018	-	11,084	311	-	14,670	311	-	18,269	311
2019	-	10,316	226	-	14,802	226	-	19,312	226
2020	-	17,198	254	-	24,297	254	31,677	31,415	248
2021	-	22,229	256	14,175	31,510	252	61,162	40,810	243
2022	84,780	25,315	229	137,775	36,339	219	196,719	47,352	208
2023	59,037	31,972	256	76,915	46,154	252	140,504	60,376	240
2024	-	35,544	255	-	51,337	255	43,881	67,119	245
2025	132,181	51,905	303	248,041	74,749	281	359,442	97,483	260
NPV	**122,008**	**105,288**	**NPV**	**210,214**	**149,235**	**NPV**	**377,878**	**193,173**	**NPV**

(Source: Navigant)

Table 3.8 Illinois Avoided Capacity Costs: 2016-2025

	Low Case			Middle Case			High Case		
Year	Clearing Price ($/ MW-Day)	Price Suppress-ion Value ($000)	Capacity Cost Reallocat-ion ($000)	Clearing Price ($/ MW-Day)	Price Sup-press-ion Value ($000)	Capacity Cost Reallocat-ion ($000)	Clearing Price ($/ MW-Day)	Price Suppress-ion Value ($000)	Capacity Cost Reallocat-ion ($000)
2016	NA	-	-	-	NA	-	-	-	NA
2017	NA	-	-	7,941	NA	-	-	9,164	NA
2018	NA	-	-	23,447	NA	-	-	27,497	NA
2019	NA	-	-	62,362	NA	-	161	73,683	NA
2020	NA	50,679	1,649	96,475	NA	82,490	2,783	115,763	NA
2021	NA	40,421	3,618	156,450	NA	53,609	4,918	185,819	NA
2022	NA	226,462	5,348	216,509	NA	243,118	7,325	253,435	NA
2023	NA	78,253	7,882	242,394	NA	84,392	10,159	284,413	NA
2024	NA	143,563	9,717	322,630	NA	264,803	11,782	378,467	NA
2025	NA	344,031	18,480	383,004	NA	389,198	22,285	451,311	NA
NPV		**400,524**	**20,733**	**723,661**		**507,963**	**26,701**	**852,569**	

(Source: Navigant)

3.3.2 Energy Avoided Costs

Two main mechanisms for peak demand reduction help consumers avoid energy costs:

- The demand reduction directly allows LSEs to avoid having to procure energy during the periods when there is a load reduction. This provides much higher benefits than average load reduction, as the peak demand times often correspond with the highest prices.
- The demand reduction also can reduce energy prices in high prices hours by reducing the marginal generating cost of the system.

For this analysis, the direct benefits of reducing load during the highest load periods is calculated by determining the hours in which there would be a load reduction due to the scenarios, determining the amount that load

would have to be reduced to meet the peak load reduction requirements, and multiplying this amount by Navigant's Reference case forecast of hourly energy prices. For demand reduction, this usually occurs over a relatively small number of hours, so the overall value of this direct value is material but relatively small.

Table 3.9 gives the direct avoided cost from the energy market for the demand reduction scenarios. The table gives the average on-peak energy price, the energy price during turndowns, the avoided GWh of generation due to the scenario, and the total value of the turndown. As can be seen, the total avoided energy consumption is relatively low in Massachusetts, as the reduction is due to DR in a limited number of hours. The NPV is between $1.2 MM and $5.5 MM over the analysis period.

Less easy to calculate, but having more impact on the total benefits of demand reduction in the energy market, is the ability of the demand reduction to reduce the overall marginal cost of generation in the system during high stress hours. An example of this occurred in PJM on July 15, 2013. Calling 900 MW of DR resources reduced locational marginal price (LMP) from $375/MWh to $75/MWh. Assuming that PJM load during this time was 160,000 MW, this had a total reduction of PJM customer costs of $48 MM for a single hour reduction. This is an extreme case for estimating the price suppression benefits of DR, but there are other studies and data points that can be used to estimate more typical price suppression impacts.

The report Quantifying Demand Response Benefits in PJM showed that reducing peak load by 0.9% had an impact of $8/MWh–$25/MWh in PJM. This was done over the top 100 hours, so the higher estimate is more reasonable for the lower number of hours assumed in this study. Prorating this to peak load in Massachusetts results in an estimated reduction of $0.10/MWh for every MW of DR. In ISO-NE on June 24, 2010, calling 670 MW of DR dropped LMPs $180/MWh, which is $0.28/MWh for every MW of called DR. For further discussion of the value of DR to customers by reducing extreme prices, FERC reported to congress in 2006 that "not all customers need to respond simultaneously for markets to benefit by lowered overall prices." The report also provided an estimated reduction from DR of $0.04 – $1.43/MWh for every MW of DR The report provides further evidence from NYISO that DR programs can reduce prices from emergency levels (~$1,000/MWh) to normal levels.

To estimate the benefits of calling DR in Massachusetts and Illinois for this study, assume:

- The benefit per MW of DR being called is assumed to be $0.15/MW, which is between the two studies.
- Assume that the time periods where the peak demand reduction overlaps with particularly high LMPs occur 10 hours per year.
- The benefit of price suppression is calculated as the LMP impact per MW X the number of MW DR * 10 * State Load.

The results of this estimate are shown in Table 3.9, Table 3.10, Table 3.11, and Table 3.12.

Table 3.9 Massachusetts Direct Energy Avoided Costs: 2016-2025

			Avoided GWh			Value ($000)		
Year	On-Peak LMPs ($, 2014/MWh)	Weighted Avg LMP during Low Case Turndown ($, 2014)	Low	Middle	High	Low	Middle	High
2016	$50.73	$176.24	0	1	1	$78	$102	$127
2017	$51.28	$189.68	0	1	1	$68	$113	$164
2018	$48.69	$228.95	1	1	2	$157	$249	$340
2019	$47.19	$96.85	1	2	3	$104	$164	$284
2020	$46.50	$119.00	1	3	6	$166	$296	$575
2021	$50.68	$119.87	2	4	10	$206	$441	$931
2022	$53.64	$91.58	2	7	15	$210	$587	$1,290
2023	$53.22	$112.28	3	10	23	$369	$971	$1,997
2024	$53.36	$92.16	5	13	30	$417	$1,155	$2,465
2025	$54.28	$96.09	7	20	41	$647	$1,746	$3,410
					NPV	**$1,242**	**$2,835**	**$5,536**

(Source: Navigant)

Table 3.10 Massachusetts Benefits of Calling DR: 2016-2025

		Price Suppression Level ($/MWh)			Price Suppression Value ($000)		
Year	**Price Suppression per MW ($/MWh)**	**Low**	**Middle**	**High**	**Low**	**Middle**	**High**
2016	$0.15	$22.65	$27.26	$31.87	$2,783	$3,341	$3,896
2017	0.15	20.25	29.45	38.63	2,488	3,601	4,700
2018	0.15	33.00	46.79	60.51	4,055	5,706	7,324
2019	0.15	45.75	64.11	82.34	5,621	7,799	9,916
2020	0.15	54.60	77.52	100.22	6,709	9,407	12,009
2021	0.15	63.30	90.77	117.90	7,778	10,987	14,058
2022	0.15	73.50	105.51	137.05	9,031	12,739	16,258
2023	0.15	84.60	121.14	157.04	10,395	14,589	18,538
2024	0.15	96.90	137.96	178.20	11,906	16,573	20,929
2025	$ 0.15	$109.20	$154.76	$199.31	13,417	18,545	23,292
				NPV	**$39,734**	**$55,191**	**$69,939**

(Source: Navigant)

Table 3.11 Illinois Direct Energy Avoided Costs: 2016-2025

			Avoided GWh			Value ($000)		
Year	On-Peak LMPs ($, 2014/MWh)	Weighted Avg LMP during Low Case Turndown ($, 2014)	Low	Middle	High	Low	Middle	High
2016	$37.62	$69.74	0	0	0	21	25	29
2017	$39.40	$69.20	1	1	1	43	54	66
2018	$39.51	$74.51	1	1	1	60	74	91
2019	$39.44	$94.30	1	2	3	131	188	264
2020	$42.80	$87.39	5	7	9	419	580	769
2021	$48.97	$91.56	6	9	12	545	803	1,100
2022	$54.22	$102.19	9	13	18	914	1,371	1,877
2023	$54.59	$104.48	11	16	22	1,113	1,634	2,235
2024	$55.80	$116.75	14	22	31	1,656	2,484	3,492
2025	$56.65	$107.57	23	32	41	2,465	3,375	4,375
					NPV	**3,398**	**4,886**	**6,602**

(Source: Navigant)

Table 3.12 Illinois Benefits of Calling DR: 2016-2025

		Price Suppression Level ($/MWh)			Price Suppression Value ($000)		
Year	**Price Suppression per MW ($/MWh)**	**Low**	**Middle**	**High**	**Low**	**Middle**	**High**
2016	$0.15	$38.55	$44.49	$50.44	$12,220	$14,104	$15,988
2017	0.15	64.74	76.61	88.46	20,522	24,225	27,900
2018	0.15	99.37	117.15	134.85	31,499	36,952	42,321
2019	0.15	109.41	133.10	156.60	34,682	41,875	48,902
2020	0.15	177.05	206.62	235.89	56,122	64,843	73,292
2021	0.15	208.31	243.75	278.75	66,034	76,307	86,176
2022	0.15	240.38	281.68	322.36	76,200	87,959	99,158
2023	0.15	279.09	326.23	372.54	88,470	101,616	114,022
2024	0.15	291.56	344.52	396.43	92,424	107,047	120,728
2025	$ 0.15	$364.73	$423.50	$480.97	115,618	131,258	145,739
				NPV	**$311,693**	**$361,088**	**$408,406**

(Source: Navigant)

3.3.3 T&D Deferral

For the purposes of this study, Navigant defined T&D deferral as the future T&D infrastructure expenditures that can be avoided if future load growth can be reduced with DR programs. Because Massachusetts is a net importer of electricity, Navigant assumed that peak demand reduction programs would reduce both transmission and distribution investment. Because Illinois is a net exporter of electricity, Navigant assumed that that peak demand reductions would reduce only distribution costs. Deferred costs were calculated using the following methodology:

- Navigant based avoided T&D investment per unit of peak demand reduction on a study entitled Demand Response Potential Pennsylvania.
- Navigant averaged reported T&D costs in the study weighted by utility peak-load to arrive at avoided T&D costs by MW-year of peak load reduction.

Table 3.13 Navigant Load Weighted Average T&D Avoided Costs

Avoided Cost Type	$/MW-Year
Load-Weighted Average Avoided Transmission Costs $/kW-Year	$10,783
Load-Weighted Average Avoided Distribution Costs $/kW-Year	$27,674

(Sources: Navigant, data from Pennsylvania Statewide Evaluation Team)

- For each year of the study period, Navigant multiplied load-weighted avoided T&D costs per MW-year by the MW of peak demand reduction.
- Navigant calculated the NPV of the value of T&D investment deferral using a 10% discount rate for each of the Low, Medium, and High scenarios.

3.3.3.1 Results and Discussion

As peak demand increases, utilities must invest in T&D infrastructure upgrades to accommodate the additional demand. Some of this investment can be avoided through programs designed to reduce peak load. As mentioned above, Navigant assumes that since Massachusetts is a net importer of electricity, peak demand reduction programs reduce both transmission and distribution investment. Because Illinois is a net exporter of electricity, Navigant assumes that that peak demand reductions only reduce distribution costs.

