A Methodology for Estimating Large-Customer Demand Response Market Potential

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ABSTRACT

Demand response (DR) is increasingly recognized as an essential ingredient to well-functioning electricity markets. DR market potential studies can answer questions about the amount of DR available in a given area and from which market segments. Several recent DR market potential studies have been conducted, most adapting techniques used to estimate energy-efficiency (EE) potential. In this scoping study, we: reviewed and categorized seven recent DR market potential studies; recommended a methodology for estimating DR market potential for large, non-residential utility customers that uses price elasticities to account for behavior and prices; compiled participation rates and elasticity values from six DR options offered to large customers in recent years, and demonstrated our recommended methodology with large customer market potential scenarios at an illustrative Northeastern utility. We observe that EE and DR have several important differences that argue for an elasticity approach for large-customer DR options that rely on customer-initiated response to prices, rather than the engineering approaches typical of EE potential studies. Base-case estimates suggest that offering DR options to large, non-residential customers results in 1-3% reductions in their class peak demand in response to prices or incentive payments of \$500/MWh. Participation rates (i.e., enrollment in voluntary DR programs or acceptance of default hourly pricing) have the greatest influence on DR impacts of all factors studied, yet are the least well understood. Elasticity refinements to reflect the impact of enabling technologies and response at high prices provide more accurate market potential estimates, particularly when arc elasticities (rather than substitution elasticities) are estimated.

Introduction

Demand response (DR) is increasingly recognized as an essential ingredient to well functioning electricity markets. This growing consensus was formalized in the Energy Policy Act of 2005 (EPACT), which established DR as an official policy of the U.S. government, and directed states (and their electric utilities) to consider implementing DR, with a particular focus on "price-based" mechanisms. The resulting deliberations, along with a variety of state and regional DR initiatives, are raising important policy questions: for example, *How much DR is enough? How much is available? From what sources? At what cost?*

In this paper, we examine analytical techniques and data sources to support DR market assessments that can, in turn, answer the second and third of these questions. We focus on DR for large (> 350 kW), commercial and industrial (C&I) customers, although many of the concepts could equally be applied to similar programs and tariffs for small commercial and residential customers.[1] We define DR market potential as *the amount of DR—measured as short-term load reductions in response to high prices or incentive payment offerings—that policymakers can expect to achieve by offering a particular set of*

[1] Our proposed approach may not be appropriate for direct load control programs, which involves cycling or shedding of equipment (e.g. air conditioners, water heaters) of residential and small commercial customers.

DR options to groups of similar customers (e.g. market segments) under expected market or operating conditions.[2]

In this scoping study, we review analytical methods and data that can support market assessments (e.g., for dynamic pricing tariffs) or market potential studies (e.g., for programmatic DR) for DR options offered to large commercial, industrial and institutional utility customers. We comment on differences between energy efficiency (EE) and DR that make translation of methods for EE potential studies problematic, present a conceptual framework for estimating market potential for large customer DR, compile participation rates and elasticity values from six large customer dynamic pricing and DR programs and apply them to estimate DR market potential in an illustrative utility service territory. Finally, we present a research agenda that identifies additional information and improved methods that would support more reliable DR market assessments.

Approaches Used to Study DR Market Potential

A number of utilities and regional groups have performed DR market potential studies in recent years, primarily to develop the demand-side section of utility resource plans, or to assist with planning or screening of potential DR programs.[3] A few states and regions have begun to set DR goals; market assessment studies could serve as a foundation to ensure that such goals are achievable, and help identify market segments and strategies to meet them. Studies of DR market potential necessarily involve estimating two separate elements: *participation*, the number of customers enrolling in programs or taking service on a dynamic pricing tariff; and *response*, quantities of load reductions at times of high prices or when curtailment incentives are offered. Among seven reviewed DR market potential studies, four distinct approaches were used: [4]

- *Customer surveys*—Participation rates and expected load curtailments are obtained from surveys of utility customers about their expected actions if offered hypothetical DR options and used to estimate market potential. This approach uses information obtained locally, but the responses are subjective—customers may not know what they would actually do (particularly if they have no prior DR experience), or may respond strategically. We found only one example of this approach.
- *Benchmarking*—Participation rates and load reductions observed among customers in other jurisdictions are applied to the population of interest. An advantage of this approach is that it relies on actual customer experience and actions. However, it assumes that any differences in the customers and market context have an insignificant impact on participation and load response. Only one of the reviewed studies adopted this approach.
- *Engineering approach*—Four of the seven reviewed studies used bottom-up engineering techniques, similar to those used to estimate EE market potential. They are variations on the approach of applying assumed participation and response rates to data on local customers, loads or equipment stock. These rates are typically assumed to be constant, regardless of price or incentive levels.
- *Elasticity approach*—This approach, adopted by one of the reviewed studies, involves estimating price elasticities from the usage data of customers exposed to DR programs and/or dynamic

[2] DR market potential can be expressed as a percentage reduction in market demand that can be expected at, for example, a price (or offered curtailment incentive) of $500/MWh.

[3] See Haeri and Gage (2006), Quantum Consulting and Summit Blue Consulting (2004), SCE (2003), and EPRI Solutions (2005).

