CON EDISON CALLABLE LOAD STUDY

Submitted To:
Consolidated Edison Company of New York (Con Edison)

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SUMMIT BLUE
CONSULTING, LLC

FINAL REPORT

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E EXECUTIVE SUMMARY

This report was prepared for Consolidated Edison Company of New York (Con Edison) to assess "callable load opportunities" in New York City and Westchester County during the next 10 years. For purposes of this study, callable load opportunities represent short-term reductions in system demand, typically four hours or less in duration, that are provided by individual customers (or aggregated groups of customers) curtailing their electricity consumption or deploying emergency generation on request.

This study achieves two primary objectives:

1. Assess the potential, in megawatts, for peak load reductions that can be called by Con Edison.
2. Present program concepts that provide pathways to cost-effectively achieve this potential.

The study is part of a planning process for developing effective demand response (DR) programs to reduce peak system loads. As a planning tool, the study develops a scenario analysis using current information from Con Edison customers' participation in DR programs and from utility experience around the country. This is meant to provide a practical roadmap for pursuing opportunities that are likely to be available.

The potential literature that has been developed for energy efficiency generally uses the terms "technical" potential, "economic" potential, and "market" (or "achievable") potential. In terms of *technical potential,* many customers have the physical capability of shutting off most or all of their facilities; however, for the vast majority of customers, this level of curtailment—while *technically* possible—is not practical. A more practical way to view callable load potential is in terms of the *achievable* potential. Consequently, this study adopts the following approach (see Section 2.1):

- *Achievable potential* is the appropriate starting point for estimation and is defined as firm, verifiable callable load reductions that are likely to be achievable given sufficient incentives and based on curtailment levels observed through DR programs in Con Edison's service territory and elsewhere.
- *Economic potential* is based on the achievable potential passing a screening tool with a benefit-cost ratio of greater than 1.0.
- *Technical potential* may be a useful benchmark and is defined as the load reductions that could be expected at 100% participation, with the estimated load curtailment assumptions based on the DR program designs.

Project activities were focused on two primary efforts: 1) estimation of callable load potential and 2) development of cost-effective program strategies to achieve that potential. Many of the initial data analysis and research activities contributed to these efforts, including customer data analysis, survey development and administration, and assessment of secondary data and survey findings. Estimation of callable load potential was conducted primarily with detailed customer billing data and secondary data from DR program experiences at other utilities. Recommendations on program strategy development incorporated customer data, interviews with market actors, and a high-level assessment of program costs.

E.1 Demand Response Market Characterization

The potential for callable load reduction in the Con Edison service territory was estimated via analysis of data specific to Con Edison customers that was used to characterize the regional market. This market characterization provided input to the Callable Load Reduction Potential Estimator, a model that was developed for this study and tailored specifically to the Con Edison market (see Appendix I-B). Key findings from the market characterization include the following (also see Chapter 4):

- Total nominal *enrollment* by Con Edison customers in DR programs in 2007 was 783 MW. *Available* demand response from the enrolled customers is somewhat less than this value, however, due to the fact that some Distribution Load Relief Program (DLRP) participants are also enrolled in NYISO programs. Furthermore, roughly 231 MW of enrollments represent voluntary commitments through either the EDRP or the voluntary component of the DLRP. Historically, participants in these programs have provided load reductions of between 35% and 63% of commitments. The combined effect of the enrollment overlap and the effective curtailment rates is that achievable callable load reductions are currently estimated at approximately 569 MW.

- Office buildings, government facilities, and residential customers constitute the majority of peak demand, collectively representing 71% of the total coincident peak demand in the Con Edison service territory.

- Two customer segments, government facilities and office buildings, are estimated to constitute 74% of the entire installed capacity for emergency generation of 1,470 MW.

- A substantial fraction of the peak demand in many customer segments is in the hands of a small percentage of the total customers, indicating that a focus on the largest customers in each demand segment is more likely to be cost-effective and that diminishing returns may ensue once certain thresholds of penetration are reached.

E.2 Callable Load Potential in 2017

To estimate the potential for callable load reduction in the Con Edison service territory, the study team characterized the market in this region via analysis of data specific to Con Edison customers. This market characterization provided input to the Callable Load Reduction Potential Estimator, which was developed specifically for this analysis and used to estimate both the *achievable* and *technical* potential for callable load reduction in 2017.

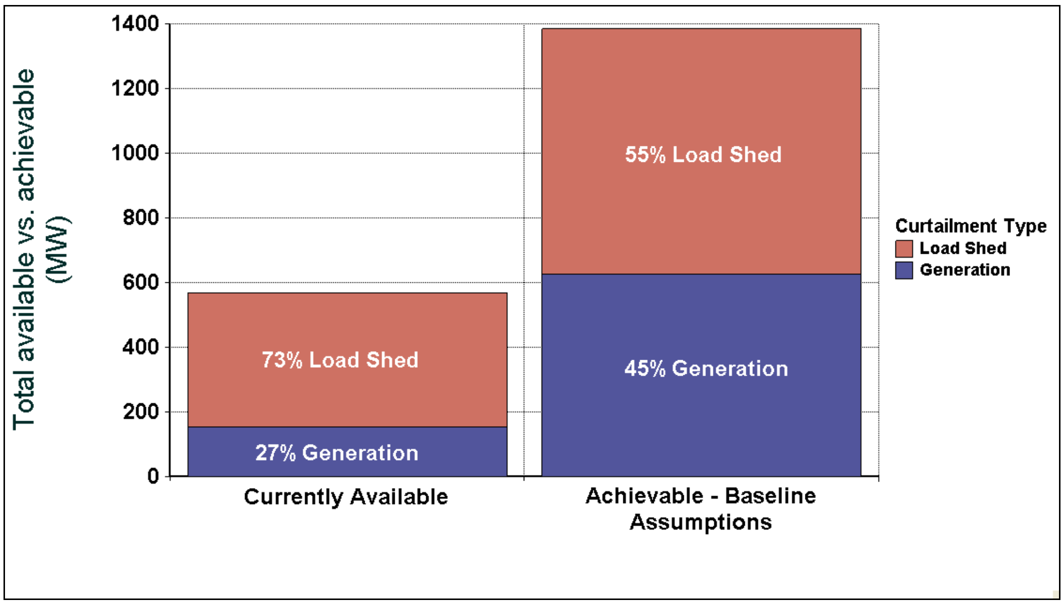
Achievable potential was examined in detail by both customer segment and curtailment type (i.e., load shed vs. emergency generation) to identify customer segments providing the greatest opportunity for callable load reduction. Further, gap analysis was conducted by comparing the callable load reduction currently estimated to be available with the achievable potential to estimate the gap that would need to be closed, by customer segment, to realize the achievable potential in 2017. Finally, the total technical potential for callable load reduction was estimated as a theoretical upper bound on callable reduction opportunities.

For callable load reductions to be used in utility resource planning, they must be reliable ("firm" reductions) and verifiable. The term "verifiable" could be construed as use of a meter capable of providing continuous interval data that can be used to estimate an accurate baseline for use in calculating load reductions.[1]

Highlights of the findings of callable load potential are provided below (also see Chapter 5).

- The achievable potential for callable load reduction in the Con Edison service territory in 2017 is estimated to be 1,384 MW through various programs, more than double the 569 MW assumed to be available today through current DR programs (Figure E-1). This represents 9.3% of the forecast peak demand (net of savings from energy efficiency) of 14,900 MW in 2017.[2] The share of total curtailments contributed by emergency generation would have to grow from 27% to 45% by 2017 to realize the achievable potential, depending in part on future regulation of distributed generation as a demand response resource. [3]

Figure E-1. Currently Available Callable Load Resources vs. 2017 Achievable Potential



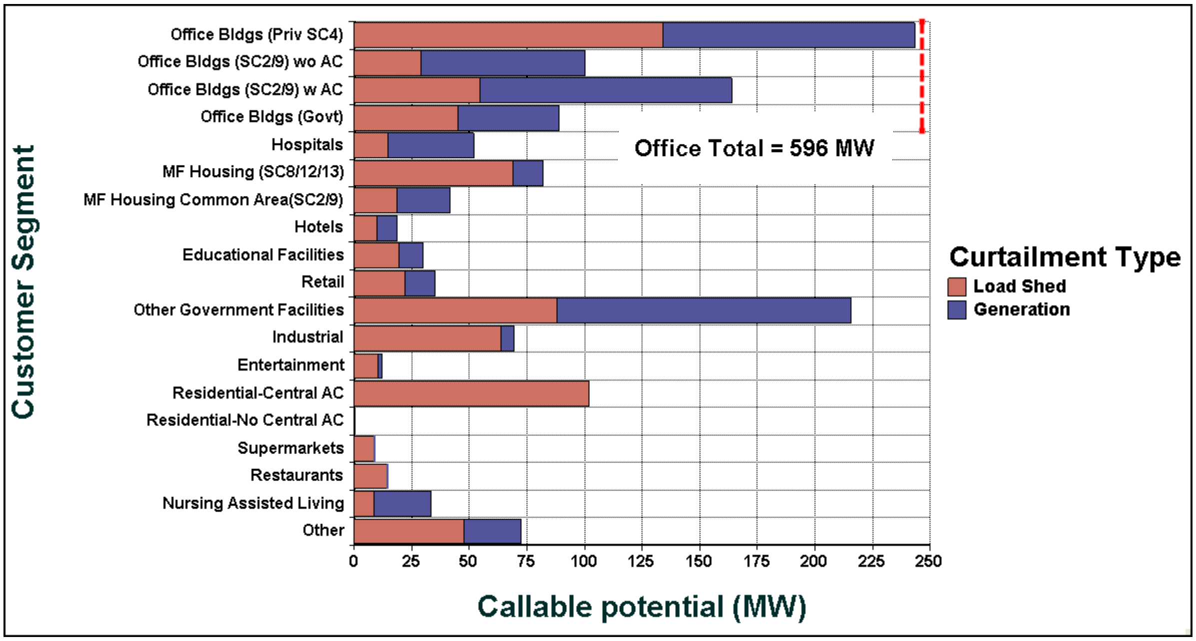
[1] Customer load reductions in DR programs in New York are commonly calculated by establishing a baseline load determined by the Average Peak Monthly Demand (APMD). APMD, which is defined as the average of the highest one-hour demands in the months of June through September of the previous year, may provide less accurate baseline estimates than would other methods and may result in an overestimate of actual load reductions. This raises questions about the reliability of using DR load curtailments, as currently calculated, for purposes of utility resource planning. Some other jurisdictions use a customer baseline load (CBL) method based on recent similar-day loads, with a same-day adjustment that can account for changes in baseline loads due to weather.

[2] The finding of potential callable load reductions of 9.3% of system peak demand in 2017 is similar to that of a recent analysis by the Electric Power Research Institute (EPRI), estimating that peak load reductions from demand response in the Northeast will be 8.2% of system peak load in 2020 and more than 11% by 2030, although it should be noted that Con Edison's service territory has a low percentage of industrial load, which is generally more easily curtailed. Source: Electric Power Research Institute and Edison Electric Institute. *Potential for Energy Efficiency and Demand Response in the U.S., 2008 to 2030*. EPRI. Palo Alto, CA. 2008.

[3] The study team is aware that regulations are currently being considered that could reduce the ability of emergency generation to contribute to demand response (see New York State Department of Environmental Conservation, proposed rule modifying 6 NYCRR Part 222 Distributed Generation Sources, October 25, 2007). The ultimate ramifications of such regulations, if proposed and adopted, are still largely uncertain, however, and therefore were not explicitly included as part of the scenario analysis.

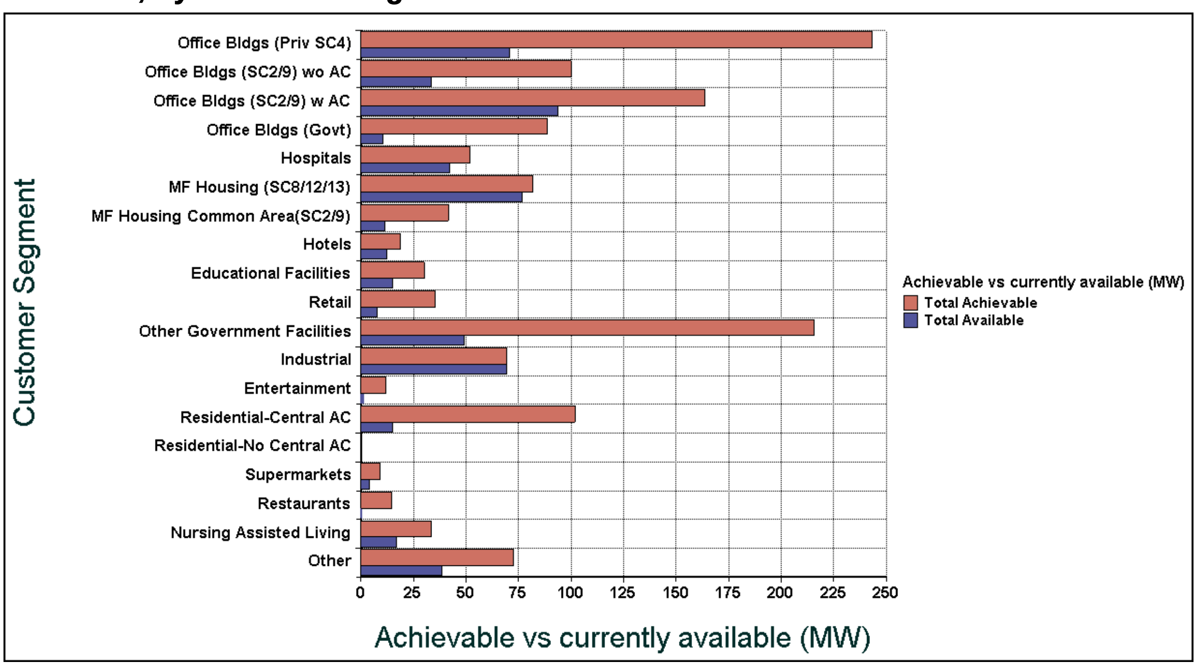
- The combined achievable potential of office buildings (596 MW), government facilities (216 MW), and residential customers (102 MW) accounts for 66% of the total projected achievable potential of 1,384 MW by 2017 (Figure E-2).

Figure E-2. Achievable Callable Load Potential in 2017 by Customer Segment



- The gap between currently available load reduction and achievable potential is estimated to be 815 MW (1,384 MW of achievable potential minus 569 MW of currently available load reduction). Office buildings, government facilities, and residential customers account for 69% of the 815 MW gap between currently available load reduction and achievable potential (Figure E-3).

Figure E-3. Currently Available Callable Load Resources vs. 2017 Achievable Potential, by Customer Segment



- Most reasonable scenarios for achievable callable load potential appear to be cost-effective based on the avoided generation and transmission and distribution (T&D) costs used in this analysis. It is estimated that a C&I sector DR program that would achieve the potential callable load reductions described above would have a benefit-cost (B/C) ratio of 3.4 under the TRC test (see Section 7.2). The Utility Cost Test measures benefits and costs from a Con Edison perspective (*i.e.*, Con Edison receives benefits only from avoided T&D system investments but not from avoided generation capacity). The B/C ratio for the Utility Cost Test is estimated at 1.5.
- This suggests that it would be cost-effective from the perspective of Con Edison as the program administrator. However, a sensitivity analysis that uses lower avoided T&D cost values that are approximately half those used in the base case economic analysis (*i.e.*, new values of $55/kW-year for short-notice demand response and half again, $28/kW-year, for longer-notification demand response) would yield a B/C ratio of 0.7. Avoided distribution and substation costs are uncertain due to the need for DR of the right magnitude, at the right time, and at the right place (*i.e.*, geographically focused), and that is assured and verifiable, before distribution costs can be deferred.
- The implication of these findings is that the significant increase in callable load capability envisioned by this analysis is likely cost-effective from a societal perspective but may not be economic for Con Edison, depending upon the value assumed for the avoided T&D costs. The driver behind this finding is that demand response under DLRP is being paid for by Con Edison but the Company does not receive all of the benefits of the DR investment.

E.3 Summary of Findings from Market Research

Market research efforts in support of this study were used to identify customer participation drivers and barriers, load curtailment capabilities, and availability of technologies to facilitate demand response such as emergency generation and building energy management systems (see Chapter 3). Key findings from this effort include the following:

- *More than 80% of DR program participants intend to re-enroll in DR programs, and nearly two-thirds are "definite."* Only 21% of non-participants expressed a likelihood of enrolling, suggesting that once a customer becomes familiar with demand response, the barriers to participation are lowered.
- *DR program participants are currently providing as much load curtailment as they believe they can reasonably do, even if an electricity shortage were imminent.* These curtailments are estimated at 20% of lighting load, 34% of HVAC load, and 16% of other loads.
- *The most common load shed measures (not including use of emergency generation) include various lighting measures such as turning off common area and decorative lighting and using daylighting where possible* (nearly 50% of respondents). Common HVAC measures include turning off select fans (83% of all respondents), turning off chillers and AC units, and using pre-cooling strategies.
- *Roughly one-third of respondents with emergency generation would consider using it for demand response.* More than 40% would be interested in a program sponsored by Con Edison to help provide and maintain emergency generation in exchange for an agreement to allow Con Edison to use the resources when the grid is under stress.
- *A majority of customers responding to the survey have building energy management systems that can be used to automate load shed.* Nearly half of these systems can control lighting, ventilation rates, and other loads that can contribute to demand response.
- *Customers not currently participating in any DR programs tend to favor voluntary programs with longer notification periods* (assuming no change in incentives). There was a strong preference for the NYISO Emergency Demand Response Program (EDRP), which may be attributable to greater

familiarity with the NYISO programs relative to Con Edison’s DLRP program. However, the longer notification period likely also played a role in respondents’ preferences. The average likelihood of enrolling in a DR program dropped from 2.8 (on a 5-point scale) to 2.3 when it was suggested that notification time would be decreased.

E.4 Recommendations

Recommendations are presented in three groups. The first group consists of *near-term recommendations* for actions that can be taken in the next year to several years (Table E-1). These recommendations are targeted at improving current DR efforts and establishing a platform for meeting the estimated callable load potential in 2017. The second group of recommendations consists of *longer-term recommendations* that would be rolled out in the next several years, and whose impact may not be fully realized for three to five years or longer (Table E-2). Finally, recommendations are presented for the components of a *demand response program portfolio* that can cost-effectively reach the achievable callable load reduction potential estimated in this report. (See below for a summary of the program portfolio recommendations; a full discussion of all recommendations is presented in Chapter 8.

Table E-1. Near-term Recommendations

Program Design	***Use of Emergency Generation***
N1. Continue offering the “mandatory” or “firm load shed” participation options that currently provide firm commitments. N2. Ensure that new program designs continue to have appropriate financial penalties/incentives. N3. Include a program participation option for 10-minute response. N4. Continue offering voluntary participation options.	N12. Promote installation of grid-synchronized emergency generation. N13. Consider company-owned emergency generation located strategically throughout the distribution system. N14. Facilitate retro-fitting of diesel generators. N15. Serve as a neutral source of information to customers and regulators to assist in increasing the availability of emergency generation for use in demand response.
Marketing and Delivery	***Assistance to Customers***
N5. Combine marketing and installation of DR technologies with energy efficiency programs where positive synergies exist. N6. Focus marketing efforts on office buildings and government facilities, which have the greatest potential for expanded callable load opportunities. N7. Focus marketing efforts on the largest customers. N8. Develop marketing communications specific to certain target sets of customers to speak to the issues raised by different customer segments. N9. Encourage or incent property owners and managers to bring their major tenants into the demand response decision-making process. N10. Investigate building a cooperative relationship with NYPA to jointly build DR pilots and programs. N11. Work with curtailment service providers/aggregators and leading technology companies who have expertise in addressing key customer segments to provide callable load reductions.	N16. Develop materials and methods to assist organizations in identifying the ways in which they can reduce their load during peak periods. N17. Develop methods to give recognition (*e.g.*, public via a web page) and appreciation (*e.g.*, via letters of appreciation) to organizations that participate in demand response programs. N18. Continue to develop customer relationships that reinforce customer service and overall customer satisfaction. N19. Develop the appropriate level of technical assistance for customers less knowledgeable about demand response. N20. Enhance the electricity market IQ of customers.

Table E-2. Longer-term Recommendations

L1.	Develop an ongoing marketing effort to encourage customers currently enrolled in voluntary programs to migrate to a firm capacity program.
L2.	Leverage new construction activity to promote pre-installation of technologies that facilitate demand response.
L3.	Increase the share of enrolled callable load that is automated via a remote signal from Con Edison or push button at the customer site.
L4.	Increase the share of enrolled callable load that can respond in 10 minutes.
L5.	Integrate DR planning with AMI business case development.
L6.	Research the feasibility and economics of using steam cooling for demand response.
L7.	Investigate the merits of establishing a demand response research center to test new DR technologies and to demonstrate successful technology applications.

It is recommended that these concepts be incorporated, where appropriate, into a **DR program portfolio** consisting of the following components:

1) **EXPANDED DLRP PROGRAM** that builds on Con Edison's current program. This program would continue both the voluntary and the mandatory (firm commitment) components and would also include an option for 10-minute event notification that would provide greater system benefits and significantly higher incentives for participants choosing this option.

2) **EXPANDED MASS MARKET DLC PROGRAM THAT IS AMI COMPATIBLE.** This expanded program could potentially reach more customers by leveraging the communications capability provided by a future AMI infrastructure. This may alleviate the need for two-way communicating thermostats and could allow for provision of additional customer services using the AMI gateway and new in-home thermostat and energy display technologies.

3) **AUTO-DR TECHNOLOGY ASSISTANCE FOR DLRP PARTICIPANTS** that automates load curtailments in C&I buildings. This is not as much a new program as it is a technology concept that would increase the ease with which customers can achieve load sheds, thereby increasing customer retention and reliability of load reductions.

4) **CLEAN DISTRIBUTED GENERATION INITIATIVE FOR RELIABILITY AND DEMAND RESPONSE**. The goal of this effort would be to increase the amount of available customer-sited emergency generation that can be used for demand response.

If an addition were to be made to this portfolio, it is recommended that Con Edison add a pricing program such as real-time pricing or a time-of-use or critical peak pricing program. These programs could be designed for either C&I customers or residential customers and might allow customers that are not currently suitable for participating in existing DR programs to benefit from a Con Edison DR program that allows them to better manage their energy bills. These pricing options are likely to also offer additional benefits to participants in DR programs by allowing them to shift load every day and see the benefits on their electric bill. These programs would be in addition to Con Edison's Mandatory Hourly Pricing and the NYISO's Day-Ahead Demand Reduction Program, and could be made available to residential and smaller commercial customers.

1 INTRODUCTION

This report was prepared for Consolidated Edison Company of New York (Con Edison) to assess "callable load opportunities" in New York City and Westchester County during the next 10 years.[4] For the purposes of this study, callable load opportunities represent short-term reductions in system demand, typically four hours or less in duration, that are provided by individual customers (or aggregated groups of customers) curtailing their electricity consumption or deploying emergency generation on request. Callable load events are initiated by Con Edison, the New York Independent System Operator (NYISO), or the New York Power Authority (NYPA) and can yield measurable load reductions as quickly as 10 minutes from the time that participating customers are notified.

This callable load assessment encompasses distribution customers across all of Con Edison's territory regardless of whether they purchase their electricity commodity from Con Edison or another provider. The assessment also includes participants in demand response programs offered through other entities, such as the NYISO and NYPA.

This study achieves <u>two primary objectives</u>:

1. Assess the potential, in megawatts, for peak load reductions that can be called by Con Edison;
2. Present program concepts that provide pathways to cost-effectively achieve this potential.

The study is part of a planning process for developing effective demand response (DR) programs to reduce peak system loads. As a planning tool, the study develops a scenario analysis using current information from Con Edison customer's participation in DR programs and from utility experience around the country. This is meant to provide a practical road map for pursuing cost-effective opportunities that are *likely to be available*. Given recent and on-going development of the DR industry, particularly when compared to energy efficiency programs, it is important to appropriately characterize the data and scenarios rather that omit context and develop what could be interpreted as a false sense of precision around callable load potential and the associated costs for DR program delivery. The approach used in this study reflects Con Edison's stated objectives to assess "peak reduction and callable load "opportunities." As such, this effort is meant to meet the following broader strategic goals:

1. *Identify priority markets for targeting demand response initiatives*, and
2. Provide recommendations on *how to allocate resources* most effectively to *develop delivery mechanisms* (whether "programs" or aggregator contracts) that achieve the best return on Con Edison's investment in load curtailment capability.

The remainder of this introductory section provides background on 1) the context for this study, 2) Con Edison's system load forecast and load shape, and 3) existing DR programs available to Con Edison customers.

1.1 Study Context

In May 2007 Con Edison produced a marketing and implementation plan with the stated objective to "increase by 20% current levels of participation in [demand response programs] as registered through Con

[4] Con Edison, *Request for Proposal Evaluating Peak Reduction/Callable Load Opportunities in New York City/Westchester County*, Request for Quote (Event 14038), September 2007.

Edison."[5] One element of the strategy for achieving this goal is conducting additional market research including market segmentation (building types, demographics, and load data) and surveys to further understand customer attitudes and behaviors. This Callable Load Study is one of several efforts that will assist Con Edison in identifying promising customer markets and developing programs to increase participation and achieve the potential for callable load reductions.

Over the past year, several modifications have been made to Con Edison's existing Rider U, which sets forth the tariff elements of the company's Distribution Load Relief Program (DLRP). For example, originally Rider U only provided for voluntary load curtailment resources. However, in a June 21, 2007 Commission Order (Case 07-E-0392), the NYSDPS, which is the staff arm of the Public Service Commission, suggested that more demand response resources might be attainable and could be used to protect against major customer service interruptions in the near term. Effective July 1, 2007, modifications were made to the Rider U tariff, including the allowance of load aggregators into the program and the development of a tariff component providing payment to customers willing to commit load reduction capability.[6]

In April 2008 the Commission approved further changes to the DLRP, including an increase in payment for committed load curtailment resources from "Tier 2" networks (those deemed most susceptible to failure) from $4.50 per kW-month to $6.00 per kW-month. Other major changes include recommendations to increase the number of networks in Tier 2 designation and increasing the notification time to customers from 30 minutes to two hours.

In addition, this Callable Load Study was ordered to be filed with the Commission by May 15, 2008. The Commission intends to consider information from the study in considering Rider U program goals in the future.[7]

1.2 Demand Response for Con Edison System Peak Loads

Callable load curtailments can assist Con Edison in meeting peak system demands as well as addressing contingencies on the transmission and distribution system. The Con Edison system peak load, which typically occurs during the late afternoons of the summer air conditioning season, reached 13,141 MW in August 2006. The 2007 peak was somewhat lower, at 12,807 MW, with nearly 50% serving Con Edison's full-service customers, more than one-third serving customers participating in its electric retail access program, and approximately 15% serving customers of NYPA and the municipal electric utilities association.

Con Edison's 2008 peak demand forecast is for a peak of 13,775 MW, which would represent a new system peak. Peak load growth is expected to continue at about 1% per year throughout the next decade,

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[5] For the purpose of the Plan, Demand Response Programs (DRP) are defined as the Con Edison Distribution Load Relief Program (DLRP) and the New York Independent System Operator's Emergency Demand Response Program (EDRP) and Installed Capacity Program (ICAP).

[6] *DLRP Program Evaluation Final Report*, Nexant, Inc., February 26, 2008.

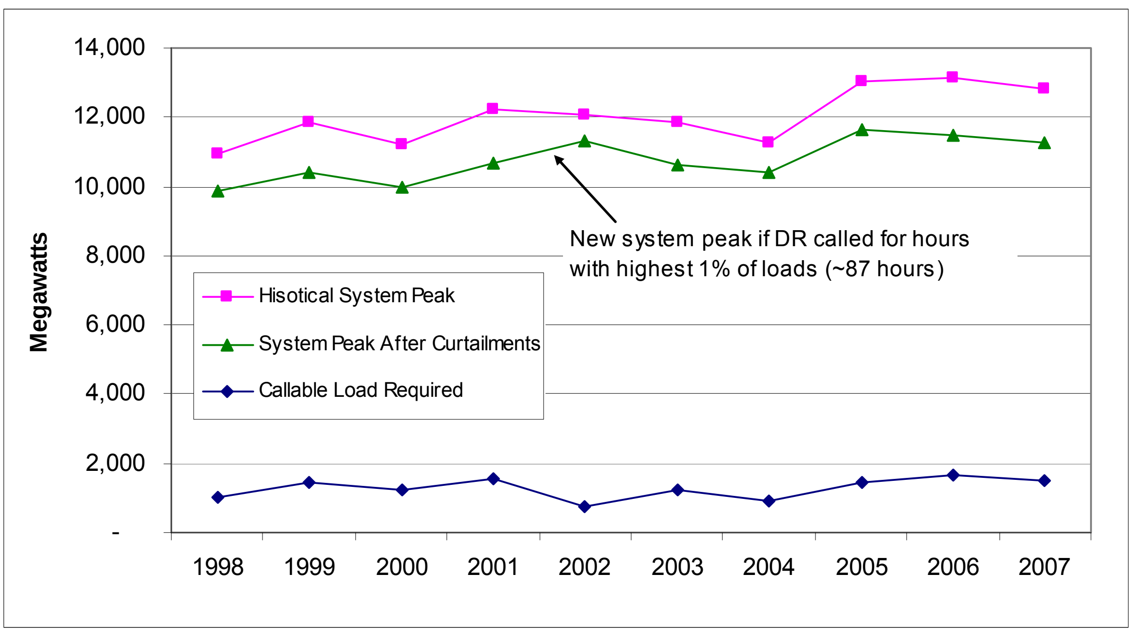
[7] NYSDPS Staff Order, Issued and Effective April 24, 2008. Subject: *CASE 07-E-0392 - Tariff amendments to increase participation in Rider U - Distribution Load Relief Program (DLRP) in compliance with Commission Order issued June 21, 2007* and *CASE 08-E-0176 – Report assessing the effectiveness of the Rider U including tariff amendments implementing changes to the program prior to the summer 2008 capability period.* Staff recommends that the amendments filed in Case 07-E-0392 be authorized to become effective on a permanent basis as of the issue date of the order.

with the 2017 peak projected to be approximately 14,900 MW. Increases in verifiable, firm demand response capability can economically meet some of the projected load growth, particularly given the difficulty in siting generation and the growing cost of supply side options.

For callable load reductions to be used in utility resource planning, they must be reliable ("firm" reductions) and verifiable. "Verifiable" could be construed as use of a revenue-grade interval meter and it implies provision of continuous interval meter data that can be used to estimate an accurate baseline for use in calculating load reductions. Customer load reductions in DR programs in New York are commonly calculated by establishing a baseline load determined by the Average Peak Monthly Demand (APMD). APMD, which is defined as the average of the highest one-hour demands in the months of June through September of the previous year, may provide less accurate baseline estimates than would other methods and may result in an overestimate of actual load reductions. This raises questions about the reliability of using DR load curtailments, as currently calculated, for purposes of utility resource planning. Some other jurisdictions use a customer baseline load (CBL) method based on recent similar-day loads, with a same-day adjustment that can account for changes in baseline loads due to weather. [8]

Despite the rising demand for peak power, Con Edison must serve at or near the maximum system load for only a small number of hours each year. In fact, the highest load in 2007 would have been only 11,283 MW (12% lower than the actual peak load) firm demand response resources were available for just the top 1% of hours with the highest loads (Figure 1-1). This suggests that ***if firm callable load reductions were employed for just the top 87 hours, more than 1,500 MW of generation capacity could be avoided***. The investment in expanding DR resources is particularly attractive given the economics of new peaking generation used less than about 200 hours per year.

Figure 1-1. Possible Reduction in Peak Demand from DR in Top 1% of Hours

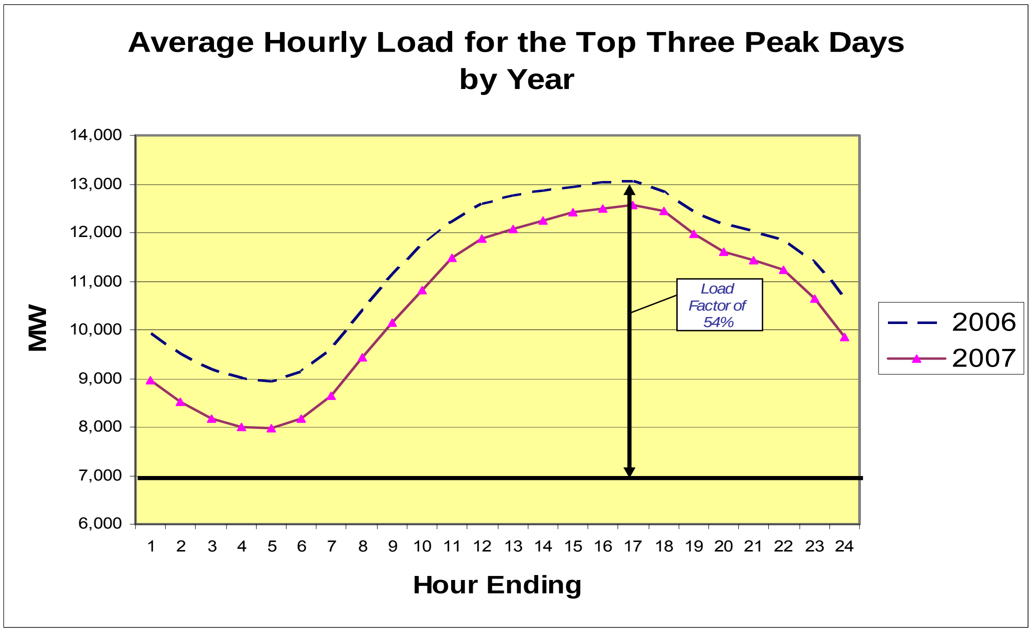


For callable load reductions to be most effective in reducing system peak demand, the loads need to be available during the times of highest system peak. This peak period is typically during the hot summer months when air conditioning load is highest, and in particular during the late afternoons from

[8] The limitations of shadow meters and the fact that they do not allow for baseline estimation using the CBL method are address in *DLRP Program Evaluation Final Report,* Nexant, Inc., February 26, 2008.

approximately 2 p.m. to 6 p.m. After this time system load drops sufficiently such that demand response resources are expected to play a less significant role in meeting system needs. Figure 1-2 presents the hourly load shapes for the top three peak days in 2006 and 2007, illustrating the time-dependent need for callable load reductions in the late afternoon hours.

Figure 1-2. Hourly Load Profile from High-Demand Days



Callable load has value on a network basis as well as for the system as a whole. In fact, demand response resources at Con Edison are largely designed to address distribution system contingencies as opposed to system-wide imbalances of supply and demand. Furthermore, the Con Edison service territory includes night-peaking networks that could also benefit from the use of callable load reductions in emergency situations.

There has been increasing activity across the country to develop and implement demand reduction programs in order to avoid electricity delivery interruption. Specifically, demand management programs help to mitigate price spikes, distribution and transmission congestion and it can help manage short and potentially longer emergencies and outages. Peak load management can be an economic resource within the portfolio of resources necessary for delivering reliable, safe, and clean supplies of electricity. This is particularly true for peaks that occur during only a few hours, i.e., less than 1% to 2% of the hours per year. It may not be economic to supply these loads during these few hours through traditional generation options. Other issues such as plant siting, fuel costs, transmission congestion, and limits on T&D expansion also can make DR resources both a sound economic and a service reliability choice when selecting resource investments, depending on the circumstances.

1.3 Existing Callable Load Programs

Con Edison currently offers several callable load programs, and many Con Edison customers also participated in demand response programs offered by the New York ISO. In 2007 approximately 783 MW of callable load commitments were enrolled by Con Edison customers in demand response programs.

Callable load and other types of demand response program offering are typically customized to specific sectors or end-uses, and Con Edison's programs do so. For example, the utility offers a "mass-market" program geared toward residential customers and small businesses (under 100 kW peak load) that is limited to controlling central air conditioners. Con Edison's "commercial/industrial" programs (including New York ISO programs offered to Con Edison customers) are available to Con Edison and NYPA electric customers capable of curtailing at least 50 kW or 100 kW, depending on the program.

Callable load programs are a category of demand response that specifically addresses load reductions during discrete events called by the program administrator. For purposes of this study, callable loads are specific loads, or kilowatt quantities, that have been previously identified by the customer as curtailable during a DR event. Some types of pricing programs, such as critical peak pricing,[9] can also yield event-based load reductions. However, pricing programs are not a primary focus of this effort.

Callable load offerings *currently available* to Con Edison customers include the following four programs:

1. Distribution Load Relief Program (DLRP)
2. Direct Load Control (DLC) Program
3. New York ISO Installed Capacity Program (ICAP)
4. New York ISO Emergency Demand Response Program (EDRP)

Participation in these programs in 2007 was varied, with nearly 500 MW enrolled in the ICAP program, approximately 140 MW each in DLRP and EDRP, and 30 MW in the DLC program.[10] Table 1-1 presents the breakdown of enrollment by program type, along with the total nominal enrollment value of 783 MW.