Table 3.14 gives the direct avoided T&D investment for the peak demand reduction scenarios in Massachusetts. The table shows the avoided T&D costs per MW-year of peak demand reduction. These costs were multiplied by the MW Massachusetts peak demand reduction under the Low, Middle, and High scenarios to arrive annual Massachusetts annual deferred T&D investment. The NPV for T&D deferral in Massachusetts is between $82 MM and $150 MM over the analysis period.

Table 3.14 Massachusetts Avoided Transmission & Distribution Investment: 2016-2025

			Annual Avoided Transmission Investment Costs ($000)			Annual Avoided Distribution Investment Costs ($000)		
Year	Avoided Transmis-sion Costs $/MW-Year	Avoided Distribution Costs $/MW-Year	Low	Middle	High	Low	Middle	High
2016	$10,783	$27,674	$1,628	$1,963	$2,286	$4,179	$5,037	$5,867
2017	$10,783	$27,674	$1,456	$2,114	$2,782	$3,736	$5,424	$7,140
2018	$10,783	$27,674	$2,372	$3,364	$4,346	$6,088	$8,634	$11,152
2019	$10,783	$27,674	$3,289	$4,605	$5,920	$8,440	$11,817	$15,193
2020	$10,783	$27,674	$3,925	$5,575	$7,203	$10,073	$14,307	$18,486
2021	$10,783	$27,674	$4,551	$6,524	$8,476	$11,678	$16,742	$21,751
2022	$10,783	$27,674	$5,284	$7,581	$9,856	$13,560	$19,454	$25,294
2023	$10,783	$27,674	$6,082	$8,713	$11,290	$15,608	$22,360	$28,974
2024	$10,783	$27,674	$6,966	$9,921	$12,811	$17,877	$25,460	$32,876
2025	$10,783	$27,674	$7,850	$11,128	$14,331	$20,146	$28,559	$36,778
		NPV	**$23,248**	**$32,800**	**$42,226**	**$59,661**	**$84,176**	**$108,365**

(Source: Navigant)

Table 3.15 gives the direct avoided distribution investment for the peak demand reduction scenarios in Illinois. The NPV for T&D deferral in Illinois is between $362 MM and $488 MM over the analysis period.

Table 3.15 Illinois Avoided Distribution Investment: 2016-2025

			Annual Avoided Distribution Investment Costs ($000)		
Year	Avoided Transmission Costs $/MW-Year	Avoided Distribution Costs $/MW-Year	Low	Middle	High
2016	$0	$27,674	$14,224	$16,410	$18,597
2017	$0	$27,674	$23,882	$28,255	$32,627
2018	$0	$27,674	$36,667	$43,226	$49,757
2019	$0	$27,674	$40,376	$49,121	$57,782
2020	$0	$27,674	$65,337	$76,241	$87,033
2021	$0	$27,674	$76,877	$89,939	$102,862
2022	$0	$27,674	$88,694	$103,942	$118,941
2023	$0	$27,674	$102,973	$120,380	$137,454
2024	$0	$27,674	$107,595	$127,132	$146,282
2025	$0	$27,674	$134,576	$156,272	$177,470
		NPV	**$362,826**	**$426,066**	**$488,443**

(Source: Navigant)

3.4 Peak Demand Reduction Benefits

3.4.1 Clean Power Plan Compliance

Since the U.S. Environmental Protection Agency (EPA) released the final version of the Clean Power Plan on August 3, 2015, both Massachusetts and Illinois will have to determine how to comply. The policy includes two main components: emissions standards by state and implementation options for states.

The emissions standards for each state were developed using three building blocks: coal plant heat rate improvements, natural gas generation, and zero carbon generation. EE, including DR, is stated as a compliance option as well.

However, the policy is not prescriptive about how each state should comply and explicitly encourages states to coordinate regional compliance mechanisms. Massachusetts is part of the Regional Greenhouse Gas Initiative (RGGI) cap-and-trade program and is likely to use an expansion of RGGI for compliance. Illinois is currently considering options, but is also relatively likely to join RGGI for compliance. It may, however, also determine a state compliance plan that would be more top-down than a cap-and-trade programs.

Figure 3.1 Clean Power Plan Diagram: EPA's Proposal Has Two Parts

Clean Power Plan			
Emission standards by state		Direction on state implementation plans	
Three building blocks	Used 2012 data	Collaboration allowed	Structural flexibility

No matter the mechanism, compliance with the Clean Power Plan will cause both Massachusetts and Illinois to incur costs as the power system is changed to reduce carbon emissions. Peak demand reduction provides significant benefits in mitigating this cost. Especially in a cap-and-trade program, any incremental reduction in emissions has a market value at the allowance price.

The benefits of peak demand reduction for complying with the Clean Power Plan can be split into direct and indirect values. The direct value can be calculated using the estimated allowance cost under the policy and is limited to the number of hours in which load is being curtailed. The indirect value of peak demand reduction is due to the support that the demand-side resources can give to states in adapting the system to lower carbon emissions. A further indirect benefit is that the peak demand reduction can change the marginal generating unit from a less efficient, higher emissions unit to a more efficient, lower emissions unit.

The direct values for Massachusetts are calculated in Table 3.16. The GHG price prior to 2022 is the forecasted RGGI allowance price while GHG prices after that are the forecasted allowances prices under the Clean Power Plan. Note that since allowance costs can be bid into the energy market, the direct GHG reduction avoided costs are a component of the energy avoided costs and should not be double counted. Direct values for Illinois are given in Table 3.17. Values are zero prior to 2022, as Illinois is not a participant in RGGI.

Table 3.16 Massachusetts Direct Emissions Reduction Values: 2016-2025

		GHG Reductions (tons)			GHG Reduction Value ($000)		
Year	GHG Price ($2014/ton)	Low	Middle	High	Low	Middle	High
2016	$7.10	238	316	399	$2	$2	$3
2017	$7.88	193	333	497	$2	$3	$4
2018	$7.88	368	614	859	$3	$5	$7
2019	$7.88	574	917	1,728	$5	$7	$14
2020	$2.76	749	1,479	3,311	$2	$4	$9
2021	$7.37	918	2,300	5,544	$7	$17	$41
2022	$11.97	1,228	3,643	8,289	$15	$44	$99
2023	$11.97	1,758	5,444	12,118	$21	$65	$145
2024	$11.97	2,425	7,213	16,110	$29	$86	$193
2025	$12.89	3,606	10,753	21,896	$46	$139	$282
				NPV	**$61**	**$168**	**$358**

(Source: Navigant)

Table 3.17 Illinois Direct Emissions Reduction Values: 2016-2025

		GHG Reductions (tons)			GHG Reduction Value ($000)		
Year	GHG Price ($2014/ton)	Low	Middle	High	Low	Middle	High
2016	$0.00	160	192	224	$0	$0	$0
2017	$0.00	336	421	514	$0	$0	$0
2018	$0.00	429	533	660	$0	$0	$0
2019	$0.00	745	1,114	1,617	$0	$0	$0
2020	$0.00	2,568	3,572	4,739	$0	$0	$0
2021	$0.00	3,186	4,658	6,356	$0	$0	$0
2022	$11.97	4,789	7,189	9,867	$57	$86	$118
2023	$11.97	5,705	8,445	11,628	$68	$101	$139
2024	$11.97	7,595	11,529	16,378	$91	$138	$196
2025	$12.89	12,271	16,897	22,032	$158	$218	$284
				NPV	**$178**	**$259**	**$353**

(Source: Navigant)

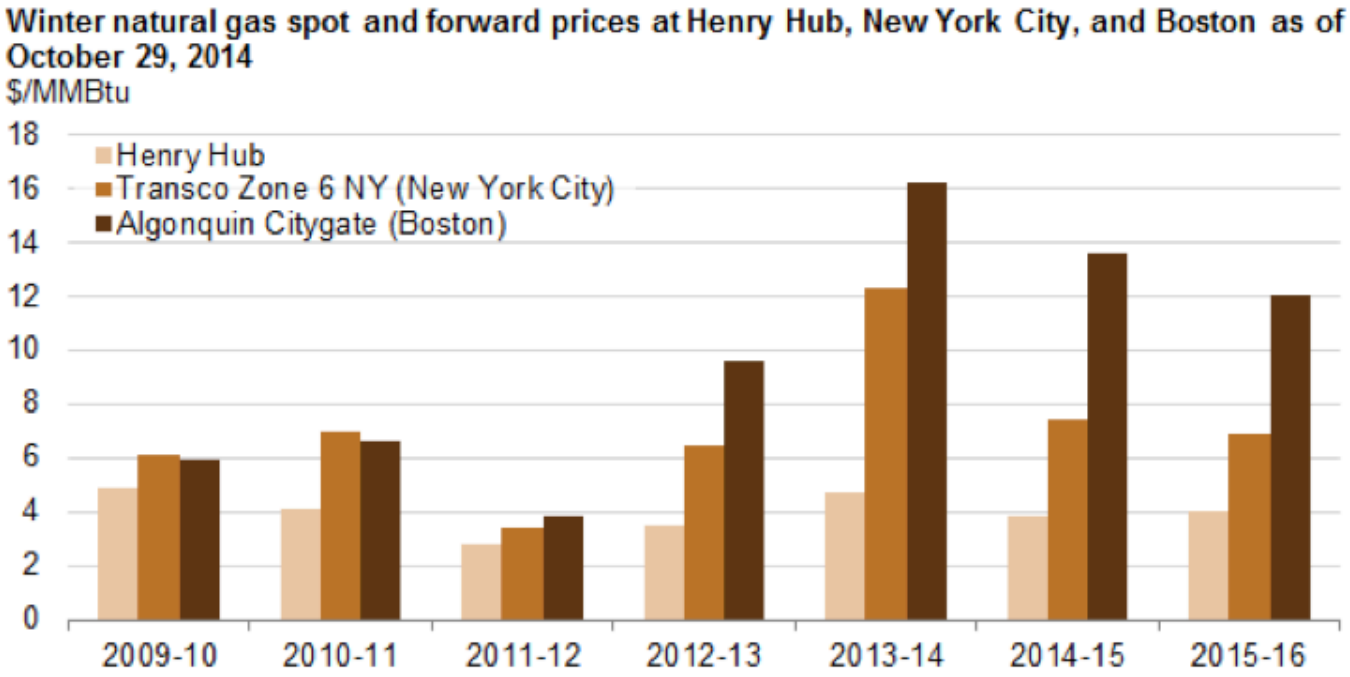
Probably more importantly, peak demand reduction will increase the flexibility of the system to adapt to the mandated emissions reductions. The Clean Power Plan starts mandating reductions in 2022. The ability to procure demand-side resources quickly is a large benefit for the early year mandates, and it is significantly easier to comply with GHG reductions if the system is not also forced to increase generating capacity at the same time.

Navigant completed a study in 2014 showing that DR could be used to reduce GHG emissions significantly and should be considered an important part of state compliance plans. The key takeaway for the value of a demand reduction mandate is that compliance with the Clean Power Plan is likely to put stress on the system and resources such as DR that can be procured quickly and flexibly will support compliance and materially mitigate overall cost to consumers.

3.4.2 Winter Demand Response

New England in particular has significant gas supply and reliability issues in the winter months that peak demand reduction could mitigate if load were reduced during peak hours in those months. As can be seen in Figure 3.2, pipeline constraints have led to extremely high gas prices in Massachusetts during winter months. This causes power prices to spike.