[4] See Appendix A of Goldman et al. (2007) for a summary of the reviewed studies and their methods.

pricing tariffs. After determining an expected participation level, price elasticities are applied to the population of interest to estimate load impacts under an expected range of prices or level of financial incentives to curtail load. Like the benchmarking approach, elasticities are based on actual customer response. They also quantify the relationship between customer behavior (i.e., load reductions) and price. When demand models are used to estimate elasticities, variables can be introduced to account for customer- or market-specific factors that influence price response, enabling the translation of results to other jurisdictions that may vary in these factors.

What Makes DR Different from EE?

While EE and DR both involve modifying large customers' use of and demand for electricity, they differ in several important ways that may affect market potential: *The nature of participation*—For DR options, participation involves two steps: enrolling in a program or tariff, usually on an annual (or other periodic) basis; and providing load reductions during specific events (e.g., system emergencies or periods of high prices). For EE, "participation" consists of a one-time decision to invest in EE measures or equipment.

- *The drivers of benefits*—DR benefits often hinge on customer behavior (i.e., ability and willingness to curtail) in response to hourly prices, financial incentives, and/or system emergencies. EE-related savings are largely a function of the technical characteristics and performance of the installed equipment or measures.
- *The time horizon and valuation of benefits*—From a customer perspective, DR benefits—which depend on rare events that occur in near-real time (system emergencies or energy price fluctuations)—may be highly variable and are often short-term. In contrast, investments in EE measures typically produce a fairly certain stream of savings over a multi-year period (i.e. the economic lifetime of the measure) which the customer can value at expected retail energy rates.

Given these differences, we make the following observations and recommendations on methods for estimating DR market potential:

- For residential and small commercial direct load control programs, customer load impact estimates can be derived from bottom-up engineering approaches or statistical evaluations of samples of participating customers with appropriate metering.
- For large customer DR options that rely on customer-initiated response to prices (e.g., hourly or critical-peak pricing) or curtailment incentives (e.g., short notice emergency or price response event programs), we recommend an elasticity approach.[5]
- Participation should be thought of in terms of market *penetration* in a given year. Unfortunately, participation is the most difficult aspect of DR options to estimate, due to a limited experience base. With time and experience, this should improve.
- Because of the limited experience base for many DR options, approaches that rely on customer survey response to hypothetical DR options, or benchmarking, are probably not all that meaningful. The "best practices" approach, which has been used in some EE market potential studies, makes most sense when there is a larger experience base (i.e., mature programs offered by many utilities or ISOs over a lengthy period).

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[5] We note, however, that DR programs involving reserve or capacity payments and/or penalties for non-response (e.g., interruptible rates, capacity programs) present difficulties in estimating elasticities, because customer incentives are less clearly tied to individual events.

A Framework for Estimating Large Customer DR Market Potential

We propose a framework for estimating large customer DR market potential in a given jurisdiction or utility service territory that involves five steps:

- *Establishing the study scope*—identifying the target population and types of DR options to be considered;
- *Customer segmentation*—identifying "customer market segments" among the target population;
- *Estimating net program penetration rates*—using available data to estimate customer enrollment in voluntary programs and customer exposure to default pricing programs;
- *Estimating price response*—selecting an appropriate measure of price response (price elasticity of demand, substitution elasticity or arc elasticity) given available data, and developing elasticity estimates for various DR options, customer market segments, and factors found to influence price response from the observed load response of customers exposed to DR options; and
- *Estimating load impacts*—combining the above steps to estimate the expected DR that can be expected from the target population at a reference price.

We applied this methodology, using available data on large customer participation and response, to estimate the market potential for several DR options at an illustrative urban utility in the Northeastern U.S.

Establishing the Study Scope

We limited our analysis to large, non-residential customers with peak demand greater than 350 kW and examined the five different types of DR options described in **Table 1**.

We analyzed these options *independently* and did not account for possible interactions between different options should they be offered simultaneously to a given set of customers. Thus, our results likely *overestimate* the combined market potential for these DR programs and dynamic pricing tariffs should two or more of them be offered to the same customers at once.

Our data sources for participation rates and price elasticities for each of these DR options are provided in **Table 2**.

Customer Segmentation

Analysts conducting DR market potential studies should use available information about the target population to identify customer market segments that are expected to respond in similar ways, or that could be approached with specific marketing strategies or program designs.

For this study, we adopted five market segments based on SIC codes—manufacturing, government/education, commercial/retail, healthcare, and public works—that Goldman et al. (2005) found to be well correlated with differences in large, non-residential customers' willingness to participate in and respond to DR options.