Table 1-1. Enrollment in Con Edison and New York ISO Demand Response Programs, 2007

Program	MW Enrolled
DLRP	138
ICAP	485
EDRP	140
DLC	30
TOTAL	**783**[11]

Curtailment potential from the enrolled customers is somewhat less than 783 MW due to the fact that some DLRP participants are also enrolled in NYISO programs. It is estimated that removing this overlap from the accounting of callable load potential results in approximately 690 MW of unique enrollments. Furthermore, roughly 231 MW of enrollments represent voluntary commitments through either the EDRP

[9] Critical peak pricing (CPP) programs typically are built on top of an underlying time-of-use (TOU) rate where customers are subject to different electric rates depending on the time of day and season. Rates during CPP events are significantly higher than even the highest TOU rate, thus encouraging a reduction in load during the event.

[10] Enrollment information provided by Con Edison: EDRP and ICAP enrollments based on NYISO data; DLC enrollments from *Con Edison Direct Load Control Program 2006 Annual Report*, Applied Energy Group, Inc.

[11] Enrollment in the four callable load programs through 2007 is estimated at 793 MW. However, updated 2007 values for the DLC program were not incorporated into this report until shortly before publication. As a result, comparisons between current enrollment and future callable load potential are based on the 2006 DLC enrollment of 20 MW, rather than the 30 MW enrolled through 2007. *Estimation of callable load potential is unaffected* by this use of 2006 data.

or the voluntary component of the DLRP. Historically, participants in the EDRP program have provided load reductions equal to approximately 35% of commitments, and those in the voluntary DLRP have provided reductions of roughly 63% of commitments.[12] Participants in the mandatory programs have achieved, on average, 97% of committed megawatts. The combined effect of the enrollment overlap and the effective curtailment rates is that achievable callable load reductions are currently estimated at approximately 569 MW.[13]

The four callable load programs available to Con Edison customers are discussed below and summarized in Table 1-2 directly after the descriptions.

Distribution Load Relief Program (DLRP)

This program is available to all Con Edison and NYPA electric customers located in the Con Edison service territory and capable of reducing at least 50 kW, and it is a designed to reduce strain at localized points on the distribution system during times of heavy demand. The program began as a voluntary curtailment program in which customers enrolled a specified megawatt amount but were not obligated to achieve this level of reduction and were not subject to penalties. In 2007, Con Edison added a reservation payment to the DLRP which pays participants for curtailments that the customers commit to make, regardless of when an event is called.[14] In 2007 Con Edison had enrolled roughly 138 MW in the program, approximately 89 MW in the voluntary component and 49 MW in the mandatory component. Actual load reductions have varied between events, depending largely on the number of customers called but also on the level of response of those customers.

Under the voluntary component, for each of the four continuous hours, customers are paid the higher of 50 cents for each kilowatt-hour curtailed or the real time zonal locational based marginal price (LBMP), less the retail rate. Under the mandatory component, customers receive the same 50 cent energy payment in addition to monthly reservation payments of between $3 and $6 per kW/month, based on two tiers:

- Tier 1 capacity payment of $3 per kW/month with a mandatory performance element consisting of a maximum of six calls to reduce load for a period of 4 hours each during the summer capability period of May through October.
- Tier 2 relates to customers in designated priority distribution networks. The customer may receive a reservation payment of twice the Tier 1 payment, or $6/kW-month (per the recent Commission ruling—see Footnote 7).

An incremental $1.00-$1.50 per kW-month payment is provided for more than six calls and/or to reduce load longer than four hours during the summer period. However, a Performance Adjustment applies if the customer or aggregator does not provide the entire contracted load reduction. The adjustment is calculated as "the ratio of the lowest kW actually reduced in any hour to the kW of contract Load Relief."[15]

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[12] Event summary data for Zones H, I, and J provided in spreadsheets by Con Edison. 1) "Summary of Con Edison Aggregated Load in EDRP and ICAP Events by Zone from 2001-2007"; 2) "Summary of Con Edison DLRP Events by Zone from 2001-2007."

[13] The estimate of 579 MW of achievable callable load reductions from current enrollments assumes that the Average Peak Monthly Demand (APMD) is a reliable method of estimating actual load curtailments. Some other jurisdictions use a customer baseline load (CBL) method based on recent similar-day loads, with a same-day adjustment that can account for changes in baseline loads due to weather.

[14] Internet-based software is provided to all Con Edison customers who install a revenue based interval meter.

[15] Con Edison, Rider U tariff, P.S.C. No. 9 –Electricity, Fifth Revised Leaf No. 158-R-3, Effective April 28, 2008.

Direct Load Control Program

Con Edison's mass-market (*i.e.*, residential and small business) Direct Load Control (DLC) program for central air conditioners can provide approximately 30 MW of callable load capability. While this is significantly less load reduction than that provided by the DLRP, curtailments from the DLC program are much more reliable and predictable. Furthermore, since the curtailments can be realized in less than 10 minutes, they provide greater value to Con Edison in terms of responding to emergencies and possibly avoiding transmission and distribution system investments.

The DLC program provides a free programmable "communicating" thermostat and a cash incentive of $25 for a residential customer and $50 for a commercial customer. The thermostat is a standard 7-day programmable thermostat with four time settings per day, but with the added feature of internet programming. The communication module built into the thermostat allows customers to manage their energy use by setting temperatures within the house/business or via the internet to settings that are appropriate for different times of day and for different days. In order to receive this new thermostat, customers agree to allow Con Edison to remotely cycle the compressor on the central air conditioning unit during callable load events. Customer's central air conditioning unit can be cycled as many times as required by Con Edison, but customers may override the curtailment manually at the thermostat.

In 2006, businesses participating in four load curtailment events averaged 1.24 kW per thermostat, with an average override rate of 26%. Residential participants averaged 1.13 kW per thermostat, with an average afternoon override rate of 10%.

New York ISO Installed Capacity Program (ICAP)

The ICAP is offered by the New York ISO but is available to Con Edison customers able to provide a minimum of 100 kW of load curtailment (including emergency generation) for at least four hours. Customers can be signed up by NYISO, CECONY, Aggregators/Demand Response Providers, Curtailment Service Providers, Energy Service Companies, and Regional Interface Providers. During the curtailment capability periods (May 1 through October 31 and November 1 through April 30) the customers receive a notice at least 21 hours in advance of the request to curtail, and a notice of two hours before the event. Participating customers receive Internet-based software, which can be used to identify ways to reduce electricity consumption and lower operating costs.[16]

Customers receive variable capacity payments, which are dependent on the amount of load reduced, the capability period, and location of load. However, penalties are invoked for failure to respond to NYISO calls. Customers also receive an energy payment that equals the higher of the real time LBMP adjusted for line losses or the amount specified on the customer's application, and not more than $.50/kWh. Customers enrolled in the Emergency Demand Response Program, discussed below, are not eligible to participate in ICAP. An interval meter is required for participation.

New York ISO Emergency Demand Response Program (EDRP)

The EDRP is another New York ISO program available to Con Edison customers able to curtail 100 kW or more for four hours. However, curtailments are voluntary and there is no penalty for under-performance. Customers receive the greater of $.45 for each kilowatt-hour curtailed, or 90% of the price of energy in the real-time zonal LBMP. In addition, customers receive Internet-based software, which can be used to identify ways to reduce electric loads and lower operating costs. Customers enrolled in the Emergency Demand Response Program are not eligible to participate in ICAP, and it is required that the customers have an interval meter.

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[16] Internet-based software is provided to all Con Edison customers who install a revenue based interval meter.

Table 1-2. Summary of Current Callable Load Programs Available to Con Edison Customers

Program	Program Description	Requirements	Incentives		Penalty	Capability Period
			Capacity (kW)	Energy (kWh)		
Distribution Load Relief (DLRP) Voluntary Option	Activated by Con Edison when there is a local network condition that makes a load reduction necessary. DLRP voluntary option is for both winter and summer capability periods. No penalty is assessed if load reduction commitment is not met.	Customers: Minimum reduction - 50 kW Aggregators: Minimum reduction - 100 kW. Load reduction minimum four hours.	None	Energy incentive payment equal to greater of $.50 for each kWh curtailed, or the real-time zonal LBMP less the retail rate for an event,; no less than $.50 per kWh.	None	Summer: May 1 - October 31 Winter: November 1 - April 30
Distribution Load Relief (DLRP) Mandatory Option	Activated by Con Edison when there is a local network condition that makes a load reduction necessary. DLRP mandatory option is for the summer capability period. A performance adjustment applies if the customer or aggregator does not provide the entire contracted load reduction.	Customers: Minimum reduction - 50 kW Aggregators: Minimum reduction - 100 kW. Load reduction minimum four hours.	$3/kW-month in Tier I networks; $6/kW-month in Tier II networks. Additional payments possible.	Same as DLRP voluntary.	A performance adjustment applies if the customer or aggregator does not provide the entire contracted load reduction.	Summer: May 1 - October 31
Direct Load Control (DLC) (www.coned.com/cool)	Central air-conditioning load-reduction program for residential and business customers	Central air-conditioning and Con Edison-installed programmable thermostat.	None	Free programmable thermostat installed at no charge. $25 thank you gift for residential customers. $50 thank you gift for business customers.	None	Summer: May 1 - October 31
Emergency Demand Response (EDRP)	Activated by the NYISO when the reliability of transmission systems may be compromised, or the demand for power exceeds available supply. Customers can apply through the NYISO, Con Edison, or aggregator.	Minimum reduction - 100 kW. Interval meter with telephone line. Load reduction for four hours.	None	Energy incentive payment equal to greater of $.45 for each kWh curtailed, or 90% of the real-time zonal LBMP, but no less than $.45 per kWh.	None	Summer: May 1 - October 31 Winter: November 1 - April 30
<u>Installed Capacity</u> (ICAP)	NYISO program for reliability of the state's transmission systems, or when the demand for power exceeds supply. Incentives for both energy and capacity are subject to financial penalty or de-rating for non-performance. Customers can apply through the NYISO, Con Edison, or aggregator.	Minimum reduction - 100 kW. Interval meter with telephone line. Load reduction for four hours.	Based on capability period and location. For more information, refer to ICAP program description.	Same as EDRP.	Participants will be de-rated for the following capability period if reduced kW did not meet contracted demand.	Summer: May 1 - October 31 Winter: November 1 - April 30

2 APPROACH TO MEETING THE STUDY OBJECTIVES

This section describes the approach taken to develop estimates of the potential for "Callable Load" reductions and to assess broad program strategies that can cost-effectively meet that potential. Callable DR that can be viewed as firm capacity is the focus of the potential estimates. This can encompass both mandatory programs and voluntary programs. The voluntary programs are meant both to attract additional enrollments and to allow customers to become familiar with DR participation and hopefully transition them into a firm capacity program. This focus on firm capacity will allow DR to receive greater validity as a resource that can be counted in resource plans, and viewed as deferring investment in generation assets or transmission and distribution resources. The approach discussion is organized into the following two parts:

1. Defining "potential" for callable loads
2. Assignment activities

The development of estimates of potential for callable DR programs over a 10-year planning horizon is quite different from actually designing a specific portfolio of DR programs that would be implemented. The design of DR programs for rollout would include all the details on marketing, incentives, settlements baselines, and technology to increase response at a site. Still, it is necessary to develop potential estimates based on viable program concepts that represent classes of callable load resources. In this study, the focus is on callable load that is reliable enough to avoid new capacity and, where appropriate, might be able to avoid investments in transmission and distribution.

The underlying program concepts implicitly assumed in assessing the potential for DR in this study have two characteristics: 1) they are a composite of DR program designs viewed as subsuming a number of specific DR programs that might actually be offered; and 2) they represent recent best practice DR offerings that have been successfully applied in the field.

In short, the program concepts used in this potential study are believed to be appropriate as a DR offer umbrella that represents a variety of specific programs. These specific DR programs could be developed for rollout as part of a program design effort by Con Edison. As such, the achievable market potential estimates produced in this study are meant to be estimates that can be met by a number of specific DR programs that would comprise a portfolio of activities. The focus is on event-based firm reductions in demand (*i.e.,* reductions that a participant is contractually obligated to make). There have been on-going demonstrations through both utility programs and DR aggregators that firm reductions can be obtained using currently available technologies. In the actual design of a program portfolio, a voluntary (as opposed to firm) component may be included as well as event-based pricing tariffs that provide additional participation options for customers.

2.1 Defining Potential for Callable Load

"Callable load" opportunities, as discussed above, represent short-term reductions in system demand, typically four hours or less in duration, that are provided by individual customers curtailing their electricity consumption or using emergency generation. Estimating the potential for callable load requires a brief explanation for what is meant by "potential." The potential literature that has been developed for energy efficiency generally uses the terms "technical" potential, "economic" potential, and "market" (or "achievable) potential. In a general context, these terms have been used as follows:

- *Technical potential* is the MW potential resulting from the most efficient technology or approach being implemented by customers in a sector or segments subject to applicability, feasibility, and technology availability.

- *Economic potential* is based on the options that pass threshold financial criteria subject to applicability, feasibility, and technology availability.

- *Achievable potential* is based on what is likely to be attained in the field and incorporates customer/market factors such as awareness and familiarity with the demand-side management, views towards program offers, marketing, information, and often whether a customer believes that by participating they are contributing to an economic, more reliable electric system for the region.

A number of DR potential studies move directly from technical potential to achievable potential and omit any estimation of economic potential.[17] Several reasons have been cited for this. First, direct financial considerations may play less of a role in the decision making process. What often is more important is having the technical ability to achieve a load reduction, *i.e.*, some industrial processes may not be able to respond to a same day notification for a reduction in energy use. Also, there is the practicality/convenience factor *i.e.*, ability to cope with a reduction in electricity use for a few hours. For residential customers, this may mean cycling their air conditioners or setting their thermostat up one degree per hour which may result in slightly higher temperatures in their homes on hot days. These temperature changes usually range from 1 degree to 3 degrees, and 4 degrees in some instances.[18] When outdoor temperatures are in the range of 95 to 100 degrees, this indoor temperature increase may not be noticed by some customers (*e.g.*, temperature tolerant customers). In many instances, a sizeable fraction of residential customers go through an event and are not aware it occurred unless informed. On the other hand, there are customers that really notice the increase in indoor temperature (temperature sensitive customers). As a result, a decision for a residential customer to participate in an AC direct load control program may be entirely a function of personal perceptions of comfort; with the economic benefit they may accrue simply not being a significant factor.

A different set of practical/convenience factors may be the drivers in the choice to participate in a commercial and industrial (C&I) DR program. Industrial facilities, office buildings and many large retail stores have been shown to have a high technical potential for load shedding. However, industrial facilities may have certain batch processes that cannot be interrupted, or they may have production requirements that make load shedding difficult in the absence of considerable advance notice. Office buildings have other concerns regarding worker or tenant comfort and productivity, often based on the relatively low cost of energy to other business expenses. Similarly, large retail stores may be concerned about shopper's comfort, merchandise/display appearance if lighting is reduced, or lost product if refrigeration is reduced. While offices and large retail stores were used as examples for negative practical/convenience factors that

[17] The approach of moving directly from technical potential to achievable potential is used in Electric Power Research Institute and Edison Electric Institute. *Potential for Energy Efficiency and Demand Response in the U.S., 2008 to 2030.* EPRI. Palo Alto, CA. forthcoming 2008. Also, the difficulty of obtaining customer cost data needed for the economic potential can be difficult to obtain, as the DR landscape has many pilot programs but few "at scale" programs other than residential DLC programs. The actual customer costs may not be in the installed equipment but in the value of the foregone electricity use and the resulting change in comfort or other impacts at the customer site.

[18] A number of pilot studies of residential AC pilots have documented this modest temperature increase. See the MyPower Pilot Project, PSEG, filed with the New Jersey Public Utilities Commission. Recent research by Baltimore Gas & Electric (BGE) also confirmed this modest increase in temperature. Their pilot program results showed the "temperature/humidity increase was between 2 – 3°F in majority of homes during 33%, 50% and 75% cycling," See Greenberg, D. "Demand Response Infrastructure Pilot -- BGE's Smart Energy Savers Program," Peak Load Management Alliance (PLMA) paper, presented Spring 2008 p.7.

may influence participation, the fact is that these two customer categories usually are among those that provide sizeable amounts of load shed capabilities in C&I DR programs.[19] As was the case for most residential DR participants, only modest changes in the customer environment were experienced by most C&I participants.

The Demand Response Research Center (DRRC) in California has piloted an auto-DR program for C&I customers that has now been picked up for implementation at scale by the three investor-owned utilities in California (SDG&E, PG&E, and SCE). This DRRC pilot program had a diverse set of building types, including office buildings, retail chain stores, schools, museums, laboratory buildings, a museum, and a bakery. During the severe heat wave of July 2006, all of the Auto-CPP sites continued to participate in DR at a time when it was needed most. None of facilities opted out. Internal temperatures in the buildings did rise above normal conditions, with some increase in occupant complaints, but not to the point of disrupting activities in the buildings or causing facilities personnel to disable the automation. Lawrence Berkeley National Laboratories conducted analysis of EMCS data at several of the sites to understand how warm interior spaces got during the heat wave. Indoor temperatures reached 78°F in one retail store, but there were no complaints registered regarding these temperatures.[20]

Technical versus Achievable Potential

In terms of technical potential, many customers have the physical capability of shutting off most or all of their facilities; however, for the vast majority of customers, this level of curtailment—while *technically* possible—is not practical. Still, it is common practice to use the observed load sheds at individual facilities (kW shed as a share of peak load) from benchmark DR programs and assume 100% participation of a customer segment to provide a "reasonable technical potential." This is the construct used in this study.

A more practical way to view callable load potential is in terms of the *achievable* potential—or firm, verifiable reductions that are likely to be achievable given sufficient incentives. This achievable potential may or may not be cost-effective, depending on factors including program administrative costs, incentives required to encourage participation, and the avoided costs attributable to the callable load capability.[21]

[19] One issue in examining the impacts of DR programs is the growing role of aggregators that have contracts to, generally, provide firm load to utilities or ISOs and they understandably want the customers they market to and the load shed attained to be confidential. DR aggregators participate very much in a competitive market and each has proprietary marketing and technical approaches to achieving load reductions at customer sites. Generally, specific information for program loads administered by aggregators are often available only under a confidentiality agreement, but general information provided when utilities verify participation and load shed values show high participation for office buildings and big box retail (e.g., Target, Home Depot, and Walmart). This demonstrates that practical/convenience factors are not discouraging many C&I facilities from participating in C&I DR programs.

[20] See Piette, M.A. et al. *Automated Critical Peak Pricing Field Tests: 2006 Pilot Program Description and Results.* LBNL-62218. August 2007.

[21] There are many factors influencing a customer's decision to participate in a DR program. The level of economic incentive is just one factor, with others including the number and duration of events, the amount of advanced notification provided prior to an event, penalties for under-performance, and even non-program factors such as public relations. For these reasons, and the fact that tariff programs have standard terms for all customers, it is difficult to develop a callable load supply curve that would indicate the number of participants or megawatts that would be provided at varying incentive levels. Developing such a supply curve can be done for the Con Edison market, but would require targeted research methods such as a pilot program testing various incentive levels or a conjoint survey analysis offering customers hypothetical bundles of program elements with several levels of incentives and other program characteristics.

A study of *callable load* potential differs from traditional *energy efficiency* potential studies that have been conducted throughout the industry. Reductions in consumption from energy efficiency measures are generally based on technical specifications such as the installation of high-efficiency equipment that has a known increase in efficiency and a known incremental cost compared to standard equipment. With some exceptions, the efficient equipment performs as well or better than the standard equipment, and the customer is relatively unaffected.

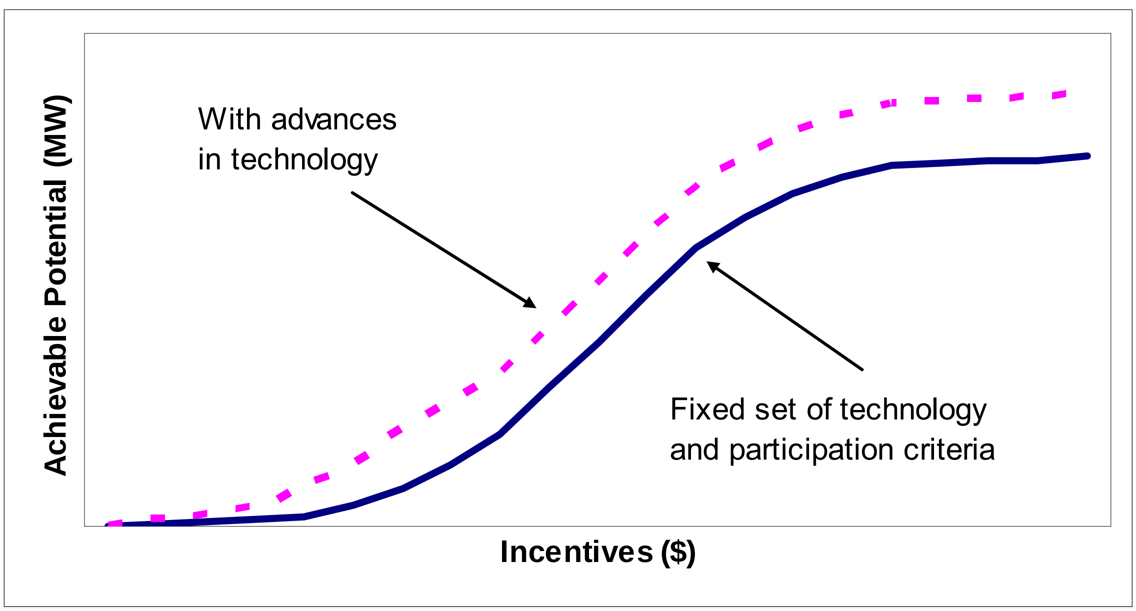
As discussed above, callable load opportunities are less about using technology which has a measurable change in load, but rather about what actions customers are willing to take and what changes in their business or home environment they are willing to accept. The achievable potential is the load reduction that customers are willing to provide at a given level of incentives and with a given set of available technologies.

Consequently, **this study adopts the approach that achievable potential is the appropriate starting point for estimation,** and that cost-effectiveness is based on the achievable potential passing a screening tool with a benefit-cost ratio of greater than 1.0. Technical potential may be a useful benchmark and is defined as the load reductions that could be expected at 100% participation, with the estimated load curtailment assumptions based on the DR program designs.

Growing Achievable Potential over Time

In theory, there is a supply curve for customers' provision of callable load capability. Some modest amount of incentive is required (whether direct financial payments or an object of value such as an internet-ready programmable thermostat) to achieve significant levels of participation. Beyond this, additional incentives can be expected to result in greater participation—and perhaps greater load reduction per participant—until a saturation point is reached where the perceived cost of reducing load is greater than any reasonable level of incentives. At this point, additional incentives produce an insignificant increase in achievable potential, as illustrated in Figure 2-1. The callable load potential curve is both unknown with any certainty (as DR supply curves are not easily predictable) and it is moving over time as advances in technology allow for greater participation and load reductions.

Figure 2-1. Effect of Incentives and Technology on Achievable Potential



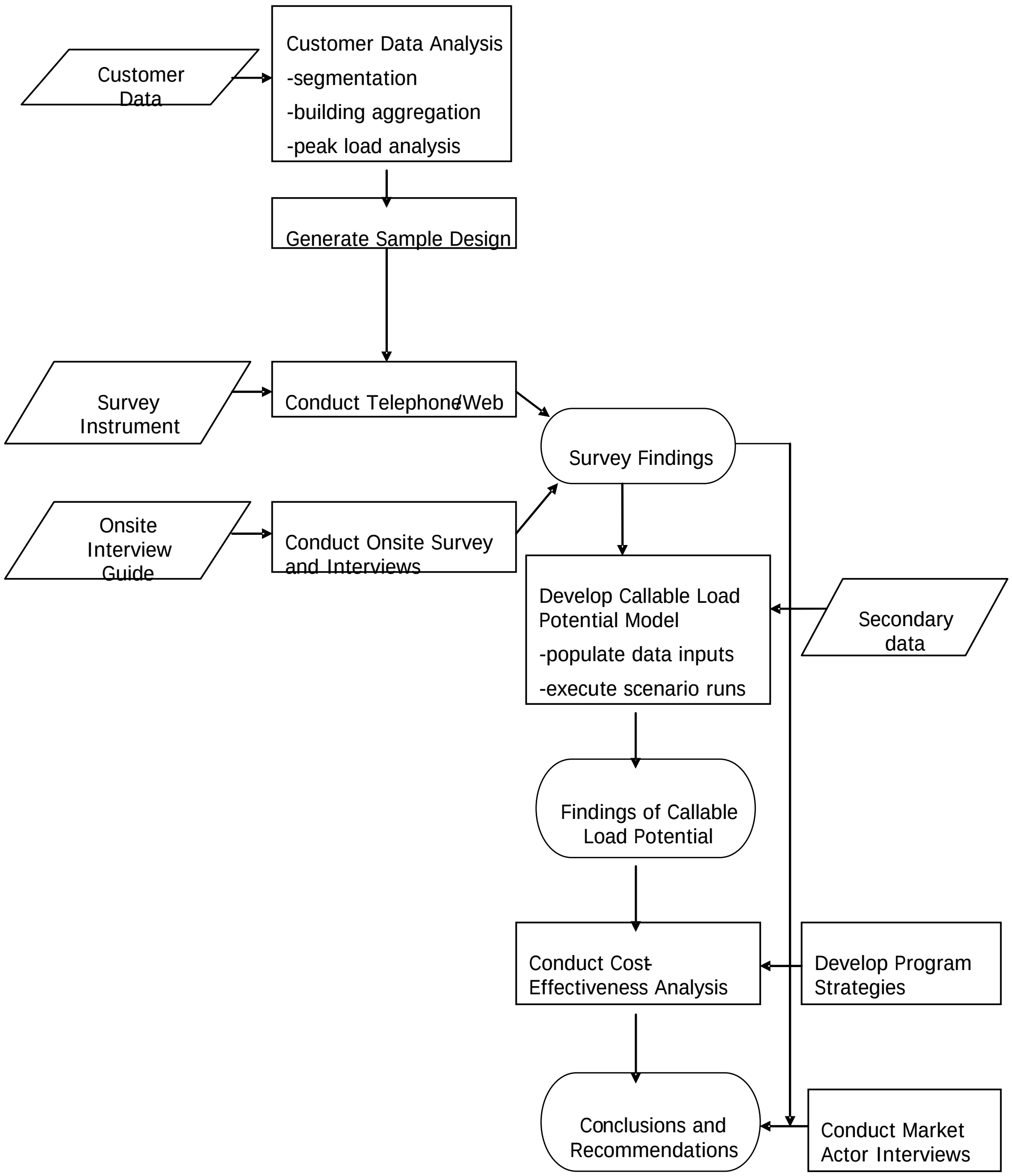
An individual curve represents what is achievable based on technology assumptions at a given point in time. For example, some customers may be willing to participate if curtailment can be automated or lighting can be dimmed by 33% rather than having every third bank of lights shut off. As technology provides for less expensive automation through energy management systems and as dimmable ballasts are increasingly available and affordable, participation can be expected to increase even at the same level of incentive. The pace of this technology innovation and the associated costs are uncertain, resulting in a supply curve that cannot be known even with significant market research. One curtailment service provider operating in the New York market reported that roughly half of its customers' callable load in the past has been automated and able to be called remotely by the aggregator, if not always by the utility.[22] Today, roughly 75% of its new callable load placed under contract is automated due to advances in technology and growing customer acceptance of automated control by a third party such as a utility or an aggregator.

2.2 Assignment Activities

Project activities were focused on two primary efforts: 1) estimation of callable load potential and 2) development of cost-effective program strategies to achieve that potential. Many of the initial data analysis and survey activities contributed to both efforts. These activities included customer data analysis, development of samples and survey instruments, administration of surveys, and assessment of secondary data and survey findings. Recommendations on program strategy development also incorporated interviews with market actors and a high-level assessment of program costs. An overview of the project activities is shown in Figure 2-2.

[22] Confidential interview with demand response aggregator operating in the New York market, 2007.

Figure 2-2. Project Activities Flow Chart



Con Edison customer data analysis. The initial step was analysis of Con Edison customer data to assign customers to major market segments (e.g., office buildings, hospitals, retail). For segments such as offices and multi-family housing in which the building tenants often are not the account holders, accounts were aggregated into buildings, such that the single building could become the sampling unit for the survey effort. Peak loads were then assessed for each market segment to prioritize sampling (see Appendix II-A).

Primary telephone/internet customer survey research. A detailed survey instrument was developed to elicit information and customer views on a variety of topics including information on the customer facility and emergency generation capability, ability to curtail load, and likelihood of participating in a demand response program. Primary data collection consisted of two distinct survey approaches that each used a version of this survey instrument. The first approach was to survey a random sample of Con Edison commercial customers, recruiting and administering an initial set of questions by telephone. Respondents were also emailed a link to a secure web page where they could complete a web-based survey on their own time and using facility documentation and records as needed to facilitate responses.

Onsite customer survey research. A smaller sample of customers completed the same survey but with the assistance of an engineer visiting onsite at the customer facility. Through these onsite surveys the engineer was able to guide customers through the survey, walking through the facility and discussing curtailment opportunities. A separate set of interview questions was also administered to elicit a more open-ended discussion of interest in demand response, drivers of participation, and how Con Edison can support businesses interested in participating. The full survey instrument is provided in Appendix II-A, and the interview questions in Appendix II-B.

Modeling callable load reduction potential. Survey findings were compiled and, along with secondary data from the demand response literature, fed into the callable load potential model developed and customized for this study. The model, referred to as the Callable Load Reduction Potential (CLRP) Estimator is a stochastic model that takes into account the uncertainty inherent in any estimation of demand response potential. Key model inputs are represented as probability distribution functions rather than as point estimates to facilitate understanding the uncertainty in the final potential estimation. The model was created with a focus on both transparency and ease of use to maximize the long term benefit to Con Edison. Model input values include system load forecasts, customer segments' contributions to peak system demand, program participation rates, facility curtailment estimates, and other key parameters.

Program strategy development and economic analysis. Several program strategies (Chapter 6) were developed to encompass the range of customer markets, program components, and program delivery mechanisms that are likely to be part of any Con Edison portfolio that aims to achieve the potential for callable load reductions estimated in this study. Findings of callable load potential drove assumptions used in the cost-effectiveness analysis (Chapter 7), which assessed a likely range of costs and benefits from several broad program concepts.

Recommendations. Recommendations are offered for how Con Edison can achieve the callable load potential estimated earlier in this study. These recommendations identify specific actions that can improve program offerings by making them more attractive to customers and more beneficial to Con Edison. The final set of recommendations address components of an effective program portfolio.

3 MARKET RESEARCH FINDINGS

Market research efforts in support of this study were used to identify customer participation drivers and barriers, load curtailment capabilities, and availability of technologies to facilitate demand response such as emergency generation and building energy management systems. Market research was conducted through three distinct efforts:

1. Primary data collection *survey efforts*, one using telephone and internet and a second based on onsite visits to customers;[23]
2. Secondary data collection including Con Edison customer data, DR program participation data, and a literature review of DR impacts;
3. Market research interviews with prominent local organizations/associations and demand response aggregators. These organizations included the New York Power Authority, the Real Estate Board of New York, and the Greater New York Hospital Association, among others. (A complete list is provided in Appendix I-A.)

This section is focused on findings from the primary market research, which utilized a sample of customers to generate survey data that can be quantified and presented. Secondary data and market actor interviews were used as inputs to the modeling analysis of callable load potential and to program strategies and recommendations and, as such, are cited where appropriate throughout this report.

The discussion of findings addresses four relevant topic areas:

1. Likelihood of participation in callable load programs
2. Load shed activities
3. Emergency generation
4. Building energy management systems

3.1 Program Participation

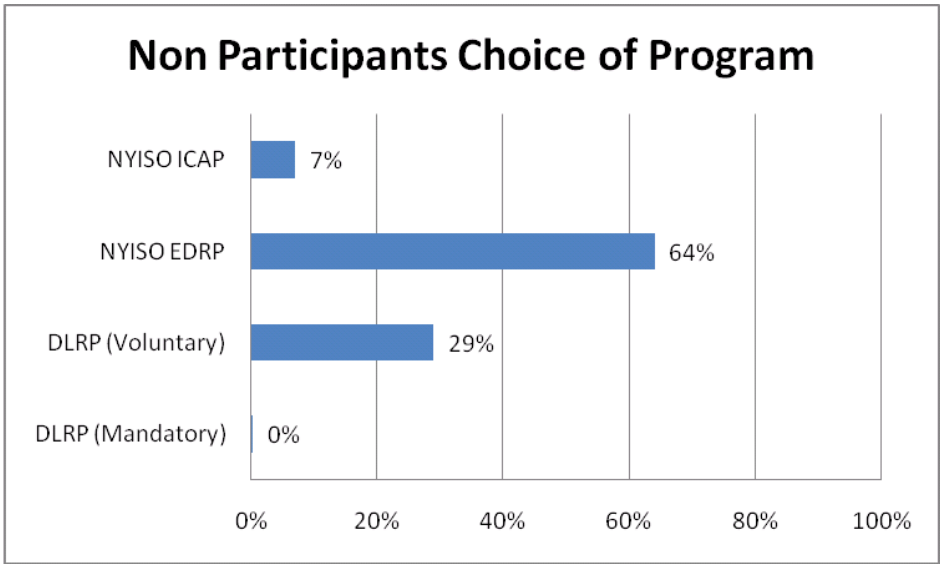
Program participation preferences vary considerably, both among current participants and among those who have not yet participated in one of the Con Edison or NYISO programs. This section presents findings from a series of questions asked of non-participants. Each of the current program offerings was described to respondents before questions about preferences were asked.

Figure 3-1 displays nonparticipants' choice of the demand response program in which they would be most likely to participate. The majority (64%) of nonparticipants prefer the NYISO Emergency Demand Response Program (EDRP), followed by Con Ed's DLRP programs at 29% and then the NYISO ICAP program at just 7%. Based on the responses to questions regarding influences on program choice (see Figure 3-3 below), this preference appears to be due to the voluntary nature of the program. The preference for the EDRP over the voluntary component of the DLRP may suggest that customers are more familiar with the NYISO programs. It may also be due to the difference in notification periods between the two programs; the EDRP provides a 2-hour notification, whereas DLRP (as the tariff read at the time of this survey) provided only a 30-minute notification. Short notification times are one of the

[23] Survey research remains in progress.

factors identified as a barrier to participation in callable load programs.[24] This and other program factors are noted below in Figure 3-3.

Figure 3-1. Nonparticipants' Choice of Program

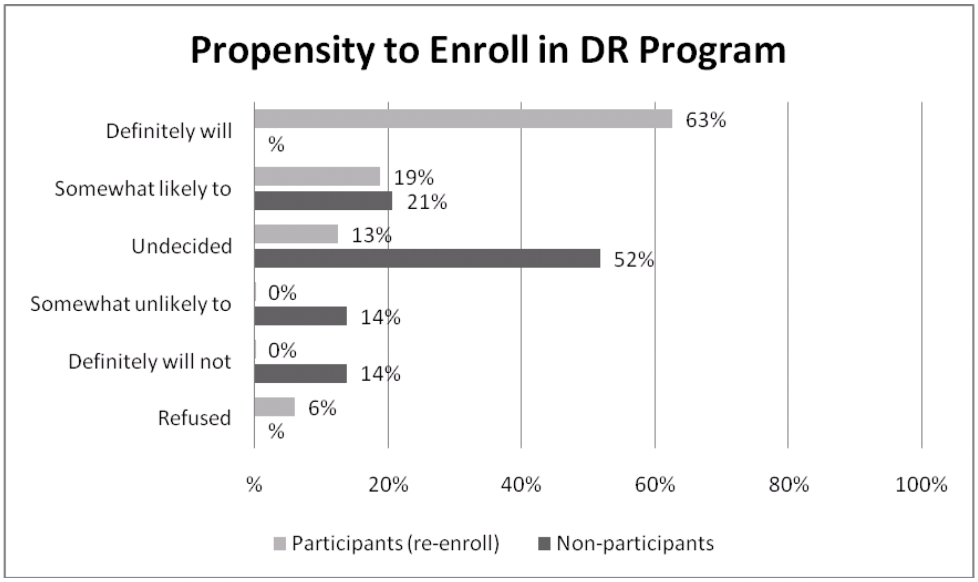


Question 4.1

When asked if they would actually enroll in their preferred programs, nonparticipants were only moderately inclined to consider participating in their demand response program of choice (Figure 3-2). More than half (52%) were completely undecided and just 21% said that they were somewhat likely to enroll in the program. None said they definitely would. Compare to 63% of participants who said they were definitely going to re-enroll or 19% who were somewhat likely to re-enroll; this suggests that once customers are in the program and have gained some understanding of the program, they are less likely to opt out of participation.

[24] Although many customers prefer longer notification periods, others do not view shorter notification as a barrier. Experience with automated demand response (Auto-DR) suggests that little notification is needed if responses such as global temperature adjustments and dimming of lights can be accomplished through building energy management systems that do not require manual actions by facility personnel.