Figure 3.2 New England Winter Gas Prices



(Source: U.S. Energy Information Administration)

Since Massachusetts has recently had most of its coal capacity and some of its nuclear capacity retire, the region has increasing reliance on gas supply. If the peak demand reduction resources supported demand reduction in the winter, consumers in the state would receive several benefits:

- **Increased diversity of sources to ensure that supply and demand are balanced**: The pipeline constraints and reliance on gas increase the value of this diversity.
- **Reduced severity of power price spikes, even if the gas prices spike**: Some of the power price spikes are the result of oil-fired generation being required, an option that has very high operating costs.

A significant but difficult to quantify benefit of winter peak demand reduction is that it could mitigate the risk premium charged by suppliers. For instance, the price spike during the polar vortex increased the risk premium in fixed price contracts that were signed after the polar vortex. This can raise overall costs of procuring power in the market for multiple years, as evidenced by the recent increases in rates for default service customers in Massachusetts. If peak demand reduction reduces the frequency and severity of these types of events, risk premiums and prices can be reduced. In Illinois, there are fewer concerns about winter gas supply, so the value of winter DR is likely to be muted.

4. Peak Demand Reduction Scenario Cost-Effectiveness

4.1 Resource Procurement Program Costs

DR resources are usually less costly upfront to procure than traditional generation resources. Seizing on data from programs across the country, the Demand Response Potential Study completed for the Pennsylvania Public Utility Commission (PUC) estimated procurement costs for DR resources for a similar peak load reduction program to be an average of $52,310/MW. To estimate the costs of procuring EE for the Illinois mandate, the Maryland EmPOWER study estimated a one-time cost of $331,955 to procure a MW of EE, which is levelized to $54,024 for the purposes of this study. Using these as assumed costs, Table 4.1 shows the estimated program costs for the Massachusetts peak demand reduction scenarios and Table 4.2 shows the estimated programs costs for Illinois.

Table 4.1 Massachusetts Resource Procurement Costs: 2016-2025

		Capacity Procured (MW)			Total Procurement Cost ($000, 2014)		
Year	Procurement Cost ($, 2014/MW)	Low	Middle	High	Low	Middle	High
2016	$52,310	151	182	212	$7,899	$9,506	$11,112
2017	$52,310	135	196	258	$7,062	$10,271	$13,473
2018	$52,310	220	312	403	$11,508	$16,317	$21,101
2019	$52,310	305	427	549	$15,955	$22,358	$28,713
2020	$52,310	364	517	668	$19,041	$27,035	$34,949
2021	$52,310	422	605	786	$22,075	$31,656	$41,117
2022	$52,310	490	703	914	$25,632	$36,796	$47,793
2023	$52,310	564	808	1,047	$29,503	$42,246	$54,767
2024	$52,310	646	920	1,188	$33,792	$48,110	$62,143
2025	$52,310	728	1,032	1,329	$38,082	$53,970	$69,505
				NPV	**$112,774**	**$159,117**	**$204,839**

(Source: Navigant)

Table 4.2 Illinois Resource Procurement Costs: 2016-2025

		Capacity Procured (MW)			Total Procurement Cost ($000, 2014)		
Year	Procurement Cost ($, 2014/MW)	Low	Middle	High	Low	Middle	High
2016	$53,167	514	593	672	$27,328	$31,541	$35,755
2017	$53,167	863	1,021	1,179	$45,894	$54,310	$62,705
2018	$53,167	1,325	1,562	1,798	$70,441	$83,050	$95,595
2019	$53,167	1,459	1,775	2,088	$77,560	$94,351	$111,015
2020	$53,167	2,361	2,755	3,145	$125,506	$146,468	$167,221
2021	$53,167	2,778	3,250	3,717	$147,671	$172,794	$197,605
2022	$53,167	3,205	3,756	4,298	$170,406	$199,679	$228,516
2023	$53,167	3,721	4,350	4,967	$197,845	$231,259	$264,092
2024	$53,167	3,888	4,594	5,286	$206,687	$244,230	$281,029
2025	$53,167	4,863	5,647	6,413	$258,556	$300,220	$340,954
				NPV	**$697,037**	**$818,557**	**$938,449**

(Source: Navigant)

4.2 Cost Benefit Analysis

The benefit/cost ratio is shown in Table 4.3 for Massachusetts and Table 4.4 for Illinois. For all three scenarios, the B/C ratio is above three for Massachusetts and above two for Illinois, suggesting that peak demand reduction resources are a good investment.

Table 4.3 Massachusetts Benefit/Cost Analysis: 2014

Scenario	Capacity Avoided Cost ($000, 2014)	Energy Avoided Cost ($000, 2014	T&D Avoided Cost ($000, 2014)	Total Avoided Cost ($000, 2014)	Program Procurement Costs ($000, 2014)	B/C Ratio
Low	$243,538	$40,976	$82,908	$367,422	$112,774	3.26
Middle	$386,397	$58,026	$116,977	$561,400	$159,117	3.53
High	$607,460	$75,476	$150,591	$833,527	$204,839	4.07

(Source: Navigant)

Table 4.4 Illinois Benefit/Cost Analysis

Scenario	Capacity Avoided Cost ($000, 2014)	Energy Avoided Cost ($000, 2014	T&D Avoided Cost ($000, 2014)	Total Avoided Cost ($000, 2014)	Program Procurement Costs ($000, 2014)	B/C Ratio
Low	$1,144,918	$315,091	$362,826	$1,822,836	$697,037	2.62
Middle	$1,387,232	$365,974	$426,066	$2,179,273	$818,557	2.66
High	$1,660,501	$415,008	$488,443	$2,563,953	$938,449	2.73

(Source: Navigant)

5. Designing Peak Demand Reduction Mandates and Programs to Maximize Benefits

5.1 Introduction

A number of program design characteristics can affect the effectiveness of peak demand reduction programs, including: wholesale market interactions, peak reduction valuation, cost recovery, third-party implementation considerations, and customer engagement. Some design components may be state- or program-specific, but some best practices and lessons learned can be applied from past and current industry experience.

5.2 How Capacity Markets Work

One important issue to address in states that reside within a RTO or ISO territory is how a state peak demand reduction mandate will affect wholesale electricity costs in the RTO/ISO. The largest impact is seen in the capacity market, where the bulk of savings potential exists. The two main avenues to reduce wholesale capacity charges through peak demand reduction are shifting capacity cost allocation and reducing the installed capacity requirement (ICR), as described below. Wholesale transmission charges may also be reducible through demand reduction strategies, but generally have a lesser economic effect.

5.2.1 Capacity Cost Allocation

Each year, RTOs/ISOs with mandatory capacity markets (PJM, ISO-NE, and NYISO) procure enough capacity to meet the expected peak demand plus a reserve margin. The supply resources receive a fixed capacity payment, similar to an insurance policy premium, and agree to be available when the system needs the extra capacity. These capacity costs are recovered from LSEs such as utilities and competitive retail electricity suppliers and based on their customers' share of the system peak load. These costs are passed through to customers in the supply/generation portion of their bills. Typically, the peak load from one year will be used to allocate capacity costs for the next year, creating a one-year lag.

Capacity costs for larger commercial and industrial (C&I) customers are based on their actual load during peak hours, since they have interval meters that are capable of recording such granular data. Capacity costs for residential and small commercial customers are allocated across the sectors based on average load shapes, because historically there was no way to measure each individual customer's load based on the basic metering technology. With the addition of advanced metering infrastructure (AMI) in certain utility territories, such measurement is technically feasible now, but the RTOs/ISOs have not yet incorporated it into the capacity cost allocation methodology. That situation may change in the future as they learn how to deal with the data and utilities and as states roll out new rate and pricing structures for residential and small commercial customers that take advantage of the more granular data.

Each RTO/ISO has a different methodology for allocating these costs to LSEs, but every model has potential for an LSE to reduce its capacity costs by strategically reducing its customers' load during system peak hours. In general, peak demand reductions in one year will result in capacity savings the next year, rather than

immediately. Note, however, that the overall pie of system capacity costs does not decrease, since the RTO/ISO has already paid for it. It merely shifts these costs to other LSEs that may not have reduced their loads during the peak times. In theory, if every LSE reduced its peak load, all participants would still have the same capacity charge as before, since it could not be shifted elsewhere. (The long-term effects of lowering peak load are discussed in Section 5.2.2.)

Many large C&I customers have their own in-house expertise to forecast and estimate when the peak hours will occur. Others use services from competitive suppliers or third-party vendors that recommend when customers should reduce load during peak hours. Utilities have extensive forecasting capabilities and should be able to estimate peak hours with high accuracy. If a utility ran its own peak demand reduction program, it could notify or dispatch its customers a day ahead or on several hours' notice.

All of the RTOs/ISOs with capacity markets are summer-peaking systems, so the peaks occur sometime between June and September, typically in July or August. To estimate the peaks, they look at whether the summer seasonal weather is forecast to be generally warm or cool. It may be prudent to call for peak load reductions on a hot day in June just in case the rest of the season is cool and the risk exists that an early peak gets missed. In July and August, heat waves can be tracked to see when extreme loads might be hit. By the time September rolls around, it is generally clear whether an obvious peak has been hit or there is still a chance for a new one.

5.2.1.1 ISO-NE

ISO-NE has a fairly simple method for allocating capacity costs. First, it takes each capacity zone's share of the system load at the single coincident peak (CP) hour two years prior to a given year and assigns that as the zone's capacity requirement for that year. Then, it looks at the zone's load from the one year prior and uses each LSE's share of that load as its capacity charge. Therefore, a customer or LSE just has to try to forecast when that hour will occur and reduce its load at that time.

A good load forecasting system can hit the peak hour in three-to-four seasonal dispatches of three-to-four-hour windows each, such as noon to 4:00 p.m. Note that even though capacity zones within ISO-NE may have different capacity prices, such as the Northeast Massachusetts (NEMA) Boston zone, which has higher prices than other zones, capacity costs can be shifted between them. Therefore, reductions in one zone can affect costs in other zones.

5.2.1.2 PJM

PJM's capacity cost allocation method is slightly more complex than the ISO-NE approach. PJM uses a five CP method, meaning that the five highest non-holiday weekday RTO daily peaks during the summer are used and averaged to determine the peak load contribution (PLC). Instead of LSEs targeting one day as in ISO-NE, five days must be targeted, or at least it must be understood that targeting fewer days will lead to a smaller proportion of cost savings since the load is averaged over five days. A good load forecasting system should be able to hit the five CPs in 10-to-13 seasonal dispatches of three-to-four-hour windows each. Note that capacity allocations cannot be transferred between load zones in PJM, unlike in ISO-NE.

An important factor to keep in mind is that if enough customers and LSEs attempt to reduce loads during peak hours, the effect would be of shifting the peaks to different hours. This is not a static exercise, but one that must be managed dynamically to avoid missing the correct hours.

Over the last few years, both ISO-NE and PJM have considered changes to the capacity allocation scheme, the main goals being to spread it out over more hours to better reflect seasonal peak conditions and disincentivize short-term load reductions. At present, however, such changes are not being actively pursued in either region.

5.2.2 Installed Capacity Requirement (ICR)

Another way that peak demand reductions can affect wholesale capacity charges is through a longer-term strategy of lowering the system load forecast over time. RTOs/ISOs perform short- and long-term load forecasting on a regular basis to ensure adequate supply resources exist to maintain reliability. These forecasts look at historical load data, typically on a five-ten-year time horizon, and use probabilistic models of when peaks may occur. They are based on looking at the summer season from June to August, focusing on the three-four peak hours of each day.