Table 1. DR Options Included in Market Potential Simulation

DR Option	Description

DR Option	Description
Optional hourly pricing	• A dynamic pricing tariff with bundled charges for delivery and commodity offered on an optional basis • Typical rate design is a two-part structure, in which a customer baseline load (CBL) is established and billed at an otherwise-applicable tariff rate (either TOU or flat rate), with deviations in actual usage above and below the CBL billed at hourly prices
Default hourly pricing	• A dynamic pricing tariff, in which commodity costs are unbundled from other rate components (e.g. distribution and transmission charges), offered as default service in states with retail competition • Commodity usage is billed at an hourly rate, typically indexed to an organized wholesale energy market (e.g. day-ahead or real-time energy market)
Short-notice emergency program	• A program that offers customers financial incentives for curtailing load when called by a program operator on short notice (i.e., 1-2 hours) in response to system emergencies • Typically, customer response is voluntary (i.e., in some programs, no penalties are levied for not curtailing when called)
Price-response event program	• A program that pays customers for measured load reductions when day-ahead wholesale market prices exceed a floor • Some programs may include bid requirements (i.e., customers are only paid for curtailments that they specify in advance) and/or penalties for failing to respond when committed
Critical-peak pricing	• A dynamic-pricing tariff similar to a time-of-use rate most of the time, with the exception that on declared "critical-peak" days, a pre-specified higher price comes into effect for a specific time period

Table 2. Data Sources

DR Option	Data Source(s)	Eligible Customers (peak demand)	Reference
Optional hourly pricing	Central and Southwest (CSW) Utilities' (now American Electric Power) two-part RTP rate	> 1,500 kW	Boisvert et al. (2004)
Default hourly pricing	Niagara Mohawk Power Corporation (NMPC), a National Grid Company, SC-3A tariff	> 2000 kW	Goldman et al. (2005)
Short-notice emergency program	NYISO Emergency DR Program (EDRP)	> 100 kW	Neenan et al. (2003)
	ISO-NE Real-Time DR (RTDR) Program	> 100 kW	RLW Analytics and Neenan Associates (2003, 2004 and 2005)
Price-response event program	ISO-NE Real-Time Price Response (RTPR) Program	> 100 kW	RLW Analytics and Neenan Associates (2003, 2004 and 2005)
Critical-peak pricing	California Utilities[1] Critical Peak Pricing Program	> 200 kW; > 100 kW for SDG&E	Quantum Consulting, Inc. and Summit Blue Consulting, LLC (2004 and 2006)

[1] Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) offer a critical-peak pricing tariff to large customers. The tariff design is quite different from that of the California Statewide Pricing Pilot that primarily targeted residential customers (Charles River Associates 2005).

Estimating Net Program Penetration Rates

The next step is to estimate customer participation rates for DR options included in the study. Participation can imply: (1) customer enrollment in voluntary DR programs and tariffs, or (2) the retention of customers in tariffs implemented as the default service (i.e., the number of customers who do not switch to an alternative offering).

DR participation is often fluid. Customers may enroll in a program for one or more years, and subsequently drop out. They may subsequently re-enroll in the program, or others may take their place. The benefits of customer participation are generally only realized while the customer is enrolled in the program (or exposed to hourly prices).[6] Thus, participation in DR options can be viewed as *penetration* in a given year "n" (or other applicable timeframe), as follows:

$$\text{Penetration}_n = \text{participants}_{n-1} - \text{dropouts}_n + \text{new enrollees}_n$$

This can be estimated separately for each customer market segment defined in the previous step, and the results added up to determine the overall penetration for the population of eligible customers.

This way of thinking about DR potential is useful for evaluating an established program over multiple years, particularly in the context of changes to program rules or incentives, or to the level and/or volatility of market prices. From the standpoint of a new, hypothetical program, it may be acceptable to view participation as penetration in a "typical" year of a mature program, with the understanding that a multi-year ramp-up period will be necessary, and that ongoing penetration may be subject to fluctuations due to factors both within and out of the program operator's control.

Analysts have used a number of methods to estimate penetration rates of DR programs (see Goldman et al. (2007) for discussion of various approaches). Each has pros and cons, in part because there is not yet a broad set of information on customer response to various DR options in a variety of settings. Program penetration rates present the largest uncertainty in this framework, because experience is piecemeal, and because of data limitations. We strongly recommend evaluating the impact of a range of participation levels, rather than relying on a single point estimate.

We compiled participation rates by market segment and customer size for each DR option in our simulation (see **Table 3**). Our goal was to gather data on program participation based on relatively mature programs with 3–4 years of operation. Where possible, we used actual program participation data from the data sources in **Table 2**. We filled in gaps by surveying program managers of similar programs and tariffs, and inferring data from other market segments or programs; these data are indicated in red italic font in **Table 3**.[7]

The highest participation rates are observed for large customers (>1 MW) in the default hourly pricing tariff. We believe this is largely explained by the default, "opt out" nature of the tariff, which tends to increase participation rates because some customers decide not to decide. In a default hourly pricing tariff, participation is defined as *not* selecting an alternative electricity supplier, rather than as the conscious decision to sign up that characterizes the other programs and tariffs.[8]

Table 3. Participation Rates in DR Programs and Dynamic Pricing Tariffs

DR Option	Business Type	Customer Size (peak demand)			
		0.35–0.5 MW	0.5–1 MW	1–2 MW	>2 MW
Optional	Commercial/retail	*0%*	*0%*	*1%*	*2%*

[6] However, the experience of responding to a particular program may provide benefits beyond that particular program if the customer subsequently exhibits DR behavior in other programs or dynamic pricing options that were learned in the initial program.

[7] For the two short-notice emergency programs, information on the number of participating customers was available from NYISO and ISO-NE. However, neither agency collects information on the number of customers eligible for their programs. We constructed eligible population data from information obtained from third party sources (see Goldman et al. 2007).