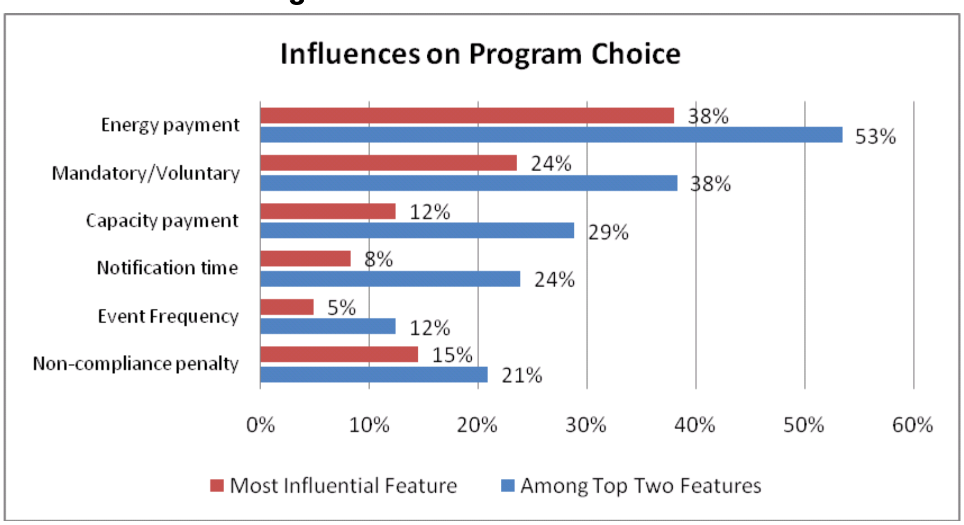
Figure 3-2. Likelihood of Enrolling/Re-enrolling in DR Program



Question 4.2

Figure 3-3 displays the program features that influence nonparticipants' choice of what demand response program they are most likely to participate in. The graph shows the percent of respondents who indicated a particular feature was either the first or second most influential feature for them, as well as bars for the single most important feature. The most influential factors are the amount of energy payment (53% cited it as one of the top two features), and whether the program was mandatory or voluntary (38%). Capacity payments were cited by 29% of the nonparticipants surveyed. Event frequency and non-compliance penalties were cited by 12% and 21% respectively. Non-compliance penalties are likely a significant barrier to participation, as evidenced by the fact that only 7% of respondents selected a mandatory program option among the choices provided (see Figure 3-1).

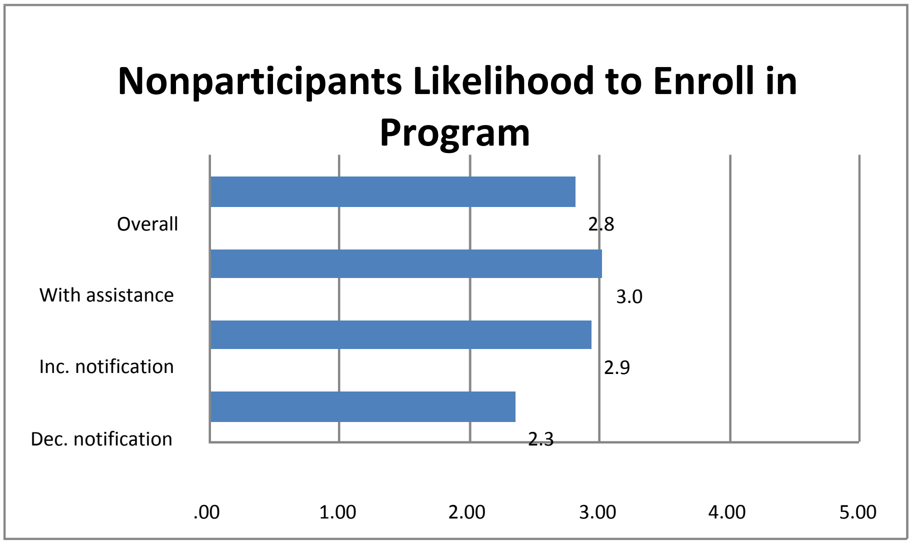
Figure 3-3. Influences on Program Choice



Question 4.3

Figure 3-4 displays nonparticipants' average likelihood to enroll in a program (on a scale of 1 to 5, with 5 being "definitely will enroll"), under varying conditions. The overall average likelihood to enroll in the program of choice is 2.8; that increases slightly with the addition of technical assistance (to 3.0) and with increased notification time before events (2.9). However, decreased notification time has a significant detrimental effect on nonparticipants' likelihood of enrolling.

Figure 3-4. Likelihood to Enroll in Program Based on Program Parameters



Questions 4.2, 4.4, 4.5

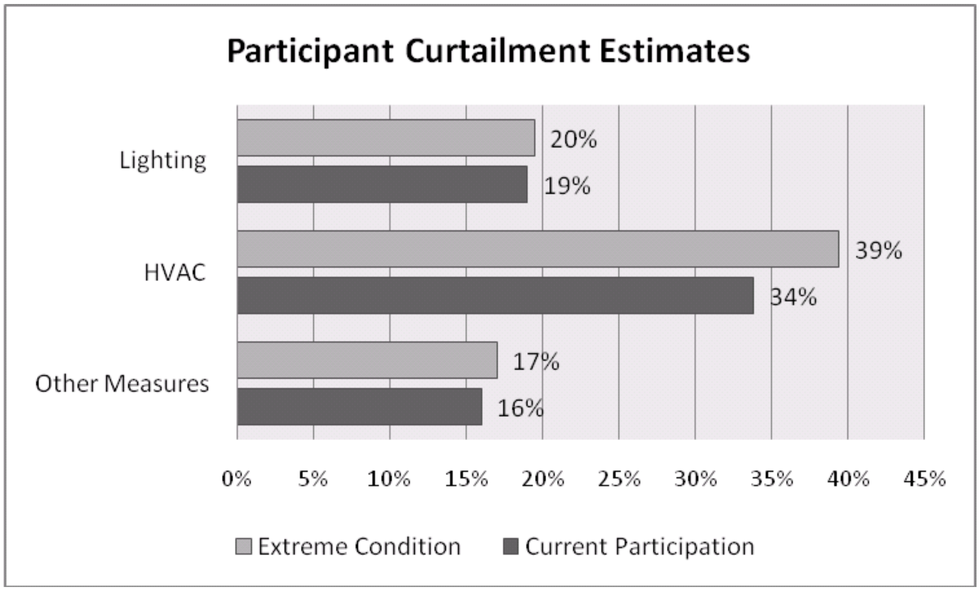
As noted earlier in Footnote 24, not all customers view shorter notification as a barrier. Specifically, experience with automated demand response (Auto-DR) suggests that little notification is needed if responses such as global temperature adjustments and dimming of lights can be accomplished through building energy management systems that do not require manual actions by facility personnel. While longer notification may increase overall participation rates, a portion of participants will still be willing and able to participate with notification provisions as little as 10 minutes. This is particularly true for facilities with advanced building automation controls, which can be expected to increase in prominence as new construction incorporates more advanced systems and as retro-commissioning activities for energy efficiency identify building control systems as a cost-effective means of reducing energy costs and improving building operation.

3.2 Load Shed Activities and Curtailment Estimates

This section examines the amount of load that respondents estimate they can shed for three end-use categories (lighting, HVAC, other) and explores in detail the methods employed to reduce demand in each of these three categories. Questions were asked of both current participants (regarding methods they *currently* employ) and non-participants (regarding methods they would *consider* employing). In general, those who currently participate in demand response programs estimate a greater ability to shed load than those who are not participating. This difference may be attributable to self-selection (whereby participants are enrolled due to their greater ability to shed load) or due to underestimation of non-participants' load shed capability stemming primarily from a lack of knowledge. Participants have the advantage of knowing what they have achieved in the past, and may therefore be more comfortable with higher load reduction levels.

Figure 3-5 shows participant estimates, by end-use, of achievable load reduction under current conditions, and under extreme conditions (defined as the *most* the organization could do to help avoid an imminent electricity shortage while continuing to operate). It is interesting to note that there is little apparent difference between their estimates of curtailment under normal program conditions and their estimates of curtailment under conditions where faced with imminent electricity shortages. This suggests that current participants are already providing as much load curtailment as they believe they can reasonably do.

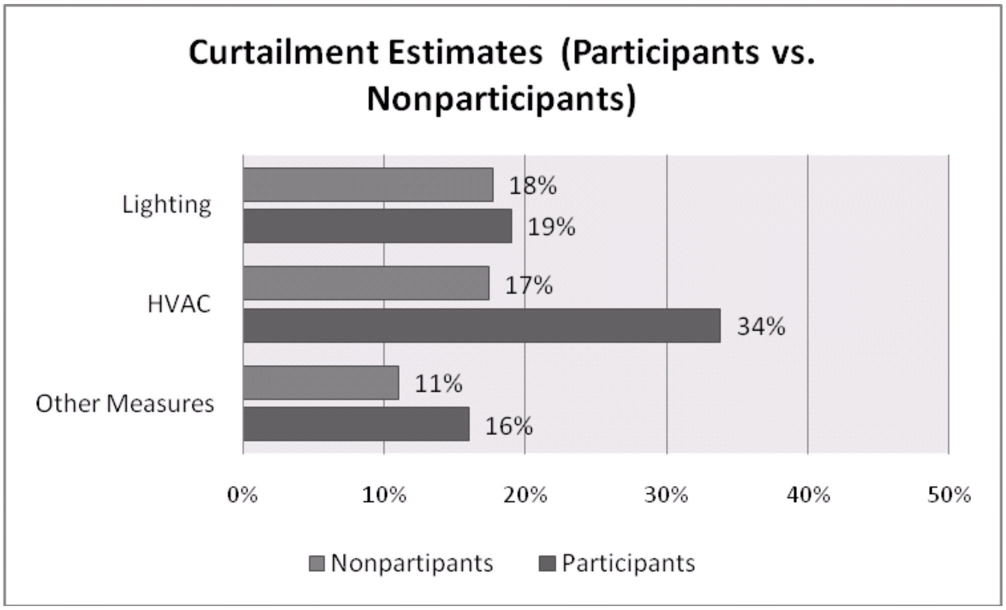
Figure 3-5. Participant Estimates of Current and Extreme Curtailable Loads



Questions 3.3, 3.10, 3.17

Nonparticipants generally estimate lower load curtailment even under extreme conditions. This difference is illustrated in Figure 3-6, which compares participants' current estimates of reduction by end-use (as shown above) with nonparticipants' estimates of what they could shed when facing an imminent outage. While the nonparticipant estimate of lighting load that can be shed is similar to the participant estimate, nonparticipants do not appear to believe they can shed as much HVAC load as participants currently estimate. Figure 3-6 illustrates that non-participants estimate roughly half the load shed ability for HVAC as participants. An apparent difference exists for other measures but it is not as dramatic.

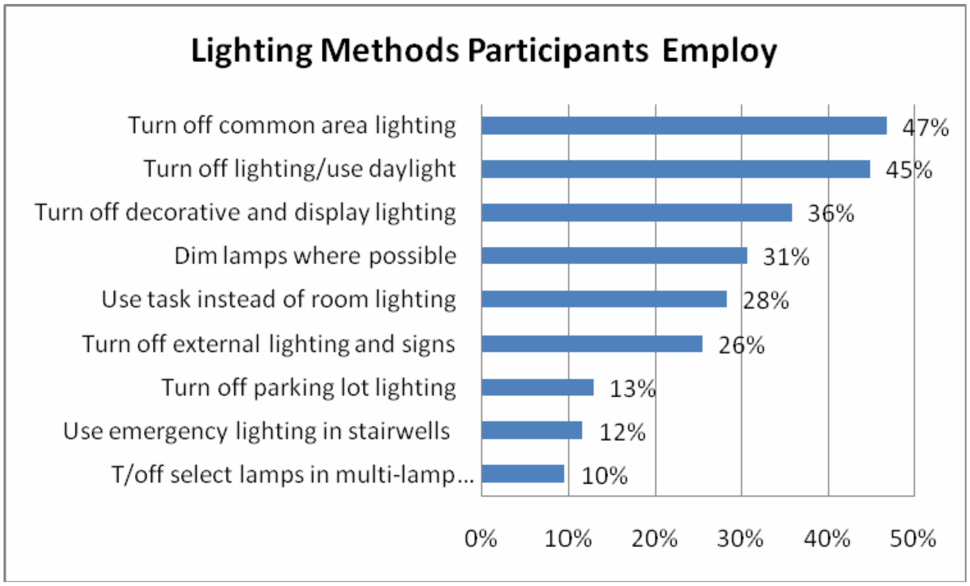
Figure 3-6. Curtailment Estimates for Participant Current Estimates and Nonparticipant Estimates Under Extreme Conditions



Questions 3.3, 3.10, 3.17

Methods of achieving curtailment estimates were explored through a series of prompts about a range of methods that could be deployed to reduce end use loads. Figure 3-7 summarizes the responses of participants regarding the lighting load reduction methods they used at their facilities. *Turning off common area lighting* was the most common method (47%) deployed. Other common approaches include the *use of daylight to allow lights to be turned off* (45%), and *turning off decorative or display lighting* (36%). Dimming lamps, use of task lights, and turning off exterior lighting were all used by more than a quarter of participants as well. When considering the results presented in Figure 3-7, it is important to recognize that these percentages effectively combine the *technical* capability to shed load via these measures with the *behavioral* willingness to shed load via these measures. For instance, linear fluorescent lighting must have dimmable ballasts to permit dimming these lamps as a load shed measure. Likewise, turning off select lamps in multi-lamp fixtures first requires having lamp fixtures capable of doing so.

Figure 3-7. Lighting Reduction Methods Employed by Participants



Question 3.1

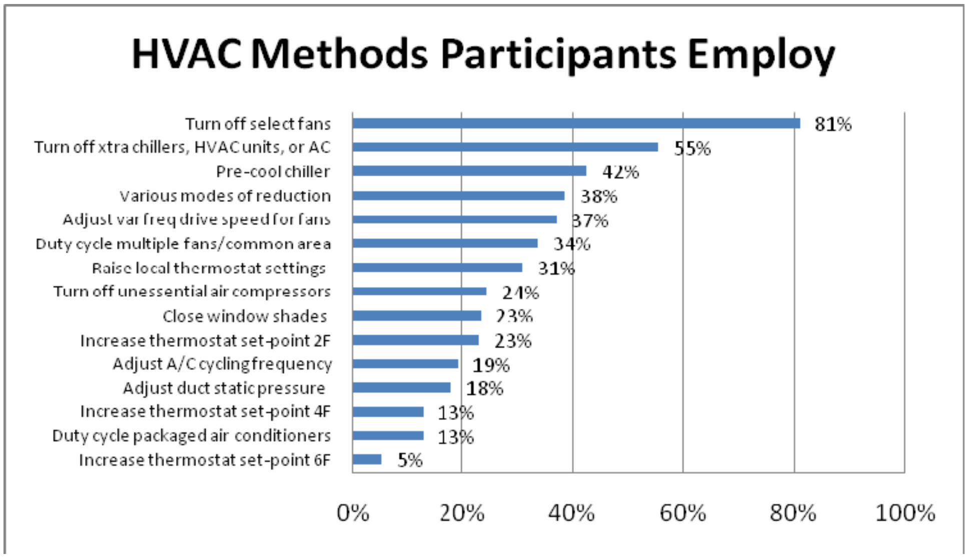
The survey also sought to explore the reasons respondents could not achieve higher levels of load reductions for each of the end uses. This was an open ended question asked after the query regarding which methods they utilize. The table below provides select verbatim responses regarding constraints that limit load reductions for lighting.

Table 3-1. Participant Constraints on Lighting Reductions

Hotel guest demands
In patient care areas we are not be able to reduce lighting levels
Its up to Nokia in Dallas and Finland if we were to reduce power in certain areas
Need to ensure lighting levels are at a safe level and best possible for selling merchandise.
Occupied guest room lighting is out of our control. Decorative and display lighting is part of the guest experience. We cannot jeopardize guest service.
Stairways now require 24 hour lighting to keep luminous strips 'powered' due to new codes requiring luminous strips in all stairways.
This is a Broadway theatre that does Wednesday afternoon matinees. Most of the lights would not be able to be turned down/off during the matinee, and the show uses a lot of lighting equipment in the performance
We are a hotel that operates 24/7, it is very hard for us to shut down or reduce lighting due to the business
We are a REIT first BMR would initiate the program then the tenants would need to buy in.
Question 3.2

Figure 3-8 presents the most common methods employed to reduce HVAC loads. Turning off select fans was by far the most common strategy used by participants (81%). Over half (55%) indicate they turn off nonessential chillers, HVAC units, or AC to achieve reductions. Reducing AC usage is common, whether by cycling package air conditioners or increasing thermostat setpoints. Over one-quarter (27%) of participants reported increasing their thermostat setpoint by at least 2 degrees.[25]

Figure 3-8. HVAC Reduction Methods Employed by Participants



Question 3.8

Again, respondents were asked what factors constrain them from achieving further load reductions in HVAC. Table 3-2 provides a few verbatim responses.

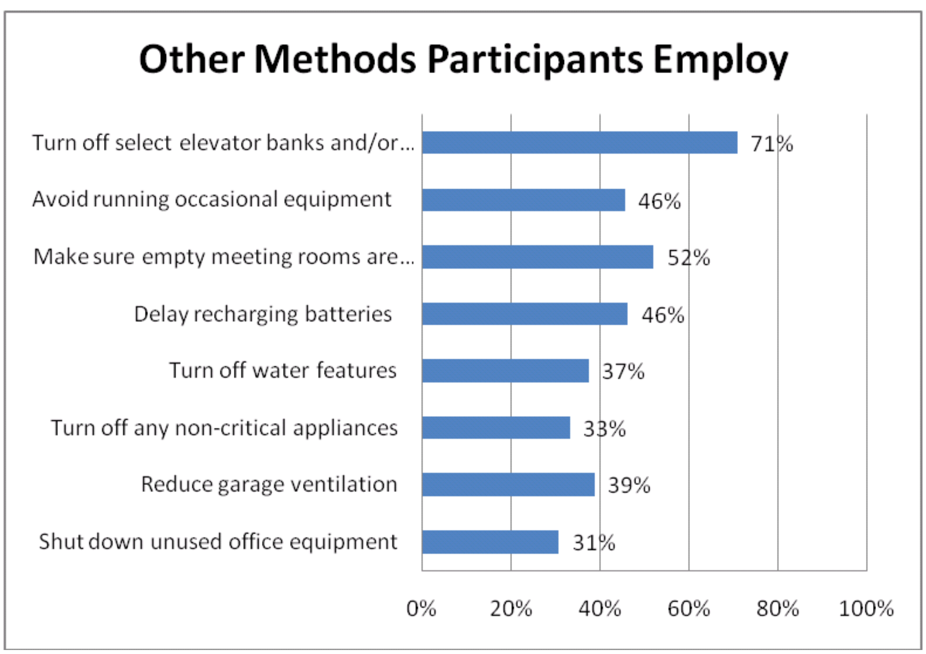
[25] The percentage of respondents who reported increasing their thermostat setpoint by 2 degrees, 4 degrees, and 6 degrees as shown in Figure 3-8 sums to more than the 27% value because respondents could choose multiple reduction methods and some chose *both* "increase thermostat set-point 2F" and "increase thermostat set-point 4", for example.

Table 3-2. Participant Constraints on HVAC Reductions

Any area that is not occupied all lights and AC equipment are turned off
Building is occupied by multiple tenants. All glass building, we need AC for tenants to be able to operate. We have only four main fans serving whole building. We do have VFDs on Cooling Tower fans and main building fans.
Depending upon occupancy & meetings in the hotel
During the Wednesday matinees with 1,300 people in the theatre we need all our a/c equipment to keep our patrons cool.
HVAC in patient care areas could not be reduced
Lease obligations
Most of our residential buildings are high end. Raising set points above 74degF would not be acceptable to our tenants even short term
Need to ensure comfort level in store is not compromised
Our line of work is in the banking field, and we must have a degree of comfort for our clients and customers
Tenant's unwillingness
Tenant restrictions in the research labs
The guest demand high volume of A/C
We are still in process of installing central chilled water system. Currently have multiple window AC units.
Question 3.8

Figure 3-9 below shows the other methods deployed by participants to achieve load reductions. The most common action reported was turning off select elevator banks or escalators (71%), followed by ensuring that meeting rooms and ballroom facilities are shut down when not in use (52%).

Figure 3-9. Other Demand Reduction Methods Employed by Participants



Question 3.15

Table 3-3 provides participant responses on their constraints in achieving other reductions.

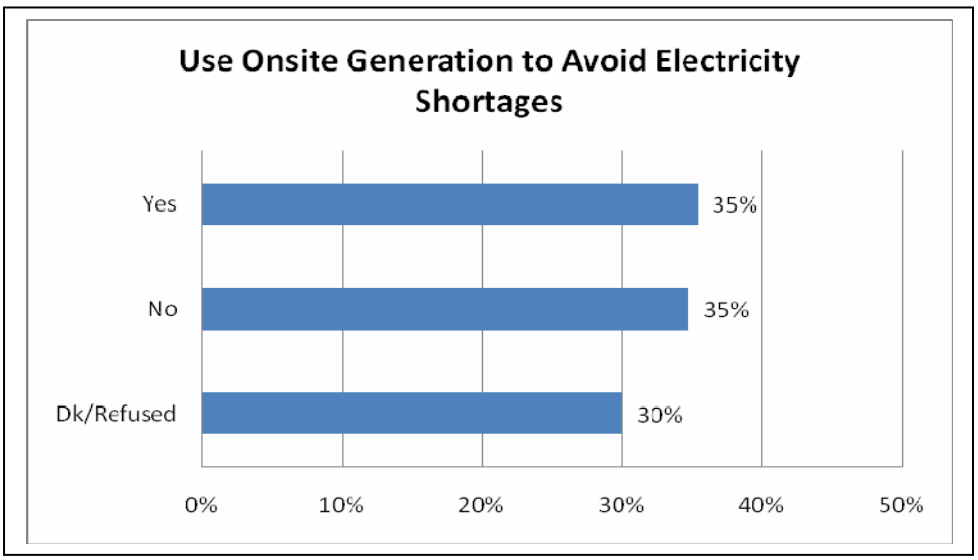
Table 3-3. Participant Constraints with Other Demand Reduction Methods.

Customer service related and not willing to do it unless it was a real emergency.
Hospital
Lack of tenant consent.
Tenant's unwillingness
The elevator is used during our Wednesday matinees.
We cannot close gym, turn off vending machines, delay dishwashing, or laundry. All of this is part of service.
Question 3.16

3.3 Emergency Generation

Over one-third of respondents[26] who have emergency generation indicated that they would consider using their generation capability to help avoid electricity shortages; an equally high share said that they would *not* consider it (Figure 3-10). A number of barriers related to use of emergency generation could contribute to these percentages, including for instance the permitting process[27] and emissions requirements for use of emergency generation in demand response programs (most of which are diesel generators) and the inconvenience of switching and/or temporary interruptions for generation that is not synchronized with the grid.

Figure 3-10. Willingness to Use Emergency Generation to Avoid Electricity Shortages



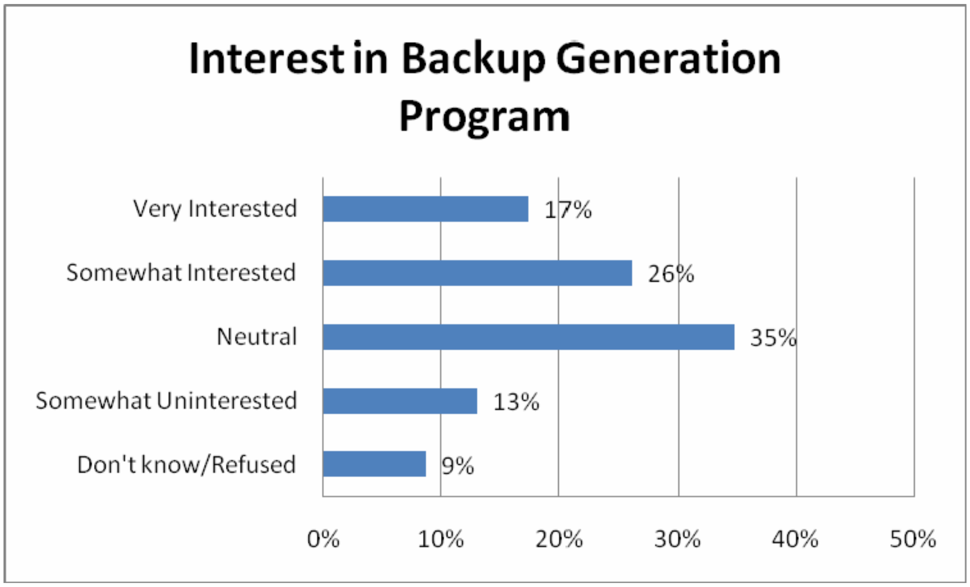
Question 3.23

[26] Bear in mind that this percentage is on a customer count basis, not on the basis of the percentage of actual kW of generation. Considering that large generators provide a proportionally greater reduction impact on a per customer basis, the percentage of actual generation (as a percentage of actual kW of generation) could be substantially higher.

[27] Currently the DLRP program, for instance, includes a requirement that the applicant submit a copy of their New York State Department of Environmental Conservation (NYSDEC) permit for their generator, or if they do not yet have a permit, a copy of their permit application to NYSDEC.

Respondents overall seem interested in participating in a backup generation program should one be offered to provide a neutral source of information on permitting and technology. The concept for a backup generation program, as discussed in the Program Strategies (Chapter 6) is that Con Edison could manage and maintain emergency generation at a customer site (for a fee) while retaining the right to exercise the emergency generation during demand response events. Such a program could reduce the management burden associated with maintenance and testing of emergency generation and would also provide emergency generation capability to the site itself. Seventeen percent of respondents were very interested in such a program, and 26% were somewhat interested; 35% were neither interested nor uninterested (Figure 3-11).

Figure 3-11. Interest in Backup Generation Program



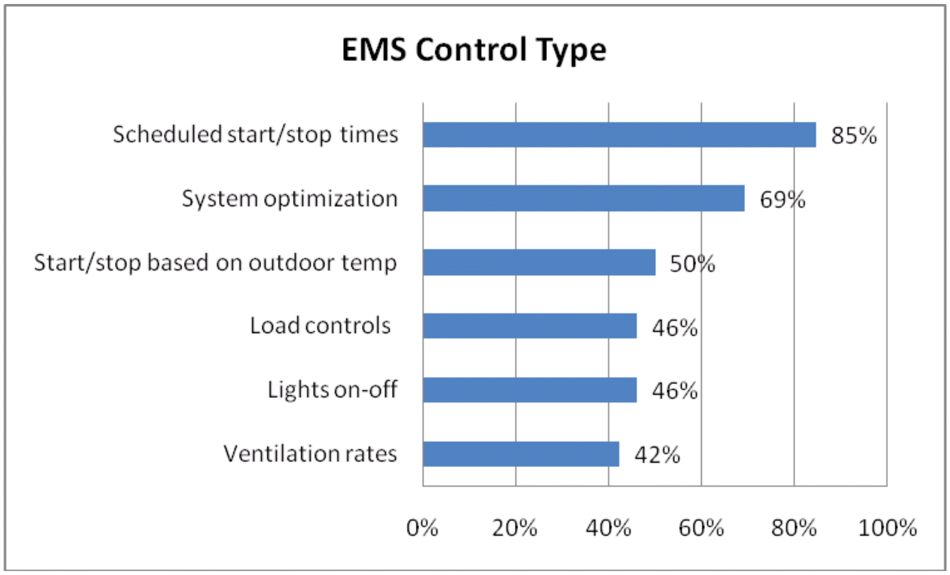
Question 3.26

3.4 Building Energy Management Systems

Building energy management systems (EMS) provide a means for automated load shed that can often be done more quickly and easily and with less customer impact than manual load shed activities. An EMS is also an important tool in enabling Auto-DR, which can provide 10-minute load response. Fifty-nine percent of survey respondents, including 62% of offices, have EMS systems[28]. As shown in Figure 3-12, these systems most commonly control scheduled start/stop times (85% of respondents with EMS systems), and nearly half of the systems can control lighting, ventilation rates, and other loads that can contribute to demand response.

[28] These values contributed to the team's estimation described later of the percentage of callable load potential that may be available with a 10-minute notification period.

Figure 3-12. Energy Management Systems Control Types



Question 2.7

4 CALLABLE LOAD MARKET CHARACTERIZATION

The potential for callable load reduction in the Con Edison service territory was estimated via analysis of data specific to Con Edison customers that was used to characterize the regional market. This market characterization provided input to the Callable Load Reduction Potential (CLRP) Estimator,[29] a model that was developed for this study and tailored specifically to the Con Edison market. This chapter reviews components of the callable load market as follows:

- **Peak Demand:** This section summarizes the methodology and results of analysis conducted to calculate coincident peak demand by customer segment and size, providing a first indication of the opportunities for load reduction in the Con Edison service territory.
- **Load Shed:** This section describes analysis of secondary data (i.e., pre-existing research) and Con Edison demand response participant data that were used to estimate load shed fractions by customer segment and size.
- **Emergency generation:** This section details the analysis of existing emergency generation and describes the assumptions used to estimate the ability of emergency generation to contribute to demand response.
- **Current enrollment and "available" demand response:** This section characterizes the current enrollment of demand response participants, including an assessment of currently "available" demand response by customer segment.

This section serves as a prelude to Chapter 5, which describes the achievable and technical potential for demand response in the Con Edison service territory.

4.1 Market Characterization and Model Input Activities

The following summary of the activities undertaken to characterize the market for callable load and to provide inputs to the CLRP Estimator that produced the callable load potential estimates presented in Chapter 5. Primary market research survey data was not a major contributor to the model inputs or to development of estimates of callable load potential.

1. *Analyzed demand data* provided by Con Edison and estimated peak demand for each customer segment through analysis of customer classification codes.
2. *Analyzed customer interval data and system load curve data* provided by Con Edison to estimate coincidence factors for each customer segment and size category, and to ensure the peak demand summed over each segment rolled up to the system peak demand.
3. *Analyzed customer enrollment data* provide by Con Edison and assigned total enrollment to each customer segment and curtailment type (i.e., load shed or generation).

[29] See Appendix II-B for a detailed discussion of the CLRP Estimator.

4. *Analyzed demand response event data* to estimate correction factors that could be applied to enrollment numbers (due to the difference between enrollment commitments and actual load reduction during DR events), which permits estimating the currently “available” demand response capability.[30]
5. *Estimated the emergency generation capacity* for each customer segment and size by analyzing Con Edison’s Emergency Operations System (EMOPSYS) database.
6. *Conducted a literature review to permit initial estimates of load shed fraction* by customer segment. (See Footnote 36 in Section 4.3.1 for sources used.)
7. *Analyzed current commitments vs. peak load for demand response participants* in the Con Edison service territory as another data source for estimating load shed fractions by customer segment.
8. *Developed model architecture* to calculate peak demand and demand response potential from both load shed activities and emergency generation, including explicitly representing uncertainty in key data inputs.
9. *Coded a model in the Analytica™ modeling environment*, including development of a visual influence diagram and graphical user interface to facilitate transparency in the analysis.
10. *Thoroughly tested the model and conducted model runs* to generate estimates of callable load potential.

4.2 Peak Demand

This section summarizes the methodology and results of analysis conducted to calculate coincident peak demand by customer segment and size, providing a first indication of the opportunities for load reduction in the Con Edison service territory. The section starts by describing estimates of non-coincident peak demand. Next, estimates of coincidence factors based on analysis of customer interval data and system peak load are illustrated. Finally, the resultant peak demand values by customer segment and size our outlined.

4.2.1 Non-Coincident Peak Demand

Eighteen customer segments were included in the CLRP Estimator. The same customer data that were used to develop the sample design for primary data collection (see Appendix I-A) were used to calculate the non-coincident peak demand values for these eighteen customer segments. Figure 4-1 illustrates the customer segmentation scheme used to estimate load reduction potential and identifies the non-coincident peak demand for each customer segment and peak demand category (i.e., <300 kW or >300 kW). Peak demand data is based on the peak loads and industry codes associated with individual customer accounts.

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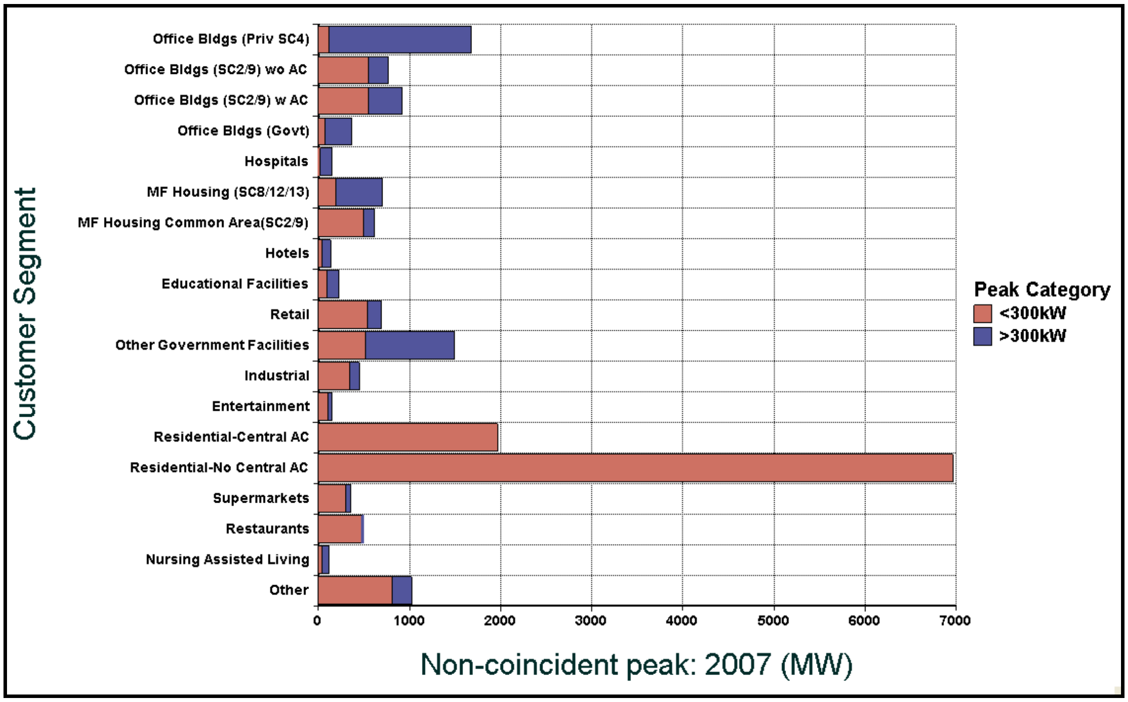
[30] Due to some uncertainty regarding the accuracy of the APMD baseline method that is currently used in the existing DR programs, currently achievable curtailments may differ from what is estimated here. See Footnote 13.

Figure 4-1: Non-Coincident Peak Demand



Three key differences exist between the categories above and the categories used to develop the primary survey sample (see Appendix I-A). First, the demand data presented here is at the customer account level, whereas the sample methodology aggregated accounts into building units for the office and multi-family segments. Second, SC2/SC9 offices have been split into accounts with air conditioning and those without air conditioning to better represent the differences in load shed potential between these building types.[31] Third, the multi-family housing segment was split into the following two sub-segments:

- Multi-Family Housing - Service Class 8/12/13: These accounts have a master meter for the entire building, including tenants.
- Multi-Family Housing Common Area – Service Class 2/9: These accounts are for the "common" building loads (i.e., those loads that are part of a commercial building account such as elevators, A/C (if applicable), lobby lighting, etc.), but individual tenants in these buildings have their own accounts (which are included in the separate residential customer segment).

Residential peak demand values were also subdivided into two sub-segments – *with* and *without* central air conditioning[32]—since Con Edison's direct load control program currently applies only to accounts with central air conditioning.

[31] Several tests were used to determine whether an account was likely to have air-conditioning. First, any account less than three kVA was considered unlikely to have air-conditioning. After marking these small accounts as non-air-conditioning, monthly billing records were examined for the other accounts. If billing demand data were available, a customer was classified as an AC customer if its maximum summer demand was equal to its maximum annual demand. This test identifies that a customer's demand peaks in the summer, which provides some indication that the customer also has an air-conditioning load. When monthly billed demand data were unavailable, monthly energy bills were examined. Any account that had a maximum monthly energy use greater than 1.5 times its minimum monthly energy use was considered likely to be an air-conditioning customer.

[32] There are 400,000 central air conditioners (CAC) in the Con Edison service territory serving residential customers either through residential accounts of small commercial multi-family accounts. Participants in the DLC program average 1.22 AC units per account, based on figures in the 2006 Annual Report of Con Edison's Direct Load

4.2.2 Coincidence Factors

While the previous section described estimation of *non-coincident* peak demand, *coincident* peak demand is of course the value of interest in a demand response potential study. To convert non-coincident peak demands, which were based on individual customer billed demand data, to coincident demand, a coincidence factor must be estimated for each customer segment and peak demand category.