These forecasts are used to calculate the ICR for the system, which determines how much capacity must be procured to meet peak loads plus a reserve margin. ISO-NE and PJM have forward capacity markets, meaning that they hold auctions three years in advance of a delivery year to procure capacity. Therefore, the load forecast used is based on data developed three—four years before the actual time for which the capacity is intended. The RTOs/ISOs do hold follow-up auctions to true up the system in case the forecast increases or decreases, but it takes a significant amount of data to create a meaningful adjustment to the ICR calculation.

On the demand side of the equation, DR bid into the capacity market as a supply resource, as PJM and ISO-NE allow, does not lower the ICR. It is just considered a resource to meet the requirement. Until recently, ICR was purely based on the load data without any assumptions for policies that may affect load. ISO-NE has undertaken an Energy Efficiency Forecast for the last several years, so that state-mandated EE programs can be built into the load forecast. PJM is now undertaking a similar effort. ISO-NE has moved on and is going through a parallel exercise for distributed generation, mostly focused on rooftop solar installations. As a result, the ICR forecasts should more accurately reflect these resources on a prospective basis instead of waiting for the historical data and reacting to it.

Peak load reductions to reduce the ICR must meet higher operational requirements than those described in the section above if they are to directly lower capacity charges by hitting the CP hours. Reducing load for 10-20 hours for one year will not make a sizeable dent in the multi-year, full-summer model that RTOs use to calculate ICR. The full effect would require closer to 15 days of reductions and 60–80 hours and to see the effect work its way into the ICR calculation would require two–three consecutive years. There is some benefit from a lower number of hours of reduction, such as 30–40, but the relationship is not necessarily linear.

There are a couple of caveats to keep in mind in this ICR exercise. First, the months with the highest loads (at least historically) are July and August. Reducing daily peak loads significantly and consistently week-after-week and year-after-year in those months would have the biggest impact on ICR. At some point, however, any additional reduction in load in July and only, should bring no additional reduction in ICR. This is because the peak would shift to other months that would then need to be addressed by load reductions.

Second, the nature of load served by the bulk power system in the near future could be very different from the historical load pattern. For example, the New England states are pushing to install more solar PV generation. PV will have an increasingly large impact on the net load shape that the bulk power system must serve, shifting the peak from its traditional mid-summer afternoon hours to earlier or later in the day. Such a shift in the peak would significantly affect how load reductions could affect the ICR going forward.

5.2.3 Transmission Costs

Transmission is another wholesale energy cost that may be reduced by peak load reduction. It is typically a much smaller charge than capacity, but in regions with capacity constraints, such as New England, it constitutes a growing portion of the overall bill. Like capacity, two means can reduce transmission charges: direct load reductions and non-transmission alternatives (NTAs).

5.2.3.1 Direct Load Reductions to Reduce Transmission Costs

Transmission cost allocations—like capacity cost allocations—are based on contribution to the system, with a couple of key differences. First, transmission costs are allocated directly to the transmission owners, typically the utilities, as opposed to the LSEs. So utilities can control a peak load program rather than worry about the multitude of LSEs operating within their territories.

Second, transmission cost allocations are based on non-coincident peaks rather than the CP approach for capacity, so the utility's own peak load, regardless of when the system peaks, is the basis. PJM uses the zone's single annual non-coincident peak, regardless of season. The transmission year runs from November to October for calculation purposes, but charges are on a calendar year schedule. ISO-NE uses the non-coincident monthly peak hour for transmission charges, meaning that it may change every month depending on peak usage.

The use of non-coincident peaks for transmission costs has some benefits and some drawbacks when comparing peak load reduction program design with coincident peak cost allocation. The coincident system peak may be easier to forecast, since it is primarily based on weather, and all utilities in a state could work together to try to hit that same reduction target. However, each utility may have a better view and understanding of when its own system peaks, so that information could provide a more accurate picture for planning reduction strategies.

5.2.3.2 Non-Transmission Alternatives (NTAs)

In addition to direct load reductions, there is a way to reduce transmission costs through the wholesale transmission planning process. When an RTO/ISO looks at an area that requires a transmission upgrade, it also considers NTAs, which could range from generation to EE to DR. If an NTA can prove to be cheaper than—and as reliable as—the transmission proposal, the transmission component can be reduced or removed. Such a replacement will lower costs of that specific project, which then get allocated to the loads that benefit from the project. This approach would require engagement in the RTO/ISO stakeholder process to know when these opportunities arise and what is needed to submit an NTA proposal.

5.3 Valuing Peak Reductions in States without Competitive Wholesale Capacity Markets

Aside from the utilities that reside within RTO/ISO territories with capacity markets, are utilities in other RTO/ISO areas (ERCOT, CAISO, and MISO) without mandatory capacity markets, as well as vertically integrated utilities outside of a wholesale market territory. Entities that operate in markets or regions without capacity markets must create non-market-based methods to determine avoided costs and peak reduction payment values for their programs.

5.3.1 Avoided Capacity Costs

Typically, a utility will compare the cost of peak reduction to that of its own generation capacity or a power purchase agreement (PPA) with a merchant generator. That represents the most direct method of comparison for capacity value. The element of time must also be considered, depending on the intent of the peak load reduction program. For short-term decisions, peaking power plants can be used as a proxy for peak reduction value. In the mid-term range, PPAs may best reflect the cost. Long-term comparisons should utilize the estimated costs of building new generation resources in the territory.

Such a valuation function is usually done by a utility's system planning group that will understand the costs to build generation, operate a power plant, and purchase power from a plant. Demand-side solutions such as DR and EE can be compared to those costs and essentially treated on an equal basis. Some utilities may require that a reliability need exists for such measures; otherwise no capacity credit will be given.

California, through the California Public Utilities Commission (CPUC), maintains a model on a statewide basis to determine avoided costs. The mid-term cost for traditional resources is $100/kW-yr. Short-term is cheaper at $30/kW-yr. It also applies discount factors to different types of DR based on the availability factor of the peak load reduction program, taking into consideration characteristics like number of hours, peak times, consecutive dispatches, and notice period (day-ahead has less value).

Regulatory jurisdictions and states lack uniformity in how they calculate avoided cost. Compounding this disparity is a lack of transparency on these calculations in public documentation, which are often redacted to prevent disclosing potentially sensitive information. While this concern is understandable, avoided cost calculations should be communicated to the market in a way that is easy to understand so that stakeholders can conduct economic analysis before getting too far with program design.

5.3.2 Avoided T&D Costs

T&D costs are more complicated to estimate than capacity avoided costs. Capacity has one basic purpose: to meet peak load needs. T&D has numerous purposes that can change on the basis of location.

Some of the basic avoided T&D categories are:

- Avoided or delayed capacity upgrades (capital costs) and associated operation and maintenance costs.
- Reduced equipment degradation and the frequency of maintenance by reducing the amount of time components must carry loads at or near design capacity.
- Improved reliability when upgrades are delayed and interim solutions are required.

In a recent study for the Pennsylvania PUC, T&D avoided costs were defined as "the T&D infrastructure expenditures that can be avoided if [a utility's] future load growth can be reduced with DR programs that reduce load at the time of utility peak loads." The annual forecast of T&D expenditures was divided by the change in the system peak load forecast to arrive at the T&D avoided costs per kW.

The study "used a capital cost recovery factor to convert the average avoided T&D investment cost to be on a $ per kW/year basis. This approach is relatively inexpensive and less time-consuming than other approaches as it does not require an engineering study of the electric system, nor does it require obtaining site-specific load and investment data.

As a weak point, it does not provide an accurate picture of avoided costs for specific T&D projects. It fails to capture the highest value projects that DR programs might defer. Still, an average value estimated using the projected embedded analysis does provide an indicator of T&D avoided costs sufficient for evaluating DR resources for an energy future scenario that assumes a significant amount of DR deployment statewide." For commercial customers, the study applied both transmission and distribution avoided costs, while industrial customers were assumed to receive high voltage service and thus only considered transmission costs in that case.

5.3.2.1 Avoided Distribution Costs

A study on the cost-effectiveness of Consolidated Edison's DR programs focused on the value of distribution savings, which depends on the characteristics of the distribution area in which the resources are available. According to that study, peak reductions "can avoid or delay distribution upgrades" and "improve reliability and reduce equipment degradation by reducing the amount of time distribution components carry loads at or near design capacity. The benefits of avoiding distribution investments are quantified by calculating the present value of distribution investments with and without demand management."

The study concluded that the size of avoided distribution costs varies with the design of the system, location, load growth, load patterns, excess distribution capacity, and equipment characteristics. The coincidence of DR availability, size of load response and network need are key factors to consider. The availability of DR for specific hours when overloading is most likely to occur determines DR potential to alleviate the risk of overloading networks and reduce the risk of failures.

5.3.3 Peak Reduction Payment Valuation

Other considerations, beyond using avoided cost metrics, may come into play when determining the value of peak load reductions. Avoided costs may not fully represent the cost or value to the utility and/or the customers. Payments for peak reduction are an important component for estimating peak reduction value because they must be equal to or greater than the cost of providing peak reduction capacity; otherwise, potential customers would elect not to participate in the program. Policy comes into play as well, since participants want higher payments, non-participants want as little cost as possible, and regulators want to ensure fairness and equity within the industry.

As noted above regarding the California method of calculating avoided costs, different peak reduction programs may have different characteristics. The value depends on several factors, including: how well DR resources coincide with system and local peaks, performance during reduction events, limits on availability, and limits on maximum event duration. In California, avoided costs are built into time-of-use (TOU) rates based on the expected difference between summer and non-summer and peak versus off-peak periods. In this way, the value of payments is shaped over all months of the year, with the majority of the value being assigned to August and September.

Baltimore Gas and Electric (BGE) pays customers $1.25/kWh on its Peak Time Rebate program. This figure was calculated on the expected capacity and energy revenue from bidding the program into the PJM market, from which the revenue is passed through to the customers.

Utilities may use focus groups and engage their account management groups to determine true customer valuation of peak reduction programs, including rate implications, benefits, and opt-out rules. It is also possible to look at industry standards for peak reduction valuation and market research to perform benchmarking on other similar programs.

5.3.3.1 California DR Valuation Working Group

California recently undertook an initiative to specifically measure the value of DR to the grid. The CPUC convened a working group made up of utilities, regulators, and stakeholders throughout the spring of 2015, and published a report in May 2015.

From a capacity standpoint, the group came to strong agreement on three topics:

- DR should receive value for system capacity in the Resource Adequacy, Long-Term Procurement Plan, and Transmission Planning processes if they are dispatched on pre-defined "hard triggers."
- An initial "hard trigger" for valuing DR for Flexible Resource Adequacy was proposed that should be considered on a provisional basis.
- A study on DR for Local Resource Adequacy could be useful.

A strong consensus supported a T&D process that determines how DR should be valued for T&D benefits. The T&D valuation recommendations offered were:

- Each utility will calculate a $/kW locational avoided cost for each T&D project where a DR program may contribute to project mitigation either as a standalone solution or as part of a portfolio of solutions.
- The amount of avoided cost credited to DR will be determined by calculating the needs of the DR program in the local area.

Four additional value streams for DR were also identified:

- Option Value: Incorporating statistical analysis is expected to have the greatest degree of significance in valuation results
- Avoided Energy Value
- Avoided Environmental Externalities
- Secondary Market Effects: The effect of DR revenue on the deployment of distributed energy resources whose primary role is other than the provision of DR

5.3.4 Cost-Effectiveness Tests

A critical part of peak reduction or DR valuation is whether it has to undergo some kind of cost-effectiveness test in order to get implemented. Several generally accepted tests that measure EE cost-effectiveness are now beginning to be applied more broadly to distributed energy resources, including DR. The following table shows benefit and cost components of some common tests.