[8] The default hourly pricing participation rates do not include those customers that switched to competitive retailers and entered into contracts in which they faced hourly prices indexed to day-ahead or real-time markets for some or all of their load.

DR Option	Business Type	Customer Size (peak demand)			
		0.35–0.5 MW	0.5–1 MW	1–2 MW	>2 MW
hourly pricing	Government/education	*3%*	*4%*	*6%*	*25%*
	Healthcare	*0%*	*0%*	*1%*	*2%*
	Manufacturing	*3%*	*5%*	*6%*	*25%*
	Public works	*0%*	*0%*	*3%*	*20%*
Default hourly pricing	Commercial/retail	*4.3%*	*11%*	*50%*	43%
	Government/education	*4.2%*	*10%*	30%	42%
	Healthcare	*0.7%*	*1.8%*	50%	7.1%
	Manufacturing	*3.3%*	*8.3%*	29%	33%
	Public works	*3.7%*	*9.2%*	50%	37%
Short-notice emergency program	Commercial/retail	1.2%	23%	5.5%	20%
	Government/education	0.3%	5.3%	2.6%	9%
	Healthcare	0.6%	4.2%	4.3%	22%
	Manufacturing	0.2%	15%	17%	23%
	Public works	1.1%	10%	67%	17%
Price-response event program	Commercial/retail	0.3%	0.8%	1.8%	5.7%
	Government/education	0.3%	2.9%	4.1%	10%
	Healthcare	0.3%	1.6%	8.9%	22%
	Manufacturing	5.7%	10%	9.1%	30%
	Public works	0.1%	0.2%	0.4%	1.1%
Critical-peak pricing	Commercial/retail	0.9%	3.1%	5.2%	4.2%
	Government/education	1.5%	4.1%	2.3%	1.9%
	Healthcare	*0.9%*	*3.1%*	*5.2%*	*4.2%*
	Manufacturing	0.9%	4.5%	7.3%	6.9%
	Public works	1.2%	3.3%	1.3%	2.8%

Note: *Red-italicized* figures are based on expert judgment.

Another factor that strongly impacts participation rates is the definition and size of the eligible customer population. For the default hourly pricing tariff, only a specific set of large customers, with peak demand above 2 MW were eligible. In contrast, the other DR programs were open to significantly wider classes of customers. The threshold for the critical-peak pricing program was 100 or 200 kW (depending on the utility). For the ISO programs, eligibility is defined not by customer size class, but by a minimum allowable load reduction (i.e., 100 kW). To develop participation rates, we constructed the pool of eligible customers, assuming that the 100 kW minimum load reduction would be feasible among customers with peak demands of 350 kW and above[9]—thus, a very large number of non-residential customers in New York and the New England states were considered "eligible" for the ISO programs. Consequently, even though the actual number of participants (100–400 customers) is comparable across the programs and tariffs, the denominators range from hundreds to thousands of eligible customers.

A number of additional factors may influence rates of customer participation in DR programs and tariffs, including: program design features such as the structure and level of incentive payments, penalties for non-performance, and the duration, frequency and advance notice of events; customer familiarity with

[9] Though allowed in the program rules, load aggregators were not that active in these short-notice emergency DR programs (although they were active in the NYISO ICAP/SCR program). With aggregation, the pool of "eligible" customers would be even less well-defined.

or reputation of the entity administering the program; the effectiveness of marketing and/or customer education efforts; and the availability of technical or financial assistance.

Estimating Price Response

The next step in this framework is to assign *price elasticities* to each customer market segment, for each type of DR option, using available information on how similar customers have responded to high prices or program events afforded by similar DR options.

Analysts typically measure consumer response to changes in electricity prices with one of three measures of price elasticity: the *price elasticity of demand*, the *elasticity of substitution*, and the *arc price elasticity of demand*. All are estimated from a sample of observed customer electricity usage data in the face of changing prices.

From a theoretical standpoint, the price elasticity of demand (also known as the "own-price" elasticity) provides the most consistent characterization of consumer behavior. However, its estimation requires data on customers' production output, or the utility they derive from electricity usage, that is usually not available.[10] A number of studies of large customer price response have instead estimated substitution elasticities, which are also grounded in economic theory and can be estimated without output data, but impose assumptions about how customers use electricity. Arc elasticities are much easier to compute (only a limited number of observations of customer loads and prices are necessary) but this comes at the cost of limited explanatory power.

The tradeoffs between theoretical consistency and the amount of data required to estimate these three elasticity measures are summarized in **Figure 1**. As a general rule of thumb, analysts should choose the measure with the greatest theoretical consistency possible given available data.

For each DR option included in our simulation, we calculated elasticity values, disaggregated by market segment, using individual customer load and price data. For the two hourly pricing tariffs, we estimated demand models to calculate *substitution elasticities*.[11] For the other programs, insufficient numbers of observations covering too small a range of prices were available to estimate a fully specified demand model, so we calculated *arc elasticities*. [12] The resulting average elasticity values estimated for each program and market segment are presented in **Table 4**.[13]

Studies of customer price response indicate that there is considerable diversity in how customers respond to similar prices and incentives, even among customer market segments. External factors—such as high-price or program event characteristics and weather—and customer-specific characteristics or circumstances—such as customer experience, ownership of onsite generation and other enabling technologies, and electricity intensity—may influence price response. Unfortunately, insufficient information was available among our data sources to evaluate the impacts of most such factors (see Goldman et al. 2007).