The procedures for estimating coincidence factors differed depending on whether the customer was a residential or non-residential customer. For residential customers, the *2005 Class Load Study* from Con Edison was used to estimate the coincidence factor. This study indicated that the average non-coincident load for residential accounts was 3.2 kW and that the average coincident load was 1.6 kW, resulting in an estimated 50% coincidence factor for residential customers.

For non-residential customers, coincidence factors were developed for each customer segment by analyzing available interval data for those customers. First, the 2007 Con Edison system load curve was used to identify the hour and value of system peak. It indicated a peak demand of 12,807 MW was reached at 1700 on August 8. All available interval data for non-residential customers were assigned to the appropriate customer segment and each segment's total demand at 1700 on August 8 was then compared with the segment's total non-coincident peak demand. The ratio of these two values is the coincidence factor estimated for the customer segment.

The estimated peak demand contributions from each segment were then calibrated to meet the total system load by making reasonable assumptions regarding coincidence factors for small non-residential customers that did not have sufficient interval data[33]. This calibration created a total estimate of coincident load delivery to customers that was within 6% of system generation at the peak hour. The results of this analysis are summarized in Table 4-1, which presents the coincidence factors estimated for each customer segment and size category.

Control Program. At an estimated peak load of 6 kW per account, this suggests a peak load of roughly 2,000 MW. The remainder of the residential sector, which account for approximately 7,000 MW, either has room AC or no primary air conditioning on the account. For purposes of this analysis, all accounts with CACs are categorized as residential.

[33] Coincidence factors for the smallest non-residential customers needed to be estimated when there were insufficient interval data available. Often interval data were available for some accounts in the <300 kW peak demand category, but typically data only existed for the larger customers in this size category. Coincidence factors were therefore calculated based on the data available and then reduced by 20% to account for the smaller customers in that peak demand category. This 20% reduction factor is consistent with a general pattern observed in the data analysis that smaller customers tend to have lower coincidence factors than larger customers. This assumption resulted in an overall coincident peak demand that differed by only 5.6% from power delivered during the peak hour.

Table 4-1. Coincidence Factors

Calculated Coincidence Factors		
Customer segment	**Peak category**	
	<300kW	**>300kW**
Office Buildings (Private SC4)	66%	93%
Office Buildings (SC2/SC9) w/o HVAC	57%	87%
Office Buildings (SC2/SC9) w HVAC	67%	92%
Office Buildings (Government)	64%	85%
Hospitals	73%	89%
MF Housing (SC8/12/13)	65%	83%
MF Housing Common Area (SC2/9)	59%	89%
Hotels	62%	95%
Educational Facilities	55%	81%
Retail	58%	92%
Other Government Facilities	52%	83%
Industrial	52%	73%
Entertainment	62%	80%
Residential – with central AC	50%	0%
Residential – without central AC	50%	0%
Supermarkets	71%	90%
Restaurants	60%	97%
Nursing Assisted Living	74%	93%
Other	60%	86%

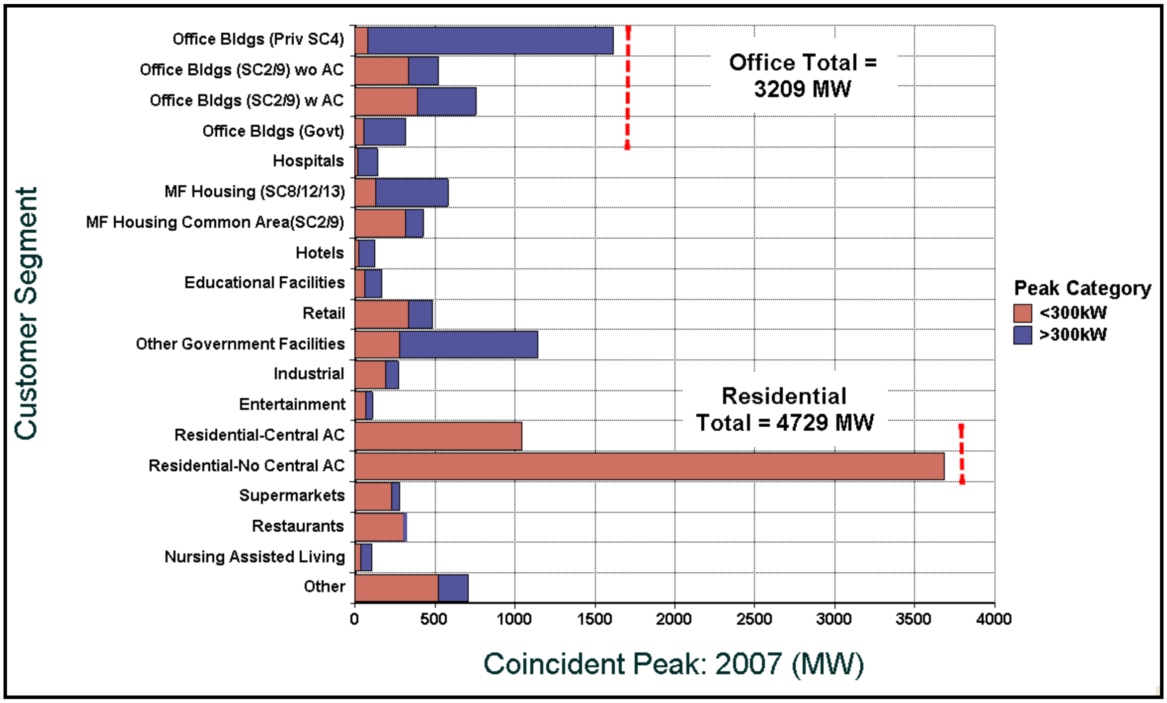
4.2.3 Coincident Peak Demand

The product of non-coincident peak demand (Section 4.2.1) and the coincidence factor for each segment (Section 4.2.2) results in the estimated coincident peak demand by customer segment, which is illustrated in Figure 4-2. The sum of peak demand across all customer segments yields the total system peak demand of 12,807 MW for 2007[34]. The residential sector is the largest contributor to system peak demand with an estimated 4,729 MW. However, the large contribution of office buildings is somewhat masked visually due to the disaggregation of the office sector into four distinct subsectors. If all four office sub-sectors are combined, total peak demand from office buildings is 3,209 MW, making them the second largest contributor to system peak demand. Ranking third with 1,143 MW of coincident peak demand are “other government facilities”, which includes any government facility not falling into the category of an office

[34] After including the previously discussed 5.6% difference between total delivery and generation.

building (e.g., transit systems, public schools, wastewater treatment, correctional facilities). These top three peak demand segments represent roughly 71% of the total system coincident peak.

Figure 4-2. Coincident Peak Demand in 2007[35]



The analysis above provides a first indication of the customer segments that may provide the greatest opportunities for demand response. However, additional estimation of load shed ability (Section 4.3), load shed participation rates (Section 4.3) and emergency generation potential (Section 4.4) are required to fully quantify callable load potential, which is addressed in Chapter 5.

4.3 Load Shed

Load shed in the CLRP Estimator refers to actions taken that reduce peak demand via foregone electricity consumption and is treated separately from a reduction in peak demand resulting from use of emergency generation. This section describes the assumptions for load shed in the estimation of callable load potential, while Section 4.4 addresses assumptions regarding emergency generation.

4.3.1 Load Shed Percentages

To estimate the ability of each customer segment to shed load during a demand response event, two complementary approaches were used. The first approach entailed conducting a literature search to identify existing estimates of the fraction of load that has been shed by participants in various demand response programs. The second approach involved calculating the fraction of peak demand committed by customers currently enrolled in demand response programs in the Con Edison service territory. The final

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[35] The 2007 Coincident peak load demand chart shown above establishes an estimated baseline and input assumptions for callable load potential but is not intended to replace or supplement the rigor/criteria associated with an analysis necessary to meet utility supply, capacity and demand requirements.

values used in the CLRP Estimator for load shed fraction equally weighted the results from the two different approaches.

Table 4-2 summarizes by customer segment the secondary data used as one source of input for estimating the load shed fractions. [36] All values in this table refer to actual shed of peak load, as compared with use of emergency generation to reduce peak demand, which is addressed separately. The load shed values are taken directly from the sources listed in Footnote 36.

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[36] Sources for Table 4-2:

1. Doug Nordham, EnerNOC, "Demand Response Measures for Commercial and Industrial Facilities," presented at the 20th Annual E Source Forum, September 26, 2007.
2. Mary Anne Piette, Demand Response Research Center at Lawrence Berkeley National Laboratory, "Control Strategies that Work" (Average Value)
3. Mary Anne Piette, Demand Response Research Center at Lawrence Berkeley National Laboratory, "Control Strategies that Work" (Maximum Value)
4. Consortium for Electric Reliability Technology Solutions, New York ISO 2002 Demand Response Programs: Evaluation Results, presentation to U.S. Department of Energy Peer Review, January 28, 2004.
5. http://energyconnectinc.com/about/case-studies/
6. Confidential interview with a curtailment service provider, December 12, 2007.
7. Quantec, LLC with Summit Blue Consulting and Nexant, Inc. for PacifiCorp. Assessment of Long-Term System-Wide Potential for Demand-Side and Other Supplemental Resources. June 19, 2007

Table 4-2. Secondary Data Estimates for Load Shed Percentages[37]

Customer Segment	Data Source 1	2	3	4	5	6	7	Mean (%)
Office Bldgs (Priv SC4)	12%	15%	30%	32%	14%	27%	16%	21%
Office Bldgs (SC2/SC9) - w/o AC	see above							
Office Bldgs (SC2/SC9) - w/AC	see above							
Office Bldgs (Govt)	see above							
Hospitals	34%			7%			12%	18%
MF Housing - (SC8/12/13)				4%				4%
MF Housing Common Area (SC2/9)	see above							
Hotels	10%					18%	17%	15%
Educational Facilities	6%			23%		41%	17%	22%
Retail		12%	22%			20%	16%	18%
Other Government Facilities		21%	54%	39%				38%
Industrial	75%			30%			17%	41%
Entertainment				43%				43%
Residential							17%	17%
Supermarkets	13%							13%
Restaurants							17%	17%
Nursing Assisted Living								N/A
Other								N/A

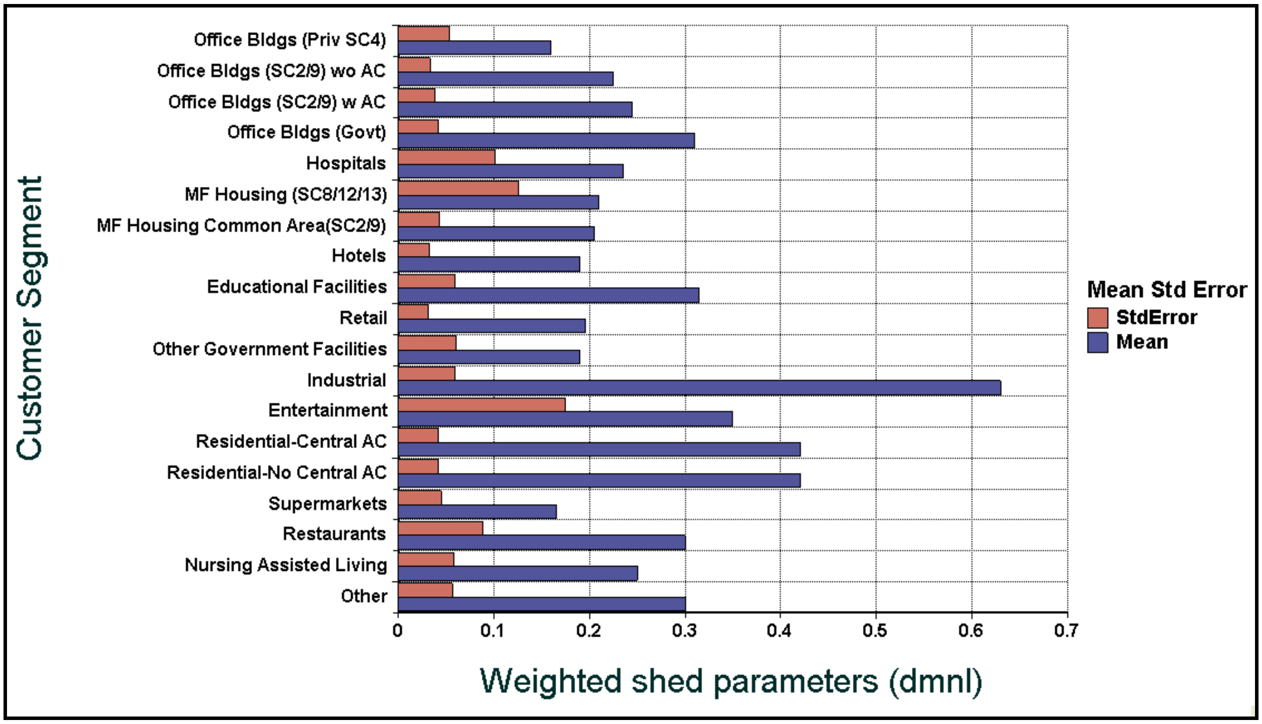
In addition to analyzing secondary data sources, the study team analyzed data from participants in existing demand response programs in the Con Edison service territory. The committed load reduction was divided by the peak demand for each participant to calculate the fraction of peak demand each participant committed to reduce. The results were then averaged over all customers in each segment. To avoid overlap with reductions due to use of emergency generation, any customer known to have emergency generation was excluded from this calculation (via merging the participant data set with Con Edison's Emergency Operation Systems database).

The final values input to the CLRP Estimator equally weighted the load shed fractions calculated from secondary data with the shed fractions calculated from analysis of participant data. The values for the mean and calculated standard error on the mean are illustrated below in Figure 4-3.

[37] The mean values from the secondary data shown in Table 4-2 were used as input to the CLRP Estimator with the following exceptions. For the "Nursing Assisted Living" and "Other" category, a load shed fraction of 15% was used, as no secondary were available. For the following two segments, the "Participant Data" analysis was deemed more reliable than the secondary data and was therefore weighted 100%: 1) the "Industrial" segment load shed percentages were highly variable in the secondary data, and the types of industrial customers in New York may be significantly different from those in other service territories, 2) the "MF Housing SC8/12/13" customer segment is fairly unique to New York City, and the secondary data (which had only a single data point at 4%) may not be reflective of what can actually be achieved from this customer group.

A separate calculation was used to estimate the load shed fraction for residential customers. For accounts with central air conditioning, the DLC program average of 1.38 kW per participant was divided by the assumed coincident load of 3.0 kW (50% coincidence factor times the non-coincident peak load of 6 kW – see Footnote 32); this results in a curtailment percent of approximately 42% after accounting for the estimated 10% opt-out rate. Accounts with room AC units are assumed to be able to curtail at the same percentage rate, although with smaller loads per customer.

Figure 4-3. Mean and Standard Error for Load Shed Fraction (Shed as % of Segment Peak Load)



As can be seen in the above figure, the highest estimated load shed fraction is in the industrial sector, which is often capable of substantial reductions in peak demand from delaying operations until later shifts. Residential customers also have significant load shed capability, as summer air conditioning loads, which can be significantly curtailed during peak periods via set-point adjustments and/or cycling, are a substantial portion of their peak demand.

4.3.2 Load Shed Participation Rates

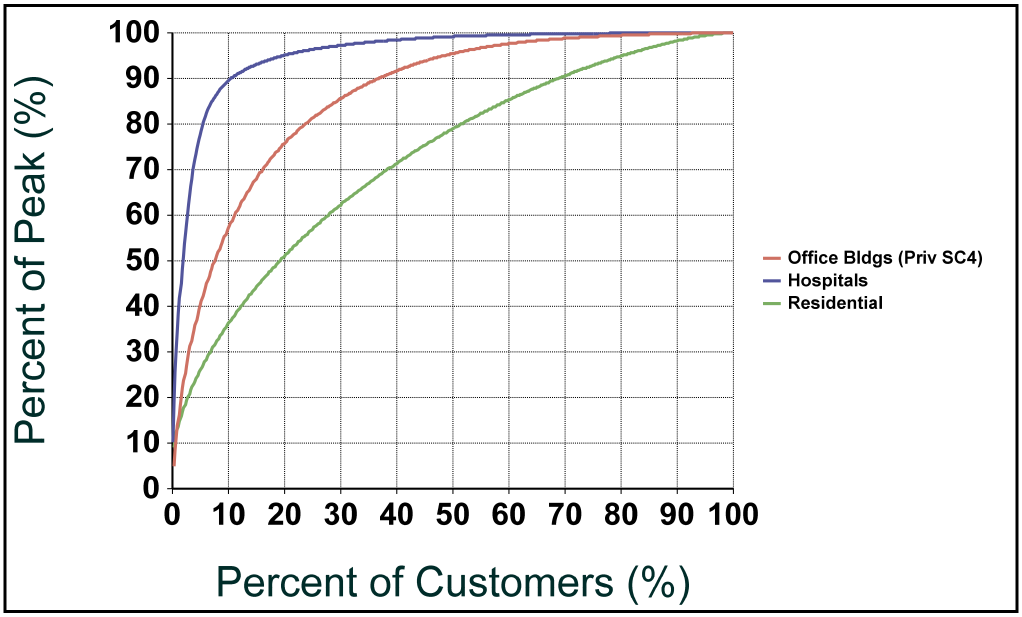
Another key parameter in the CLRP Estimator is the percentage of customers who are assumed to be willing to participate in demand response programs. This value is especially difficult to estimate and is arguably the largest contributor to uncertainty in the final estimate of load shed reduction potential. Estimates of participation rates in other demand response studies are typically “broad-brush” and depend largely on the judgment of the estimator[38]. While judgment is also used in estimating participation rates in this study, a somewhat more rigorous approach is used in this analysis to account for observed differences in participation rates among customers of different sizes.

A complicating factor in modeling the participation rate is the high degree of heterogeneity of peak demand per customer within every customer segment. This problem can be mitigated to some extent by segmenting customers into different size strata, which has been done in the CLRP Estimator, but it cannot be avoided entirely.

[38] For example, round number, judgment-based estimates for participation ranging from 5% to 50% depending on the application are seen in a recent demand response potential study conducted by the Electric Power Research Institute (EPRI). See Electric Power Research Institute and Edison Electric Institute. "Potential for Energy Efficiency and Demand Response in the U.S., 2008 to 2030". EPRI. Palo Alto, CA. 2008, forthcoming publication provided in an email to Summit Blue Consulting by EPRI on May 5, 2008. .

To illustrate, consider Figure 4-4, which plots the percent of peak demand vs. the percent of customers for three different customer segments. Depending on the customer segment, the percentage of customers assumed to participate can result in vastly different values for the percentage of peak demand represented by those customers.

Figure 4-4. Percent of Peak Demand vs. Percent of Customers[39]



For instance, assume for the moment that the *largest* 10% of customers participate in a demand response program. The peak demand represented by the largest 10% of customers varies from roughly 35% (in the case of residential customers) to 90% (in the case of hospitals). Thus, if one were to specify the participation rate in terms of "percent of customers", one must be clear *which* customer segment, and just as importantly, *which* customers (*e.g.*, the largest customers or the smallest customers). In the CLRP Estimator, rather than using as a model input the percentage of *customers* assumed to participate, the study team chose to use the percentage of *customer peak demand* (in kW) assumed to participate in demand response programs. Customer peak demand can be thought of as the product of the number of customers and the peak demand represented by those customers. Thus, participation rates are effectively the *percentage of total kW* in a customer segment that is assumed to be willing to participate in a demand response program. The percentage of actual customers that would have to participate to achieve the assumed percentage of kW would typically be much lower than the percent of kW if the larger customers are enrolled in demand response programs

In the CLRP Estimator, the distribution of customers by size was explicitly taken into account when estimating the likelihood of a customer to participate in a demand response program. For the baseline participation scenario (the "medium" participation case), Table 4-3 illustrates the assumptions made for the likelihood of participating in a demand response program as a function of peak demand category.

[39] The percent of peak demand vs. percent of customers is detailed for every customer segment in the CLRP Estimator model. Here, only three customer segments are shown for illustration only.

Table 4-3. Load Shed Participation Rate (% of kW demand) vs. Peak Demand

Peak Demand Category	Participation Rate (% of kW)
<20kW	10%
20-100kW	10%
100-200kW	15%
200-300kW	20%
300-500kW	30%
500-1000kW	40%
>1000kW	50%

The above participation rates were multiplied by the total peak demand in each demand category to achieve an effectively weighted estimate of the overall participation rate for a customer segment. Since the CLRP Estimator is disaggregated into two different peak demand categories (<300 kW and >300 kW), this weighted estimate was calculated for each peak category and customer segment, as shown in Table 4-4.[40] This table establishes the *baseline* scenario for participation rates. Sensitivity analysis on these participation rates is discussed in Chapter 5.

Table 4-4. Load Shed Participation Rates (as a % of peak kW) – Baseline

Customer Segment	Peak Category	
	<300kW	>300kW
Office Bldgs (Priv SC4)	15%	47%
Office Bldgs (SC2/SC9) - w/HVAC	11%	45%
Office Bldgs (SC2/SC9) - w/o HVAC	12%	45%
Office Bldgs (Govt)	15%	48%
Hospitals	13%	48%
MF Housing - (SC8/12/13)	16%	41%
MF Housing Common Area (SC2/9)	11%	43%
Hotels	14%	45%
Educational Facilities	13%	43%
Retail	11%	42%
Other Government Facilities	15%	44%
Industrial	25%	50%
Entertainment	13%	41%
Residential - Central AC	20%	N/A
Residential - No Central AC	0%	N/A
Supermarkets	12%	33%
Restaurants	11%	39%
Nursing Assisted Living	15%	38%
Other	11%	44%

[40] This procedure was not applied to residential customer accounts with central air conditioning, where a 20% participation rate is assumed for the baseline value, based on the experiences of other utilities that have operated long-standing residential DLC programs (see Appendix I-C). Residential accounts without central AC are assumed to have no participation in the base case. Also, the industrial customer segment was assigned a higher participation rate than would be called for by the procedure described above. Industrial customers tend to have unique opportunities for load curtailment and often comprise a disproportionate share of DR program participation.

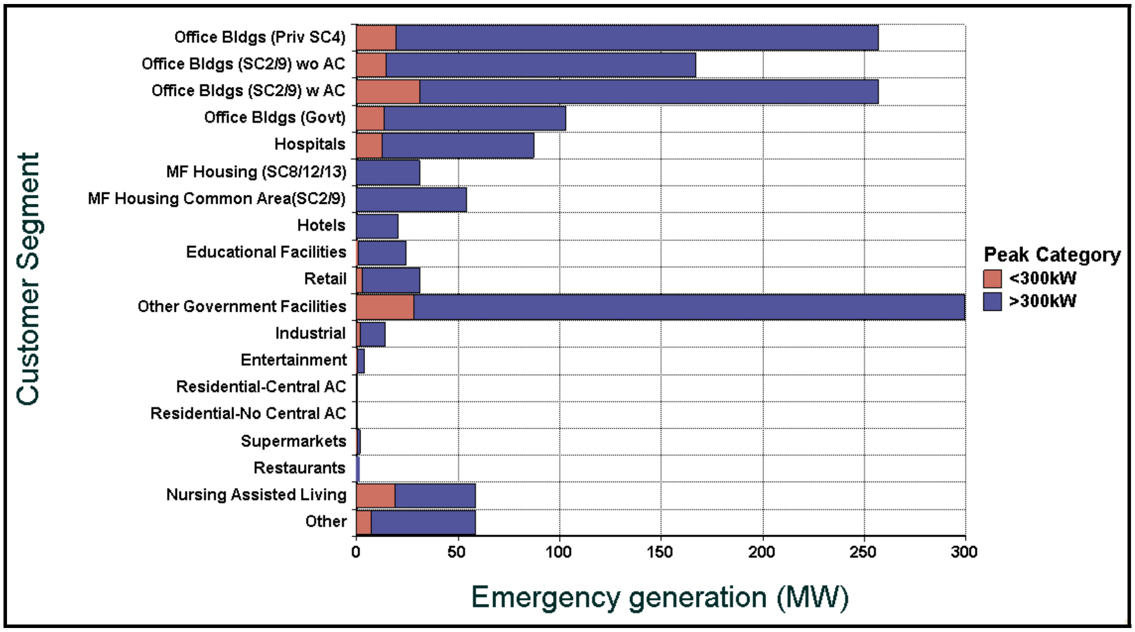
4.4 Emergency Generation

In addition to estimating the ability of customers to shed load, one must consider the ability of emergency generation to contribute to the future demand response portfolio. This section first describes the estimated capacity for emergency generation and then details the assumptions affecting utilization of that emergency generation for future demand response.

4.4.1 Existing Capacity

To estimate demand response potential from emergency generation capacity, one must first identify the total installed capacity for emergency generation. The study team analyzed the Emergency Operations System (EMOPSYS) database provided by Con Edison to estimate the emergency generation capacity by customer segment. Figure 4-5 summarizes existing customer generation by both customer segment and peak demand category. A total of 1,470 MW of emergency generation capacity is estimated from data in the EMOPSYS database, with the majority of generation owned by customers with peak demand greater than 300 kW.

Figure 4-5. Emergency Generation Capacity



As can be seen in the above figure, government facilities and office buildings clearly constitute a major portion of the total emergency generation capacity with a combined estimate of 1,083 MW of emergency generation capacity, or 74% of the total capacity of 1,470 MW. These capacities, in conjunction with the high peak demand estimated for these customer segments (described previously in Section 4.2.3), drive the substantial achievable callable load potential for these segments, as will be illustrated in Chapter 5.

4.4.2 Utilization of Generation for Demand Response

Several factors must be estimated when considering the ability of emergency generation to contribute to demand response. First, one must estimate the percentage of emergency generation that would ultimately be eligible to participate in demand response programs. The future eligibility of emergency generation is largely dependent on regulatory requirements regarding permitting and emissions of emergency generation. As future requirements are highly uncertain, the fraction of generation assumed to be eligible is treated as a scenario variable, with *low*, *medium*, and *high* values[41]. In this analysis, the eligibility fraction is assumed to be 50%, 70% and 90% for these scenarios, respectively.[42] Next, one must estimate the percentage of *eligible* generation that may ultimately participate in a demand response program. As illustrated previously in Figure 3-10, primary market research indicated that roughly 35% of customers with emergency generation indicated a willingness to use that generation as part of a demand response program. Analysis of the size distribution of emergency generators indicates that the 35% of the customers with the *largest* generators account for roughly 84% of the total kW of existing emergency generation. Assuming that the largest generators are targeted first, but that some smaller generators would also be enrolled, a baseline value of 60% participation (of the total kW of emergency generation, not on a customer count basis) of *eligible* emergency generation is assumed. As this participation rates is highly uncertain, however, it is treated as a scenario variable using 40%, 60%, and 80% participation rates (on a kW basis) for the low, medium, and high scenarios.

Finally, it is recognized that the rated capacity of emergency generation must be discounted somewhat to account for the degree to which installed capacity is oversized relative to connected load. Thus, a *fraction-of-capacity-connected* factor is also applied. This factor is modeled as a normally distributed random variable with a mean value of 0.9 and a standard error of 0.1.[43]

4.5 Current Enrollment and Available Demand Response

A key component of a callable load market characterization is identifying the extent to which customers are currently enrolled in programs *and* participating in demand response events when called upon. This section describes current enrollment by customer category as well as the portion of that enrollment estimated to be "available" for demand response events when program overlap and actual participation history during events are taken into account.

Demand response participation values for Con Edison's DLRP and EDRP programs and for NYISO's ICAP program were assigned to the appropriate customer segment. Additionally, participation in Con Edison's Direct Load Control (DLC) program was estimated[44]. Figure 4-76 summarizes the demand response enrollment data by customer segment, which indicates a total demand response *enrollment* of 783 MW.

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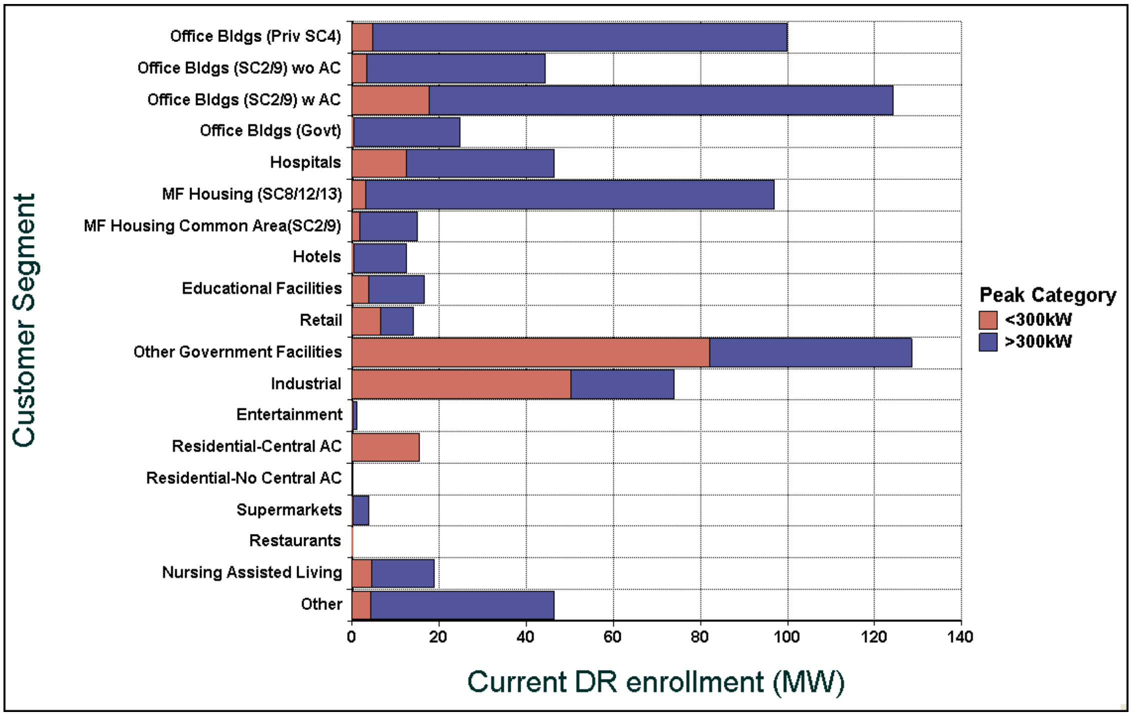
[41] The details of the different scenarios considered when estimating achievable potential are described in Chapter 5.

[42] The study team is aware that legislation is currently being considered that could significantly reduce the ability of distributed generation to contribute to demand response (see New York State Department of Environmental Conservation, proposed rule modifying 6 NYCRR Part 222 Distributed Generation Sources, October 25, 2007). The ultimate ramifications of pending legislation are still largely uncertain, however, and therefore were not explicitly included as part of the scenario analysis.

[43] The normal distribution is truncated to be less than 1.

[44] The DLC program uses communicating thermostats to control air-conditioning load in residential homes and small businesses during summer peak hours. The 2006 DLC evaluation report was used to estimate the demand response participation for the Residential segment. A total of 16,056 thermostats each contributed 1.13 kW of load reduction during system peak. An additional 5,737 thermostats in small businesses contributed 1.24 kW each. Since the segment identification was not known for each of the small business customers, it was assumed that the reduction was spread proportionately across all of the other segments. SC4 Offices, Government Offices, and nonresidential Multi-Family Housing were excluded from this proportional allocation because it is unlikely they participated in the small business thermostat program.

Figure 4-6. Current Demand Response Program Enrollment[45]



Note: Residential enrollment data reflect 2006 values. Enrollment in 2007 was 19.7 MW.

The above figure illustrates that office buildings (when the four office sub-segments are combined), government facilities, multi-family housing (SC8/12/13), and industrial facilities are the top participants in demand response programs. These four segments collectively represent 593 MW of the 783 MW of enrollment, or 73% of the total.

While enrollment values present the actual registered commitments in DR programs, they fail to provide a complete picture of available demand response resources for three reasons.

1. Facilities are permitted to *enroll* in multiple programs (e.g., DLRP and ICAP), but overlap between program enrollments results in lower *available* resources than enrollment numbers alone would indicate.

2. Actual load curtailment during demand response events varies considerably with program type and is lower than the committed values, on average, for every program type (with voluntary programs expectedly having the lowest participation rates during events). For instance, analysis of events called in 2005 and 2006 reveals that actual load reductions as a percentage of committed load reduction were 97%, 63%, and 35% for the ICAP, DLRP Voluntary, and EDRP programs, respectively.

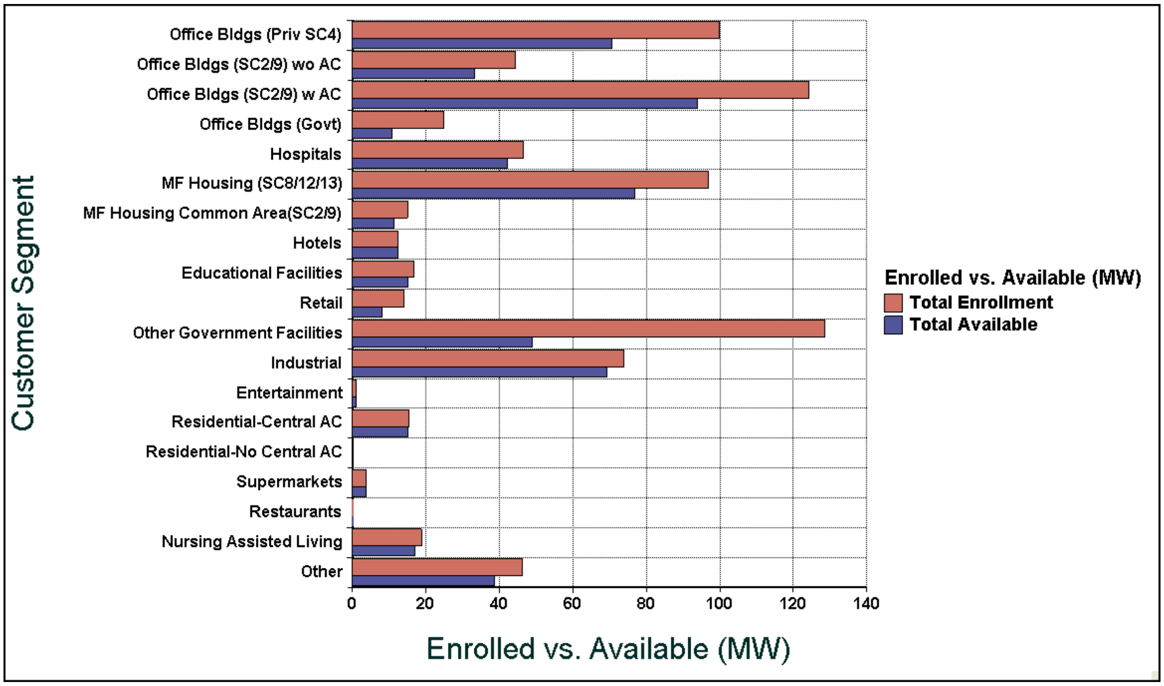
3. Unlike the potential curtailments estimated for this study, the currently available reductions are not necessarily available at the time of system peak demand and therefore may over-estimate reductions that can be provided when needed most.

The first two factors cited above (program overlap and actual curtailments during called events) can be quantified from available data and—when both are taken into consideration—the estimated MW of

[45] Including enrollment in ICAP, DLRP, EDRP, and DLC programs.

available demand response drops from 783 MW to an estimated 569 MW.[46] A comparison by customer segment of the available vs. enrolled MW in demand response programs is provided in Figure 4-7.