Figure 5.1 Common Cost-Effectiveness Tests

Cost	Participant	RIM	PAC	TRC	Societal
Program Adminstrator Expenses	--	Yes	Yes	Yes	Yes
Program Adminstrator Capital Costs	--	Yes	Yes	Yes	Yes
Financial Incentive to Participate	--	Yes	Yes	--	--
DR Measure Cost: Administrator Contribution	--	Yes	Yes	Yes	Yes
DR Measure Cost: Participant Contribution	Yes	--	--	Yes	Yes
Participant Transactional Costs	Yes	--	--	Yes	Yes
Participant Value of Lost Service	Yes	--	--	Yes	Yes
Increased Energy Consumption	--	Yes	Yes	Yes	Yes
Lost Revenue to the Utility	--	Yes	--	--	--
Environmental Compliance Costs	--	Yes	Yes	Yes	Yes
Environmental Externalities	--	--	--	--	Yes
Benefit	**Participant**	**RIM**	**PAC**	**TRC**	**Societal**
Avoid Capacity Costs	--	Yes	Yes	Yes	Yes
Avoided Energy Costs	--	Yes	Yes	Yes	Yes
Avoided Transmission & Distribution Costs	--	Yes	Yes	Yes	Yes
Avoided Ancillary Service Costs	--	Yes	Yes	Yes	Yes
Revenues from Wholesale DR Programs	--	Yes	Yes	Yes	--
Market Price Suppression Effects	--	Yes	Yes	Yes	--
Avoided Environmental Compliance Costs	--	Yes	Yes	Yes	Yes
Avoided Environmental Externalities	--	--	--	--	Yes
Participant Bill Savings	Yes	--	--	--	--
Financial Incentive to Participate	Yes	--	--	--	--
Tax Credits	Yes	--	--	Yes	--
Other Benefits (e.g. market competitivness, reduced price volatility, improved reliability)	Depends	Depends	Depends	Depends	Depends

Participant= Participant Cost Test, RIM= Rate Impact Measure, PAC= Program Administrator Cost, TRC= Total Resource Cost, Societal= Societal Cost
(Source: Synapse Energy Economics, A Framework for Evaluating the Cost-Effectiveness of Demand Response, February, 2013)

A commonly used test for screening DR programs is the total resource cost (TRC) test. The TRC test includes the full incremental cost of the resource and focuses on the most tangible costs and benefits. It also assesses whether utility customers, in aggregate, are better off with the program. The rate impact measure and participant tests factor in distribution-related charges. From a participant's perspective, program participation reduces costs. However, for ratepayers who are not participating, the costs of the programs can result in higher rates, since their rates may rise to cover program costs, while their consumption patterns do not change. Nevertheless, this is offset by system-wide benefits resulting from EE or DR programs that accrue to participants and non-participants alike.

The RIM and participant tests measure the distributional effects of DR programs, but do not describe the overall societal benefits or average customer benefits of running such programs. The PCT is of limited use to regulators when evaluating voluntary DR programs, because customers generally do not participate in programs that do not decrease their net costs. The RIM test is the most restrictive of the tests, and most states have ruled that it should not be used as the primary test to determine program cost-effectiveness.

The RIM test focuses inordinately on the effect of programs on non-participants, ignoring the savings presented to program participants. In addition, the RIM test focuses on a program's effect on rates, ignoring the average effect on overall bill savings and the longer-term savings from more efficient capital utilization. For these reasons, the National Forum on the National Action Plan on Demand Response (NAPDR) recommends against using the RIM Test as the primary test for evaluating DR program cost-effectiveness.

Consolidated Edison historically used the Utility Cost Test (UCT) test for its Distribution Load Relief Program (DLRP). According to a report on the program, this was partly due to the main cost of the program being participant payments, which the TRC test treated as transfers. The prior TRC model did not include cost associated with providing DR since these costs are not directly observable (e.g., opportunity cost of production, comfort, etc.). The updated TRC framework assumes that the cost of delivering DR is 75% of participant payments. This is not grounded in any empirical data, but matches the proxies used in other jurisdictions such as California. The theory being that these costs are unlikely to be higher than 75% of payments, since customers would not participate if their costs approached or exceeded their payments."

On the other hand, a case can be made to argue against the legitimacy of including such proxies for customer costs. Customers are weighing their own costs and benefits when they consider participating, and will not participate if customer costs are higher than benefits.

Regarding lessons learned from existing programs, simply using standard EE cost-effectiveness models for peak reduction or DR purposes is not necessarily accurate, since the costs and benefits are different, unless these other attributes can be integrated into the existing models. DR offers a variety of potential benefits that are not applicable for EE. For example, DR can be dispatched by system operators, which suggests possible benefits such as avoiding starts of combustion turbines and reducing the amount of required spinning reserves.

Care must be taken to assure that the proper metrics are being measured in the cost-effectiveness model. Furthermore, the industry could benefit from more uniformity in cost-effectiveness and evaluation methods in order to standardize practices and allow for more realistic comparisons of programs across jurisdictions.

5.3.5 Other Benefits

Some peak reduction benefits and costs are difficult to quantify:

- Improved efficiency of wholesale markets by connecting retail customers to the time varying nature of electricity costs and mitigating the potential for market manipulation by suppliers withholding supply or manipulating prices.
- Greater certainty about load growth forecasts because DR can be added incrementally. Most distribution investments are driven by multi-year projections about load growth that typically have a wide degree of uncertainty. DR project development can typically ramp up or ramp down more quickly and at a more granular level than alternative infrastructure investments.
- Improved reliability: Many distribution investments are undertaken only when existing distribution capacity is nearly exhausted. DR could be used to ensure that customers do not experience poor reliability associated with this practice. Avoided disruption costs associated with T&D upgrades. Conducting major upgrades can require excavating the streets and can lead to traffic congestion, noise, and disruption of businesses. Deferring or avoiding major distribution and transmission upgrades can reduce the societal and economic costs associated with those upgrades.
- Providing load control devices and energy management systems to give customers the ability to control end uses for peak reduction, leading to non-event day energy savings if they get into a habit of using them.

5.4 Regulatory Policies that Assure Cost Recovery

Across the country, different states and utility territories use various methods to recover costs from DR and peak reduction programs. Cost recovery is commonly broken into two components: direct cost recovery and performance incentives. Recovery of lost revenue may also be included, though this is generally an insignificant issue for DR programs due to a small volume of kWh reduced compared to energy efficiency.

5.4.1 Direct Cost Recovery

Direct cost recovery refers to regulator-approved mechanisms for the recovery of costs related to the administration of the program by the administrator, implementation costs such as marketing, and the actual cost of product rebates and retailer incentives. It also includes the authorization to apply wholesale market and emissions trading revenues to pay for DR programs. Such costs are recovered through rate cases, system benefits charges, and tariff riders or surcharges.

A rate case enables utilities to recover the direct costs associated with DR programs. A utility may ask its regulator in a rate case to allow it to adjust its basic service charges in order to recover costs. This may be done on an annual basis, for a multi-year period, or ad hoc.

In addition to, or in place of a rate case, a utility may institute a systems benefit charge or other separate rider/surcharge to recover DR program costs. This surcharge may be specifically listed in a tariff rider, and it may apply to all customers or a certain subset of customer classes, depending on the program. An annual true-up mechanism may be used to adjust the rider value in order to maintain collection of the appropriate amount of funds to compensate the utility for its DR expenditures.

5.4.2 Performance Incentives

Performance Incentives are mechanisms that reward utilities for reaching certain program goals and may also impose a penalty for performance below agreed-upon goals. Performance incentives may be in the form of specific dollar amounts or basis point adders to the allowed rate of return. Most utilities do not earn any performance incentives for DR, while a few earn 5% to 10%.

5.4.3 State Cost Recovery Mechanisms

The Edison Foundation Institute for Electric Innovation published a report in 2014 that summarized the cost recovery mechanisms used by each state for demand-side management (DSM) programs.

Only about one-third of states use rate cases for cost recovery of DSM programs. Some states have multiple utilities with unique cost recovery mechanisms. Some utilities have legacy programs in base rates and newer programs funded via tariff riders. Rate cases have drawbacks for DSM cost recovery, such as the difficulty of accurately estimating program participation and associated costs. The utility is harmed if it oversubscribes DSM programs and does not get full cost recovery; ratepayers are harmed if a DSM program is undersubscribed and the utility still gets full cost recovery.

Almost every state (46 of 50) has an SBC/surcharge. Most states using rate cases have a surcharge as well (except Louisiana and Missouri). Most new programs are funded via surcharges rather than rate cases. Utilities tend to favor surcharges since they provide immediate recovery and can easily be adjusted, as opposed to rate cases. In general, program costs are approved either annually or for three-year terms.

Table 5.1 Forty-six States with DSM Cost Recovery Mechanisms

Cost Recovery		Performance Incentives
Rate Case	Rider/Surcharge	31
16*	44*	

* Several states have a combination of mechanisms. Note: Cost recovery mechanisms are generally for DSM and are not often specific to DR.

(Source: Edison Foundation Institute for Electric Innovation, 2014)

The following table compares rate cases to riders/surcharges for DSM cost recovery.

Table 5.2 Comparison of DSM Cost Recovery Mechanisms

Category	Rate Case	Rider/ Surcharge
Ease of initial setup	Medium	High
Ease of adjustments	Medium	High
Timely recovery	Low	High
Incentive to outperform	Low	Medium
Transparency	Medium	High
Treatment of DR as a resource (compatibility with regulatory treatment on equal footing with generation resources)	High	Medium

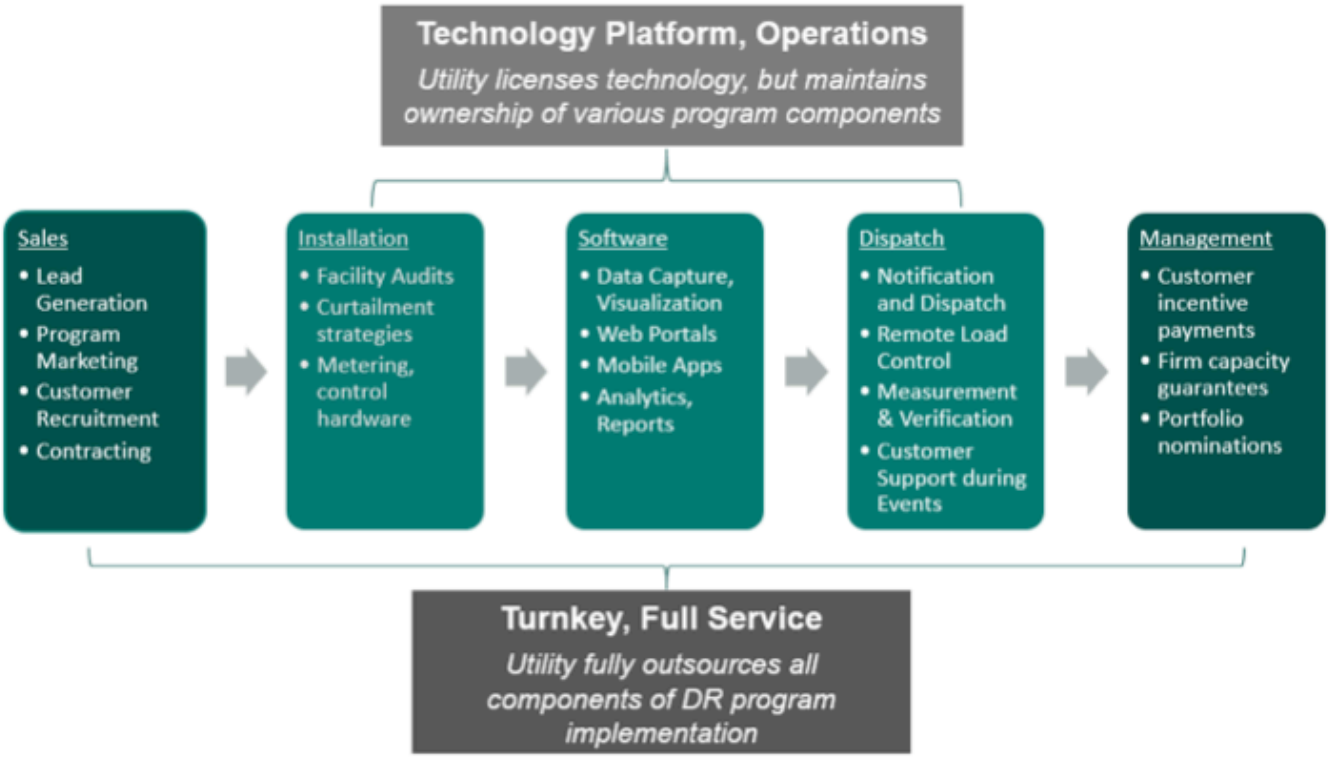
(Source: Navigant)

Surcharges suit DR/peak reduction well because of the short-term program cycle that does not require long-term rate recovery, which can allow for implementation of programs more flexibly and quickly. However, if comparability to generation resources is the key factor, it can be rate-based in T&D rates as a reliability resource or generation rates as a supply resource across all affected ratepayers.