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[10] Those analysts that have estimated own-price elasticities derived a proxy for firm output or customer utility that assumes a cyclical pattern.

[11] For more details, see Goldman et al. (2005) and Boisvert et al. (2004).

[12] Substitution and arc elasticity values are not directly comparable, although the market potential impacts derived from them are.

[13] For the price response event program, a number of program events occurred when prices were quite low (\$100–150/MWh). Including observations from these low-price events resulted in extremely high average elasticities, because there was considerable variation in loads, but relatively small price differentials. To remove this "noise" from the elasticity estimates, we restricted our analysis to observations where the price was \$150/MWh or higher.

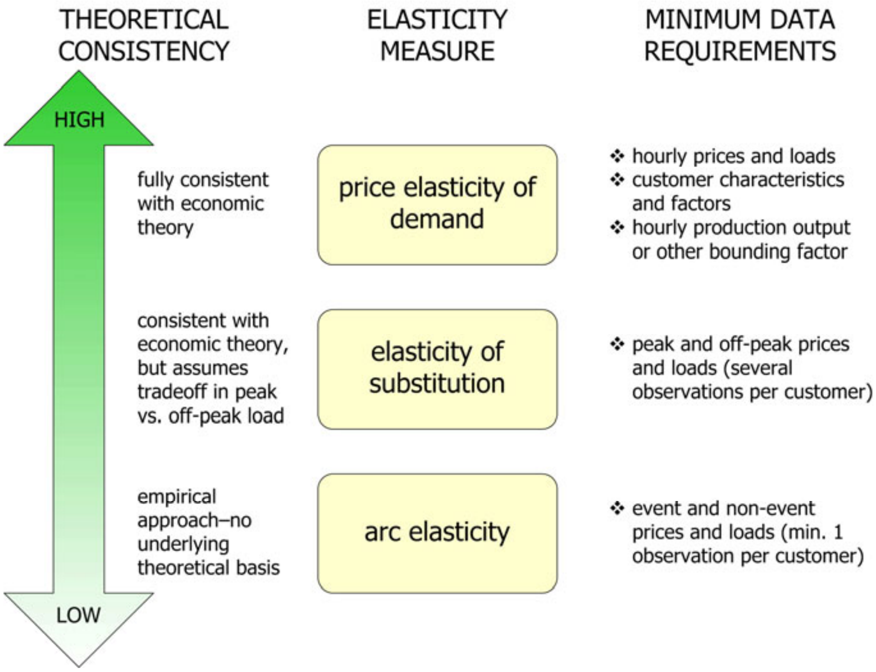


Figure 1. Features of Price Elasticity Measures

Table 4. Average Elasticity Values

Customer Market Segment	DR Option				
	Optional Hourly Pricing	**Default Hourly Pricing**	**Short-notice Emergency Program**	**Price Response Event Program**	**Critical-peak Pricing**
Commercial/retail	0.01	0.06	-0.03	-0.09	-0.10
Government/education	0.01	0.10	-0.02	-0.16	-0.06
Healthcare	0.01	0.04	-0.04	-0.05	-0.01
Manufacturing	0.26	0.16	-0.04	-0.16	-0.05
Public works	0.07	0.02	-0.08	-0.22	-0.08

Note: Elasticity of substitution values are shown for optional and default hourly pricing; arc elasticity values are shown for all other DR options.

However, for one of the short-notice emergency programs (NYISO EDRP), enough information was available to differentiate response among customers owning onsite generation from those without this technology. On average, customers in this DR program with onsite generators had arc elasticities about 40% higher than customers that did not. This translates to elasticity values for customers without onsite generation that are 14% lower than the average elasticities for each market segment (see **Table 5**). For those with onsite generation, the elasticity values are 52% higher than the average.

We also refined the elasticity estimates to reflect customer response at high prices (> $450/MWh). The base case elasticity estimates were evaluated over a range of prices, and this refinement tests the sensitivity of the estimates to this assumption.[14] Our market potential simulations assume an "event" (or high hourly) price of $500/MWh, so this refinement brings the elasticity estimates in closer alignment

[14] Applying average elasticities derived from a range of price levels to estimate response to a specific price may be misleading if customers respond differently at different price thresholds. Goldman et al. (2005) found statistically significant differences in customer price response at different prices.

with the simulated conditions.

Table 5. Arc Elasticity Values Adjusted for Onsite Generation

Customer Market Segment	Short-notice Emergency Program	
	without DG	**with DG**
Commercial/retail	-0.03	-0.05
Government/education	-0.02	-0.03
Healthcare	-0.03	-0.05
Manufacturing	-0.04	-0.07
Public works	-0.07	-0.12

For the default hourly pricing option, high-price substitution elasticities were developed using a flexible model that allowed for statistical evaluation of response at different price thresholds (see Goldman et al. 2005). We applied adjustment factors derived from this model to each market segment to develop elasticities tailored to response at high prices.

For the arc-elasticity values calculated from the DR programs, we simply eliminated observations for which the event price was below $450/MWh, and recomputed average elasticities for each sector and program from this smaller set of observations.