Figure 4-7. Enrolled MW vs. Available MW in DR Programs

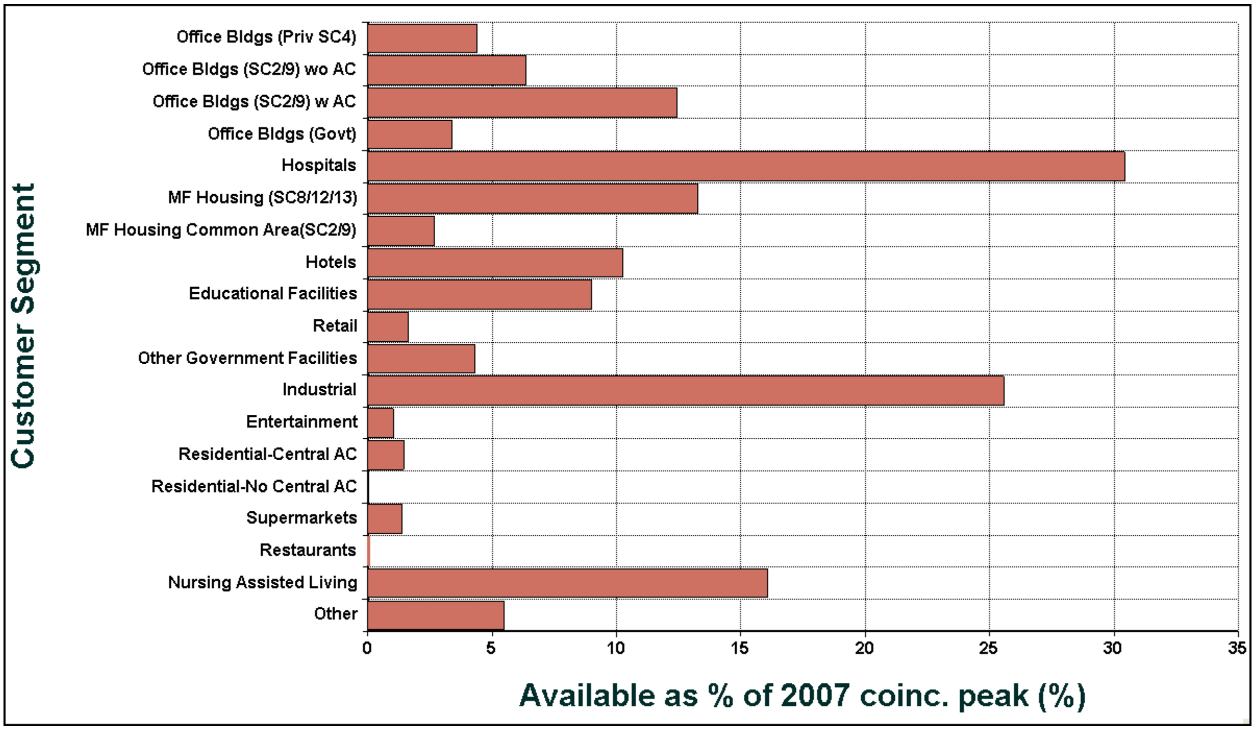


Note: Residential enrollment data reflect 2006 values. Enrollment in 2007 was 19.7 MW.

To better understand how the values above compare with the total peak demand for each customer segment, the percentage of peak demand that is currently available by customer segment is also illustrated below in Figure 4-8.

[46] As noted previously, the estimate of 569 MW of achievable callable load reductions from current enrollments assumes that the Average Peak Monthly Demand (APMD) is a reliable method of estimating actual load curtailments. Many states use a customer baseline load (CBL) method based on recent similar-day loads, with a same-day adjustment that can account for changes in baseline loads due to weather. Regardless of the baseline calculation method, it is important that metering equipment and procedures allow for adequate verification of meter data.

Figure 4-8. Currently Available DR as a % of 2007 Coincident Peak



As can be seen above, hospitals currently have available for a demand response event the greatest percentage of their total segment's peak demand, due in large part to their abundant emergency generation. Industrial facilities are also able to contribute a substantial portion of the entire industrial segment's peak demand, at roughly 25%.

The above discussed values for available demand response will be compared in Section 5.1.4 with the estimated achievable potential for each customer segment to better understand the remaining opportunities for demand response that exist by customer segment.

4.6 Market Characterization Summary

Substantial effort was put into analyzing data provided by Con Edison to characterize the market for callable load and to provide sound input to the CLRP Estimator for calculations of achievable and technical potential for callable load reduction. The process of analyzing the market data revealed the following key items:

- While enrollment in demand response programs currently total 783 MW, only an estimated 569 MW of that enrolled total is likely to be available when rates of participation during called events and program overlap are taken into account.

- Office buildings[47], government facilities, and residential customers constitute the lion's share of peak demand, collectively representing 71% of the total coincident peak demand in the Con Edison service territory.

[47] When the four office sub-segments are combined.

- Two customer segments, government facilities and office buildings[48], are estimated to constitute 74% of the entire installed capacity for emergency generation of 1,470 MW.

- A substantial fraction of the peak demand in many customer segments is in the hands of a small percentage of the total customers, indicating that a focus on the largest customers in each demand segment is more likely to be cost effective and that diminishing returns may ensue once certain thresholds of penetration are reached.

[48] When the four office sub-segments are combined.

5 CALLABLE LOAD POTENTIAL: 2017 PROJECTION

Chapter 4 described the data and methods used to characterize the market for callable load potential in the Con Edison region. It also detailed key assumptions and parameter inputs to the CLRP Estimator[49], which was used to generate estimates of both achievable and technical potential for callable load reductions in the year 2017. This chapter builds on the information in Chapter 4 and describes the estimate of achievable and technical potential for callable load reduction.

This chapter is organized into the following five sections:

- **Achievable Potential:** This section defines achievable potential, describes two different scenarios developed for estimating potential, and details the achievable potential in total and by customer segment and curtailment type (i.e., load shed or generation). Additionally, the percentage of achievable potential that is estimated to be available with a 10-minute notification time is detailed in this section.

- **Gap Analysis:** This section compares currently available demand response with future achievable potential to identify the gaps that would need to be closed to realize the estimated achievable potential.

- **Current vs. Future Market Mix (Load Shed and Emergency Generation):** This section illustrates that realization of achievable potential would require a relative increase in the share of demand response that comes from emergency generation as compared to load shed.

- **Technical Potential:** This section briefly describes the ultimate technical potential for callable load reduction, assuming 100% participation in demand response programs.

- **Summary:** Finally, this section summarizes key observations from this chapter regarding the estimated achievable potential for callable load reduction.

Subsequent chapters will discuss program design issues and recommendations to maximize the likelihood that the achievable potential could be realized by 2017.

5.1 Achievable Potential

Achievable potential for callable load reduction is that which could reasonably be achieved using a diverse portfolio of demand response programs that address multiple market segments and curtailment methods. Achievable potential is by definition lower than technical potential (which assumes 100% participation), which is described in the next section, in that it considers the likelihood that customers will actually participate in a demand response program. *Achievable potential represents the estimated firm load curtailments that can be provided by Con Edison customers concurrent with the system peak in 2017.*

[49] See Appendix I-B for a detailed description of the CLRP Estimator.

5.1.1 Scenarios

As alluded to in the previous chapter describing key model inputs, two different scenarios were defined for the estimates of achievable potential, a *Shed Scenario* and a *Generation Scenario*. This section describes key differences between these two scenarios. Section 5.1.2 will illustrate the effect of these different scenario assumptions on the estimated achievable potential for demand response.

Shed Scenario[50]

In the *Shed Scenario,* the only variable changing in the CLRP Estimator relative to the baseline values provided in the preceding chapter is the assumed participation rate (as a percentage of non-coincident peak demand for each customer segment) of customer accounts engaging in load shed activities. All assumptions regarding the utilization of emergency generation for demand response are held constant at baseline levels. The baseline participation rates described in Section 4.3.2 (which are taken as the *medium* level in the scenario) are varied by customer segment to generate *low, medium, and high* scenarios for participation. For non-residential customers, participation rates for the high and low scenarios were assumed to be a factor of 0.8 (low) and 1.2 (high) times the baseline participation rate (which is assumed for the medium scenario).

For residential customers, the assumed participation rates vary depending on the sub-segment (with or without central air conditioning). For the residential sub-segment with central air conditioning, participation rates are assumed to be 10%, 20%, and 30% (again, on a kW basis, not on the basis of customer count) for the low, medium, and high scenarios. As noted earlier, existing current direct load control programs apply only to customers with central air conditioning. For customers *without* central air conditioning, 0% participation is assumed for the baseline (consistent with the status quo), 0% for the low scenario, and 10% for the high scenario (which represents a situation where advances in communications technology and cooperation with AC manufacturers could allow for direct load control programs to be applied to room air conditioning as well).[51]

Generation Scenario

In the *Generation Scenario*, two variables are adjusted to generate *low, medium, and high* scenarios. It was noted in Section 4.4.2 that the ability of emergency generation to contribute to future demand response potential is largely dependent on future regulation of distributed generation (e.g., emissions requirements, permitting requirements, and possible limitations of the amount of generation that could be utilized for demand response). Thus, the percentage of generation assumed to be eligible for demand response is varied for the three generation scenarios (50%, 70%, and 90% eligibility is the assumed eligibility for the low, medium, and high generation scenarios). Additionally, there is considerable uncertainty as to the percentage of *eligible* generation that is likely to become enrolled in a demand response program. Thus, the assumed *generation participation rate* is also varied for these scenarios. As described in Section 4.4.2, assumed generation participation rates are 40%, 60%, and 80% for the low, medium, and high values in the *generation scenario*.

---

[50] Load reduction values assume a forecast 2017 peak demand of 14,900 MW, which is net of savings from energy efficiency measures.

[51] The participation rate for residential customers with central air conditioning (CAC) is based on the assumption that all central air conditioning units are used by residential accounts. The study team recognizes that many CAC units are part of small commercial accounts serving two- to four-family housing. This assumption allows for better estimation of the CAC units that might participate in a DLC program.

5.1.2 Total Achievable by Scenario Type

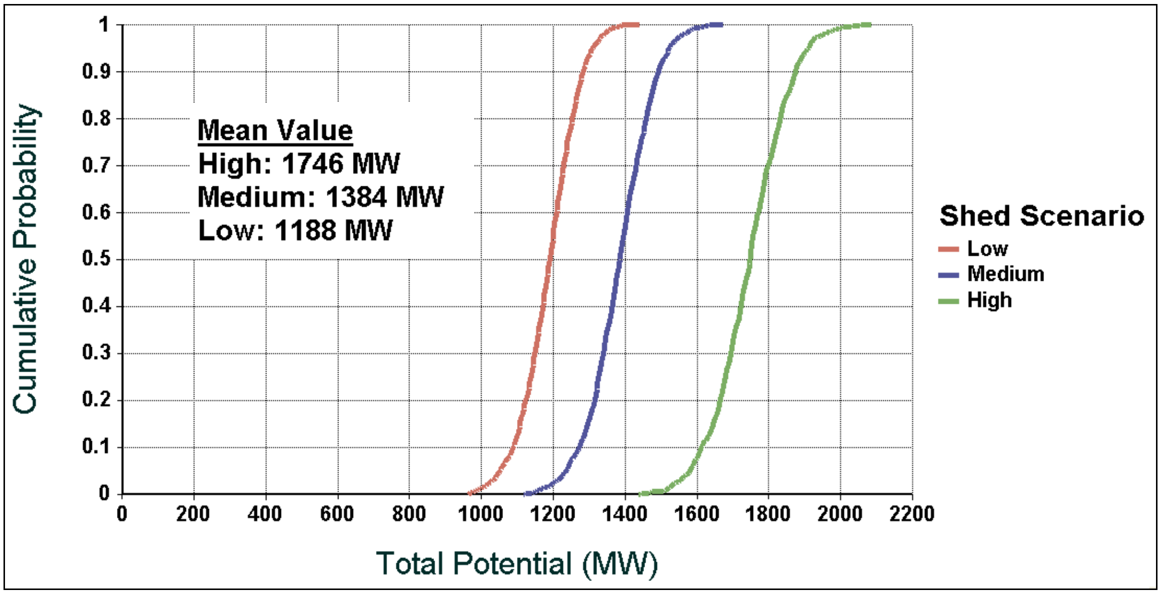
As discussed in the previous section, two different scenario types (a *shed scenario* and a *generation scenario*) were defined so that achievable demand response potential could be estimated under different assumptions regarding load shed and utilization of emergency generation. This section first describes the *total* achievable demand response potential (summed over customer segments and curtailment types – i.e., load shed and generation) for the different parameter values in the shed scenario and then illustrates the total achievable potential for the different parameter values in the generation scenario. The following section then breaks down the achievable potential by customer segment and curtailment type using the baseline assumptions regarding load shed and generation (i.e., for the *medium* level of each scenario only).

Total achievable curtailment potential. The following discussions of load shed scenarios and generation scenarios present estimates for total achievable curtailment potential. These "total achievable" estimates include curtailments from both load shedding *and* use of emergency generation. In the load shed scenarios, the generation assumptions are held constant at the base case (medium scenario) level. In the generation scenarios, the load shed assumptions are held constant with values corresponding to the base case (medium) load shed scenario.

Load Shed Scenarios

Figure 5-1 portrays the *cumulative distribution functions* for total achievable potential (including both load shed and generation) for callable load reduction for the high, medium, and low values in the *shed scenario*. As this is the first introduction of a cumulative distribution function in this report, a short explanation of Figure 5-1 is warranted. Each line represents the probability (read from the vertical axis) that the achievable potential for callable load reduction will be lower than the value on the horizontal axis. For instance, there is a 90% chance the achievable potential would be lower than 1,284 MW, 1,493 MW, and 1,874 MW for the low, medium, and high levels, respectively. Likewise, there is a 10% chance the achievable potential would be less than 1,089 MW, 1,273 MW, and 1,612 MW for the low, medium, and high values in the shed scenario. The mean values for achievable potential are 1,188 MW, 1,384 MW, and 1,746 MW for the low, medium, and high shed scenarios, respectively.

Figure 5-1. Total Achievable Potential - by Shed Scenario



Note: Total Achievable Potential includes both load shed *and* generation. The three scenarios represent low, medium, and high assumptions regarding *participation* by customers engaging in load shed activities; base case assumptions are used for generation. The cumulative probabilities for each scenario reflect uncertainty in the amount of *load curtailment* achieved by each participant.

The asymmetry in the above scenarios (i.e., the high scenario is further from the medium scenario than is the low scenario) is driven by the assumption of a 10% demand response participation for residential customers without central air conditioning compared with 0% participation for the base case, whereas other participation rates are adjusted linearly relative to the base case.

While Figure 5-1 illustrates the absolute achievable potential, in MW, it is also useful to understand the percentage of total system peak load this represents. The mean system peak demand projection for 2017 is 14,900 MW (net of savings from energy efficiency). The resulting achievable potential as a percentage of projected system peak demand and the uncertainty in this projection are illustrated below in Figure 5-2, again as cumulative distribution functions. The mean achievable potential for callable load as a percentage of the 2017 projected system coincident peak demand is 8%, 9.3%, and 11.7% for the low, medium, and high shed scenarios, as shown in Figure 5-2.[52]

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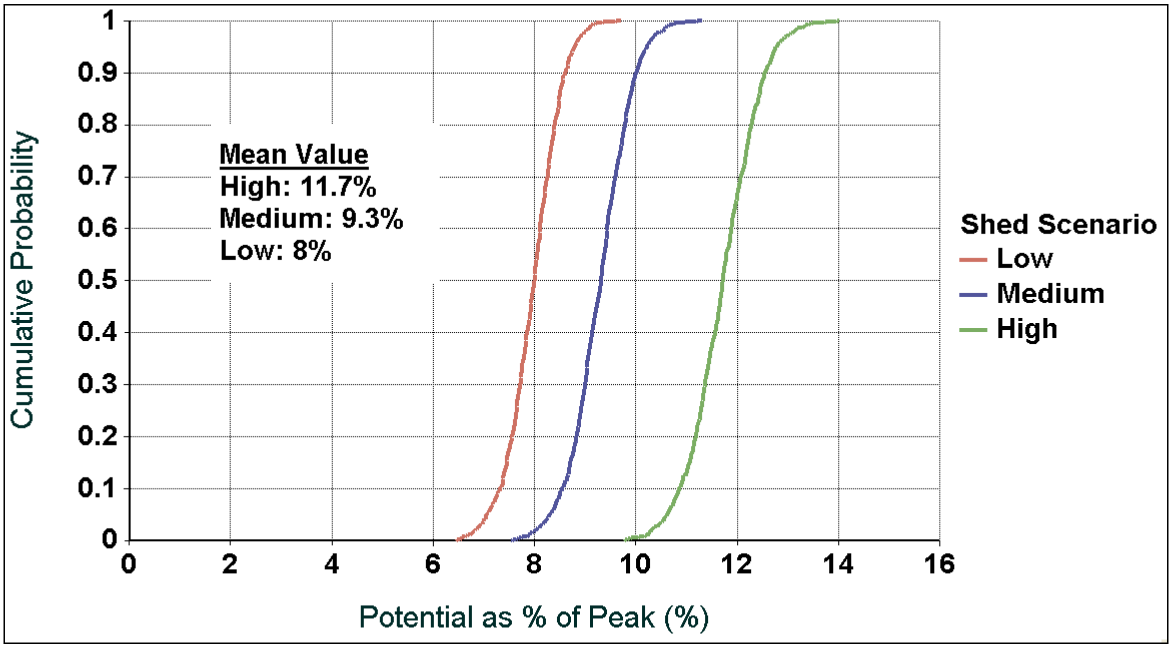
[52] The medium load shed scenario indicates callable load reductions of 9.3% of system peak demand in 2017. This finding is similar to that of a recent analysis by the Electric Power Research Institute (EPRI) estimating that peak load reductions from demand response in the Northeast will be 8.2% of system peak load in 2020 and more than 11% by 2030. Source: Electric Power Research Institute and Edison Electric Institute. *Potential for Energy Efficiency and Demand Response in the U.S., 2008 to 2030*. EPRI. Palo Alto, CA. 2008

Figure 5-2. Total Achievable Potential as a % of Peak – by Shed Scenario



Note: Total Achievable Potential includes both load shed *and* generation. The three scenarios represent low, medium, and high assumptions regarding *participation* by customers engaging in load shed activities; base case assumptions are used for generation. The cumulative probabilities for each scenario reflect uncertainty in the amount of *load curtailment* achieved by each participant.

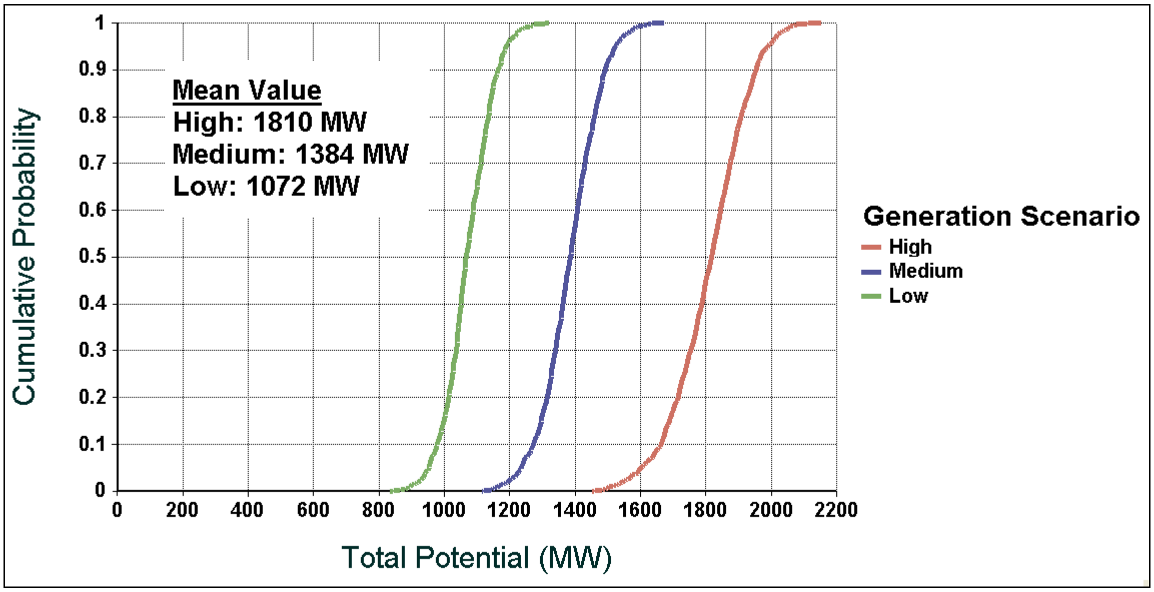
Generation Scenarios

Figure 5-3 portrays cumulative distribution functions for the total achievable potential (including both load shed and generation) for callable load reduction for the high, medium, and low *generation* scenarios.[53] As described earlier[54], each of these generation scenarios holds constant the assumed participation rates of those engaging in load shed activities (at baseline values – i.e., the medium level in the shed scenario). As illustrated in this figure, the mean values for achievable potential are 1,072 MW, 1,384 MW, and 1,810 MW for the low, medium, and high *generation* scenarios, respectively.

[53] The above Shed Scenario paragraph describes how to read and interpret a cumulative distribution function.

[54] A description of the Generation Scenario is provided earlier in Section 5.1.1

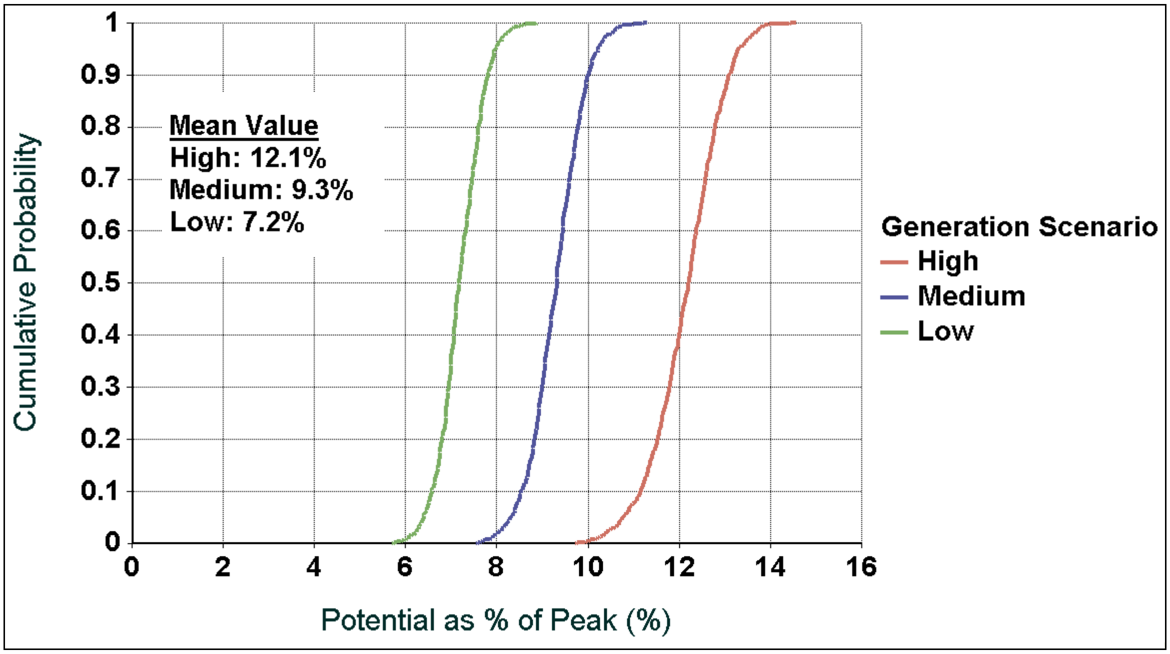
Figure 5-3. Total Achievable Potential - by Generation Scenario



Note: Total Achievable Potential includes both load shed *and* generation. The three scenarios represent low, medium, and high assumptions regarding both the *eligibility* of emergency generators to participate in demand response as well as the *participation rate* of eligible customers who use emergency generation to reduce demand on the Con Edison system; base case assumptions are used for load shedding. The cumulative probabilities for each scenario reflect uncertainty in the amount of *load curtailment* achieved by participants employing load shed measures.

Again, the above values for total achievable potential are also portrayed as percentage of the total system peak of 14,900 MW in Figure 5-4. The mean achievable potential for callable load as a percentage of the 2017 projected system coincident peak demand is 7.2%, 9.3%, and 12.1% for the low, medium, and high generation scenarios, as shown in Figure 5-4.

Figure 5-4. Total Achievable Potential as a % of Peak – by Generation Scenario



Note: Total Achievable Potential includes both load shed *and* generation. The three scenarios represent low, medium, and high assumptions regarding both the *eligibility* of emergency generators to participate in demand response as well as the *participation rate* of eligible customers who use emergency generation to reduce demand on the Con Edison system; base case assumptions are used for load shedding. The cumulative probabilities for each scenario reflect uncertainty in the amount of *load curtailment* achieved by participants employing load shed measures.

While understanding the total achievable potential for callable load reduction in the Con Edison service territory is of course valuable, understanding the breakdown of this potential by customer segment and curtailment type (load shed or generation) is also of interest for planning and marketing purposes. This breakdown is described in the next section.

5.1.3 Medium Scenarios – By Customer Segment and Curtailment Type

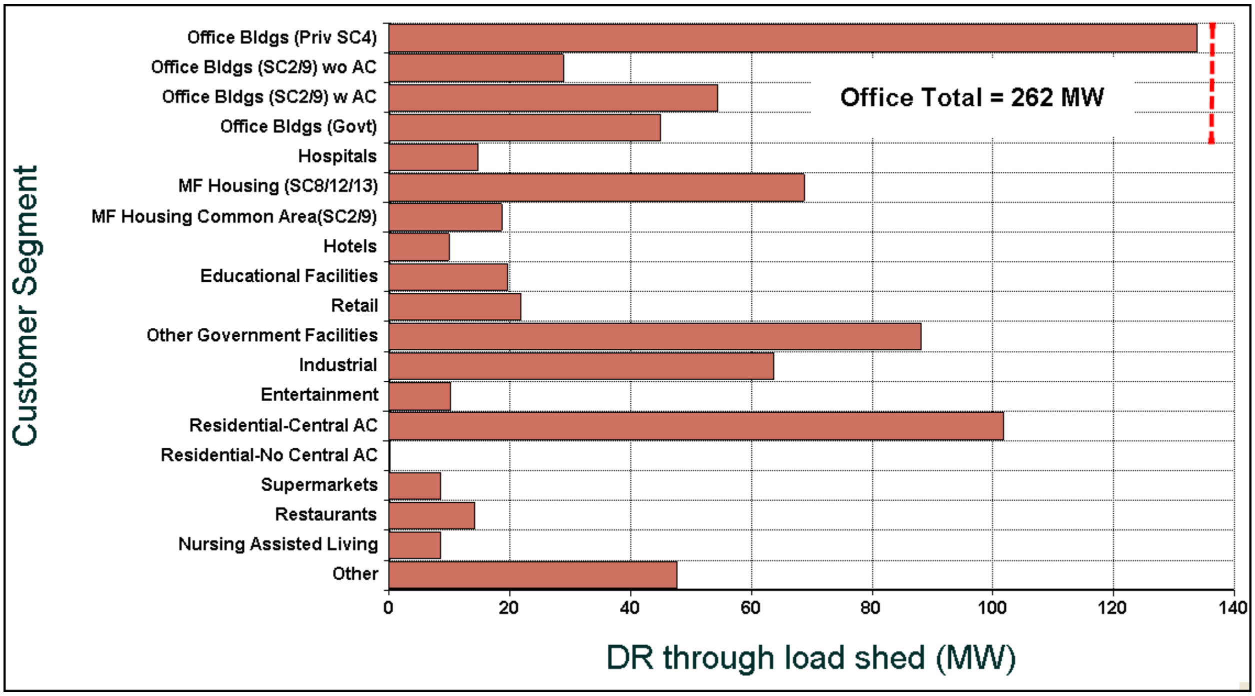
This section breaks down the achievable potential for callable load reduction by customer segment and curtailment type (i.e., by load shed[55] and emergency generation). For results presented in the section, all model values are held constant at baseline values for clarity (i.e., at the *medium* level in both the shed scenario and generation scenario). Additionally, although a probability distribution exists for each model output, only the mean values of the output of interest are reported in this section. Achievable potential for load shed by customer segment is illustrated first, followed by achievable potential for emergency generation. Finally, the combined potential by customer segment (including both load shed and emergency generation) is described.

[55] As described previously in Section 4.3, load shed refers explicitly to activities where actual electricity demand is reduced (via foregone electricity consumption), as opposed to reduction of electricity generation required at the utility due to use of distributed generation at the customer site.

Load Shed Potential – By Customer Segment

Figure 5-5 depicts the achievable potential, by customer segment, for *callable load reduction due to load shed activities*. Curtailments from generation are not included in these figures. Summing the values over customer segments, an achievable potential of 758 MW is estimated for load shed. When all four office sub-segments are combined, office buildings represent the greatest potential for load shed at a combined 262 MW, or 35% of the total achievable potential for load shed. The residential sector (with central AC) is also a substantial contributor to load shed potential at 102 MW, followed by government facilities (88 MW) and Multi-Family Housing – SC8/12/13 (69 MW). These top four segments comprise a total of 521 MW of achievable potential for load shed, or 69% of the *total* potential for load shed of 758 MW.

Figure 5-5. Achievable Potential for Load Shed

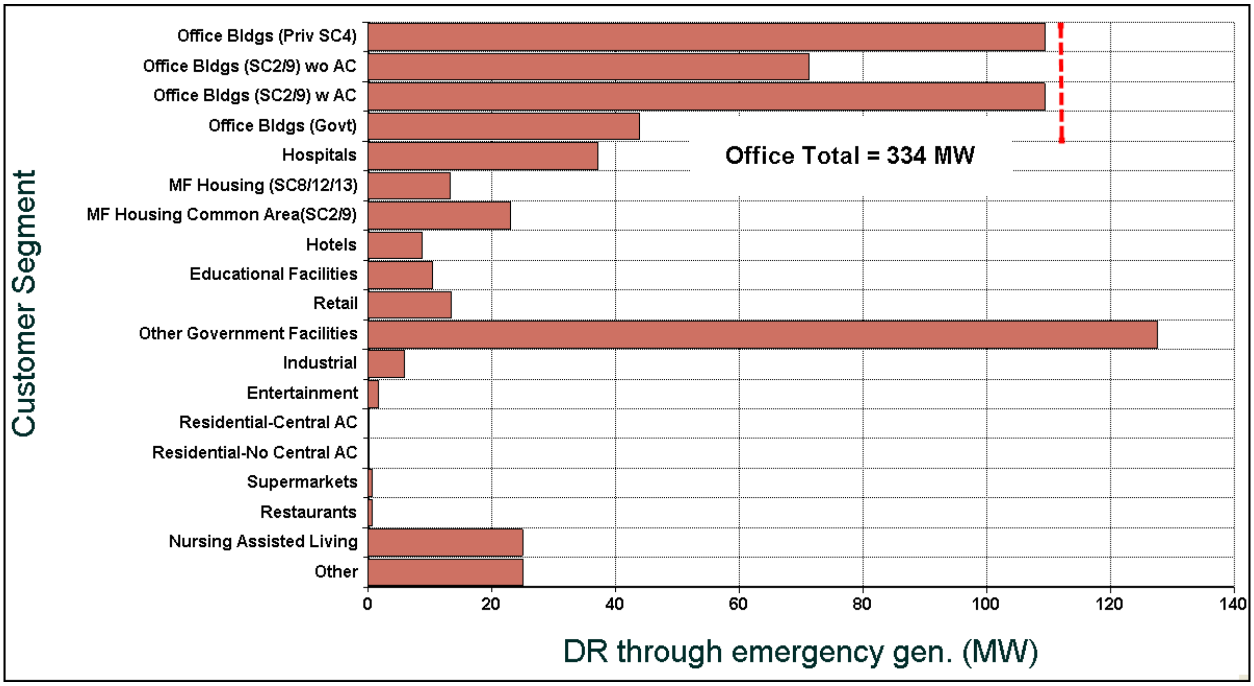


Note: Customer segmentation by account. Achievable Potential for Load Shed represents callable load reductions due to *load shed activities only*. Curtailments from generation are not included in these figures.

Emergency Generation Potential – By Customer Segment

The potential for *callable load reduction via emergency generation* was estimated separately and is illustrated below in Figure 5-6. Curtailments from load shed activities are not included in these figures. Summing the values over customer segments, an achievable potential of 626 MW is estimated for callable load reduction through utilization of emergency generation. When all four office sub-segments are combined, office buildings also represent the greatest potential for emergency generation at a combined 334 MW, or 53% of the total achievable potential for emergency generation. Government facilities also provide significant opportunities for load reduction via emergency generation, with an estimated 128 MW of achievable potential. These top two segments constitute a total of 462 MW of achievable potential for emergency generation, or 74% of the *total* potential for emergency generation of 626 MW.

Figure 5-6. Achievable Potential for Emergency Generation



Note: Customer segmentation by account. Achievable Potential for Emergency Generation represents callable load reductions due to *use of emergency generation only*. Curtailments from load shed are not included in these figures.

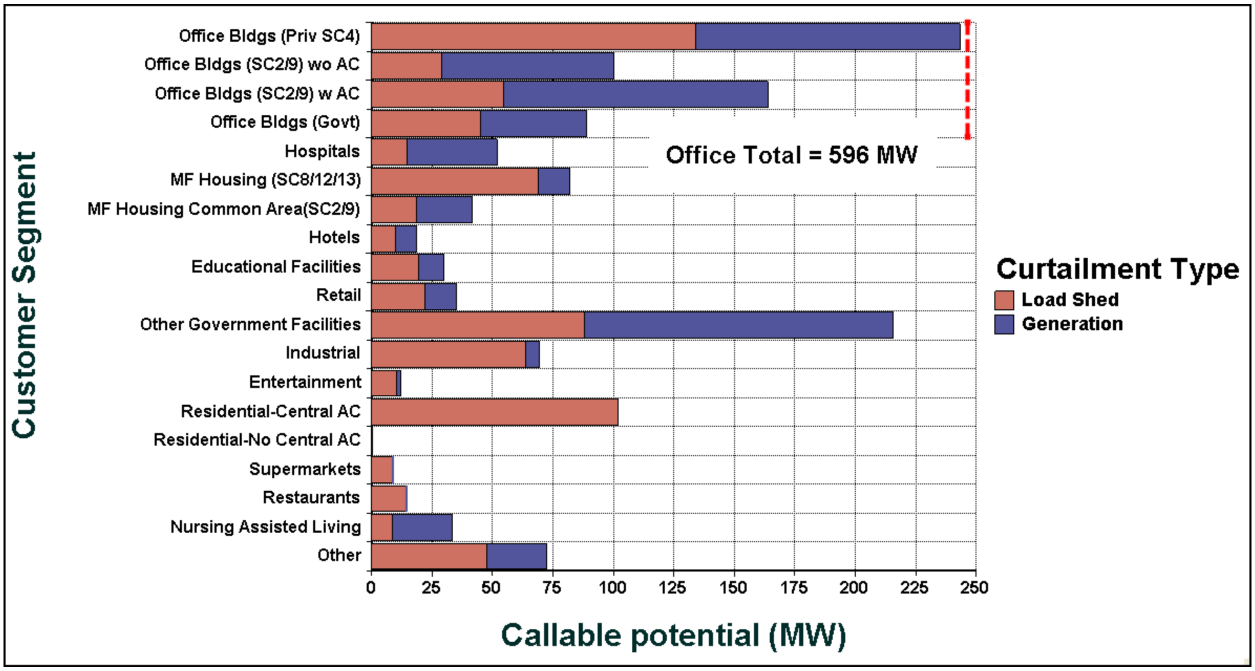
Finally, the results of achievable potential for load shed and emergency generation are combined in the following paragraph to understand the total achievable potential for callable load reduction by customer segment.

Load Shed and Generation Potential by Customer Segment

The total achievable potential is again 1,384 MW for the baseline values of model input parameters (the medium level for both the shed scenario and the generation scenario)[56]. As can be seen in Figure 5-7, office buildings provide the greatest opportunity for callable load reduction due to a large peak demand (resulting in a high load shed potential) combined with abundant emergency generation. A total of 596 MW of achievable potential, or 43% of the total achievable potential, is estimated for office buildings when the four office sub-segments are combined.

[56] Load reduction values assume a forecast 2017 peak demand of 14,900 MW, which is net of savings from energy efficiency measures.

Figure 5-7. Total Achievable Potential - By Customer Segment

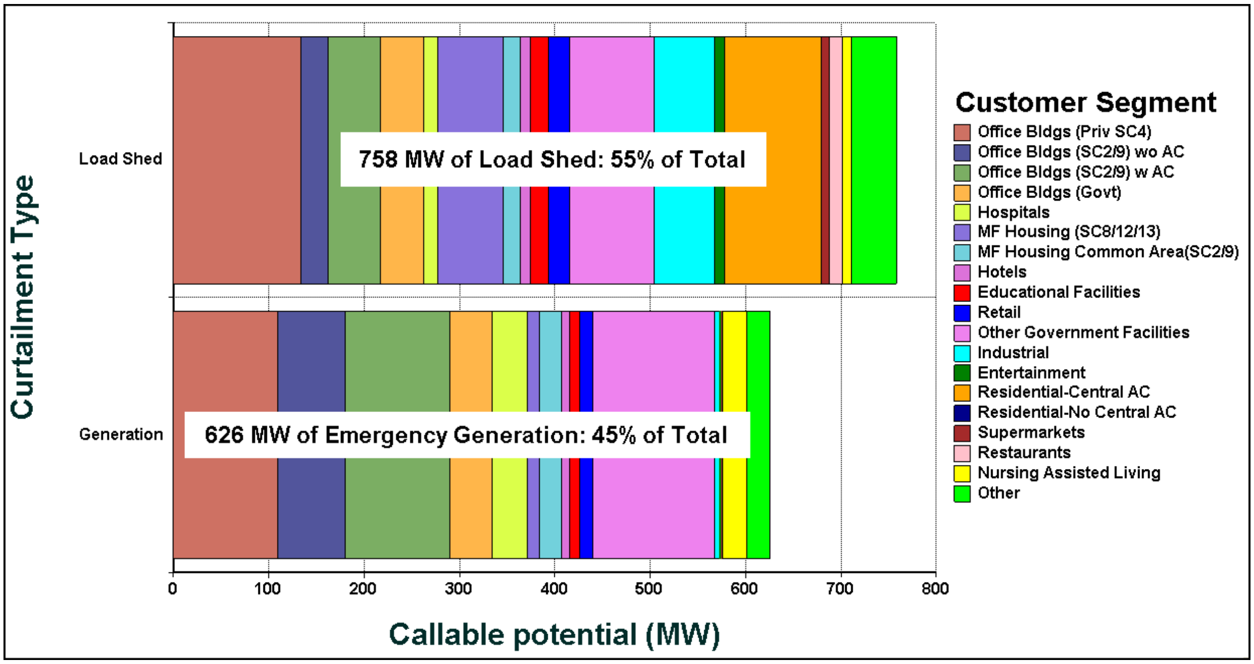


Note: Customer segmentation by account.