5.5 Outsourcing Considerations for Demand Reduction Program Implementation

Aside from cost-related metrics, several operational and program design elements affect the success of peak load reduction programs. One important decision is whether a utility should try to implement a program internally or outsource some or all of the implementation to a third party. There is not necessarily a one-size-fits-all answer. It will depend on the utility's situation, the type of program, and the availability of qualified vendors. The figure below show the scope of potential outsourced services.

Figure 5.2 Range of Outsourcing Services



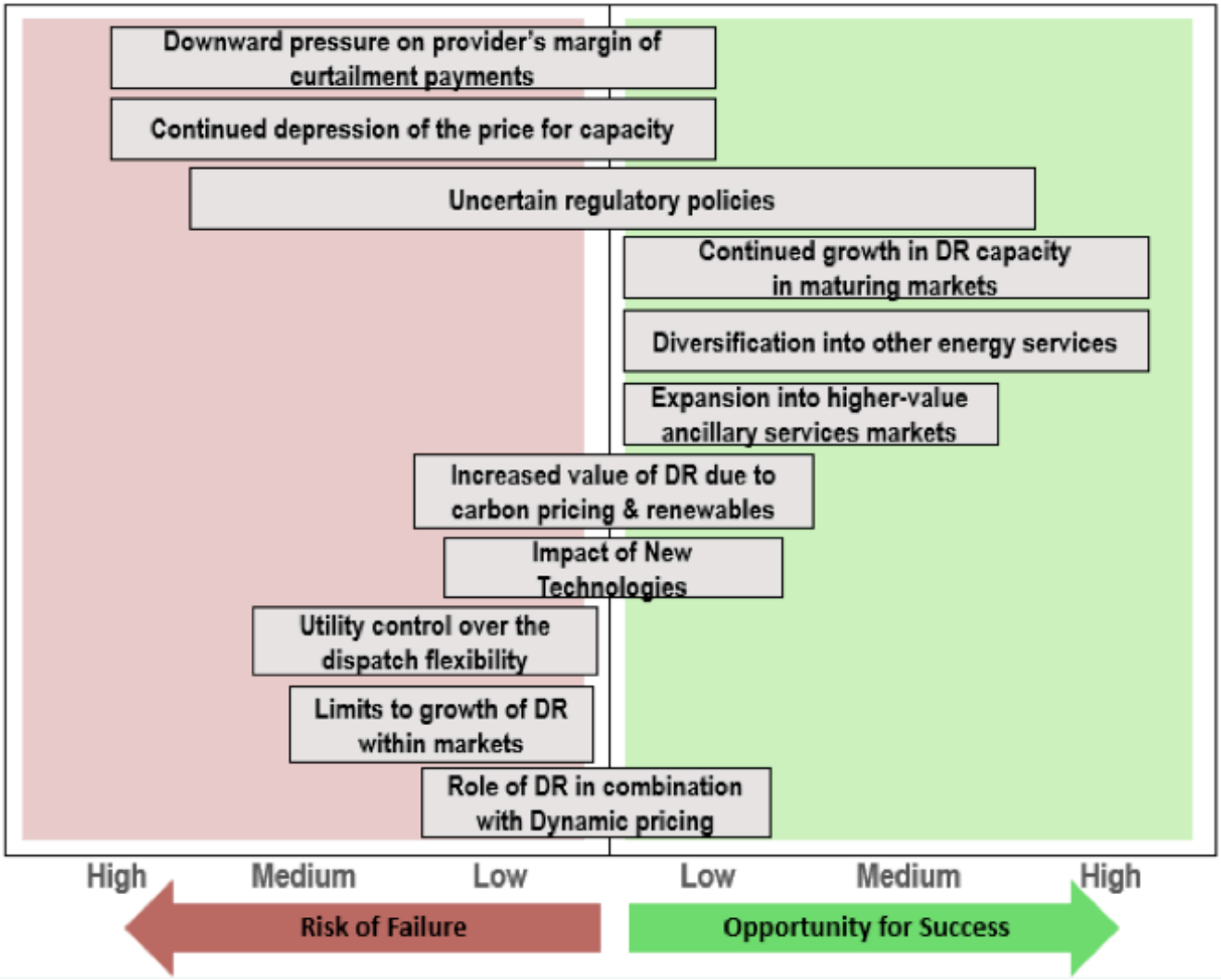
(Source: Navigant)

Outsourcing may consist of a turnkey service, but is not necessarily an all-or-nothing proposition. The utility may have some activities that it wants to maintain in-house, and others that would be better accomplished through a vendor. For instance, the utility may want to keep technology systems internal but outsource customer service or device installation. Some utilities are willing to hire internal resources while others prefer to keep headcount low and bring in external resources on an as-needed basis.

The decisions may have a timing element as well, based on the maturity level of programs. It might make sense to outsource the initiation of a new program and then bring management in-house once the program is established. Starting up a program requires adequate staffing and technical expertise. It can prove expensive and time-consuming to build this internally versus putting out a request for proposal (RFP) for an existing vendor, particularly if speed to market is a concern for the program. Once the program is up-and-running, processes and systems are in place, a firm revenue stream is flowing, and the utility is able to devote more resources to it, the utility can feel more comfortable about committing to a management role.

The potential risks and benefits of outsourcing must be weighed at the outset of the decision-making process. Risk to the utility can be minimized with performance guarantees in the contract, as many arrangements are structured. However, in some cases, dealing with customer and regulator risks and concerns may be easier if programs are managed internally. The figure below shows the range of risks and opportunities.

Figure 5.3 Risks and Opportunities of Strategic Outsourcing



(Source: Navigant)

Even with a turnkey outsourced arrangement, internal resources are required to keep a program on track. Being vigilant about oversight issues is vital. New systems may be needed to coordinate with a vendor, such as updates to billing systems, settlements, and meter data transfer. On the operations side, if peak demand gets integrated into supply-side control center protocols, outsourcing may add a layer of complexity for system operators. Overcoming these barriers is possible, but should be achieved before moving too far with implementation.

On a grander scale, the question is: Does every utility need to develop in-house expertise to manage peak reduction programs, or is utilizing outside vendors, who have technology that can be leveraged at scale and can provide a consistent customer experience, more efficient? Should each utility go through the research and development process, or can ratepayer money be better spent elsewhere when others have already invested in the required infrastructure?

In California, an awkward scenario exists when the utility has a competing program with an outsourced program, especially when there is not much differentiation between the two. The value of the outsourced program must have some rationale; otherwise, customers have no incentive to go that route.

On the other hand, in New York, Con Edison allows direct enrollment into its DR programs, but does not actively recruit customers to participate. Instead, outsourced aggregators do all the customer marketing and recruitment and bring value-added services that enhance the customer program experience.

5.6 Unlocking Demand Reduction's Potential in the Residential Space

DR and peak reduction in the residential sector has historically lagged behind participation in the C&I sectors. As with many products and services, businesses have a strong incentive to control costs and can often obtain economies of scale by addressing issues in a larger volume than individuals can achieve. C&I DR and EE programs are almost always more cost-effective than residential programs; therefore, utilities place more emphasis on them for program deployment. Some utilities are finding that electricity may actually be a smaller portion of household budgets than it once was, because of technologies like cable, Internet, and smartphones. Many consumers do not want to compromise the comfort of temperature or lighting if cost is not top-of-mind.

According to FERC's latest Assessment of Demand Response and Advanced Metering Staff Report, less than 5% of U.S. households are participating in DR programs. Given the potential barriers, how can residential demand reduction penetration get beyond current levels? Several options exist, including tweaks to existing program design, new technologies to expand the availability of dynamic pricing, and considering new program models like behavioral DR and "bring your own device/thermostat."

5.6.1 Existing Programs

Direct load control (DLC) residential central air conditioning, water heater, and pool pump DR programs have been around for decades, using simple technologies like one-way load control switches and thermostats. Utilities tend to like DLC programs because they have control and their operators feel the programs are reliable. A segment of customers prefer a hands-free approach in which they do not need to engage with the utility to participate in a program and earn payments. Such programs will not disappear, but as described below, some adjustments can make them more effective.

5.6.1.1 Technological Advances

Technology is one channel that can expand DLC programs. The old one-way technology did not provide any feedback, such as meter performance data or device status, to the utility operator. With the addition of AMI and two-way communicating load switches and thermostats, utilities may feel more comfortable expanding programs, knowing that they can get timely information about availability and performance and have the opportunity to adjust plans to maintain reliability if needed.