The resulting elasticity values of customer response to high prices are presented in **Table 6**. For the default hourly pricing tariff, commercial/retail and government/education customers *increase* their response at high prices while there is no change in manufacturing customers' response.

Table 6. Elasticities Based on Customer Response to High Prices ($500/MWh)

Customer Market Segment	DR Option			
	Default Hourly Pricing	**Short-notice Emergency Program**	**Price Response Event Program**	**Critical-peak Pricing**
Commercial/retail	0.10	-0.03	-0.02	-0.04
Government/education	0.16	-0.02	-0.02	-0.04
Healthcare	0.03	-0.04	-0.01	-0.00
Manufacturing	0.16	-0.04	-0.03	-0.03
Public works	0.01	-0.08	-0.02	-0.05

Note: Elasticity of substitution values are shown for optional and default hourly pricing; arc elasticity values are shown for all other DR options.

Very few of the observations for the two short-notice emergency programs involved event prices lower than $450/MWh, so the revised elasticity estimates are essentially unchanged.[15]

For the price response event program and critical-peak pricing, the elasticities shown in Table 6 decrease compared to the averages in **Table 4** in all market segments. This occurs because these customers' load response (the numerator in the arc elasticity) was fairly consistent across the range of prices, while the price differential (the denominator) increases with higher event prices. We believe that

[15] The program design of the NYISO EDRP program sets a floor price of $500/MWh, so none of these observations were removed. ISO-NE's emergency program offers two floor-price options—$500/MWh and $250/MWh—depending on the amount of notice customers receive of impending events.

this result may be partly attributable to the program design and is also consistent with the notion that many large business and institutional customers are only willing to curtail or forego load which they consider "discretionary." Restricting the dataset to events with higher prices therefore results in lower average elasticities. This effect is relatively minor for the critical-peak pricing example, but is quite pronounced for the price response event program (compare elasticity values in Table 4 vs. Table 6).

Estimating Load Impacts

The final step is to pull together all the pieces to estimate aggregate load impacts, which should be done separately for each DR option under consideration.[16]

For each customer market segment, program penetration rates should be applied to the target population in that segment. Then, elasticity values are applied to the customers in each market segment, allocating any factor-specific elasticity estimates (such as those developed for customers with and without onsite generation in the previous section) to those customers to whom they apply.

Once each customer has been assigned an elasticity value, it remains to translate the results into an estimate of aggregate load impacts for a range of expected prices or incentive levels. The methods for doing this depend on the type of elasticity estimated (e.g., substitution or arc elasticity). Goldman et al. (2007) discusses these methods in detail. Once the load impacts have been established (in MW), they can be expressed as a percentage of the peak demand of the applicable customer class.

To demonstrate the application of our methodology, we applied our compiled participation rate and elasticity values to information on the customer population of an urban utility in the Northeastern U.S. to develop market potential estimates. The selected utility is relatively small; the peak demand of its large, non-residential customers is ~1,700 MW. These customers represent about 40% of the utility's peak demand, and consist largely of commercial/retail, government/education and healthcare facilities. Manufacturing customers are less prevalent than is typical among utilities that serve suburban or rural communities.

To estimate load impacts, we used business-class-specific load profiles derived from NMPC SC-3A customer data to establish "expected" customer loads absent DR (i.e., customer baseline loads). We also assumed an "event" (or high hourly) price of $500/MWh for all DR options. This is fairly typical of the high prices observed in hourly pricing programs, as well as incentive floor prices offered by ISO emergency programs, in recent years.

We developed five scenarios to demonstrate the effects of various factors on DR market potentials and to evaluate the robustness of the substitution and arc elasticities to changes in the simulation inputs;we highlight results from several of the scenarios (see Goldman et al (2007) for complete results).

Base Case. The base-case scenario uses average elasticity values by market segment (**Table 4**), and the participation rates in **Table 3** to estimate market potential for each DR option. The results range from <1% to 3% of the peak demand of the target population of customers larger than 350 kW (see **Table 7**).[17] The load reductions for the largest customers (>1 MW) enrolled in the default hourly pricing and price response event programs represent 5-6% of their aggregate peak demand. The highest market potential (3% of peak demand) corresponds to the default hourly pricing tariff—this is largely due to relatively high customer acceptance rates for this tariff.

[16] Analysts may wish to account for interactive effects arising from program eligibility rules that limit participation in multiple programs.

[17] We did not have access to class-level peak demand for the Northeastern utility. To approximate class-peak demand, we summed individual customers' peak demands. Because they are not simultaneous, this overestimates the actual class peak (and therefore under-estimates the proportional load impacts).

Table 7. Market Potential Results: Base Case

Customer Size (MW)	Optional Hourly Pricing		Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]
0.35–0.5	1.0	0%	2.8	0%	0.4	0%	1.6	0%	1.3	0%
0.5–1	1.1	0%	3.9	1%	4.3	1%	3.0	1%	1.7	1%
1–2	1.9	1%	14.4	6%	3.8	2%	3.9	2%	1.9	1%
> 2	21.6	4%	34.8	6%	11.5	2%	29.1	5%	2.4	0%
Total	**25.6**	**2%**	**55.9**	**3%**	**19.9**	**1%**	**37.6**	**2%**	**7.3**	**<1%**

[1] Peak demand is non-coincident.