Other government facilities (e.g., transit systems, public schools, wastewater treatment, correctional facilities), also provide abundant load reduction potential at an estimated 216 MW, again due largely due the high peak demand of this customer segment combined with substantial installed emergency generation resources. The residential sector (with central AC) provides the third largest potential with an estimated 102 MW of reduction through direct load control of central air conditioning. Office buildings, government facilities, and residential customers together comprise a total achievable potential of 914 MW, or 66% of the total achievable potential of 1,384 MW.

These same data are illustrated somewhat differently in the chart below, which illustrates the achievable potential for load reduction for both load shed and emergency generation. As can be seen in this figure, the load shed potential of 758 MW accounts for 55% of the total achievable potential. Emergency generation, with an estimated 626 MW, accounts for an estimated 45% of the total achievable potential for load reduction.

Figure 5-8. Total Achievable Potential - By Curtailment Type



Note: Customer segmentation by account.

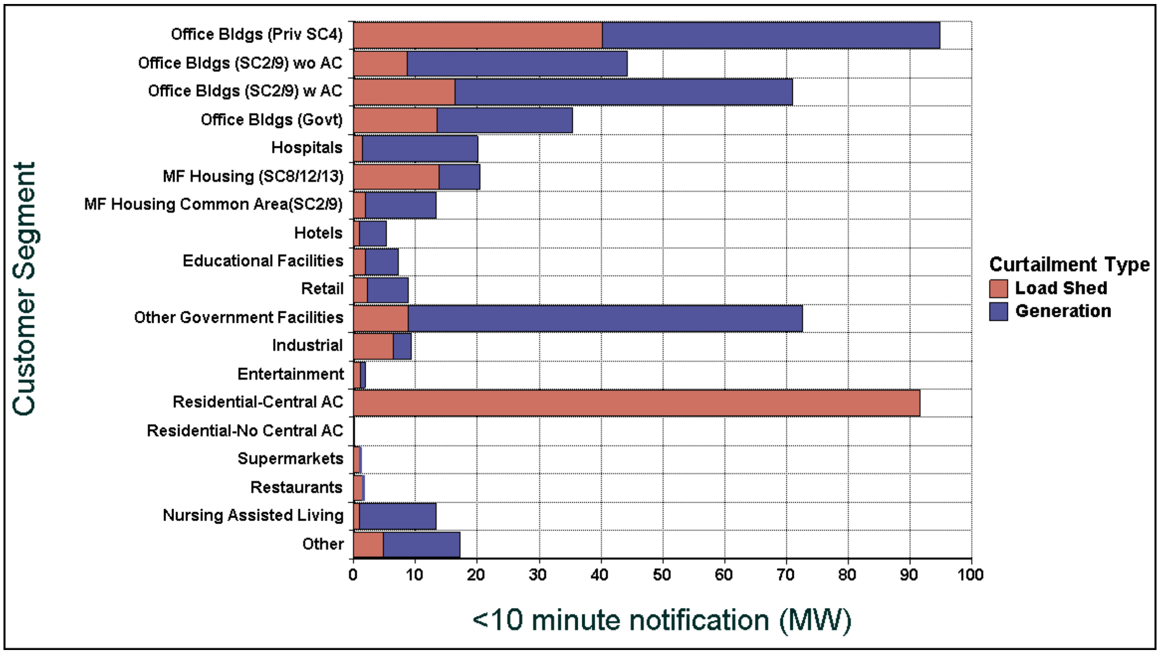
5.1.4 Demand Response Achievable with 10-minute Notification

Callable load reductions that can be realized with little notification to the customer may be more valuable to Con Edison in responding to local distribution system contingencies (see Chapter 7 for a discussion of the relative benefits of different notification times). For this reason, estimates are provided for the achievable potential that can provide curtailments within 10 minutes of initial event notification from Con Edison. These estimates are derived from assumptions regarding the manner in which curtailments are projected to occur. For example, emergency generators can often provide short-notice curtailments, and offices using automation via building energy management systems are also good candidates to provide 10 minute response.[57]

Estimates of callable load reductions achievable with 10-minute notification are provided for each customer segment in Figure 5-9. The three largest providers of this short-notice curtailment are offices, residential accounts, and other government facilities. Figure 5-10 present these same 10-minute estimates by customer segment, but as a share of total achievable curtailment potential. All estimates reported in this section are the mean values of the output of interest using baseline values for all model parameters.

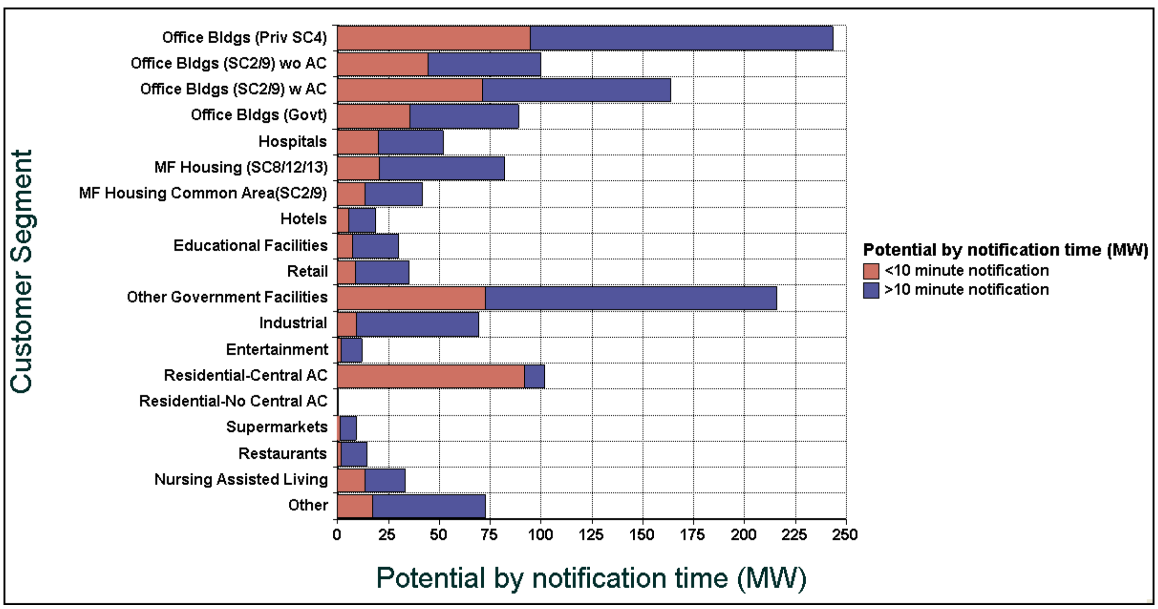
[57] Interviews with aggregators indicated that emergency generation can usually be configured to be callable within 10 minutes; to be conservative, it was assumed that 50% of curtailments from generators can be provided in under 10 minutes. Residential DLC can produce load reductions in seconds or minutes, and a 90% value is assumed to account for failed radio frequency signals or other communications that must be identified and rebroadcast. Since a share of multi-family housing load reductions are likely to come from direct expansion AC units, a value of 20% (as opposed to the 10% default) is applied. The share of curtailments from offices that can be enacted in 10 minutes is assumed to be 30% due to the prevalence of EMS systems. Unless otherwise indicated, it is assumed that 10% of achievable curtailments can be initiated within 10 minutes of notification from Con Edison. These short-notice curtailments can be provided by EMS systems and direct load control of packaged AC units that are common in many commercial facilities.

Figure 5-9. Callable Reduction Achievable with 10-Minute Notification



Note: Customer segmentation by account.

Figure 5-10. Achievable Potential - By Notification Time



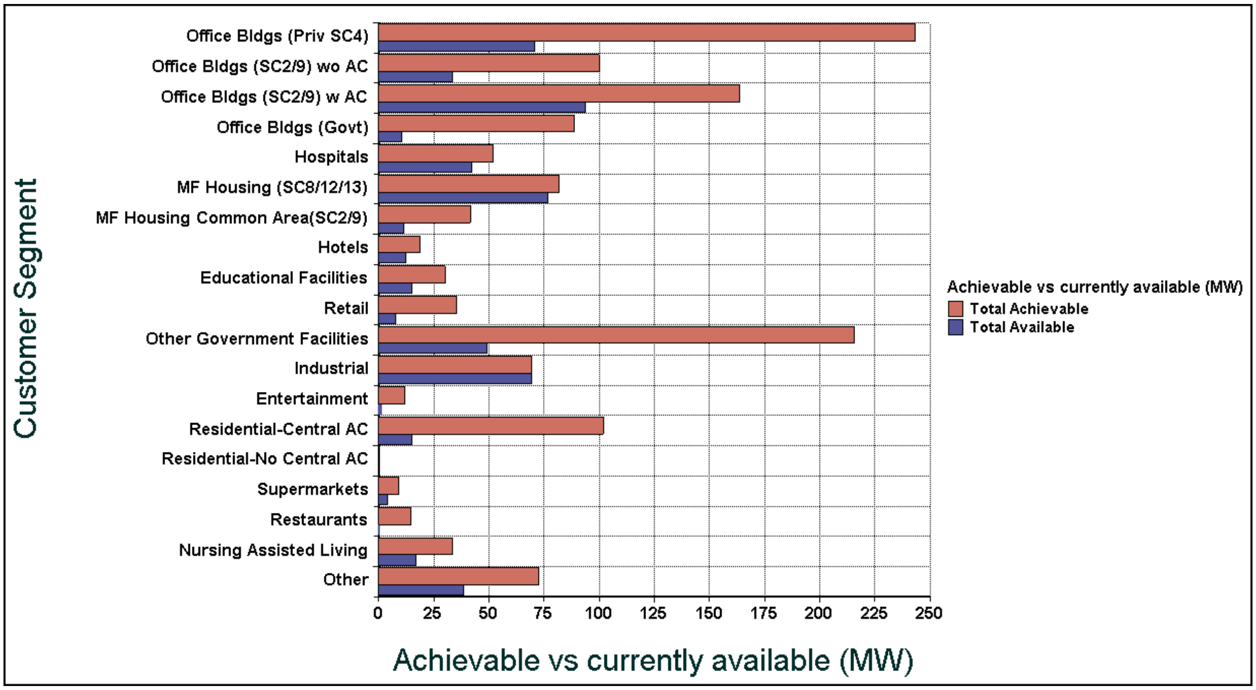
Note: Customer segmentation by account.

5.2 Gap Analysis

This section compares previously described estimates of *currently available* demand response (Section 4.5) with *achievable potential* (Section 5.1.3) to better understand the gap between available demand response resources and the achievable potential estimated for 2017. The difference between the achievable potential and currently available load reduction represents the estimated gap that would need to be closed to realize the estimated achievable potential. It was noted in Section 4.5 that *currently* *available* callable load reduction has been adjusted for both overlap in program enrollment[58] and historical rates of curtailment during called events. Furthermore, unlike the potential curtailments estimated here, *the currently available reductions are not necessarily available at the time of system peak demand and therefore may over-estimate reductions that can be provided when needed most.* All estimates are mean values using baseline (medium scenario) model parameter assumptions.

Figure 5-11 compares the currently available load reduction with achievable potential load reduction for each customer segment. Few customer segments appear to be near saturation, and most have significant unrealized potential for additional callable load capability. In particular, government facilities and residential (with central AC) customers are under-represented considering their large values for estimated achievable potential relative to current participation levels; and the office sector holds the greatest potential in terms of the megawatts of unrealized load curtailment potential. As discussed in Sections 4.5 and 5.1.3, total available demand response resources are estimated to be 569 MW, whereas the achievable potential is estimated to be 1,384 MW, a difference of 815 MW.

Figure 5-11. Currently Available vs. Achievable Potential



Note: Customer segmentation by account; these potential estimates include curtailments from both load shed activities and use of emergency generation.

Multi-family housing (SC8/12/13) appears to be near saturation, with currently available curtailments from multi-family accounts nearly as high as the estimated potential. However, the estimation for this customer segment is more complex than most, and several factors may explain this situation:

1. Much of the load consumed in multi-family buildings is actually represented by residential accounts (with a common area load that may include lighting and cooling). The component of the multi-family housing market segment that is near saturation is only the subset that is master metered; the potential currently being achieved from multi-family *buildings*—which would include sub-metered buildings—is not as close to saturation.

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58 ICAP, DLRP, EDRP, and Direct Load Control (DLC) programs are included in this analysis.

2. SC8/12/13 accounts offer aggregators a single point of contact for what are often large loads. These accounts tend to be easier to attract for participation. One aggregator interviewed for this study described master metered buildings as “the path of least resistance” in terms of addressing the multi-family housing market. As a result, much of the “low-hanging fruit” in this segment has already been enrolled either directly or through aggregators.
3. The estimate of achievable potential is based on curtailments that can be provided concurrent with the Con Edison system peak. The coincidence factor for multi-family housing (like all accounts serving residential customers) is relatively low, especially for the smaller accounts. Thus, the achievable potential *at system peak* is also relatively low. By contrast, currently available load curtailments, based on current enrollments, are not necessarily available coincident with system peak.

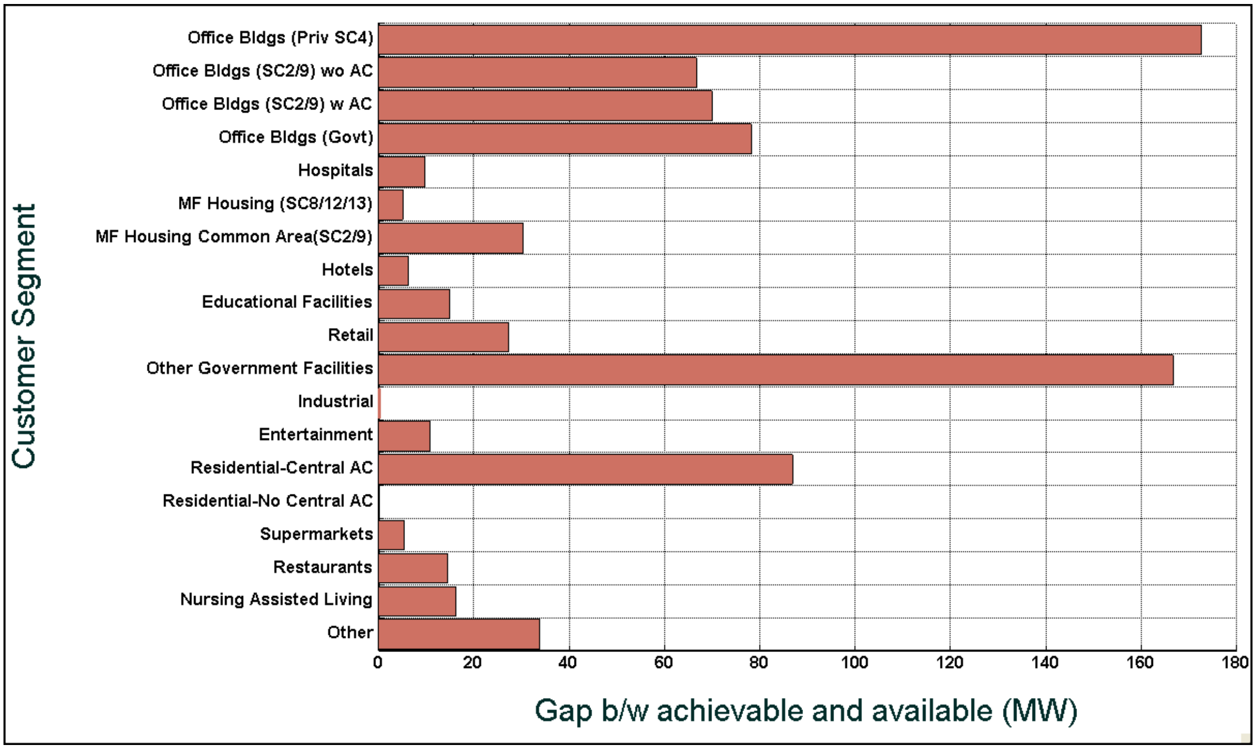
The industrial sector also appears near saturation. The reasons for this may be similar to some of the explanation presented for the high saturation in the multi-family segment: namely, the prevalence of smaller accounts and the fact that the coincidence factor for industrial facilities is among the lowest of all non-residential customer segments. Additionally, it should be considered that demand response programs have been offered in New York for nearly a decade and have been heavily marketed by aggregators whose core business is enrolling customers in DR programs. As of 2007, two-thirds of the 1,338 MW of ICAP enrollments were signed up through aggregators.[59]

The difference between the currently available load reduction and achievable potential is portrayed for each customer segment in Figure 5-12. As described in Section 5.1.3 office buildings, government facilities, and residential customers together represented a total *achievable* potential of 914 MW, or 66% of the total achievable potential of 1,384 MW. Similarly, these three segments[60] represent the largest *gap* between currently available and achievable potential for callable load reduction, collectively accounting for 641 MW of the total gap of 815 MW (69% of the total gap).

[59] New York ISO. FERC Compliance Filing, Docket Nos. ER01-3001 and ER03-647, January 15, 2008.

[60] The gap from office buildings, government facilities, and residential customers are 387 MW, 167 MW, and 87 MW, respectively.

Figure 5-12. Estimated "Gap" Between Currently Available and Achievable Potential



Note: Customer segmentation by account.

5.3 Current vs. Future Market Mix (Load Shed vs. Emergency Generation)

The previous section compared the currently available and achievable potential load reduction by customer segment. This section focuses on the relative contributions of emergency generation and load shed to both currently available load reduction and achievable potential for load reduction. As will be seen in this section, a significant shift in the relative contributions of these two different curtailment methods would be required if the achievable potential is to be realized.

As described in Section 4.5, an estimated 569 MW of callable load reduction is currently available for demand response. Of this 569 MW, an estimated 211 MW, or 27% of the total, is estimated to come from emergency generation[61], with the remaining amount coming from load shed activities. As can be seen in Figure 5-13, the current 27% contribution from emergency generation compares with a 45% contribution from emergency generation for future achievable potential, indicating increasing reliance on use of emergency generation as demand response resources are expanded.

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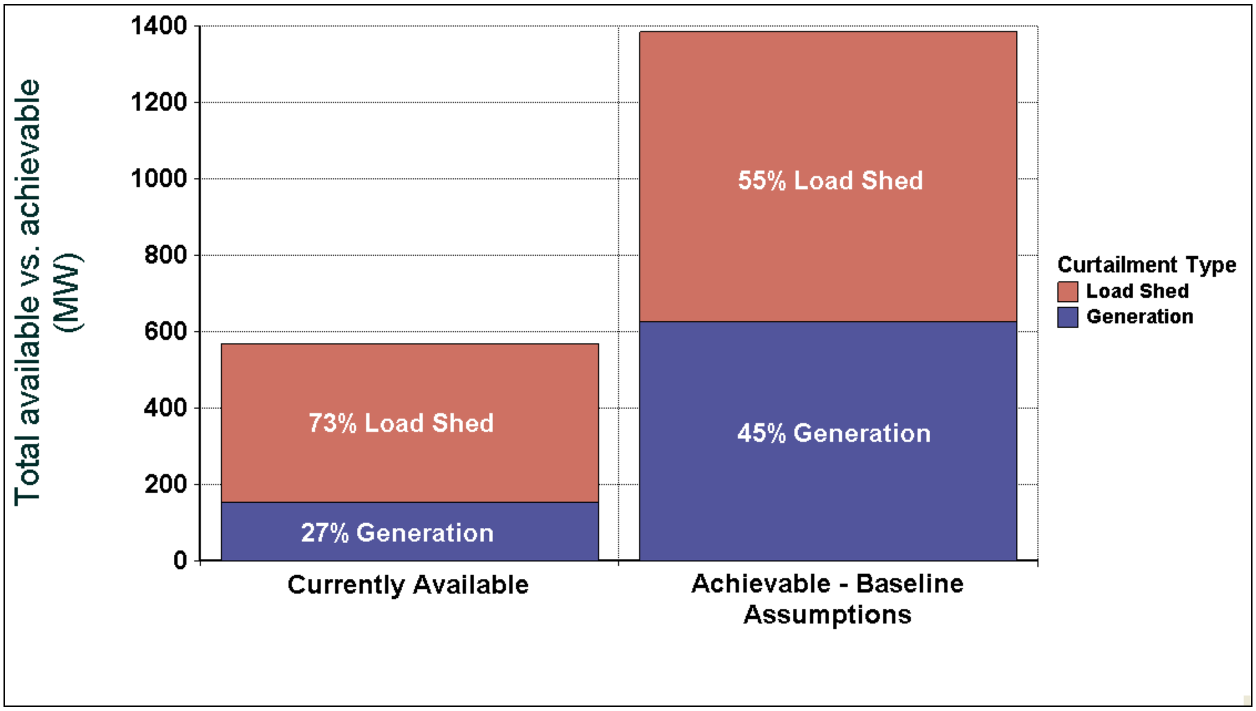
[61] The estimated 27% of currently available callable load resources is derived from the breakdown of existing resources into DLRP, ICAP, EDRP, and DLC programs (as provided in Table 1-1) combined with the following estimates of the percentage of resources coming from emergency generation by program: EDRP - 32%, ICAP - 15 %, DLRP – 68%. EDRP and ICAP estimates of percentage generation are derived from NYISO data -- https://www.nyiso.com/public/webdocs/committees/bic_prlwg/meeting_materials/2007-09-27/2007_September_registration11.pdf). The DLRP value of 68% from generation was derived by Nexant in its evaluation of Con Edison's DLRP program (see *DLRP Program Evaluation Final Report*, Nexant, Inc., February 26, 2008.).

Figure 5-13. Current vs. Achievable Breakdown - Load Shed and Generation



More specifically, load reduction through use of emergency generation would have to increase from the currently estimated 154 MW to 626 MW, an addition of roughly 472 MW (or 306%). In contrast, load reduction from load shed activities would increase from a currently estimated 415 MW to an estimated achievable potential of 758 MW, an 83% increase over the currently available load reduction through load shedding.

5.4 Technical Potential

The last several sections have discussed in detail the estimated *achievable* potential for callable load reduction in the Con Edison service territory. This section will now address the *technical* potential for callable load reduction. For the purposes of this study, the technical potential for callable load reduction assumes 100% of the customers in Con Edison's service territory participate in a demand response program. Likewise, it assumes that 100% of the customers with *eligible*[62] emergency generation will utilize their generation as part of a demand response program. The assumptions regarding load shed parameters (e.g., mean curtailment and standard error on the curtailment) are assumed to be the same as for the achievable potential calculation (see Section 4.1 for a detailed discussion of these assumptions). Although 100% participation in demand response programs will never be realized, calculation of the ultimate technical potential at least provides a theoretical upper bound on the potential for callable load reduction. Of greater interest to planners, however, are the estimates detailed in the several preceding sections on achievable potential.

The cumulative probability distribution for the technical potential for callable load reduction is illustrated in Figure 5-14, which identifies a mean technical potential of 5,442 MW, which is nearly four times the estimated achievable potential of 1,384 MW.

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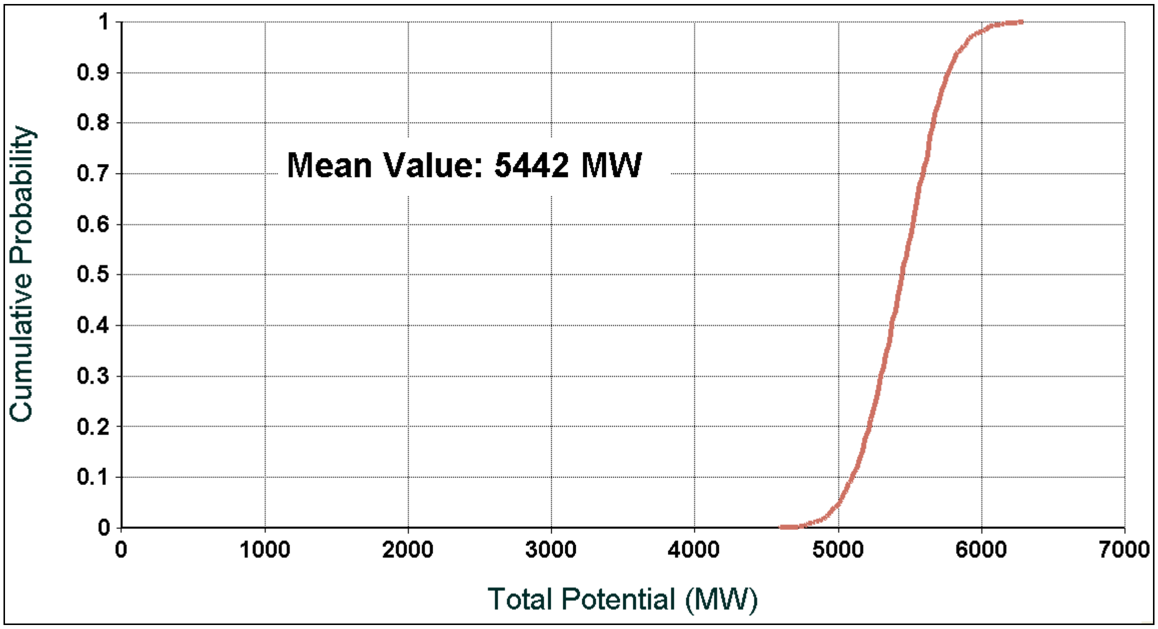
[62] *Eligible* emergency generation is that which can be expected to meet emissions requirements, such that obtaining a permit for use of emergency generation for demand response is possible.

Figure 5-14. Total Technical Potential



Note: Technical potential includes both load shed activities and use of emergency generation.

Considering the uncertainty distribution of the technical potential estimate, there is a 90% probability (0.9 on the vertical axis) that the technical potential would be lower than 5,762 MW, and there is a 10% probability that the technical potential would be lower than 5,095 MW.

The assumed *participation* rates for load shed activities and use of emergency generation are the only parameter values that changed in the above estimate of technical potential relative to the calculations for achievable potential. Since the technical potential estimate assumes a 100% participation rate, the ratio of the mean *achievable* potential (1,384 MW) to the mean *technical* potential (5,442 MW)—approximately 25%—represents the average participation rate (as a % of total kW, not on the basis of customer count) over all customer segments, peak size categories, and curtailment methods (load shed or generation).

5.5 Callable Potential Summary

To estimate the potential for callable load reduction in the Con Edison service territory, the study team characterized the market in this region via analysis of data specific to Con Edison customers, as detailed in Chapter 4. This market characterization provided input to the CLRP Estimator[63], which was developed and used to estimate both the *achievable* and *technical* potential for callable load reduction in 2017. Achievable potential was examined in detail by both customer segment and curtailment type (i.e., load shed vs. emergency generation) to identify customer segments providing the greatest opportunity for callable load reduction. Further, gap analysis was conducted by comparing the callable load reduction currently estimated to be available with the achievable potential to estimate the gap that would need to be closed, by customer segment, to realize the achievable potential in 2017. Finally, the total technical potential for callable load reduction was estimated as a theoretical upper bound on callable reduction opportunities.

Highlights of the findings described in this chapter are provided below.

[63] See Appendix I-B for a detailed discussion of the CLRP Estimator.

Achievable Potential:

- The mean achievable potential for callable load reduction in the Con Edison service territory in 2017 is estimated to be 1,384 MW for the baseline case. This represents 9.3% of the forecast peak demand of 14,900 MW in 2017.
- The combined achievable potential of office buildings[64] (596 MW), government facilities (216 MW), and residential customers (102 MW) accounts for 66% of the total *achievable* potential of 1,384 MW.

Gap Analysis:

- The gap between currently available load reduction and achievable potential is estimated to be 815 MW (1,384 MW of achievable potential minus 569 MW of currently available load reduction).
- Office buildings, government facilities, and residential customers account for 69% of the 815 MW *gap* between currently available load reduction and achievable potential. The gaps from office buildings, government facilities, and residential customers are 387 MW, 167 MW, and 87 MW, respectively.

Market Mix of Load Shed vs. Emergency Generation:

- An estimated 27% of the *currently available* load reduction of 569 MW is estimated to come from emergency generation. The current 27% contribution from emergency generation compares with a 45% contribution from emergency generation for *future achievable potential*, indicating an increasing reliance on load reductions through use of emergency generation as demand response resources are expanded.

    - More specifically, load reduction through use of emergency generation would have to increase from the currently estimated 154 MW to 626 MW, an addition of roughly 472 MW (or 306%). In contrast, load reduction from load shed activities would increase from a currently estimated 415 MW to an estimated achievable potential of 758 MW, an 83% increase over the currently available load reduction through load shedding.

[64] When the four office sub-segments are combined.

6 PROGRAM STRATEGY ASSESSMENT

This chapter presents potential strategies that could be employed to reach the callable load potential estimated for 2017 (Section 5). The estimated achievable potential in 2017 is, as one would expect, greater that the MW delivered by current DR programs (i.e., based on 2007 numbers). The strategies discussed in this section are meant to be forward-looking and designed to help establish sustainable DR that would meet this achievable potential ten years out. This requires the development of short-term actions and anticipation of longer term trends over the 10-year horizon. Strategies that are meant to meet DR goals in the future are necessarily broad in design. They present reasonable options based on what is known today combined with observed industry trends that would allow the 2017 DR potential estimates to be met.

This chapter first addresses the "gap" between MW delivered through today's DR programs and the estimated achievable DR potential in 2017. The balance of the chapter discusses industry trends in DR program development and select program concepts that could be used to bridge the gap between the delivered MW from today's programs and the 2017 achievable estimate. The DR program strategies and concepts discussed in this chapter serve as the basis for a number of the recommendations presented in the following chapter.

6.1 Bridging the Gap between Current and Potential Callable Load Capability

The base case scenario for callable load potential had a mean estimate of approximately 1,384 MW in 2017, with a low participation scenario indicating 1,190 MW and a high participation scenario suggesting 1,746 MW. Given that the forecasted peak for 2017 is 14,900 MW, the percent of system peak demand that is estimated as achievable in 2017 is 9.3%, with a low/high scenario range from 8.0% to 11.7%.

The "gap" between delivered DR MW today and the estimated DR MW potential in 2017 is 815 MW, with almost all of that occurring in the C&I sector. The C&I sector counts for 728 MW of the 815 MW total gap, and the residential sector accounts for 87 MW.

Callable load programs can be designed to achieve the potential load reductions by targeting specific sectors and curtailment methods. Highlights of the possible breakdown of new callable load capability are presented below:

1. **C&I Incremental Load Shed MW**. Overall, load shed programs (not including any new emergency generation) in the C&I sector should target approximately 256 MW of additional callable load in the C&I sector. Office building is the sector expected to be the largest contributor to this additional 256 MW of DR by 2017. Office buildings comprise approximately 50 percent of the current gap in achievable potential in the C&I sector. Other C&I segments with sizeable estimates of achievable potential are "other government facilities," multifamily housing, and the retail segment.

2. **C&I Incremental Emergency Generation MW.** The additional callable DR from participants with emergency generation needed to meet the 2017 achievable DR is estimated at 472 MW. Again, office buildings account for the largest fraction of emergency generation capacity that does not yet participate in a DR program. This is followed by "other government buildings," and

multi-family housing. The strategies discussed below consider both customer-owned and utility-owned emergency generation.

3. **Residential Incremental Load Shed MW.** The additional MW that would contribute to meeting the achievable callable DR potential in 2017 is 87 MW. Most all of this future DR could be obtained from residential customers with central air conditioning through cycling similar to Con Edison's current direct load control (DLC) program. If technology advances, some of this future DR might be met though controls on room AC units. While some DR technology companies are working on controls for room AC units, they are not currently viable.

The three segments, i.e., C&I load shed, C&I emergency generation, and residential load shed from which additional DR might be obtained is discussed above, More specific trends and strategies that might be used to obtain these incremental DR MW is discussed below.

6.2 DR Program Trends

There are a number of trends that can be seen among new DR program designs and in the DR technologies being developed. Five trends are discussed below:

1. Increased automation of a customer's load response.
2. Increased focus on firm reductions within DR programs.
3. Diversification in program participation.
4. Target marketing of DR to provide higher T&D benefits.
5. More accurate estimation of delivered load impacts.

***Trend 1. Increased automation of a customer's load response to signals from an aggregator or directly from a system operator*.**

Residential DLC loads are already automated and available within minutes after called. A similar trend is occurring in the C&I sector. Discussions with aggregators of C&I loads have indicated that the fraction of load that is essentially automatically controlled through an energy management or building management system is increasing. Over the past two years, approximately 50% of the C&I response that select aggregators have been obtaining to meet firm contract requirements has used automated response that can be activated within 10 minutes. New load that is being enrolled in programs has an even higher fraction of load that responds automatically to a signal.[65] In addition, much of the industry research on DR is focused on "auto-DR" where much of the load response is automated. Still, most programs that have two or more hours of advance notice have some loads that are manually controlled and this can be expected to continue. Programs that have less than two-hour notification (e.g., 30-minute or 20-minute notification) are migrating to emergency generation options and towards the use of auto-DR concepts. Some programs are being designed that will allow a customer to have part of its load in a two-hour (or greater) notification program, and part of its designated load that can be called upon in with 10-minute notification. In general, the auto-DR programs rely on buildings that have energy management and control systems (EMCS) that can be used to control space conditioning, lighting, and other end-uses (chilled or heated water, refrigeration defrost cycles, or other equipment in the facility). Often, the load sheds are small and do not impact the building or facility significantly.

[65] Confidential interview with demand response aggregator active in New York State, April 28, 2008. . . . Some customers are not willing to have all load curtailed with less than 10 minutes' notice even if control equipment is capable of responding to such short notification.

One implication of this trend is the increased cost-effectiveness of combining C&I DR programs with new construction or major building retrofit programs where load-responsive technologies can be installed while a building or facility is being built or undergoing a major retrofit. In addition, retro-commissioning of commercial buildings is a growing energy efficiency program type. These often involve working with or installing an energy management system. A collaboration between DR needs and the design of these traditional energy efficiency programs can help to install the equipment that is needed to deploy automation systems that allow customers to participate in fully-automated DR programs. The costs of these systems have been estimated to cost between $3,000 to $5,000 in most applications in research conducted by the Demand Response Research Center (DRRC).[66] This DRRC effort on automated DR programs has encompassed a diverse set of building types including office buildings, retail chain stores, schools, museums, laboratory buildings, a museum, and a bakery.

Trend 2. Increased focus on firm reductions within DR programs.

There is an increased emphasis on DR programs that provide firm capacity that will allow DR to appropriately qualify for generation capacity deferrals and T&D deferrals. For programs offered directly by utilities to customers, this can involve financial penalties if specified load reductions are not met, or provisions where a customer's contribution is derated due to underperformance, and some customers have been dropped from DR programs. Most C&I aggregators seeking to provide high value load reductions are offering DR load reductions as firm load. This increased focus on DR programs as providing firm capacity has also resulted in operational protocols that call for at least one test event each year. A number of different strategies are being used to make DR programs act as essentially firm capacity, which could even be used for ancillary services. The NYISO is planning to roll out a Demand-Side Ancillary Service Program before the end of the second quarter of this year.[67]

Trend 3. Diversification in program participation to reduce risk.

For DR programs to provide firm capacity, there are two elements that need to work in tandem. First, if a sizeable fraction of a program's DR capability resides with just a few customers; then, it is important to stay in touch with those customers to ensure that they can respond when needed. Having a program that provides firm capacity is not the same as having each customer provide a fixed kW reduction. Many C&I programs will still have a weather component, as the actions taken to reduce load will include HVAC actions that include global temperature controls, pre-cooling, chilled water, and hot water temperature adjustments. As a result, the impacts from customers that participate in a program will vary with weather conditions to some degree, and individual customers' kW reduction will depend on the amount of response strategies that are tied to HVAC actions.[68] As a result, having a reasonably large number of customers participate in a program offers diversity that can help maintain the level of load shed across

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[66] Costs include EMCS programming, control hardware, and facility manager time. Some other labor costs may not be captured in these figures. This research is discussed in a number of DRRC reports including: M.A. Piette, D. Watson, N. Motegi, S. Kiliccote; Automated Critical Peak Pricing Field Tests: 2006 Pilot Program Description and Results, CEC PIER Demand Response Research Center, LBNL, August 2007 (LBNL Report 62218), p. 25. http://drrc.lbl.gov/pubs/62218.pdf. Other research indicates costs for DLC at commercial facilities of $14,000 for cooling and lighting end uses. See Quantec, LLC with Summit Blue Consulting and Nexant, Inc. for PacifiCorp. *Assessment of Long-Term System-Wide Potential for Demand-Side and Other Supplemental Resources.* June, 2007.