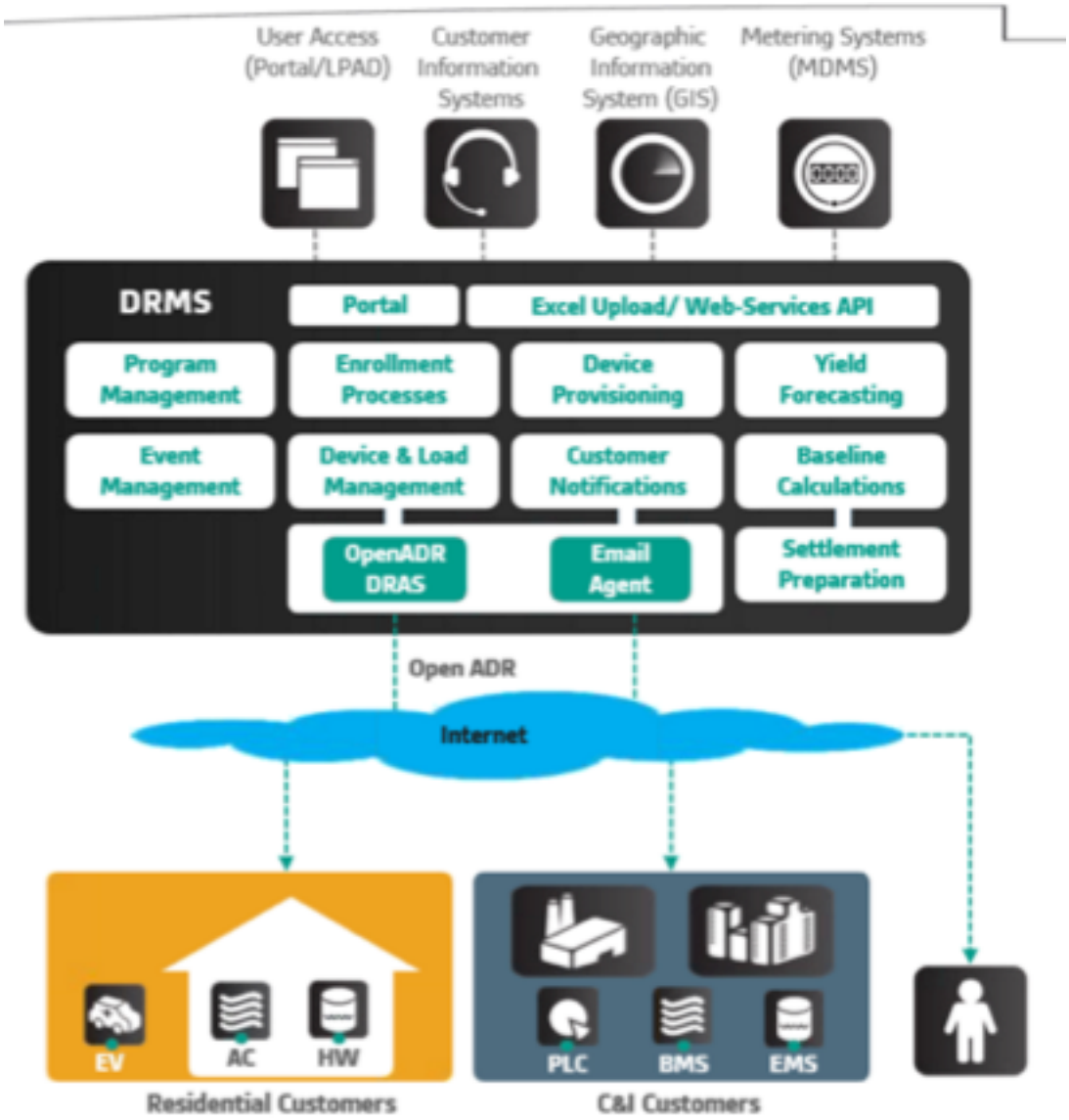
Another aspect of technology development involves demand response management systems (DRMSs), which allow utilities to monitor and dispatch resources more effectively.

- DRMSs are designed to forecast load and revenue based on usage history by meter and on an aggregated basis.
- They also forecast load reduction and perform load-shaping analysis by aggregating historical and real-time data from field-based devices.
- In addition, a DRMS will dispatch load based on system needs and manage the load rebound after an event by layering in the restart of devices instead of starting them all at once.

- Finally, it will support direct load, price-responsive, and dynamic pricing programs and will also accommodate next-generation upgrades such as variable pricing, renewable energy management, and electric vehicle (EV) charging.

When implemented in conjunction with newer two-way communicating thermostats and other devices, DRMSs can offer granular dispatches and real-time feedback on event performance. The following figure displays the functions a DRMS can perform, including program enrollment, event and device management, performance measurement, and settlements.

Figure 5.4 DRMS Overview



(Source: Alstom)

The last category of technology improvements focuses on open communications standards between utilities, DR providers, and customers. Historically, each part of the value chain and many individual companies used proprietary communication systems for its devices. As programs evolve and more interoperability is required between different vendors and systems, open communication will be key to allowing growth of cost-effective and efficient programs.

One example is Open Automated Demand Response (OpenADR). It was conceived to develop a low-cost, speedy, and reliable communications infrastructure that allows utilities to send DR signals directly to customers' existing devices using a common language and an existing communications technology such as the Internet.

OpenADR is becoming a widely accepted standard worldwide. Many DR vendors are part of the OpenADR Alliance and obtain OpenADR certification for their systems.

5.6.1.2 "Bring Your Own Thermostat" Programs

On a larger scale, two-way communicating types of thermostats can change the business model for utility residential DR programs. Using one-way versions, utilities were forced to install the devices and maintain them directly, because they had no other way to keep track of which customers had them and how they were working. Today, customers can buy two-way thermostats at retail stores, where the utility can promote programs or offer rebates, then go home and decide to enroll in a program. The DRMS can then remotely update the device and enroll the customer.

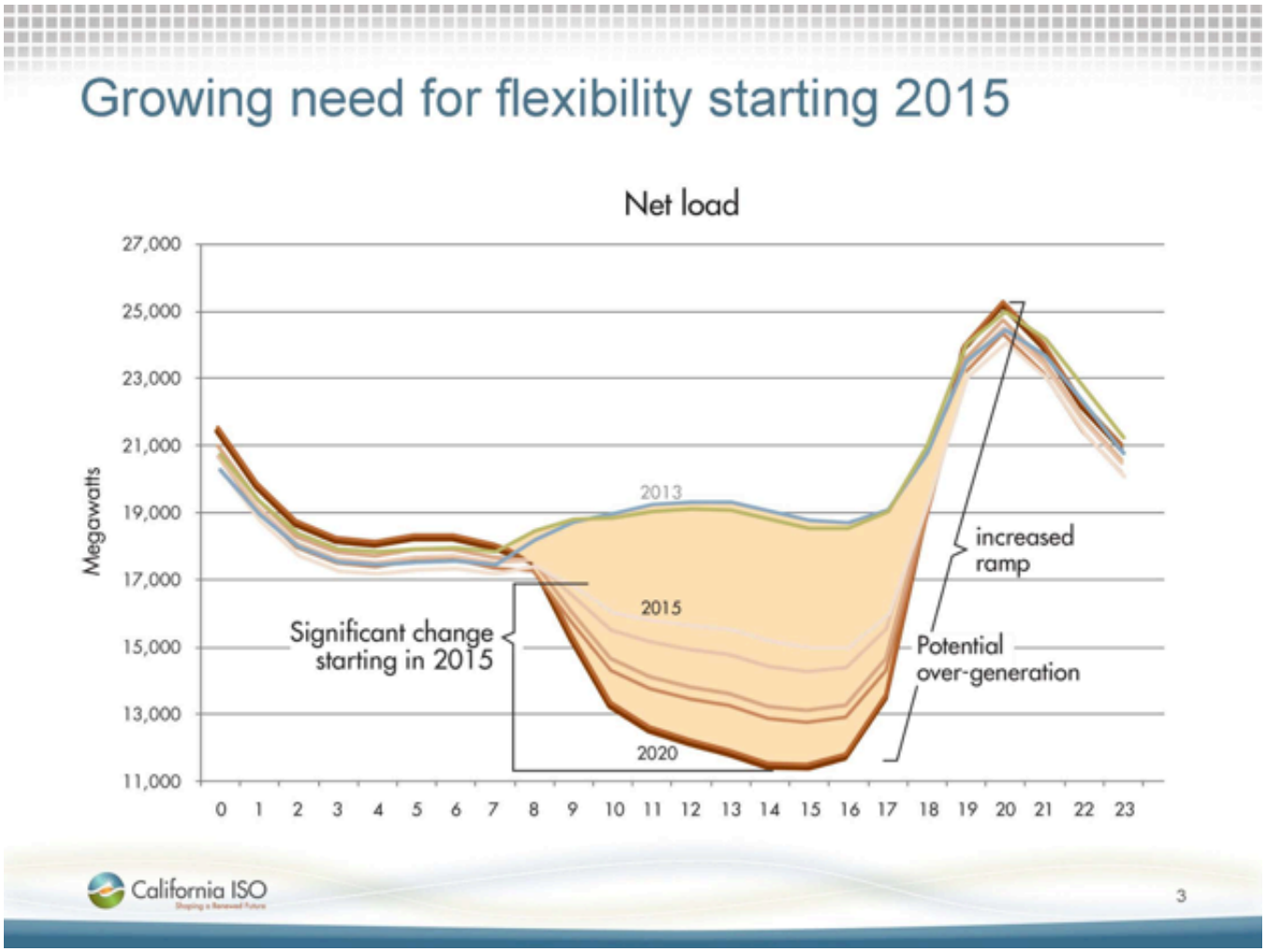
This model, known as "bring your own thermostat" (BYOT), can vastly reduce the acquisition costs for programs and lead to greater customer satisfaction since the customers choose their own devices and initiate the participation process. For these programs to succeed, utilities and retailers must educate customers so they understand the value proposition.

5.6.1.3 Variable Renewable Resources

A major driver for DR is the increasing penetration of variable renewable energy around the world. While some of this growth is due to regulatory mandates, it is increasingly based on the improving economic case of renewables reaching grid parity with fossil or nuclear generation. Resources like solar and wind power rely on natural elements that can sometimes be unpredictable and require backup power resources to respond quickly if clouds roll in or the wind stops blowing. Traditionally, this has been accomplished by existing fossil power plants that keep some power in reserves for these situations. As the penetration of variable renewables increases, however, building generation just for backup may kill the business case for the renewable energy, so cheaper, more flexible alternatives are needed. DR can help provide this flexibility.

California's evolving generation mix is an example. In 2013, CAISO constructed the now famous "duck graph," which shows the predicted load shape for the state as solar and wind become larger parts of the generation portfolio.

Figure 5.5 Duck Graph of Renewable Energy Integration: 2013-2020



(Source: California Independent System Operator)

In the next couple of years, net load is actually expected to decrease dramatically during midday, normally peak hours, due to rising solar generation. Once the sun goes down, the evening ramp rate of load will double, requiring fast-acting resources to respond quickly. This will require a package of solutions like adding more flexible generation and energy storage. DR can play a role as well.

5.6.1.4 Window Air Conditioning Units

Many utilities around the country have DR programs for central AC, but before Con Edison, none had attempted a DR program for window air conditioning (AC) units. Con Ed's Central Air Conditioning DR program had 30,000 participants, but New York City has a proliferation of window AC units in large multifamily residential buildings—and 6.5 million window AC units accounted for 20% of the city's summer peak load.

During the summer of 2014, Con Ed partnered with ThinkEco, a company that developed a smart outlet plug called a Modlet. When the AC unit is plugged into the Modlet, the utility is able to control it by adjusting the setpoint (not merely turning off the AC unit). The potential is enormous if it can be achieved without being intrusive or affecting customers' comfort.

5.6.1.5 Grid-Interactive Electric Water Heating

In addition to residential DR programs that target heating, ventilation, and air conditioning (HVAC), an end-use application with large potential is grid-interactive electric water heating (GIWH). Certain areas of the United States and the world have a large penetration of electric water heaters. Sometimes these have been included in traditional DLC programs that simply turn them on and off. With new technical capabilities, these units can be connected with real-time, two-way communications between the GIWH appliance and the system operator for carbon reduction, renewable energy storage capability, and grid optimization. When equipped with GIWH controls, a large-capacity (80-plus gallons) electric thermal storage water heater can respond to near real-time input by enabling fast up and down regulation and frequency control to the grid without sacrificing water temperature. Because of the units' storage capabilities, they can be turned down during the day and then heat up overnight—potentially at lower electric rates.

5.6.1.6 Plug-in Electric Vehicles

Residential plug-in electric vehicles (PEVs) are emerging as potential DR assets, and almost every domestic auto manufacturer has developed some sort of energy use optimization pilot. This is not an immediate opportunity because large-scale enrollment in DR programs is not likely to begin anytime soon. Moreover, when it does begin, it will likely be confined to specific utility service areas that are PEV-dense. The coming year is likely to see small-scale pilots, with wider deployments coming in 2017 or later.