Note: Each DR option was evaluated separately—the results are not additive.

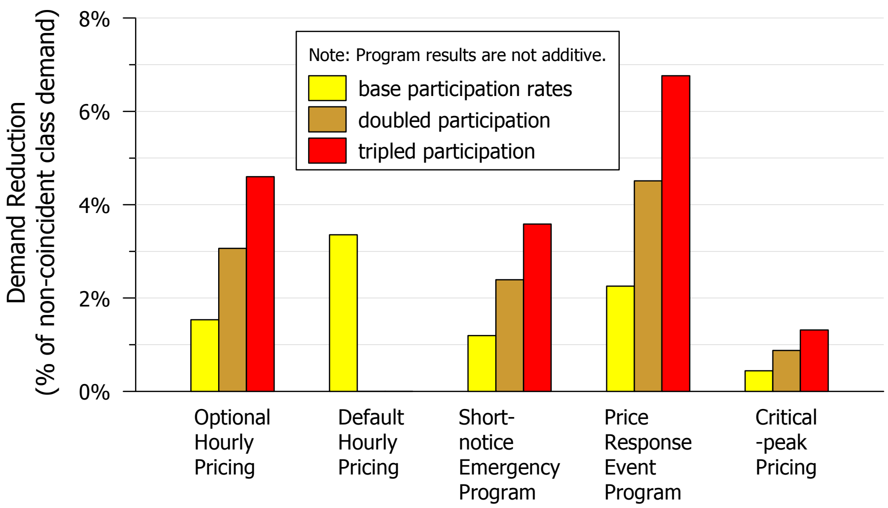
Impact of Program Participation Rates. Market assessments often examine the impact of differing rates of participation on program potential. **Figure 2** illustrates the impact of aggressively marketing programs or promoting optional tariffs to achieve two and three times the base-case participation rates, which reflect current DR experience. The results, on the order of 3–6% of non-residential peak demand, can be viewed as an approximate upper bound on DR potentials.[18] For default hourly pricing, which by definition would not be marketed to customers, we do not show enhanced participation, although the base-case results are included in the figure for comparison.

Accounting for Onsite Generation. We examined the impact of refining the short-notice emergency program elasticity estimates to account for the influence of onsite generation technology on customer response (see **Table 8**). This resulted in slightly lower market potential estimates than the base case for this DR option (i.e., 17.6 versus 19.9 MW). This is due to our assumptions about the distribution of onsite generators among the customer population at the illustrative urban utility compared to the observed distribution among the customers from whom the elasticity estimates were estimated.[19]

Although the overall market potential estimates are comparable in this example, understanding differences in the underlying elasticities among customers with and without enabling technologies can help policymakers target programs to customers that are likely to be the most responsive (e.g. those with on-site generation equipment).

[18] These results assume that the additional enrolled customers are just as responsive to price signals or emergencies as the relatively "early adopters" observed among our data sources. In reality, it may be that the most responsive customers are also the first to sign up, leading to declining average elasticities as more customers enroll. On the other hand, strategies that combine program marketing with technical assistance to develop fully automated DR could enhance both participation rates and response to prices or emergencies.

[19] Detailed information on the distribution of onsite generators among the Northeast utility's customers was not available. To perform the simulation, we developed onsite generation penetration rates from building survey data (see Goldman et al. 2007).



Note: Elasticities are assumed constant over all participation scenarios—this assumption has yet to be evaluated with actual program experience.

Figure 2. Impact of Program Participation on DR Market Potential

Table 8. Market Potential Results: Onsite Generation

Customer Size (MW)	**Short-notice Emergency Program**	
	MW	**% of class peak dmd**[1]
0.35–0.5	0.3	0%
0.5–1	3.7	1%
1–2	3.4	1%
> 2	10.2	2%
Total	**17.6**	**1%**

[1] Peak demand is non-coincident.

Accounting for Response at High Prices. In this scenario, we refined the elasticity estimates of four of the program types to better reflect customer response at the $500/MWh event price assumed for these simulations. Comparing the results in **Table 9** with the base case (**Table 7**) reveals that for the default hourly pricing program, accounting for differences in response at higher prices results in higher market potential (i.e., 74 versus 55 MW). This result is driven by the fact that customers in certain market segments (government/education and commercial/retail) were more price-responsive at higher prices and our illustrative utility had a high proportion of these types of customers.

Table 9. Market Potential Results: Response at High Prices

Customer Size (MW)	**Default Hourly Pricing**		**Short-notice Emergency Program**		**Price Response Event Program**		**Critical-peak Pricing**	
	MW	**% of class peak demand**[1]	**MW**	**% of class peak demand**[1]	**MW**	**% of class peak demand**[1]	**MW**	**% of class peak demand**[1]
0.35–0.5	4.1	1%	0.4	0%	0.3	0%	0.7	0%
0.5–1	5.7	2%	4.2	1%	0.5	0%	1.0	0%
1–2	19.2	8%	3.7	2%	0.7	0%	1.0	0%
> 2	45.3	8%	11.1	2%	5.1	1%	1.3	0%

	Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
Total	**74.2**	**4%**	**19.4**	**1%**	**6.6**	**0%**	**4.1**	**0%**

[1] Peak demand is non-coincident.
Note: Each DR option was evaluated separately—the results are not additive.