[67] Demand Response Market Product Specialist at the NYISO, personal communication April 8, 2008 and email April 28, 2008.

[68] Some utilities have enough experience with and evaluation of their DR programs that they estimate the load reductions to be provided by a program as a function of outdoor temperatures projected for that day by 10:00 AM. This may seem complex, but the dispatcher simply looks up the relationship between weather and expected load reductions and uses the appropriate load reduction as the target for that program on that day.

called events. Managing the risk of underperformance in DR programs is improving dramatically as more aggregators are providing DR under contracts that require a target load reduction to be met.

Trend 4. Target marketing of DR to provide higher T&D benefits.

Utilities and planners are recognizing the locational benefits of DR programs and are working to design and market programs that can help defer T&D investments. For this to occur, adequate DR must be available on specific networks to reduce strain on local distribution lines when contingencies occur in that network, and to be available with notice that will facilitate the potential deferral of T&D capacity investments. To defer capital investments in T&D, 10-minute notice may be needed by system operations.[69] As a result, a subset of DR that can be made available on 10-minute notice is identified and provided with higher incentives to that reflect the value of these short-notice resources to the system.

Trend 5. Increased accuracy in estimating program load impacts and customer baselines.

The calculation of overall program impacts and settlements for customers participating in DR programs is becoming more sophisticated. This includes the use of different baseline options available to customers and for estimating the program's overall impacts (which might be different than the sum of each customer's settlement load estimates). There is an increasing recognition that a single method for estimating impacts may not apply equally well to all customers. Con Edison's DLRP already takes this into account by including a weather adjustment option that can be selected by customers. Since the customers' actual loads on an event day are known, the key is estimating what the customer would have used had an event not been called. The trend is to use the method that provides the most effective and verifiable baseline, which may not be the simplest method or the one most commonly used in New York.

Traditionally, approaches for determining customer baselines have been limited. Often, some calculation based on that customer's load for 10 non-event weekdays preceding an event has been used. Alternative methods are being used in some cases that include all the data from non-event days prior to an event for that season, testing of baselines for different customer segments within a program to see if different baseline methods work better for different customers, and there have been proposals to use both days preceding an event day along with several post-event days to help ensure a more accurate baseline. These calculation methods can be automated, and settlement provisions can be determined for participating customers that are accurate and understandable. In addition, system planning may want estimates of program-wide load impacts that are as accurate as possible, and regression methods based on an entire season's data or all the data available up through an event day are being used.[70]

6.3 C&I Sector DR Strategies

The five trends discussed above help shape the DR strategies outlined in this section. Future programs in the C&I sector can build upon experience Con Edison has gained through the DLRP program and from the experiences of other utilities (see Appendix I-C for a discussion of utility C&I DR program

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[69] These conclusions are based on discussions with T&D planning staff at Con Edison, April 2008. However, Con Edison has not determined specific notification criteria that would ensure the ability to defer T&D investments.

[70] To facilitate prompt payments to customers, simpler calculations can be used to compensate customers for achieved load reductions to facilitate participation. However, it may be in the utility's interest to know with greater accuracy the program-wide load reductions, and different, more complex regression approaches are now being proposed for program-wide impact estimation. One such method would use whole-year, or whole season, data covering the period during which DR events took place, rather than just the 10 days prior to an individual event. Although this method cannot be used for prompt calculation of payments, it is perhaps a more reliable post-estimate of actual program impacts.

experience). Most of Con Edison's achievable callable load potential is in facilities that would be defined as commercial rather than industrial. DR strategies in four areas are addressed below:

1. Auto-DR programs (automated load shed)
2. Program options for 10-minute notification
3. Expanded participation of emergency generators in callable load programs
4. Expanded participation in voluntary curtailment programs

Auto-DR Programs – Automated Load Shed

Candidate concepts for new C&I programs are generally based on trying to make participation in a DR event as easy as possible. Often, this will include auto-DR concepts where the customer has to take little (if any) independent manual action. Customers have suggested that automation helps them institutionalize demand response within facility/building operations. The alternative is manual demand response, when building staff receives a signal and have to physically take actions to achieve a load shed. Commercial facility and building research has found that many building energy management control systems (EMCS)[71] and related lighting and other controls can be pre-programmed to initiate and manage demand response. Examples of demand response strategies include reducing electric loads by dimming or turning off non-critical lights, changing comfort thermostat setpoints, or turning off non-critical equipment. These automated demand response activities can be triggered by directly by the utility, a DR aggregator, or by the customer in response to a signal.[72]

Research by the Demand Response Research Center[73] (DRRC) in California with funding from the utilities in that state and by the California Energy Commission has shown that a stand-alone retrofit program can be viable. This program has encompassed a wide variety of facilities including office buildings, high-tech office buildings (e.g., Sybase Headquarters), retail stores (e.g., IKEA and Target), manufacturing, data centers, schools, grocery stores, and other various commercial facilities. The DRRC effort showed that most buildings with EMCS could participate in an auto-DR program. The period of the DRRC pilot included a severe heat wave, but all auto-DR sites continued to participate in DR at a time when it was needed most. None of facilities opted out. In addition, recent research is showing that full (or near full) automation is technically feasible and provides value to customers. The DRRC pilot showed that that the automated facilities continue to participate after many years, leading to the conclusion that automation is likely improve participation in demand response programs.

Program Options for 10-Minute Notification

DR programs that move towards the auto-DR concept can typically provide some load sheds that only require 10-minute notification or less. While customer surveys conducted as part of this study and a recent evaluation of the DLRP program[74] have shown that most customers would prefer longer notification periods, many of these customers have not put in place the technologies to automate DR both load shed within a facility and the startup of emergency generation. The value of DR and the design of DR programs should take into account system operations. 10-minute notice DR can be valuable in

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[71] Energy management and control systems (EMCS) are centralized controls, generally with computer interface, used primarily for heating, ventilation, and air conditioning systems. These systems sometimes also provide lighting control, as well as control of fire and life-safety systems.

[72] Customer triggered demand response in an auto-DR program would involve a simple "push button" action.

[73] Piette, M.A. et al., op cit.

[74] Consolidated Edison Company of New York, Inc., *DLRP Program Evaluation Interim Report,* Nexant, Inc., February 26, 2008.

helping defer some investment in T&D. While not all customers may choose to provide 10-minute notice response, there should be an increasing number of customers that will provide this type of response in the future and programs should be designed to acquire this resource.

Expanded Participation of Emergency Generators

Emergency generation is a prominent component of a callable load program strategy, as evidenced by the fact that more than 50% of the committed load in the DLRP program is provided by emergency generators. However, it is likely that many of the emergency generators not currently participating in the DLRP are not permitted for use as a demand response resource[75] and proposed regulations would further limit the availability of emergency generation for demand response.[76] Con Edison could consider a program to promote emergency generation by assisting customers with equipment specification and set-up.

Two approaches to increasing the amount of emergency generation in DR programs are discussed below: 1) facilitating customer-owned generation, and 2) utility ownership of the generation, which is used to provide additional reliability for customers willing to locate the equipment at their facilities.

Approach 1: Customer-owned Emergency Generation

One approach to increasing the availability of emergency generation for demand response is by assisting customers with ownership of grid-synchronized emergency generation.[77] The discussion below is based on Portland General Electric's Dispatchable Standby Generation program, which is geared toward encouraging development of new distributed generation at customer sites that can be dispatched by the utility up to 400 hours annually to meet peak power demands.

Under this program model, the customer would purchase a generator with a minimum capacity of perhaps 250 kW. Con Edison would pay for all equipment necessary for parallel interconnection with the utility grid as well as all maintenance and fuel expenses. Once operational, the standby generators can be monitored and dispatched from Con Edison's control center, and they can also provide backup power during an outage. An additional benefit to the customer relative to typical backup generation is the seamless transition to and from the generator without the usual momentary power interruption. The grid-synchronized connection also means that Con Edison may be able to use the generators for some ancillary service functions. If modeled after PGE, Con Edison would perform the following functions:[78]

- Upgrade switchgear and install control and communications hardware at no charge, increasing reliability and improving control of your system.
- Assume all maintenance and operation costs for customer systems, eliminating customer costs for fuel, repairs, tune-ups, oil changes, filter replacements, and overhauls.
- Provide additional sound attenuation, if needed, quieting the generator system.

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[75] Consolidated Edison Company of New York, Inc., *DLRP Program Evaluation Interim Report,* Nexant, Inc., February 26, 2008.

[76] New York State Department of Environmental Conservation, proposed rule modifying 6 NYCRR Part 222 Distributed Generation Sources, October 25, 2007.

[77] There may some areas within Con Edison's distribution system network where grid-synchronized emergency generation cannot easily be used without additional system upgrades. Furthermore, it is necessary to ensure that emergency generation has black start capability in the event that VAR support cannot be provided by the grid.

[78] See http://www.portlandgeneral.com/business/large_industrial/dispatchable_generation.asp?bhcp=1

- Provide additional fuel storage, if needed, expanding operating time during any weather-related, long-term power outages.
- Test customer systems at least once a month under full load; frequent full-load testing ensures the generator will operate successfully during an outage and is better for the engine.

Program participants would pay standard electric rates for power used, regardless of whether it is being generated by Con Edison or on-site by the generator. In case of PGE, the utility not only pays the fuel costs for the standby generators during an outage, but also for up to 15 hours per year during which the customer chooses to operate the unit.[79]

Approach 2: Utility-owned Emergency Generation

A second approach to increasing the availability of emergency generation for demand response is by locating generation at customer sites that can be owned by Con Edison. The discussion of this model is based on Progress Energy Carolinas (PEC) Premier Power tariff under which approximately 17 MW of utility-owned emergency generation units are located at the sites of approximately 10 participating customers with especially high reliability needs. Through this type of program, the customer receives emergency generation capability during system outages in exchange for paying a monthly fee consisting of both levelized capital costs and operation and maintenance costs.[80] PEC is investigating the use of these generators and other PEC- or customer-owned generation to reduce peak demands for up to 100 hours per year.[81] Participants would likely receive capacity payments ($/kW-month) and/or energy payments ($/kWh) in exchange for granting PEC permission to dispatch the units for a limited number of events and total hours per year. Although these systems are tested periodically at full load, the company has never tapped this idle resource in response to supply constraints or high marginal supply costs.

The program under consideration is a unique effort in that it would attempt to utilize existing DG resources for purposes of demand response. However, it warrants noting that such a program—utilizing resources originally designed to help ensure reliability—may be a difficult sell to customers. On the one hand, the existing program of placing utility-owned generation at customer sites sells insurance against the rare occasion of the utility's failure to deliver electricity; yet asking the same customers to help prevent outages by offering the units as dispatchable resources might create or reinforce a perception that an outage is not going to be a rare event in the future. If Con Edison were to offer such a program, it would have to reconcile these competing objectives in the value proposition.

Expanded Participation in Voluntary Curtailment Programs

Voluntary programs are generally part of every DR portfolio. These programs are a good way to generate interest in DR programs and work with customers to migrate them to a more "firm" DR program. By

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[79] Despite having fewer customers than Con Edison (peak system load is roughly one-third that of Con Edison), as of December 2007, PGE had 44 MW enrolled in its standby generation program, representing 37 generators at 22 unique locations. As of late 2007, another 17 MW were under development and PGE has a long term goal of 150 MW. The utility attempts to attract facilities considering new standby generation, as opposed to those with existing generators, since the retrofit costs tend to make the economics less attractive. PGE's C&I account representatives promote the program, and vendors of emergency generation equipment in the region are made knowledgeable about the program so that they can inform their customer about the program's benefit prior to investment decisions being made.

[80] See Carolina Power and Light Co., d/b/a Progress Energy Carolinas, Inc., Premier Power Service Rider PPS-7A, http://www.progress-energy.com/aboutenergy/rates/NC_Premier_Power.pdf.

[81] Source: Progress Energy Carolinas Resource Plan, North Carolina Utilities Commission, Docket No. E-100, Sub 109, September 2006.

gathering performance data over time, it is likely possible that you can treat a portion of this voluntary load as reliable, i.e., attained with a high level of probability. The problem often is that there may not be enough event days to generate the performance data that is needed to calibrate a voluntary program. Recent experience with NYISO programs and Con Edison's DLRP program show that actual load reductions have been 50% or more of the voluntary committed load. Customers in voluntary programs are not given any capacity payments, but they generally are paid for load reductions which may be less than their commitment. The firm DR programs discussed above would not provide payments if the committed load reduction is not reached. Also, voluntary programs would not have the same testing procedures to accredit their load reductions.

6.4 Residential DR Strategies

Con Edison currently has a program in place that can be used to duty cycle residential AC units. According to the 2006 Annual Report for the mass market direct load control program, thermostats installed in small businesses produced an average reduction of 1.24 kW during called events, while residential thermostats produced an average load reduction of 1.13 kW. Together, this mass market DLC program is capable of up to 30 MW of demand response. The additional achievable potential for this mass market/residential sector is estimated at nearly 90 MW.

The current DLC program provides short-notice load relief, and one obvious program strategy is to simply try to maximize the benefits of this program. New thermostat technologies are being developed and Con Edison will likely want to continue benchmarking its current technology with new options as they develop if this program is going to be ramped up to the point where it can deliver up to 90 MW. This would require participation by an additional 80,000 or more mass market customers, depending on the mix between residential and small commercial customers.

A number of utilities have direct load control programs of this size or larger. In some cases, aggregators have been used to achieve scale in residential programs. However, penetration rates in excess of 30% have rarely been obtained. Roughly 400,000 residential households have central air conditioners, some of which serve small commercial accounts. Having 80,000 units participate in an AC DLC program would be close to the upper limits of participation that have been seen at utilities with similar programs. (See Appendix I-C for a discussion of utility residential DLC program experience.)

New construction. Other strategies in the residential sector might be to work with the residential new construction and major remodel programs to have addressable thermostats installed when workers and electricians are already at the site. This could lower the costs of the program and provide another method for marketing the program. The California Energy Commission considered requiring communicating thermostats in all new construction, but this proposal was met with resistance and is currently on hold (see Section 6.5.3 on New Construction Standards).

Room air conditioners. Another area to explore could involve tapping into the potential for callable load reductions from room air conditioners. At least one prominent demand response provider is exploring the possibility of having manufacturers of room AC units embedding a Zigbee home-area-network communication device into new units. This would enable cycling of room air conditioners without the need to install radio frequency load switches commonly used for residential direct load control applications.[82]

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[82] Confidential telephone interview with senior manager of a prominent demand response provider, April 23, 2008.

Tapping into the potential for callable load reductions from room air conditioners would provide a significant boost to Con Edison's load control capability—and importantly, these reductions would be dispatchable in less than ten minutes and thus could help defer T&D investment. Con Edison expects that its service territory will add more than 1.4 million new room air conditioners in the next 10 years.[83] If owners of just 4% of these units participated in a DLC program (the same participation rate as for central air conditioners in Con Edison's Direct Load Control Program), these 56,000 units would represent more than three times the number of residential AC units currently controllable through the DLC program.[84] Even accounting for the lesser load reductions from room air conditioners as compared to central AC units, the increase in direct load control capability would represent a significant increase over current levels. Given that there are currently about 5.9 million room air conditioners in the service territory, enabling replacement units with load control technology would greatly expand the cost-effective callable load potential

Other appliances. Based on the experiences of other utilities, expanding the equipment controlled to other equipment beyond AC units might produce additional kW reductions. This could be accomplished using switch technology that is signaled through a thermostat or directly, and could include electric hot water heaters and pool pumps. However, the saturation of hot water heaters is much lower than for air conditioning, and control of hot water heaters generally produces only about one-third the load impact of air conditioners, especially in the summer when Con Edison would most likely be calling DR events. Similarly, the saturation of pool pumps in the New York is relatively low compared to service territories like that Florida Power & Light, where the company's On-Call residential DLC program includes air conditioning, water heating, and pool pumps and generates more than 900 MW of summer load control capability with a participation rate of approximately 25%.

6.5 Select DR Issues for Con Edison

The discussion above was organized by sector to focus strategy considerations on specific target markets within the C&I and residential customers. Several specific issues are discussed below.

6.5.1 Direct Financial Penalties for Under-performance

Ideally, future or expanded DR programs would be viewed as a reliable resource. This is best accomplished by having customers enroll in programs where the load reduction is viewed as mandatory. These programs may vary from the traditional mandatory program where there are often direct financial penalties for underperforming. Market research has shown that direct financial penalties can be a major reason why some customers choose not to participate, even if they are a good candidate for achieving load sheds with minimal impact on their building or facility.[85] It makes the DR program to seem more risky than it actually might be for that customer.

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[83] Internal Con Edison document on residential sector appliance saturation, Consolidated Edison Company of New York, Inc., Peak Load Forecasting, February 26, 2008.

[84] As of 2007, more than 25,000 of the roughly 400,000 central air conditioners in Con Edison's service territory, or approximately 6%, were participating in Con Edison's DLC program. Source: Applied Energy Group, Inc. *Con Edison Direct Load Control Program, 2007 Annual Report.*

[85] The primary survey research conducted or this study found that only 7% of respondents not currently participating in a DR program prefer one of the mandatory program options (NYISO ICP or mandatory DLRP) that have financial penalties for under-performance. See Figure 3-1.

One design issue that should be addressed by program planners is whether you can have "firm" DR programs if there are no direct financial penalties at the customer level.[86] Instead of direct financial penalties, a program with the following characteristics might provide reliable load reductions:

1. The customer signs up under the expectation that they have to achieve their target load reduction or reduce loads down to a negotiated firm service level that allows for the operation of essential equipment.[87]
2. All customers must be tested and certified to ensure they can achieve the target load reductions. In some cases the load reduction targets are modified based on these tests.
3. There are financial penalties for non-performance, but they are not fines for not achieving the load reduction. Instead, the penalties are:
    a. Participants failing to achieve their MW commitment would not receive even a partial payment for the load reductions that were achieved and the capacity payment for that month is forfeited (*i.e.*, it is not paid to the customer at the end of the month).
    b. Customers missing their contract load reductions once would have an adjustment to their future reservation payments, similar to what is in the current Rider U. However, for purposes of reservation payments, re-adjustment upwards (whether to their previous level of contracted load relief or some other level) would not be possible until at least the month *after* the next event.
    c. Customers missing their contract load reductions twice would be dropped from the program or enrolled in a voluntary program for at least the remainder of the summer capability period.

If repeated events and MW certification tests show that the program underperforms because there is a consistent inability of some customers to hit their full load reduction target, a discount factor can be applied to the target load reductions to satisfy the requirement of a firm load reduction. Evaluations of aggregator programs that use similar designs have been shown to be able to meet target load reductions. These aggregators employ their own risk management strategies as they are typically subject to direct financial penalties for not attaining the target load reduction, but they may use a different set of incentives/penalties for customers enrolled in their program. Experience in managing risks of underperformance in DR programs may be one advantage in allowing aggregators to participate in utility designed programs where they offer firm load reductions from aggregated customers.

6.5.2 Landlord-Tenant Issues

As discussed above, office buildings and multi-family housing are the market segments with the highest peak loads. Buildings in these segments also tend to have among the greatest institutional barriers to participation in demand response programs (and demand-side management programs in general). This is due to the fact that it is common for a single facility manager or landlord to handle the Con Edison account and also because load curtailment, such as a reduction in air conditioning load from a chiller, often affects each of the multiple tenants, who may not have the same interest in participating or the same tolerance for the effects of that participation. Furthermore, incentives for curtailing load may not be

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[86] The need for direct financial penalties is a viable design option. The goal is to get more participation in DR programs that can provide reliable load sheds such that direct financial penalties are not needed at the customer level.

[87] This latter approach where customers reduce their consumption down to a negotiated baseline load is the basis of successful C&I programs at Xcel Energy. Firm service levels are also used by PJM in DR programs.

distributed among all affected parties, or the parties may not be aware of the financial benefits, which may be passed on indirectly through lower utility charges from the building manager.

The Real Estate Board of New York (REBNY), which represents roughly 12,000 members and two million square feet of mostly high-rise real estate, has promoted the idea of demand response and energy efficiency in the past. Hoping to plan ahead to avoid problems similar to the rolling blackouts in California earlier this decade, REBNY helped to develop a series of steps for its members for electricity emergency management such as temperature set back and turning off lights, fans and elevators. According to REBNY staff,[88] this effort received a high level of participation, despite it being completely voluntary. The organization is considering putting additional demand response topics on its summer agenda.

Despite some initial participation, many offices and high-rise residential buildings have engaged in DR program. REBNY staff indicated that its members would benefit from support in marketing and communications with tenants to help increase acceptance and understanding of demand response. Its members tend to be concerned about the relative costs and benefits of participation, although part of this sentiment was focused on the use of system benefits charges for energy efficiency.

The REBNY staff believes that residential building owners have some ability to participate, although it seems more limited than for commercial buildings which have fewer unique tenants. Part of the problem is related to the difference in ownership structures between commercial buildings, often owned by a single entity, and residential buildings, which may have individual co-op/condo owners.

The institutional barriers are fewer where there is a single owner or management company. The problem becomes one of how to communicate with tenants/occupants when the owner has the ability to reduce cooling load or shut off lights. Some keys may be to ensure that the benefits flow to the individual tenants affected and to combine the load curtailment concept with energy efficiency measures that may be more readily accepted. Residents at one 100+ MW co-op in Manhattan are sharing the concurrent financial benefits of lighting retrofits, taking service on Con Edison's Rider M real-time pricing tariff, and participating in demand response through the NYISO. Common area loads are curtailed according to the level of enrollment in the program, and individual resident curtailment is done on a voluntary basis. The building posts fliers in common areas and uses word-of-mouth communications to encourage greater reductions.[89]

6.5.3 New Construction Standards

One of the limitations to widespread demand response is the inherent incompatibility of existing facility infrastructure to accommodate load curtailments, especially automated load reductions that can be dispatched by Con Edison and realized in less than ten minutes. Examples of these limitations include room air conditioners that cannot be fit with load switches, non-dimmable lighting ballasts, and energy management systems (EMS) unable to receive external signals such as via broadband internet connections. These obstacles can be overcome by incorporating DR-compatible practices into building codes, or working with architects, building engineers, and real estate developers to voluntarily adopt DR technologies.

The California Energy Commission recently proposed to include a requirement for new residential buildings to have a programmable communicating thermostat that could receive a curtailment signal.

[88] Marilyn Davenport, Sr. Vice President, Real Estate Board of New York, personal communication, April 22, 2008.

[89] "Co-op Gets Creative," *EnergyBiz Magazine,* March/April 2007, p. 78.

Commercial buildings with EMS would be required to have the capability to adjust temperature setpoints facility-wide. The CEC proposed action reads as follows:

> *Enabling new buildings to respond to electricity demand curtailments by reducing air conditioning loads at peak times is a new aspect of the 2008 Standards. Communication capabilities are proposed as requirements for all thermostats controlling unitary heating and air conditioning systems. These programmable, communicating thermostats (PCTs) are required to accept both a price and an emergency signal for demand response, and must respond by increasing the setpoint temperature for the cooling system. For nonresidential buildings with energy management systems (EMS), a new requirement is proposed to ensure that the EMS is capable of issuing a global setpoint adjustment. This will enable automatic demand response in new large commercial buildings.*[90]

Due to a great deal of public input on this subject and concerns from various interest groups about privacy issues, the CEC withdrew this proposal. However, the issue of PCTs is still under consideration through the Commission's Load Management proceeding (Docket # 08-DR-1).

6.5.4 Economic Dispatch versus Reliability-Only Dispatch of DR Programs

The use of DR load reductions during reliability events is widely accepted and is the basis of most ISO programs. However, there are quite a few DR programs that are dispatched on an economic basis. This occurs when prices get high and load shedding is less expensive; then, an event is called. Regulators of investor-owned utilities have sometimes resisted the use of economic dispatch. However, economic dispatch is widely used by public power entities as it reduces the overall costs of electricity. The decision between using callable loads for reliability only or allowing them to be used when the economics favor load shedding is a policy issue that deserves careful consideration. The economic dispatch of DR programs could be left up to the DR program administrator, or it may be possible to place some limits on the strike price (i.e., the price must exceed a certain level before the DR program is called) or on the number of times it could be used over a certain time period.

[90] California Energy Commission, Notice of Proposed Action: Revisions to the California Building Energy Efficiency Standards, California Code Of Regulations, Title 24, Part 1 and Part 6 (California Energy Code), 2008 Building Energy Efficiency Standards. Docket No. 07-Bstd-1, November 16, 2007.

7 COST-EFFECTIVENESS OF DR PROGRAM CONCEPTS

This section examines the cost-effectiveness of the program concepts discussed in Section 0. Any analysis of the benefits and costs of a DSM initiative, whether it is energy efficiency or demand response, has a number of difficult to quantify factors. In this analysis, it is proposed that only the standard avoided costs are included as DR benefits and items that may be viewed as hard to quantify benefits such as reduced market prices for all system customers during peak hours, reduced market power, and increased system efficiencies are not addressed in these benefit-cost analyses.

There is one important problem to address and that is one of the utility (i.e., Con Edison) versus the system perspective. From a Con Edison view, the only benefits the Company receives from implementing DR programs are the reduced T&D costs. The avoided generation benefits and avoided energy benefits accrue to the system as a whole. As a result, the system wide TRC test will be augmented by a utility test taking into consideration only the benefits and costs that Con Edison may incur as it implements the DR programs. In some cases, DR programs that may not pass a benefit-cost test from a distribution company point of view may still provide substantial system wide benefits and be very viable from a TRC system-wide test.

7.1 Benefits of DR Programs

One set of benefits from callable load and other DR programs is related to the costs that are avoided by having reliable load curtailment. These avoided costs are usually divided into three general categories:

1. Avoided/Deferred Generation Capacity Costs – The MW available for DR programs can help to defer or avoid building the next peaking resource – typically assumed to be a gas fired combustion turbine.

2. Avoided/Deferred Transmission and Distribution (T&D) Costs – This analysis draws a distinction between two types of T&D costs that are avoided:

    a. Using DR to slow the growth rate of peak demand in non-customer resources (i.e., DR is located at the customer site) will result in a somewhat slower investment in T&D resources over time.

    b. DR response may be able to defer capacity investments in existing and planned distribution. For this to occur, the DR must be located on networks and in substation areas that are expected to need additional investment. It must also be available at the time needed, i.e., before the investment in that network/substation is needed, and it must be available in a size (i.e., in terms of MWs) that allows the investment to be deferred. In general, it is often difficult to develop DR resources that actually defer investment in distribution substations due to these “right time” and “right place” criteria.

3. The avoided energy costs, i.e., the avoided electricity costs in terms of kWh.

The approach taken in developing the avoided cost estimates of the benefits of DR was to look at benchmarks available for the down-state New York region. Estimates from other regions might not be appropriate for the unique Con Edison service territory. Also, these estimates might be less controversial if they could be based on work already performed by or before the NYSDPS.

In summary, the avoided costs that were used in this study reflected a number of compromises. The end result was use of the avoided costs used by the Staff of the New York State Public Service Commission in the recent TRC tests applied to accelerated energy efficiency programs. While it could be argued that different avoided costs were more appropriate, it was decided that the differences would not have a material impact on the economics of the DR programs that passed economic criteria. The avoided costs used in this study were:

- Avoided Generation Costs -- $98 per kW-yr in 2007 dollars for deferred generation based on a proxy CT unit.
- Avoided T&D costs had two components:
    1. The full $110 per kW-YR used by the Staff of the NY PSC in the TRC tests for accelerated energy efficiency was viewed as appropriate only for the short-notice DR.
    2. $55 per kW-YR (about one half the $110 per kW-yr) seems more appropriate for avoided general distribution investments based on overall reduced growth in peak demand, but is not targeted at specific networks or is not short notice DR and therefore can not defer distribution capital investments.[91]
- Avoided energy costs are based on Staff's assumptions that were tied to forecasts of the locational-based marginal prices (LBMPs) for New York City.

A more complete discussion of the benefits of DR as expressed as avoided costs is presented below.

7.1.1 Avoided / Deferred Generation Capacity Costs

Two sources of avoided costs for peaking capacity were found. The first comes from the NYISO, which estimated costs required to encourage new entry of ICAP resources into the New York market. These costs reflect the net costs of providing new peaking capacity. The most recent study performed by the NYISO produced the follow costs of new entry (CONE) in the New York City market.[92] It should be noted that these are the costs for generation capacity only:

2008/2009 -- $123.18 $/kW-yr

2009/2010 -- $132.79 $/kW-yr

2010/2011 -- $143.15 $/kW-yr

These numbers would have to be escalated through the 10 year planning horizon used in this potential assessment.

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[91] In developing the original Summer Reservation Payment for the DLRP, Con Edison proposed an incentive amount of $1.50/kW-month, which was based on an estimate of the cost of renting a mobile generator, incorporating the probability and frequency of events across all Con Edison networks. (See *DLRP Program Evaluation Final Report,* Nexant, Inc., February 26, 2008.)

[92] Reference: "Proposed NYISO Installed Capacity Demand Curves for Capability Years 2008/2009, 2009/2010, and 2010/2011 – FINAL" New York Independent System Operator, Revised October 2, 2007 (See pages 15. 16. and 17)

The second source of avoided costs comes from work performed by the staff of the NYSDPS for the "Staff Revised Proposal for Energy Efficiency Design and Delivery and Reply Comments" dated December 3, 2007. A spreadsheet provided by Con Edison listed the Staff's Reply to Questions on inputs to the TRC Test used to assess the Fast-Track Proposal. Since these values have been used by the Staff of the NYSDPS, they would seem to be good candidates for valuing avoided capacity, and energy costs from DR programs.[93]

The spreadsheet provided by Staff contains estimates of capacity costs for 15x15 Capacity Prices for New York City in $/kW-Year all in 2007 dollars[94] as presented in Table 7-1.

Table 7-1. Estimated Capacity Costs for New York City (2007 dollars)

	$/kW-yr
2007	98.00
2008	99.90
2009	100.73
2010	98.65
2011	96.62
2012	94.64
2013	92.69
2014	90.78
2015	88.92
2016	90.42
2017	91.95

These capacity costs are somewhat lower than the Cost of New Entry values developed by the NYISO, but they have been used by the Staff and likely represent a conservative view of the avoided cost of capacity.

7.1.2 Avoided T&D Costs

These costs were also taken from Staff's assumptions used in the TRC analyses of the Fast-Track energy efficiency proposal. The approach by Staff is documented in the response to IR #2 in the January 9, 2008 responses to the Joint Utilities' Questions. In their approach, Staff assumed that the avoided costs of secondary distribution lines are zero – leaving the avoided cost task as one of estimating the avoided costs of primary lines and distribution substations. These estimates were developed starting from the last distribution marginal cost study "from about the year 1995." The avoided cost estimates from this study

[93] Case 07-0548, Staff's January 9 2008 IR responses to the joint utility's questions on the "Revised Proposal for Energy Efficiency Design and Delivery and Reply Comments of The Staff of The Department of Public Service," dated November 26 2007 and the "Staff Revised Proposal for Energy Efficiency Design and Delivery and Reply Comments" dated December 3, 2007.

[94] The Staff of the NYSDPS cite sources for the peaking capacity cost and energy prices as MAPS model runs and the Energy Information Administration (EIA).

for primary lines and distribution substations for the upstate utilities averaged $45.33 per kW-yr and $58.93 per kW-yr for the two down-state utilities. “Staff used judgment to make adjustments to these two values to reach Staff’s final values of $55.00 per kW-yr upstate and $110 per kW-yr downstate in 2007 values.” The response to IR #2 also contains an explanation of the judgments made by staff to reach these values. The spreadsheet of TRC values, line 51 showed that a value of $110 per kW-yr was assumed to continue through 2017 for downstate.

Transmission avoided costs were assumed to be zero by the Staff as these values tend to be captured in the congestion adder in the LBMPs and therefore are already captured in the avoided energy costs.

In summary, the values of avoided generation capacity, avoided electricity costs, and avoided T&D used in the Fast-Tracks TRC analyses are viewed as being at appropriate for use in the benefit-cost tests of the DR programs, taking into account the three notes shown below:

1. The full $110 per kW-yr for avoided distribution seems appropriate only for the short-notice DR. A value about one half the $110 per kW-yr seems more appropriate avoided general distribution investments that might be avoided by DR that is not targeted at specific networks or is not short notice and therefore can not defer distribution capital investments. Investments in T&D have to be based on DR that is available on the appropriate network and is also available in the magnitude needed to defer investment and at the right time, i.e., before the investment is made. The $55 per kW-yr seems more appropriate for distribution investments that might be deferred due to DR clipping peak demand and resulting in a lower overall growth in peak electricity use. This lower growth in peak demand will also slow the need for investment in the distribution system.

2. To value the avoided capacity cost of short-notice DR, the average difference in costs between a regular combustion turbine (CT) (e.g., a General Electric LM6000) and a quick start unit (e.g., General Electric LMS100) is used. Recent engineering estimates show that a quick start CT can cost up to twice as much as a CT that would be equivalent to a DR program that would have longer notice provisions (e.g., 1 to 2 hours notice).

3. Many avoided cost studies for DR make an adjustment in avoided generation costs to account for the fact that most DR programs are only at full capacity in the summer months. As a result, there is a modest adjustment for the LOLP that might occur in the balance of the 8 months. However, conversations with Con Edison engineers indicated that this was not an important adjustment to make in this application.

7.1.3 Avoided Electricity Costs

The avoided capacity costs to be used were taken from Staff’s TRC analysis of the Fast-Track programs. To maintain consistency, the avoided electricity costs were taken from the same analysis. In Staff’s January 9, 2008 IR Responses to the Joint Utilities’ Questions, question 1 addressed the development of the annual avoided electricity costs in the TRC analyses. In this response, Staff indicated that they used the 2006 day-ahead location-based marginal prices (LBMPs) and escalated them through 2015 using the price trajectory from the MAPS analysis that had been developed for Staff’s Proposal. Values were generated for New York City, as well as Upstate and Statewide

7.2 Benefit-Cost Scenario Analysis

This section presents a high-level analysis of the costs and benefits of a generic program for the C&I sector that can help Con Edison reach the callable load potential identified earlier in this report. Several aspects related to the analysis of the cost-effectiveness of DR programs are different from that of energy efficiency (EE) programs:

- First, many participants in DR programs are able to provide load reductions with little or no capital investment—for example, by running an emergency generator or shutting of decorative lighting. By contrast, EE programs usually require a discrete capital outlay to pay the incremental cost of the more efficient equipment or for the EE service provided.
- Second, whereas the utility costs for EE programs are generally one-time costs (plus ongoing administration), DR programs usually entail a recurring incentive payment that is proportional to the number of participants or the enrolled load. This implies that as a DR program grows, the costs to the utility increase.
- Finally, the benefits accruing to DR programs are different from EE programs, in which engineering calculations and prevailing tariffs can be used to assess the value of the measures. With demand response, the benefits depend on not only *what* the resource is, but *how* and *when* it is used. Benefits for avoided generation and T&D investments are discussed above and used in this analysis.

There is little consensus on a "right" way to assess the economics of DR programs, although many jurisdictions apply the total resource cost (TRC) test, developed in California for analysis of energy efficiency programs, for lack of a better alternative. In a 2006 resolution, the California Public Utilities Commission admitted, "It has not yet been established which of the [Standard Practice Manual] tests, if any, should be used to determine the cost-effectiveness of demand response programs…although it is likely that these two tests [the TRC and Program Administrator Tests] provide a reasonable starting point for determining demand response program cost-effectiveness. [95]

In this light, the study team applied the TRC and Program Administrator Test (also called the Utility Cost Test) to assess the economics of a generic C&I callable load program. Assumptions were used such that over the next 10 years, this program would achieve roughly the 728 MW of load reductions identified above as the "gap" between current achievable load reductions and the achievable potential in 2017.

Assumptions

Key assumptions regarding costs and benefits are described below. The 10-year cost stream is discounted to 2008 dollars at an annual discount rate of 7.82% per year, equivalent to Con Edison's weighted average cost of capital.

Participation and curtailment

- *Participation:* 2,300 additional C&I customers participate between 2008 and 2017, raising total participation in Con Edison programs to 17% of the customer accounts greater than 100 kW, representing 45% of the non-coincident peak load of these customers.
- *Curtailment:* Average curtailment of participants is 25% of peak load in 2008, including curtailments from use of emergency generation, rising at 1% per year.

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[95] California Public Utilities Commission. Resolution E-4020, Resolution E-4020, October 19, 2006. Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) are authorized to implement the Capacity Bidding Program (CBP) to replace the California Power Authority Demand Reserves Partnership.

- *Short-notice option:* 10% of new load enrolled can provide load reductions with 10-minute notice, increasing by 2% per year.
- *Events:* It is assumed that six events would be called per year at four hours per event.