5.6.2 Dynamic Pricing

Not every customer will be amenable to DLC programs, regardless of the technology advances that facilitate participation. Furthermore, reaching every customer through marketing may not be possible. Instead, utilities must offer a suite of value-added offerings to different customer segments that address needs such as convenience, comfort, and choice.

Customer engagement will become as important as operational effectiveness. Entirely new approaches may be needed to achieve the potential that exists in residential peak reduction programs. Two such approaches are dynamic pricing and behavioral DR.

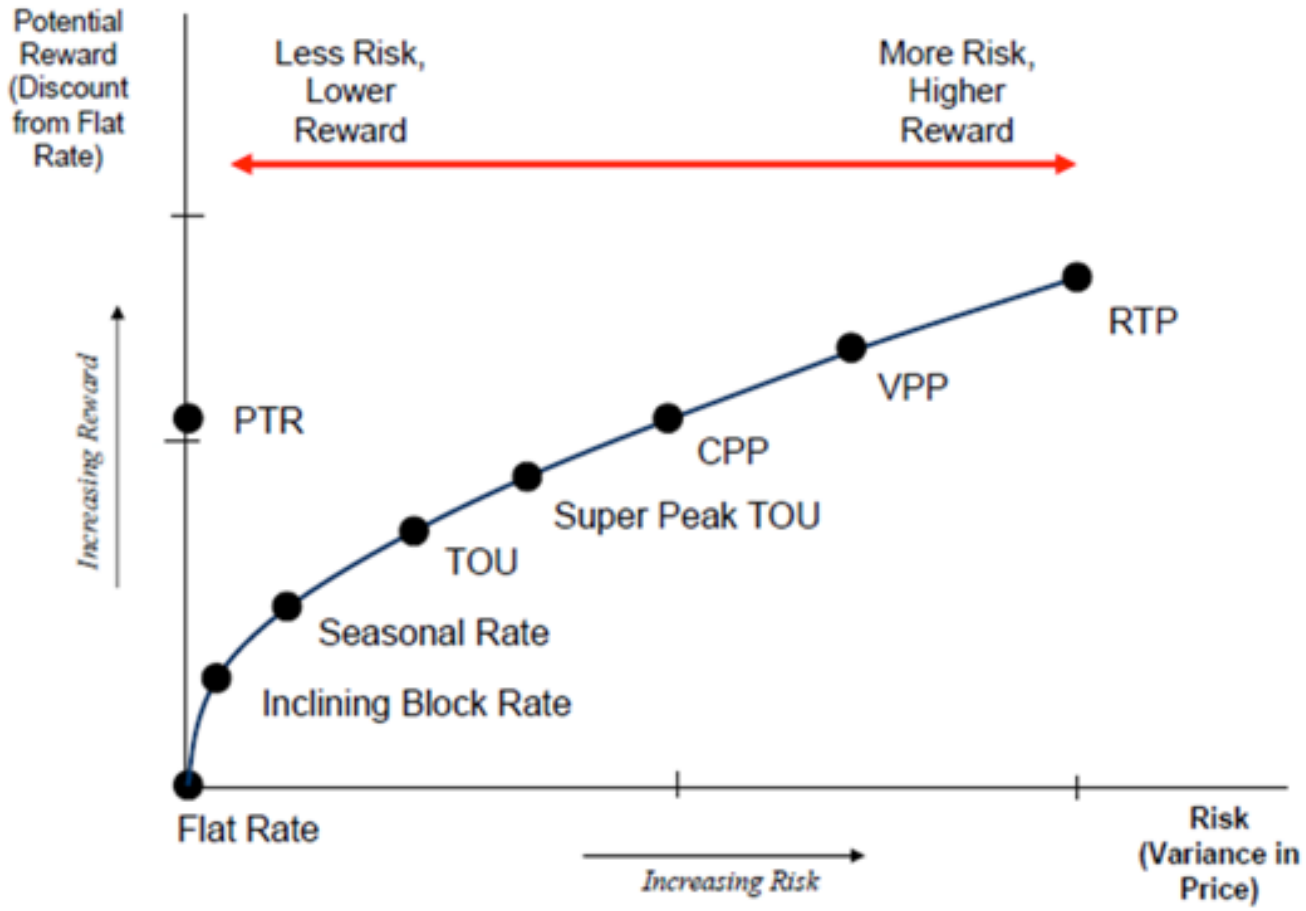
TOU electric rates, which offer set prices for predefined on- and off-peak periods, have existed for decades. They are simple tools to encourage off-peak energy consumption. Until now, Ontario, Canada and Italy have been the only regions in the world to implement default TOU rates for customers who do not choose an alternative competitive electricity supplier for their supply. The Sacramento Municipal Utility District (SMUD) is set to become the first utility in the United States with a default TOU tariff, which goes into effect in 2018. The Massachusetts Grid Modernization proceeding sets the state up to be the first to require a default TOU rate for all of its investor-owned utility (IOU) customers within five years from 2014. California is now in the midst of developing default TOU rates for its IOUs as well.

Rates that are indexed to real-time wholesale energy prices have also been around for large C&I customers since electricity market deregulation occurred the United States in the 1990s, though few customers currently take advantage of them. With the proliferation of advanced meters that can record usage at small intervals, more dynamic types of pricing can be applied down to the residential level. The ultimate possibility, which may not be realistic without more automation, is real-time pricing (RTP), which passes through the actual cost of electricity to the customer. More moderate versions include critical peak pricing (CPP), variable peak pricing (VPP), or peak-time rebates (PTRs), which charge higher prices or give refunds, respectively, during a limited number of peak hours throughout the year.

Experience with these rates is small but growing. Many pilot programs have included enabling technologies like smart thermostats in conjunction with the rates to assist customers in reacting to prices with minimal distraction. Baltimore Gas and Electric (BGE) became the first utility in the United States to make its PTR the default rate for all customers with a smart meter under a program titled Smart Energy Rewards. In 2015, the program was deployed to all 1.1 million BGE residential customers.

The following chart shows the range of dynamic pricing options and their risks and reward profiles.

Figure 5.6 Risk/Reward Profile of Dynamic Pricing Options



(Source: The Brattle Group)

The concept of opt-in versus opt-out is critical for the adoption of dynamic pricing.

- Opt-in models carry less risk of customer backlash, although experience thus far has shown little dissatisfaction with such rates.
- Opt-in programs have displayed much lower penetration than opt-out programs, as relatively few customers choose to opt-out once they are on a dynamic rate.
- Opt-in may be more politically acceptable as a starting point and a transition mechanism, but the long-run true potential lies in opt-out design.

5.6.3 Behavioral DR

The evolution of big data analytics, social media, and behavioral science provides new opportunities for cost-effectively expanding DR to residential and small-and-medium business (SMB) customers, without relying on significant deployment of additional technology/equipment. Utilities are looking to transition from one-way DLC programs to price-based DR and more customer-focused approaches. In some cases, two-way communicating thermostats and home energy management (HEM) systems may be a path to increasing program performance. However, those devices have higher costs than the old versions of thermostats and need to be cost-justified to regulators.

Behavioral DR leverages AMI data to deliver personalized, timely insights to each customer through that customer's communication channel of choice, and motivates customers to reduce usage during times of peak power demand, such as hot days when air conditioning load is high. Unlike device-based DR programs, BDR programs do not require the installation of enabling devices on customer sites, and therefore can be rapidly deployed to residential and SMB customers on an opt-out basis.

BDR programs can be offered as stand-alone programs or to complement a dynamic rate offering, such as peak time rebates (PTR) or critical peak pricing (CPP). Utilities such as Hydro Ottawa in Canada and Glendale Water and Power in California have deployed non-price BDR to drive broad-based residential peak reductions. Additionally, Baltimore Gas and Electric and Commonwealth Edison have deployed BDR as a tool to enhance PTR program performance.

BGE (mentioned in the Dynamic Pricing section of this report) has the largest behavioral DR deployment. BGE's vendor, Opower, is responsible for sending the price/event notifications to customers and providing customers' feedback on performance after events. Over a full summer season, customers receive:

- A pre-season postcard to create awareness
- A pre-event notification
- A post-event summary
- A normative comparison with neighbors

Multiple channels, such as smartphones, tablets, and computers, are used to contact customers in the way they prefer. According to Opower, the summer 2013 season showed 5% average peak reductions, about 0.2 kW per home, without the utility installing any device. A small group of customers that opted in to receive text message notifications of events showed a 13% reduction.

The savings per customer are admittedly smaller than they are with a typical DLC or smart thermostat program, but the theory is that an aggregated similar or greater performance can be gained by attracting many more customers at a much lower cost per customer. Based on known program enrollment data, most device-based programs have less than 10% customer penetration, while a few of the best programs have 25% to 30%. In the behavioral model, every customer is automatically enrolled and receives messages unless they opt-out, since there is little incremental cost to add customers to notification lists.

By comparison, it is likely not cost-effective for a utility to give every customer a free device. If there are many times the number of customers delivering a smaller individual savings, the overall effect can be equal or greater peak demand reductions.

Behavioral DR is not necessarily intended to compete with existing DR programs. Rather, it is an opportunity to enhance existing programs at a low cost. It is also a way to introduce customers to the concept of DR without their committing to a device or utility control. Those who are satisfied with the experience can be educated about other programs to deepen their engagement and savings potential.

5.7 Demand Response Goals

After the valuation and program design elements are vetted and program potential is estimated, goals can be determined. Quantitative energy efficiency goals—referred to as Energy Efficiency Resource Standards (EERS)—are an important regulatory driver of utility investment in energy efficiency programs and resulting energy savings. Similarly, experience demonstrates that mass market DR is best achieved through the establishment of utility demand reduction goals. Demand reduction goals send a clear signal to utilities and the market regarding the importance of DR. They create long-term certainty that encourages large-scale investment in DR programs.

Maryland was an early adopter of demand reduction goals for electric utilities. The EmPOWER Maryland Act of 2008 required electric utilities to implement cost-effective DR programs designed to achieve a targeted reduction of at least 5% by the end of 2011, and 10% by the end of 2015, of per capita electricity demand relative to a 2007 baseline. The Maryland PSC further enabled DR by allowing the utilities to recover DR program costs and earn a performance incentive. Under the direction of EmPOWER Maryland DR targets, Maryland's utilities are on track to achieve their aggressive peak reduction goals in 2015.

Quantitative DR goals should be set based on a DR potential study, similar to the analysis for Massachusetts and Illinois in Chapter 3 of this report. The goals should be large enough to stimulate new investment in cost-effective DR programs and must be supported by regulatory mechanisms that allow for the timely recovery of DR program costs by utilities as discussed in Section 5.4.

Appendix A. Sources and Methodology

Navigant Research's industry analysts utilize a variety of research sources in preparing Research Reports. The key component of Navigant Research's analysis is primary research gained from phone and in-person interviews with industry leaders including executives, engineers, and marketing professionals. Analysts are diligent in ensuring that they speak with representatives from every part of the value chain, including but not limited to technology companies, utilities and other service providers, industry associations, government agencies, and the investment community.

Additional analysis includes secondary research conducted by Navigant Research's analysts and its staff of research assistants. Where applicable, all secondary research sources are appropriately cited within this report.

These primary and secondary research sources, combined with the analyst's industry expertise, are synthesized into the qualitative and quantitative analysis presented in Navigant Research's reports. Great care is taken in making sure that all analysis is well-supported by facts, but where the facts are unknown and assumptions must be made, analysts document their assumptions and are prepared to explain their methodology, both within the body of a report and in direct conversations with clients.

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