In contrast, for the price response event program and critical-peak pricing, restricting observations to only high-price events resulted in lower average arc elasticities in all market segments. The arc elasticity values are lower for these options because participating customers provided similar load reductions at low prices (~$200/MWh) as they did above $450/MWh (i.e., the percentage change in load remains the same during the high price event hours, while the percentage change in price increases). As a result, the market potential estimates are lower for these two programs than the base case that used average elasticities across all observed prices. Because the short-notice emergency program elasticities were virtually unchanged (see **Table 6**), the difference in market potential relative to the base case is negligible.

This scenario demonstrates the limitations of arc elasticities in accounting for influences other than price on customer load changes. Because only prices and load at a single event are captured, there is no way to account or correct for noise in the estimates (i.e. other factors that drive changes in customer usage). At higher prices, we believe that changes in load are more likely a result of prices rather than other factors. When arc elasticities are used, it is therefore important to be cognizant of these limitations and ensure that observations are drawn from conditions similar to those being simulated.

Conclusions

The above simulations illustrate possible ranges of DR market potential for large commercial and industrial customers at an urban Northeast utility, as well as several methodological and data issues. The results are tied to the characteristics of this urban utility's large customer base as well as the specific assumptions we made about prices and other factors in the various scenarios. Nonetheless, we draw the following insights and conclusions from our scoping study of DR market potential:

- We believe that the results provide a **reasonable first approximation of the range of DR market potential among non-residential customers** if offered similar DR options by similar utilities. While the observed load reductions—1% to 3% of the peak demand of the target population of large customers—are modest, a number of studies suggest that a little DR can often go a long way towards ameliorating system emergencies or high prices. If policymakers or regulators establish higher DR goals, then our results suggest that the DR market potential of all customer classes should be considered—not just large commercial and industrial customers. Pilot program results suggest that enabling technologies and automated DR can also increase both the number of customers willing to participate in DR options as well as the predictability and consistency of their load response.
- The simulations illustrate the **relative impact of certain factors, particularly customer participation rates, on potential aggregate load reductions** of large customers. Participation rates currently represent the largest data uncertainty for analysts undertaking market potential studies. Yet achieving higher participation rates among eligible large customers is critical for obtaining a significant amount of price-responsive load. Assessment of DR potential should attempt to account for the level of program resources (e.g. education, training, technical assistance) that will be devoted to program implementation and which may influence participation rates.

- The scenarios also demonstrate **the importance of refining elasticity estimates rather than applying average values**. In several cases, this resulted in *lower* market potential estimates in our simulations. Policymakers considering establishing DR goals should be aware that goals extrapolated from pilot programs or DR potential study estimates based only on small samples of very responsive customers may not be achievable.
- Finally, we emphasize that **all DR market potential studies should examine a range of scenarios**—not limited to those demonstrated here—in estimating DR market potential.

Recommendations

To advance the state of knowledge about customer response to DR programs and dynamic pricing tariffs and facilitate DR market assessments, we recommend that state and federal policymakers and regulators encourage utilities, retailers and Independent System Operators/Regional Transmission Organizations and their program evaluators conduct the following activities:

1. ***Link Program Evaluation to Market Potential Studies*****:** Evaluations of DR programs should systematically collect data on the characteristics of participating customers; hourly customer loads and prices; other factors found to be relevant drivers of customer participation and response; and information on the size and characteristics of the target or eligible population.
2. ***Program Participation*****:** Develop predictive methods for estimating participation rates in DR programs and dynamic pricing tariffs that incorporate customer characteristics and other factors that drive participation. Where applicable, studies should include interactive effects of multiple program offerings in estimating market penetration rates.
3. ***Price Response:*** Estimate price elasticity values for different market segments, accounting for the relative impact of driving factors, and report methods and results transparently. Where possible, we recommend that provisions be made to estimate demand or substitution elasticities, using fully specified demand models, rather than arc elasticities.
4. ***Assess the Impacts of DR-Enabling Technologies*****:** For large customers, there is still a need to document the impacts of specific DR enabling technologies on customer participation and load response, given limited evidence and mixed results from existing evaluations. At a minimum, program evaluators should gather information on customer's load curtailment strategies that involve onsite generation,[20] peak load controls, energy management control systems, energy information systems, and any other technologies disseminated as part of technical assistance programs.
5. ***Publicize Results***: Explore ways to pool customer-level data, while protecting customer confidentiality, so that information to support DR market assessments is available in a standardized format.

These activities would provide more detailed and robust price response and participation rate values that can support DR market assessment activities. However, in order to make best use of this information, utilities, ISOs/RTOs, and states will need disaggregated information on the characteristics of their target population of customers (e.g., customer loads by size range, market segments, enabling technology deployment). Some of this information is not typically collected by utilities on their customers. Therefore, we recommend that **states, utilities and their consultants** conducting DR market

[20] Information on diesel-fired emergency back-up generators should be tracked separately from cogeneration, combined heat and power, and other distributed energy technologies.

assessments first assess the availability of information on customer characteristics and usage in their jurisdictions and include plans to collect or estimate any necessary incremental information in their study plans and budgets.

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