Con Edison costs and benefits

- *Incentives:* Reservation payments of $8/kW-month for 10-minute load reductions and $4/kW-month for all other firm reductions; energy payments of $0.50 per kWh.
- One-time start-up cost of $500,000 to modify existing DLRP program materials, databases, etc.
- Annual administrative costs equal to 20% of annual program costs, which results in annual administrative costs of approximately $1.4 million in 2008, rising to $8 million by 2017.
- Technical assistance and equipment rebates valued at $500 per new participant with two-hour notification requirements and $5,000 per new participant in the 10-minute notification component; all costs escalate at 3% per year.
- *Avoided costs:* Avoided generation costs of $95/kW-year; and avoided T&D costs of $55/-kW-year, or $110/kW-year from DR resources that can be dispatched on 10-minute notice. (See above in Section 7.1.2 for a discussion of T&D avoided costs.)

Customer costs

- *One-time costs:* Customer costs for interval meters and load shed automation equipment/set-up of $1,500 per new participant with two-hour notification requirements and $9,000 per new participant in the 10-minute notification component; all costs escalate at 3% per year.
- *Annual costs:* Recurring customer costs to participate in demand response, which include both out-of-pocket expenses and the direct impacts of the load curtailment, are not easily estimated.[96] A reasonable proxy for recurring customer costs is the amount of incentives paid, since economic theory holds that customers would not willingly enroll in a program and incur costs greater than the value that they are receiving for their participation. There may be additional sources of value besides incentives, such as community good will and public relations benefits, which would in theory allow customers to accept incentives that are lower than their presumed cost of participation. For purposes of this analysis, *the best estimate of this cost of participation is assumed to be value of incentives* provided by Con Edison.

Findings

Most reasonable scenarios for achievable callable load potential appear to be cost-effective in light of the relatively high avoided generation and T&D costs realized through demand response efforts. It is estimated that a C&I sector DR program to achieve the potential callable load reductions described above would have a benefit-cost **(B/C) ratio of 3.4 under the TRC test.** Under the Utility Cost Test, which for Con Edison would include benefits only from avoided transmission and distribution system (T&D) investments but not from avoided generation capacity, the B/C ratio is estimated at 1.5.

This suggests that it would be cost-effective from the perspective of Con Edison as the program administrator. However, the avoided T&D costs used in this analysis are based on values used by the staff of the New York State Public Service Commission in the TRC tests for the Fast Track energy efficiency

[96] Recurring customer costs include incremental costs for fuel/maintenance for emergency generators, preparation for curtailments at the site, training of key maintenance personnel, the productivity impact of changes in production or scheduling, reduced comfort levels, and possibly increased risk or liability.

effort. These costs of $110/kW-year are among the higher values that the study team has observed for avoided T&D costs. Lower values in the range of half those used in the base case economic analysis described above (*i.e.*, new values of $55/kW-year for short-notice demand response and half again, $28/kW-year, for longer-notification demand response) would yield a B/C ratio of 0.7 under the Utility Cost Test.

Another sensitivity analysis was conducted on the reservation payments to test the impact if higher incentives were required to attract participation at the assumed levels. Reservation payments were raised by 50% in all years: to $12/kW-month for 10-minute resources and $6/kW-month for all other firm reductions. Under this scenario, the B/C ratio for Utility Cost Test was just 1.1—still cost-effective but by only a slim margin. The TRC test showed a B/C ratio of 2.6.

The implication of these findings is that the significant increase in callable load capability envisioned by this analysis is likely cost-effective from a societal perspective but may not be economic for Con Edison The driver behind this finding is that demand response is being paid for by Con Edison but the Company does not receive all of the benefits.

Evidence suggests that demand response is cost-effective in Con Edison's service territory—the TRC test yields a B/C ratio of 2.7 even with the lower T&D benefits discussed above. However, at issue is how to fund a broader portfolio of programs and how to compensate Con Edison should specific program designs prove to be more costly to the Company than the benefits it receives. Until a specific program or programs is developed for which to run benefit-cost tests, the analysis is necessarily based on broad, albeit realistic, assumptions. Some of the key program design factors influencing the costs and benefits of demand response programs are provided in Table 7-2.

Table 7-2. Program Design Factors Influencing the Cost-Effectiveness of Callable Load Programs

Program Design Factor	Comments
Program Duration / Contract Term	The longer a program is in operation (or a contract in effect) the more load curtailment events that can be realized and more the fixed costs can be spread out over time.
Event Window (seasonality)	Year-round programs, in which customers can be curtailed in any month, tend to be more expensive than summer-only programs but provide added flexibility for addressing contingencies at any time of year.
Event Limits (# of events/hours, duration)	Customers generally require greater incentives to accept higher event limits. However, higher event limits offer greater benefits through additional deferred generation capacity and increased opportunities to respond to T&D contingencies.
Response Time	It is typically more costly to attract customers willing to curtail load on short notice. For response times of 10 minutes or less, automated communications and/or control technologies may be required. This short-notice response provides greater flexibility for system operators and provides increased value for addressing T&D contingencies.
Amount of MW Reduction (MW ultimately achieved and yearly ramp rate)	Higher levels of load curtailment tend to be more expensive since deeper market penetration is required. Rapid ramp up of curtailment capacity may also be relatively more expensive due to increased marketing and recruitment costs.
Emergency Generation	Where emergency generation is relatively available and usable (subject to environmental permitting), load curtailment may be achieved at relatively low costs due to the relative ease of recruitment and the large curtailments that may be possible. Emergency generation may provide greater short-notice response than load shedding, and thus could have greater benefits.

8 RECOMMENDATIONS

Chapter 6 discussed program strategies that could help bridge the gap between the current amount of demand response delivered in Con Edison's service territory and the estimated 2017 achievable potential for callable load, which suggests an addition of roughly 815 MW. This chapter presents recommendations based on program strategies that are expected to facilitate attainment of the 2017 callable load potential.

This report addresses demand response over a 10-year future timeframe (based on 2007 customer and DR program data), and consequently these recommendations are meant to set a path toward the achievable callable load potential estimated for 2017. There are likely to be a number of ways in which this future potential could be met, and the development and acceptance of communication (*e.g.,* AMI) and DR technologies for shedding loads will impact choices made. The trends discussed in Chapter 6 are believed to be influential in the design of effective DR programs going forward, but there is always uncertainty in an assessment of this type and the recommendations should be assessed in this context.

Recommendations are presented in three groups. The first group consists of *near-term recommendations* for actions that can be taken in the next year to several years. These recommendations are targeted at improving current DR efforts and set a platform for meeting the estimated DR potential in 2017. The second group of recommendations consists of *longer-term recommendations* that would be rolled out in the next several years, and whose impact may not be fully realized for three to five years or longer. Finally, recommendations are presented for the components of a *demand response program portfolio* that can cost-effectively reach the achievable callable load reduction potential estimated earlier in this report.

The remainder of this chapter is organized in to the following sections:

1. Near-term recommendations
2. Longer-term recommendations
3. Program portfolio recommendations

Recommendations for near-term actions are denoted with the letter "N" prior to the recommendation number. Longer-term actions are denoted with the letter "L".

8.1 Near-term Recommendations

As noted above, near-term actions are changes in program offerings or delivery that can be adopted within the next three years to increase both customer participation and the load curtailments offered by participants, and to help establish a path for meeting the 2017 callable load potential as estimated in Chapter 5. These recommended actions have been organized into the following categories:

1. Program Design
2. Marketing and Delivery
3. Use of Emergency Generation
4. Assistance to Customers

Program Design

N1. **Continue offering the "mandatory" or "firm load shed" participation options that currently provide firm commitments.** The history of the ICAP and EDRP programs demonstrates that curtailment rates (as a share of commitments) are significantly higher when participants are paid a monthly reservation payment and subject to decreased payments for underperformance. The greater level of performance allows Con Edison to perform capacity and contingency planning with a higher level of certainty and may allow greater deferral of T&D investments. A number of utilities are switching perspectives in their DR offers from "mandatory" to "firm capacity load sheds," as "mandatory" programs offered by the utility sounds like a command-and-control option in which many customers may not want to participate. In addition, the structure of financial penalties and incentives might change over time as all parties gain experience with demand response. Issues related to financial penalties and incentives are discussed in Section 6.5.1. The impact of subtle changes in marketing and design can be significant, but the expectations of customer performance must remain clear. Additionally, firm load curtailments must be verifiable and real, which requires 1) metering equipment and procedures that allow for adequate verification of meter data and 2) a baseline methodology that accurately captures what customer loads would have been in the absence of the curtailment event.

N2. **Ensure that new program designs continue to have appropriate financial penalties/incentives.** It is important that future or expanded DR programs be viewed as reliable resources. The manner in which penalties are assessed for under performance in demand response should be assessed as part of the overall program context. "Direct financial penalties" can be a major reason why some customers choose not to participate, even if they are a good candidate for achieving load sheds with minimal impact on their building or facility. One design issue that should be addressed by program planners is whether you can have "firm" DR programs with penalties, but with penalties that are designed differently that being a simple fine for underperformance. Instead of direct financial penalties, a program could still have financial penalties, but perhaps structured as follows:

a. Participants failing to achieve their MW commitment would not receive even a partial payment for the load reductions that were achieved and the capacity payment for that month is forfeited (*i.e.*, it is not paid to the customer at the end of the month). This is in contrast to the new Rider U terms under which a performance adjustment is applied that is proportional to the amount of load provided as a share of the commitment level.[97]

b. Customers missing their contract load reductions once would have an adjustment to their future reservation payments, similar to what is in the current Rider U. However, for purposes of reservation payments, re-adjustment upwards (whether to their previous level of contracted load relief or some other level) would not be possible until at least the month *after* the next event.

c. Customers missing their contract load reductions twice would be dropped from the program or enrolled in a voluntary program for at least the remainder of the summer capability period.

[97] Total forfeiture of payment for the month may be a sufficient penalty to ensure performance for individual customers. For aggregators, a modified performance adjustment formula may be appropriate; aggregators' diversification of loads and large financial stake that they have in pooled loads suggest that they are unlikely to underperform by as large a margin as an individual customer. For example, while a customer may simply fail to shed load (0% performance), aggregators will tend to have much less volatility in their level of performance. Strict penalties for anything less than 100% delivery are appropriate, but a total forfeiture of incentives may not serve the best interests of Con Edison in promoting high participation.

If repeated events and MW certification tests show that the program underperforms because there is a consistent inability of some customers to hit their full load reduction target, a discount factor can be applied to the target load reductions to satisfy the requirement of a firm load reduction. This financial structure still penalizes customers for underperformance, but it is structured in a manner that may be less onerous than other penalty provisions and still provide adequate incentives for performance. This approach also focuses on keeping the customers that do meet targets in the program and moving customers that do not meet targets out of the program or adjusting their targets. Either penalty approach may be appropriate depending on program objectives, but some "firm capacity" programs are moving in the direction of penalties structured in a manner designed to attract more firm capacity participants (see Section 6.5.1).

Rider U, recently adopted for the DLRP program, embodies several of the concepts outlined above. Regardless of the penalty/incentive approach taken, it is recommended that the vast majority of future callable load be enrolled in "firm capacity" programs that appropriately deserve credit for capacity deferrals, and that the balance between payments for demand response and penalties for underperformance supports this objective.

N3. **Include a program participation option for 10-minute response.** The value of DR resources that can respond in 10 minutes or less is roughly double that of curtailments requiring several hours' advanced notification. A 10-minute offer is based on the premise that DR programs should be designed to meet system needs, while still being acceptable to a viable number of participants. A number of other utilities have 10-minute notification program options and, with the increasing use of automated load shed capabilities (i.e., auto-DR) by aggregators and customers,[98] 10-minute notification will be viable for many customers that might participate in a DR program. Customers that can be quick-notice responders provide benefits such that this option should be developed.

Over the next few years, the number of customers that can respond to short-term (10-minute) notification is expected to increase. DLRP participants have already proven able to respond with 30 minutes notice, and curtailments are increasingly coming from automated mechanisms that are capable of response within minutes, if not seconds, of a signal from Con Edison. Customers should be provided greater incentives for providing 10-minute response.

N4. **Continue offering voluntary participation options.** Curtailments from voluntary participants, while less reliable than from those offering firm commitments via mandatory or firm capacity curtailment option, are significant and represent an opportunity to attract customers who otherwise might not be willing to commit to load reductions. NYISO experience suggests that once customers become familiar with DR program concepts, curtailment actions, and enabling technologies, some will migrate to established firm capacity programs with higher commitment levels.

Marketing and Delivery

N5. **Combine marketing and installation of DR technologies with energy efficiency programs where positive synergies exist.** One of the trends discussed in Section 6.2 was the move towards automated demand response. This occurs through the installation of appropriate technologies at residential sites (e.g., a communicating thermostat) and at C&I sites (EMCS systems that provide for communication and load shed capabilities). These technologies can be included as part of both residential and C&I energy audits and information campaigns. In addition, new construction and

[98] Automated load shed capabilities includes residential and small business DLC, as well as load sheds at C&I customers that use their energy management and control systems to automate the load shed. This is an increasing trend in the industry.

major retrofit programs in both sectors also provide a touch point with customers where DR technologies can be most cost-effectively installed. Similarly, any time an energy efficiency program touches the EMCS system in C&I facilities through building commissioning or retro-commissioning programs that are becoming increasingly popular, auto-DR options can be included in the DSM package offered to the customer.

N6. **Focus marketing efforts on office buildings and government facilities, which have the greatest potential for expanded callable load opportunities.** These two market segments account for an estimated 554 MW representing nearly 70% of the total gap between currently available demand response and estimated achievable demand response. Additionally, these segments combined have an estimated 1084 MW of emergency generation, roughly 74% of total emergency generation estimated for the Con Edison service territory.

N7. **Focus marketing efforts on the largest customers.** In most customer segments, a relatively small number of customers account for a large percentage of the total load. Focusing marketing efforts on these larger customers will maximize the cost effectiveness of demand response programs. These lower marketing costs must also be balanced against having a program rely on a few customers for most of its load shed capability. Diversification across different customers and customer segments helps enhance the reliability of a DR program. To the extent that a few customers comprise a large fraction of load shed capability, the program design should include frequent communications with these large customers, yearly on-site assessments, and testing of DR response to balance out risks of underperformance. The will help further the concept of almost all new callable load being viewed as a firm resource.

N8. **Develop marketing communications specific to certain target sets of customers to address the issues raised by different customer segments.** Several barriers to program participation have been identified through primary market research (see Chapter 3). Other potential barriers can be identified—either through the literature on demand response programs or through customer research—and solutions proposed. For instance, hotel energy management staff can be informed on what steps similar facilities take to participate in demand response programs; special tenant communications or program attributes can be developed to encourage large tenants to consider demand response programs; and owners of large residential facilities can be encouraged to use a “green” message to attract conservation minded renters.

N9. **Encourage or incent property owners and managers to bring their major tenants into the demand response decision-making process.** In some cases, the customer or the tenant is not willing to make the necessary behavioral changes that demand response participation would require. In other instances, however, Con Edison could include major tenants in the process and should pilot approaches for how to encourage or incent willing property owners to bring major tenants to the negotiating table. The Real Estate Board of New York has taken steps in the past in this regard and may be a willing partner in exploring alternative incentives and approaches. Some of these issues are discussed above (Section 6.5.2), although the “agency” issue has been a barrier to DSM for many years and the hurdles for demand response are largely the same.

N10. **Investigate building a cooperative relationship with NYPA to jointly build DR pilots and programs that can benefit both Con Edison and NYPA customers.** These efforts could include joint technology research to identify and test enabling technologies for automated load shedding and other means of increasing participation and lessening the impact on customers

N11. **Work with curtailment service providers/aggregators and leading technology companies who have expertise in addressing key customer segments to provide callable load reductions.** Aggregators offer several advantages as participants in utility DR programs that can increase enrollment levels and event performance, as evidenced by the fact that two-thirds of ICAP enrollments are now via aggregators. These companies have demonstrated expertise in recruiting new participants. Some aggregators have expertise in recruiting customers in specific segments. For example, one aggregator not currently operating in New York specializes in enrolling hospitals into DR programs and can demonstrate how other hospitals have developed load shed capabilities. In addition, aggregators are able to offer customized packages to customers (within a utility or ISO defined program) for whom a one-size-fits all program offer is not appropriate. Aggregators often have specific technical expertise to automate curtailments—which provides for the possibility of 10-minute response—and to lessen the impact on customers. Aggregators also can pool smaller customers who do not by themselves qualify for program participation, and they tend to develop portfolios of load-shedding customers that can be highly diversified by size and customer type, which reduces the risk of underperformance. It is recognized that Con Edison already is actively working with aggregators in its DR programs. This recommendation is to continue to assess the relative merits of varying forms of aggregator participation in DR programs.

Use of Emergency Generation

N12. **Promote installation of grid-synchronized emergency generation.** The vast majority of existing emergency generation in the Con Edison service territory is not synchronized with the grid and therefore may create brief power disruptions for customers employing the systems. Con Edison could develop an assistance package to facilitate installation of grid-synchronized systems (where appropriate and technically feasible within the distribution system) and offset some capital or maintenance costs in exchange for a commitment to provide 10-minute demand response capability.[99] The program could operate through vendors to promote any assistance and to identify customers already considering investment in emergency generation. (See C&I program strategies in Section 6.3.)

N13. **Consider company-owned emergency generation located strategically throughout the distribution system.** This approach would have Con Edison own and pay for distributed generation in exchange for a fee for providing emergency generation capability and a commitment to allow use of the generator on less than a 10-minute notice. Such new generation could be grid-synchronized (where appropriate and technically feasible within the distribution system) and fueled by natural gas and may be cheaper than alternatives to addressing distribution system constraints. Several utilities have been pursuing this approach with Portland General Electric Company serving as one good example. (See C&I program strategies in Section 6.3.)

N14. **Facilitate retro-fitting of diesel generators** for burning of natural gas or use with pollution controls that may limit emissions to within regulatory limits. Approximately 95% of existing emergency generation capacity in the Con Edison service territory uses fuel oil, which has higher emissions rates than natural gas and which may not be eligible for use as a demand response resource, pending approval of NYSDEC regulations. Any assistance from Con Edison could be tied to a contractual commitment to provide callable load reductions from the affected generator.

N15. **Serve as a neutral source of information to customers and regulators to assist in increasing the availability of emergency generation for use in demand response.** Emergency generation currently comprises more than one-quarter of the total demand response enrollment and likely will continue to be an important part of any demand response portfolio. However, a high degree of uncertainty exists regarding the future availability of emergency generators due to uncertain future regulations regarding permitting and emissions requirements. As a result, the availability of emergency generation to participate in demand response programs (as opposed to use as

[99] There may some areas within Con Edison's distribution system network where grid-synchronized emergency generation cannot easily be used without additional system upgrades. Furthermore, it is necessary to ensure that emergency generation has black start capability in the event that VAR support cannot be provided by the grid.

"emergency" generators) is increasingly uncertain. Being a neutral source of information can both help regulatory entities fully appreciate the benefit that emergency generation can provide to grid reliability and its impacts on the future cost of electricity.

Assistance to Customers

N16. **Develop materials and methods to assist organizations in identifying the ways in which they can reduce their load during peak periods.** Non-participants tend to underestimate their ability to curtail load during peak periods relative to program participants. Further, it is clear that the "load shed" market has higher future potential relative to the "emergency generation" market, indicating that efforts to better tap into the load shed capabilities of organizations are warranted.

N17. **Develop methods to give recognition (e.g., public via a web page) and appreciation (e.g., via letters of appreciation) to organizations that participate in demand response programs.** Corporate image and the appearance of "helping out" can be strong motivators for program enrollment for some customers. Giving participating customers public recognition and appreciation of their efforts, and describing how their participation helps all ratepayers (through lower electricity costs, higher reliability, etc.) could stimulate a strong "social marketing" effect. For some customers, it may be important to focus public recognition programs in a local geographic area appropriate for that participant. This could strengthen the effect of existing marketing efforts and can act by itself to facilitate awareness and willingness to participate in demand response programs. Such an effect could enhance both ultimate participation levels and cost-effectiveness of demand response programs.

N18. **Continue to develop customer relationships that reinforce customer service and overall customer satisfaction.** Con Edison already places a high value on customer service. DR programs can be a vehicle for enhancing customer service through program design features and technologies (e.g., AMI or commissioned EMCS systems). There are a number of ways in which DR can help with customer service issues and help improve customer satisfaction by helping customers develop the appropriate capabilities for DR programs and helping customers make appropriate choices regarding participation in DR programs. Not all customers will be suitable participants for a DR program.

N19. **Develop the appropriate level of technical assistance for customers less knowledgeable about demand response.** Many customers do not see the value of technical assistance, but many of them, especially those with less knowledge in this area, do need it. Many customers are ill-informed on 1) what types of load can be shed and 2) how to implement systems that would make the demand response shed easy to implement without disturbing guests, tenants, or customers.

N20. **Enhance the electricity market IQ of customers.** Customers participate for financial reasons, i.e., increased capabilities to manage their electric bills, but many also view participation as part of being good corporate partners helping to lower long-term and peak-period electricity prices as well as increase system reliability. Often, customers do not fully understand the system and regional benefits that are provided by DR as well as the system needs that DR programs are designed to meet. Customer surveys have shown that customers that have greater knowledge of these issues and electric markets in general are more likely to participate in firm capacity DR programs. This argues for a broad educational effort across C&I and residential customers to help ensure they understand the benefits of DR programs, their participation in programs, and electricity markets in general. While much of this information is contained in media releases, there still are many customers whose attention is focused on other issues and helping communicate a message of the role they can play in DR programs can be important.

8.2 Longer-Term Recommendations

As noted above, longer-term actions may be taken immediately to set the stage for future demand response or they might be taken several years in the future. The common factor is that their full impact likely will not be realized for at least three to five years. These actions often are designed to take advantage of advances and trends in DR technology or other changes over time to reach more customers and increase the amount of callable load that can be curtailed.

L1. **Develop an ongoing marketing effort to encourage customers currently enrolled in voluntary programs to migrate to a firm capacity program.** While voluntary programs are a vital part of a demand response portfolio in that they lower the barriers and risks for organizations unfamiliar with demand response, participation rates of voluntary programs during a called event are quite low (estimated at 63% for the DLRP Voluntary program and 35% for the EDRP program). However, once customers have had some experience with a voluntary program, their level of comfort should be greater with the risks and benefits (such as monthly capacity payments) of a firm capacity program, which has much higher participation rates during a called event (estimated at 97% for ICAP programs). Thus, voluntary programs can be treated as "gateway" programs into the firm capacity or mandatory programs. Appropriate communications with customers in voluntary programs along with technical assistance can provide participants in voluntary programs with the confidence needed to participate in DR programs that can provide firm capacity. These customers would also benefit from the higher financial incentives provided to participants offering firm load curtailment.

L2. **Leverage new construction activity to promote pre-installation of technologies that facilitate demand response.** For the C&I sector, this can include the installation of energy management systems and equipment that can respond to event-day signals. For the residential sector, this may include communicating thermostats (similar to those used for Con Edison's existing DLC program) or in the future possibly communicating relay switches built into room AC units. The cost of installing these technologies can be significantly reduced by incorporating them into new construction rather than as retrofit applications.

L3. **Increase the share of enrolled callable load that is automated via a remote signal from Con Edison or push button at the customer site.** Curtailments are more predictable and can be easier on the customer if they are automated. Opportunities to enable additional automation of customer load shed are available through large scale commercial retrofits, which may also provide an opportunity to install energy management control systems and appropriate equipment to allow for demand to respond to event-day signals. Similarly, building retro-commissioning, which ensures that building systems are operating efficiently and that the energy management and control system is working properly, is a growing activity in energy efficiency programs. Through such a program, if an EMCS is not working properly, new EMS technologies can be cost-effective to install with the controls needed for an auto-DR response capability.

L4. **Increase the share of enrolled callable load that can respond in 10 minutes.** Load response that can be realized in 10 minutes or less is of higher value to Con Edison than curtailments that require longer notification periods. Some participants may be capable of shorter response times, at least for a share of their commitments, and should be encouraged to use automation to offer these quick-response load reductions. New customers should be made aware of opportunities for automation and, if incentives vary in future programs, should be informed of the higher payments for reduced response time.

L5. **Integrate DR planning with AMI business case development.** AMI can reduce the costs of DR programs—usually without dramatically impacting the overall design or objectives of the DR programs. In some cases, these cost reductions can be substantial as an appropriate AMI system can reduce the costs of communication while also allowing for more information to be provided to customers in near real time. In general, AMI does not change the types of DR that can be offered, i.e., most DR services can be provided with current technology, but AMI can substantively reduce the costs of DR programs for both mass-market and C&I customers. With lower incremental communication costs, AMI can provide more information to help customers gauge their load-shed response during an event, provide current and day-ahead price information, and lower the costs of evaluating the delivered loads promptly and help in the overall evaluation of DR programs. AMI would make it easier for Con Edison to communicate with DR technologies to facilitate auto-DR and short-term notification programs, and would facilitate information exchange needed for pricing programs. While the majority of the AMI benefits are in lower costs for providing DR programs, new technology will also increase the impacts of high-value DR (e.g., 10-minute notification), make it easier for the customer to respond to called events by automating their response, and allow for more flexibility in pricing programs.

L6. **Research the feasibility and economics of using steam cooling for demand response.** The availability of steam south of 96th Street provides an opportunity for hybrid chillers to use steam instead of electricity for summer cooling. There are technical and operating issues for customers and the utility that need to be assessed, but it is viewed as a concept worth investigating as a future source of DR. Among the goals of the investigation should be the relative economic benefits of using steam cooling for callable events (and thus customers would receive a reservation payment) versus the cost savings from avoiding high electricity prices.

L7. **Investigate the merits of establishing a demand response research center to test new DR technologies and to demonstrate successful technology applications.** This entity could be modeled after the Demand Response Research Center (http://drrc.lbl.gov/) that is part of the Lawrence Berkeley National Laboratory and that has pioneered some of the Auto-DR work cited earlier in this study.

8.3 Recommendations for an Effective Callable Load Program Portfolio

An appropriate portfolio of DR activities does not have to be complex or include numerous programs. In the Chapter 6 on Program Strategies, it was noted that to meet the estimated 2017 achievable callable load potential, approximately a 728 MW increase is needed in C&I DR (including emergency generation) and approximately 87 MW is needed from the residential sector.

Standard principles of rate design have long followed J. Bonbright's[100] criteria calling for the practical attributes of 1) simplicity, 2) understandability, 3) public acceptability, and 4) feasibility of application. These same criteria represent a good screen for assessing portfolios of DR programs. In summary, a basic portfolio of DR offers may be comprised of:

1) **A C&I callable load shed program for "firm capacity"** which would have load that would be shed with 2-hour or more notification, and a subset of load that could be called with 10-minute notification based on auto-DR or DLC technologies. Customers could enroll in both 10-minute and 2-hour plus notification program options.

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[100] James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), republished on the web. Terry College of Business, University of Georgia (July 2005): http://www.terry.uga.edu/bonbright/publications .

2) **<u>A voluntary C&I load shed program</u>** where customers would be asked to submit target load reductions that they would attempt to achieve on called event days. In the program strategies chapter and in the recommendations above, it is encouraged that this program be designed to familiarize customers with DR technologies and programs such that they could commit a targeted amount of DR into a firm capacity program.

3) **<u>A C&I emergency generation program</u>** where emergency generators at customer facilities (owned either by the customer or the utility as discussed previously in Section 6.3) could be called on event days. Right now, some of this emergency generation capacity needs some manual effort to start up. In the future, most emergency generation would transition into automation or be of a new generation that is automated, i.e., can be started with essentially a push button procedure.[101]

4) **<u>A residential direct load control (DLC) program</u>** which would be similar to Con Edison's current residential DLC program and have equipment (mostly air conditioning) that would be directly controlled by the program operator or a systems controller.

These four programs comprise the essential elements of an acceptable DR portfolio in terms of meeting the same criteria that have become standard in rate design. This portfolio would focus on DR as "firm capacity" and solicit as much 10-minute notice load as is appropriate from participating customers. This firm capacity and short notice emphasis would help provide program designs that appropriately meet the criteria for deferring capital investment in generation and in T&D.

<u>Additional Callable Pricing Programs</u>

The question remains as to whether the above portfolio of the four general DR programs give short shrift to pricing programs such as critical peak pricing (CPP) tariffs or demand-bid programs (DBP) where customers see a price schedule and bid in the number of MW they would provide at a given price if called. These two pricing programs are both event-based and essentially achieve impacts very similar to the callable load programs presented above. Pilot studies and tariff evaluations of TOU-CPP programs[102] show the load reductions for called events are similar in magnitude to air conditioning DLC programs. This is not surprising in that most TOU-CPP participants use a programmable-automated thermostat to respond to CPP events in a manner similar to a DLC strategy. One difference is that the customer response is less under the control of the program or system operator that could change cycling strategies or thermostat set points across different events or different hours within an event. Similarly, demand-bid programs are simply calls for target load sheds, i.e., those bid into the program.

In general, the direct load shed programs seem to provide greater MW of participation and more reliable reductions. However, the use of either TOU-CPP or a demand-bid program represents a point of view or policy position that price should be a centerpiece of the DR effort and help customers see prices in the electricity markets. From a point of view of simplicity and attaining firm capacity reductions, the direct load shed programs may offer some advantages. Ultimately, the choice between these direct load shed

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[101] This is not completely accurate as safety procedures would always have to be followed, but if the emergency generation is maintained and equipped with modern start-up capabilities, almost all emergency generation could qualify for 10-minute notice.

[102] See Public Service Electric and Gas Company, "Evaluation of the MyPower Pricing Pilot Program," prepared by Summit Blue Consulting, 2007; and the California Energy Commission, "Impact evaluation of the California Statewide Pricing Pilot – Final Report," March 16, 2005. Web reference: http://www.energy.ca.gov/demandresponse/documents/index.html#group3.

programs and pricing programs may come down to customer preferences and decisions by policy makers on the emphasis of DR efforts.

Another option to consider to round out the Con Edison DR portfolio is a time-differentiated rate that may not be "callable" as defined in this study. Such rates include day-ahead real-time pricing (RTP), two-part RTP tariffs, and standard TOU rates. Although they are not "callable" in that the rate is generally in effect every day, there may be synergies between time-differentiated rates and callable load programs. In general, an RTP option will result in customers learning how to reduce energy consumption on essentially a daily basis when prices tend to be high (e.g., summer season afternoons and early evenings). Customers do not tend to track exact hourly prices, but they know when prices are likely to be higher (e.g., summer season afternoons with higher prices on hot days).[103] The benefits to the customer come from reducing consumption across many summer days when prices are high, rather than a focus on reduction during system event days. In general, the reductions on system peak days are roughly the same as on any summer day when prices are reasonably high. As a result, an RTP option can provide substantial benefits by increasing overall market and system efficiency through shifting loads from high priced periods to periods with lower prices. However, these tariffs may not provide the needed load relief on system-constrained event days.[104, 105]

A DR Portfolio for Con Edison

A tractable DR portfolio for Con Edison is discussed in this section. This effort is not meant to provide detailed program designs that might come out of a program design project, but to lay out the basic concepts of each program. This portfolio is one that would seem to meet the criteria of 1) simplicity, 2) understandability, 3) public acceptability, and 4) feasibility of application and could include the following four DR programs and concepts.

1. **EXPANDED DLRP PROGRAM** that builds on Con Edison's current program. This program would continue both the voluntary and the mandatory (firm commitment) components and would also include an option for 10-minute event notification that would provide significantly higher incentives. The incentives might be adjusted to provide for:
    a. Higher Summer Reservation Payments (incentives) for 10-minute response (e.g., 150% to 200% of standard payments, which could be $9/kW-month for Tier II network customers).
    b. Increases in incentives over time as needed to continually attract new participation.
        i. Subject to cost-effectiveness of incremental callable load additions.
        ii. May not be necessary if advances in technology allow for greater reductions with less customer effort and impact.

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[103] See evaluations of the hourly pricing experiment offered by ComEd and the Chicago Energy Cooperative performed by Summit Blue Consulting (2003 through 2006).

[104] One way to make an RTP tariff more like an event-based DR program is to overlay a critical peak pricing (CPP) component on the RTP tariff where unusually high prices would be posted to customers with some notification period. Otherwise, it is unlikely that the high levels of reduction needed for system-event days would be attained.

[105] The complementary of event-based load shed programs with RTP tariffs is assessed in: Violette, D., R. Freeman, and C. Neil. "*DR Valuation and Market Analysis – Volume II: Assessing the DR Benefits and Costs*," Prepared for the International Energy Agency, TASK XIII, Demand-Side Programme, Demand Response Resources, January 6, 2006. Updated results are presented in: Violette, D. and R. Freeman; "*Integrating Demand Side Resource Evaluations in Resource Planning*;" Proceedings of the International Energy Program Evaluation Conference (IEPEC), Chicago, August 2007 (also at www.IEPEC.com)

2. **<u>EXPANDED MASS MARKET DLC PROGRAM THAT IS AMI COMPATIBLE</u>.** Con Edison already has a well-functioning mass-market (residential and small business customers) DLC program. A number of utilities the size of Con Edison have over 80,000 customer sites participating in their DLC program. This expansion alone would essentially meet the potential gap in the residential sector.

    a. For cost-effectiveness, an ongoing analysis of DLC technologies should be conducted as thermostat technologies and information displays are rapidly evolving.

    b. As AMI is rolled out, move DLC customers over to the AMI system, which could reduce the costs of two-way communication.

    c. Assess whether it is appropriate to provide additional services to customers through in-home energy displays. At the customer's discretion, these technologies can display information provided by Con Edison or a third party on weather, traffic, and other topics, including curtailment requests or time-of-use prices.

    d. To achieve increased participation, the one-time participation incentive might be increased. Many programs offer monthly or seasonal incentives, which quickly become the dominant program cost in a well-subscribed program. With a higher one-time sign-up incentive, Con Edison may be able to significantly increase participation without necessarily increasing long-term, recurring costs.

    e. Provide a participation option for households with room AC units, as technology allows. At present, it is either difficult technically or too expensive to justify placing load control switches into room AC units. However, if technology matures to the point that relay switches can be built into new units and be controlled by a home-area-network communications protocol, this technology could help reach Con Edison's untapped market of nearly six million room AC units.

3. **<u>AUTO-DR TECHNOLOGY ASSISTANCE FOR DLRP PARTICIPANTS THAT AUTOMATES LOAD CURTAILMENTS IN C&I BUILDINGS</u>**. This is not as much of a new program as it is a technology concept that would increase the ease with which customers can achieve load sheds, thereby increasing customer retention and reliability of load reductions. Elements of this auto-DR concept include:

    a. Technical and/or financial assistance to install communications and automation systems.

    b. A goal of providing 10 minute load reductions as part of the DLRP program.

    c. Target market: Office buildings, large retail, and other facilities that typically utilize building automation systems.

    d. Benefits:

        i. Allows "passive" response by customers increases response reliability.

        ii. Provides quick (10-minute) response that can better allow Con Edison to respond to distribution system contingencies.

4. **<u>CLEAN DISTRIBUTED GENERATION INITIATIVE FOR RELIABILITY AND DEMAND RESPONSE</u>**. The goal of this effort would be to increase the amount of available customer-sited emergency generation that can be used for demand response. The initiative would have two components:

    a. Provide incentives to cover customer costs of meeting the DEC permitting requirements that would allow existing emergency generation to operate as demand response. This might include some incentives to cover the costs of the permitting process itself, and some incentives to reduce the costs of emissions control equipment that would have to be installed. In exchange, customers would have to agree to a long-term contract to offer the unit as a demand response resource. The magnitude of incentives would need careful study to balance out the benefits and costs they would provide to expanded emergency generation in DR programs.

b. Promote development of new grid-synchronized customer-sited generation for demand response in exchange for a long-term agreement to offer the unit as a demand response resource. Con Edison could pursue one or both of the following options:

   i. Customer-owned generation where Con Edison facilitates permitting and equipment specification, and may pay for fuel, maintenance, and testing.

   ii. Con Edison-owned generation sited at customer facilities.

Well-designed C&I and residential programs modeled after the four DR programs/concepts described above can be expected to allow for attainment of the medium callable load achievable potential scenario of nearly 1,400 MW by 2017. If an addition were to be made to this portfolio, it is recommended that Con Edison include a pricing program such as an RTP program variant or a TOU-CPP program. These programs could be designed for either C&I customers or residential customers and might allow customers that are not currently suitable for participating in existing DR programs to benefit from a Con Edison DR program that allows them to better manage their energy bills. These programs would be in addition to Con Edison's Mandatory Hourly Pricing and the NYISO's Day-Ahead Demand Reduction Program, and could be made available to residential and smaller commercial customers.

Reductions due to a called critical peak price event are often attained by the same actions used to achieve load reductions in existing DR programs, and an RTP variant might provide the widest opportunity for customers to actively participate in achieving load reductions and bill reductions outside of participating in a DR program. A day-ahead pricing program is offered to residential customers by ComEd and by Ameren Utilities in Illinois. RTP programs have been more common in large customer segments, and variants used by utilities in the Southern Company system (two-part RTP tariffs) or by Niagara-Mohawk for large customers may provide a design platform for Con Edison, if RTP is considered to be an acceptable option by regulators and customers.